Chapter 5

Economics of WECs

Ronan Costello and Arthur Pecher

5.1 Introduction

In wave energy, perhaps more so than any other industry, the economics of product development and product ownership are not separate from the product engineering and design. This is the case because, despite high potential of untapped energy resource and the constant attention of academic research and innovative companies and inventors, as yet no one has verifiably achieved a minimum viable product in a wave energy conversion system.

If a minimum viable product had been achieved by now then our task would be simpler than it is. Evolutionary improvement due to incremental developments by many individual subject experts would naturally follow any viable product. Revolutionary leaps forward would also be easier to finance in the knowledge of an already viable market. However, not for the want of trying, this is not currently the status of wave energy research, and therefore a new more holistic approach is needed.

Wave energy conversion systems are relatively complex systems and product development is necessarily multidisciplinary. The evidence of wave energy development experience so far is that excellence in each component discipline is a necessary but not sufficient condition for development of a successful product. In other words, it is possible that a programme that achieves excellence in each individual discipline might still not achieve a viable product. A more holistic approach that focuses on the big picture economics is needed.

R. Costello (✉)

Wave Venture Ltd., Unit 6, Penstraze Business Centre, Truro, TR4 8PN, UK
e-mail: ronan@wave-venture.com

A. Pecher

Department of Civil Engineering, Aalborg University,
Thomas Manns Vej 23, 9220 Aalborg Ø, Denmark
e-mail: apecher@gmail.com

The discipline of Systems Engineering provides a suitable framework for the holistic approach that might allow progress towards a viable wave energy conversion system. A definition of systems engineering is also an excellent introduction to the role of economic analysis in wave energy research and development:

“the Systems Engineering process aims to assure the adequacy and completeness of the system for the customers’ requirements while also balancing these objectives with available resources and the schedule of the system development programme.”

Economic analysis is invoked twice in this definition, first in the customers’ requirements which will logically include a requirement for a profitable electricity generation system, and second in the reference to available resources of the system development programme. Allocation of these scarce resources to alternative designs and alternative research programmes should be based on economic analysis.

This chapter introduces the methods of economic analysis that are relevant to wave energy in the hope that they will be applied by the technology development teams to optimise the next generation of wave energy converters and deliver a minimum viable product in a wave energy conversion system.

5.2 Power Is Vanity—Energy Is Sanity

The product of an electricity generating business is energy, electrical energy to be precise. The reason to risk stating the obvious is the need to emphasise that for an electricity generating business all other things besides electrical energy are not generally saleable products. In particular, power and energy, while obviously related, are not the same thing. **Energy** is the ability to do work and is measured in kilowatt-hour, (kWh) or megawatt-hour, (MWh).¹ **Power** is the instantaneous rate of transfer of energy and is measured in kilowatt (kW) or megawatt (MW) (see Footnote 1). The units that are sold are units of energy not power. The annual revenue of an electricity generation business is directly proportional to its annual energy production and strictly not directly related to its power capacity.

Annual Energy Production is simply the total energy produced over a one year period.

Annual Average Power is the average power over one year

$$\text{Average Power [MW]} = \frac{\text{Energy Production [MWh]}}{\text{Time [hours]}} \quad (5.1)$$

$$\text{Annual Average Power [MW]} = \frac{\text{Annual Energy Production [MWh]}}{24 \times 365 [\text{h}]} \quad (5.2)$$

¹The standard International System of Units (SI) units for power and energy are the Watt (W) and Joule (J). A Joule (J) is equivalent to a Watt $\times$ Second (Ws). More conventional units used in utility scale electricity are kW = 1000 W and kWh = 3 600 000 Ws.

Rated Power Capacity is the maximum power that can be generated over a sustained timeframe, say one or more hours, without damaging or overheating the equipment. Installed power capacity is, for most intents and purposes, the same as rated power capacity.

Capacity Factor of a generator is the ratio of its Average Power to its Rated Power Capacity

$$\begin{aligned} \text{Capacity Factor} &= \frac{\text{Annual Average Power}}{\text{Rated Power Capacity}} \\ &= \frac{\text{Annual Energy Production}}{24 \times 365 \times \text{Rated Capacity}} \end{aligned} \quad (5.3)$$

An important input to the economic calculations in the following sections is the annual energy productivity. Understanding the relationship between the rated capacity and the annual energy yield is important. The relationship can be written using the capacity factor

$$\begin{aligned} \text{Annual Energy Production} &= 24 \times 365 \times \text{Capacity Factor} \\ &\quad \times \text{Rated Power Capacity} \end{aligned} \quad (5.4)$$

It should be obvious from the preceding equation that rated power capacity alone is insufficient information to estimate the energy productivity (or revenue) of an electricity generating business, capacity factor is also needed. Power capacity alone is the figure that is invariably publicised in media reports and in company publicity. However, a rated power capacity is meaningless unless it is accompanied by a capacity factor because both measures are needed to calculate annual energy productivity—“Power is Vanity—Energy is Sanity”.

5.3 Economic Decision Making

This section will give a top down look at investment metrics without dwelling on the details of the inputs, later sections will discuss the wave energy specific details of the inputs (mainly costs, energy production and revenue) to these investment calculations. Discounted cash flow techniques are the state of the art in economic appraisal and analysis of investments. Several economic decision metrics use discounted cash flow including Net Present Value (NPV) and Levelised Cost of Energy (LCoE). NPV is the most universally applied measure of investability across all sectors of investment and LCoE is a widely used measure in electricity generation investment. These are discussed in the following sections along with a number of other relevant measures of investability.

Often companies or investors do not chose to invest on the basis of one criterion, but will evaluate the project using two or more criteria. Ranking of alternatives has to be based on a single metric, usually NPV, but additional metrics may be used as

criteria for filtering projects that do not meet certain requirements. As a result it may be necessary to evaluate more than one of the measures presented in the following sections.

5.3.1 Cash Flow Terminology

Capital Expenditure (CapEx) is the total initial costs of setting up a project. In wave energy this includes; project planning and purchasing, transporting, installing and commissioning WEC's in a wave farm. Sometimes project planning and financing is called development expenditure and is separated from CapEx as DevEx but in the equations later in this chapter DevEx is treated as being included in CapEx.

Operational Expenditure (OpEx) is the ongoing annual cost of owning and operating a project, including all costs and payments except Taxes.

Decommissioning (Dec) is the costs of uninstalling and removing equipment after the useful life of the wave farm has been expended.

Revenue is the product of units delivered and sale price

$$Revenue = Annual\ Energy\ Production \times Power\ Purchase\ Price \quad (5.5)$$

Operating Profit is the revenue less the OpEx

$$Operating\ Profit = Revenue - OpEx \quad (5.6)$$

Tax on profits less allowable deductions is due to be paid to government. Tax is a cost and must be included in the cash flow analysis. Depreciation, or capital allowance, is usually an important allowable tax deduction, especially so in wave energy since the cost of equipment is so important. In some countries tax credits (production tax credits, installation tax credits) are an important strategic incentive mechanism.

$$Tax = Tax\ Rate \times (Revenue - OpEx - Tax\ Deductions) - Tax\ Credits \quad (5.7)$$

Depreciation is not a cash flow but must be considered in detailed cash flow analysis because depreciation (or related concepts such as capital allowances) is usually an allowable tax deduction and so even though it is not a cash flow in itself depreciation can affect taxation which, unfortunately, is very much a real cash flow.

Cash Flow is the actual cash flow generated by the operations. (Some handbooks refer to this as Net Operating Profit Less Adjusted Taxes or NOPLAT)

$$Cash\ Flow = Revenue - OpEx - Tax \quad (5.8)$$

Free Cash Flow (FCF) is the Cash Flow less the CapEx, it is a measure of the cash available in any time interval in the project lifetime.

$$FCF = \text{Cash Flow} - \text{CapEx} \quad (5.9)$$

Conventional Cash Flow is a common pattern of cash flows in a project. In a conventional cash flow the FCF will be strongly negative in the early years of a project due to the timing of CapEx, in later years as the project progresses the CapEx ends, the revenue is more significant and the FCF goes positive.

5.3.2 Time Value of Money (and Energy)

The expectation of earning interest on money deposited in the bank is commonplace. Another way of expressing this expectation is to say that the future value of the deposit will be greater than its present value. It is also normal to expect that this difference in value increases with the length of time that the investor has to wait for their returns. This relationship between future value (*FV*) and present value (*PV*) can be represented by the compound interest formula

$$FV = PV \times (1 + i)^n \quad (5.10)$$

where *i* is the interest rate and *n* is the number of compounding periods, (the compounding period is often one year). Figure 5.1 shows the increasing path from present value to future value, if amount *X* is put on deposit its future value after twenty years is *Y*.

Fig. 5.1 Compound interest on deposit *X* at 5 % interest yields amount *Y* after 20 years. Or equivalently, if a future payment of *Y* is expected 20 years from now, it is equivalent to a payment of *X* now since *X* could be put on deposit now to get the same eventual payment

Since future value is greater than present value it follows that present value is less than future value, or in other words the present value of a future payment is less than the amount of the payment. So Fig. 5.1 can also represent that the future payment Y is equivalent to a payment X at the present time. The process of calculating the present value of future payments can be represented by the formula

$$PV = \frac{FV}{(1+d)^n} \quad (5.11)$$

where d is the discount rate. In the rest of the chapter we will use the notation $PV(X)$ to mean the present value of a future cash flow X .

$$PV(X) = \frac{X}{(1+d)^n} \quad (5.12)$$

The process of determining future value from the present value is called *compounding* and the opposite process of determining present value from the future value is called *discounting*.

In the formulas presented above the similarity between interest rates and discount rates is clear but in practice the terms are not interchangeable. As is common experience, interest rates generally apply to bank products such as savings, loans and mortgages. In most countries an official base rate of interest is set by a central bank. Discount rates on the other hand are used in assessing investments, especially investments in infrastructure projects. The central bank does not set a standard discount rate, each investor must choose an appropriate discount rate for each type of project. Discount rates commonly range from a similar level to interest rates up to significantly higher than interest rates.

Interest and discount rates are both intended to compensate an investor for the time waiting for the future payment and for the risk that the payment might not occur. In the case of a bank deposit or a government bond the risk of not receiving your money with interest is extremely low so the interest rate almost wholly represents compensation to the investor/depositor for the period of time that they must wait for their money to be repaid. In the case of future cash flows within a project the risk varies widely depending on the type of the project and the appropriate discount rate varies accordingly.

As implied by the title of this section the principles of discounting can be applied to productivity, in our case energy, as well as money. An implicit assumption underlying the application of discounting to productivity is that the cost per unit is constant.

5.3.3 *Economic Metrics*

Possible decision making metrics for use in wave energy projects are listed in Table 5.1. These are listed *approximately* in order of increasing sophistication. The first sub-group relate to energy generating projects are all measures of energy

Table 5.1 Selected economic metrics for wave energy technologies and wave energy projects

	Yield included	CapEx included	OpEx included	Revenue included	Time value of money	Relative/absolute	Defined for project Type	Notes
<i>A. Productivity:</i>								
Annual energy production (AEP)	Y	N	N	N	N	A	Energy	Limited applicability
Capture width	Y	N	N	N	N	A	Wave	Limited applicability
Capture width ratio	Y	S	N	N	N	R	Wave	Limited applicability
<i>B. Cost of energy:</i>								
AEP per unit displacement	Y	S	N	N	N	R	Wave	Limited applicability
AEP per unit surface AREA	Y	S	N	N	N	R	Wave	Limited applicability
AEP per unit CapEx	Y	S	N	N	N	R	Energy	Suitable for technology optimisation in early stage R&D
Levelised Cost of Energy (LCoE)	Y	Y	Y	S	Y	R	Energy	Recommended for choosing between energy projects and for technology optimisation in R&D. Best option if power purchase price is unknown
<i>C. Investability:</i>								
Payback period (PP)	Y	Y	Y	Y	N	R	All	Lower importance than NPV
Discounted payback period (DPP)	Y	Y	Y	Y	Y	R	All	Lower importance than NPV
Internal rate of return (IRR)	Y	Y	Y	Y	Y	A	All	Widely used and acceptable for all choices
Profitability index (PI)	Y	Y	Y	Y	Y	R	All	Recommended as complimentary to NPV
Net present value (NPV)	Y	Y	Y	Y	Y	A	All	Recommended for all choices

Approximately in order of increasing sophistication. *S* surrogate included in metric. *R* Relative measure. *A* Absolute measure

productivity. In this first group “capture width” and “capture width ratio” are wave energy specific and have some additional limitations; they are usually calculated for a single device rather than a wave farm and are usually calculated for a single sea-state or regular wave rather than annual or multi-annual wave data. The difficulty with all measures in this first group is that they ignore both the cost and revenue components of a wave energy project and, for this reason, are not reliable decision metrics when taken alone. In some cases these metrics are intermediate results that are in any case needed to calculate the more advanced metrics and in other cases are trivial to calculate so should always be available to the analysis for comparison.

The second sub-group in Table 5.1 attempts to address this deficiency in the first group by including costs or surrogates for costs such as cubic displacement or surface area of the machinery. These surrogates are reasonable since the size of the equipment is an important driver of the capital cost of a wave farm, but metrics that use surrogates for actual costs are still not reliable decision metrics when used on their own. Cost of Energy and Levelised Cost of Energy (LCoE) include all cost data and are the most reliable metrics in this group. **Levelised Cost of Energy (LCoE)** is a cost of energy calculation that takes into account the time value of money. For energy generating projects LCoE is a valid decision making metric in its own right, and significant effort by the Carbon Trust, MARINET, NREL, IEA, and many others has been expended on defining procedures for calculating the LCoE for renewable energy projects. The third sub group in Table 5.1 are universal investment metrics that allow investment in wave energy to be compared to investment in any alternative project.

The remainder of this subsection presents a summary of concepts selected from Table 5.1.

AEP per unit CapEx, AEP per unit displacement and AEP per unit surface area

Annual Energy Production (AEP) per unit CapEx is a measure of economic performance that is limited principally by the fact that it neglects operating costs. AEP per unit displacement and AEP per unit surface area are similar measures that also neglect OpEx but, in addition, use displacement and surface area respectively as surrogates for CapEx. For some very large devices these surrogates may be well correlated with the device structural cost, and so are most relevant where the structural cost strongly outweighs the cost of other equipment such as PTO equipment. This argument is weakened, however, by the fact that the device structural cost sometimes makes up less (sometimes significantly less) than 50 % of the total CapEx and the CapEx due to balance of system might be much less well correlated with these surrogates than the structural cost. These metrics may be suitable for economic analysis very early in the R&D process, when insufficient information is available for more complete analysis, for example in choosing between design alternatives or concept alternatives. However, these are not sufficiently complete to be used for analysis to support project development decisions or device purchasing decisions.

Levelised Cost of Energy (LCoE) is a cost of energy calculation that takes into account the time value of money. For many analysts this is the most important

measure of an energy investment. Many organisations have recommended specific methodologies and formulations for calculating the LCoE with various levels of sophistication that are appropriate for different applications. In general terms the LCoE is defined as

$$LCoE = \frac{\text{Present Value of total costs over project lifetime}}{\text{Present Value of all energy over project lifetime}} \quad (5.13)$$

following this definition the equation for LCoE is

$$LCoE = \frac{\sum_{y=0}^Y PV(CapEx_y) + \sum_{y=0}^Y PV(OpEx_y) + \sum_{y=0}^Y PV(Dec_y)}{\sum_{y=0}^Y PV(AEP_y)} \quad (5.14)$$

Equation (5.14) is similar to that given by the Carbon Trust's Marine Energy Challenge [1]. Renewable energy projects usually have conventional cash flow profiles, this means that the CapEx is always at the start and the revenue and OpEx are spread throughout the project. However in large wave farms it may not be possible to concentrate all the CapEx in a single year, or, for that matter, all the decommissioning in a single year either. Equation (5.14) is general in this regard; it does not make any assumptions about limiting any component of the cash flow to any particular time period. The equation for LCoE may be simplified if we give up some of this generality. If the costs of decommissioning are neglected and the CapEx is assumed to occur in the zero-th year then the equation becomes

$$LCoE = \frac{CapEx + \sum_{y=0}^Y PV(OpEx_y)}{\sum_{y=0}^Y PV(AEP_y)} \quad (5.15)$$

A difficulty with LCoE (and all the previous metrics) is that it is only defined for energy projects, this is because LCoE uses annual energy productivity as a surrogate for revenue. LCoE actually ignores the market value of the energy product. Therefore it is only valid in comparisons between power generation options under comparable economic conditions and it should not be used to compare energy generating projects that would attract very different power purchase prices or tax rates, for example projects in different countries. A further limitation of LCoE is that it is not useful in comparing an investment in wave energy with any other investment opportunity outside the power generation sphere. In practice some investors may be specialised in energy, renewable energy or even in one particular type of renewable energy and are interested in choosing between power generating projects in a well understood market and regulatory regime, for these investors LCoE is a suitable choice of financial metric.

Case Study: SI-Ocean LCoE Methodology The Strategic Initiative for Ocean Energy (SI OCEAN) aims to provide a co-ordinated voice for the ocean energy industry in Europe and to deliver practical recommendations to remove barriers to market penetration. The following equation for LCoE is recommended in Ref. [37].

$$LCoE = \frac{SCI + SLD}{87.6 \times LF} \times \frac{d(1+d)^n}{(1+d)^n - 1} + \frac{OpEx}{87.6 \times LF}$$

where:

LCoE Levelised cost of energy (€/MWh)

SCI Specific Capital Investment (€/kW)

SLD Specific Levelised decommissioning cost (€/kW)

$$\frac{SDC}{(1+d)^n}$$

SDC Specific decommissioning cost at end of lifetime (€/kW)

LF Capacity Factor of wave farm [–]

d Discount rate (%)

n Operational life (years)

OpEx Levelised O&M cost (€/kW/yr)

Source SI Ocean project, see Ref. [37].

Case Study: NREL onshore wind LCoE methodology The National Renewable Energy Lab in the US suggest calculating LCoE using a simplified formula designed to allow assessment of the true economic impacts of technical changes. The ICC, AOE and AEP input (defined below) characterise the technological performance (costs and output) the FCR input characterises the cost of financing.

$$LCoE = \frac{\text{Present Value of total costs over project lifetime (\$)}}{\text{Present Value of all energy over project lifetime (MWh)}}$$

$$LCoE = \frac{(FCR \times ICC) + AOE}{AEP_{net}}$$

where:

LCoE Levelised cost of energy (\$/MWh)

FCR Fixed charge rate

$$\frac{d(1+d)^n}{(1+d)^n - 1} \times \frac{1 - (T \times PV_{dep})}{1 - T}$$

ICC Installed capital cost (\$/kW)

AOE Annual operating expenses (\$/kW/yr)

$$LLC + O\&M(1 - T) + LRC$$

d	Discount rate (%)
n	Operational life (years)
T	Effective tax rate (%)
PV_{dep}	Present value of depreciation (%)
CF_{net}	Net capacity factor (%)
LLC	Land lease cost (\$/kW/yr)
$O\&M$	Levelised O&M cost (\$/kW/yr)
LRC	Levelised replacement cost (\$/kW/yr)
AEP_{net}	Annual Energy Production, net of losses and allowance for availability kWh/kW

Source NREL report, see Ref. [38].

Net Present Value (NPV) is the sum of the present values of the Free Cash Flow in all years of a project. NPV inherently accounts for the time value of money. The NPV tells us whether or not the present value of the operating profit is greater than the present value of the investment. The NPV is calculated from

$$NPV = \sum_{y=1}^Y \frac{FCF_y}{(1+d)^y} = \sum_{y=0}^Y PV(FCF_y) \quad (5.16)$$

where d is the discount rate, FCF_y is the free cash flow in year y and Y is the lifetime of the project. The condition for investment is that the NPV should be strictly positive; projects with negative NPV are not investible while projects with positive NPV are investible. NPV is an absolute measure of performance, this means it gives the value of the investment rather than a ratio. See the Profitability Index later in this section for a relative measure that is complementary to NPV. The clarity around the decision making is one of the main advantages of NPV, however, it is partly illusory since the discount rate can be difficult to choose. See the section on weighted average cost of capital for methods used to set the discount rate. NPV is currently the most widely used and most reliable investment metric because choosing the projects with the highest NPV will maximise value which is, in principle, what best serves company shareholders.

Internal Rate of Return (IRR) is the discount rate that gives an NPV of exactly zero. It satisfies the following equation

$$0 = \sum_{y=1}^Y \frac{FCF_y}{(1+IRR)^y} \quad (5.17)$$

The equation for IRR is implicit, it is most easily solved using a computer root finding algorithm, for example using the Newton-Raphson method. The equation for IRR is not guaranteed to have a single unique solution. In certain circumstances there may be no solution or there may be multiple solutions. Usually for projects with conventional cash flow there is either a single real solution or no solution. For

a project with conventional cash flow no solution to the IRR equation may be interpreted as indicating an infeasible project. The uncertainty about the existence or uniqueness of the IRR makes it less suitable for use in automatic optimisation than LCoE or NPV.

5.3.4 *Effect of Depreciation on Discounting*

Depreciation is not a cash flow but must be considered in detailed discounted cash flow analysis because depreciation, or related capital allowances, is usually tax deductible. In practice it is advantageous to apply the highest rate of depreciation allowable under the applicable tax laws so that the benefits of the allowance are accumulated before they are eroded by inflation. For further information see Ref. [14].

5.3.5 *Effect of Inflation on Discounting*

The treatment of inflation can potentially make a difference to discounting calculations such as NPV, IRR, PI, DPP and LCoE. In a simplified assessment where tax allowances or even tax as a whole are neglected then inflation will make no difference but in a more detailed assessment care is required. A key concept related to inflation is constant and current euro (pound or dollar). Cash flow can be expressed in constant euro cash flow or current euro cash flow, $\overline{CF}_n$ and CF_n respectively. Current euro cash flow refers to the actual cash flow in year n , while the constant euro cash flow is the cash flow with the effects of inflation removed. The constant euro cash flow can be calculated from

$$\overline{CF}_n = \frac{CF_n}{(1+f)^n} \quad (5.18)$$

where f is the rate of inflation, assumed constant over n years.

When making a discounted cash flow assessment inflation can be included, current euro cash flow and nominal discount rate used, or inflation can be excluded, constant euro cash flow and real discount rate used. To calculate the real discount rate from the nominal and vice versa use

$$d_n = d_r + f + d_r f \quad (5.19)$$

when the terms d_r and f are small so that $d_r f \ll d_r$ and $d_r f \ll f$ then the equation may be approximated by

$$d_n \approx d_r + f \quad (5.20)$$

In the case without taxation NPV and other metrics are the same with and without inflation if the discount rate is adjusted to a real discount rate for the inflated cash flows. In the case with taxation the operating profit will be inflated along with all cash flows but the depreciation will not so the estimate of tax paid in current dollars will be higher when inflation is taken into account, accordingly the NPV will be lower when inflation is included. It is recommended to include inflation in assessments of well understood technologies for real projects and deployments. However a simplified approach is often justified at earlier stages. For example, in making a design choice in R&D between two alternatives it is unlikely that enough information will be available or well enough understood to allow the effect of inflation to have a reliable effect on the decision so the assessment should be simplified. For further information see Ref. [14].

5.3.6 Setting the Discount Rate

There are several methods for systematically choosing the discount rate. These include the weighted average cost of capital (WACC) and the risk adjusted discount rate (RADR). Companies may finance projects with a combination of equity, raised by selling shares to shareholders, and debt, borrowed from lenders. The Weighted Average Cost of Capital (WACC) also called the financial cost of capital is the weighted average of the cost of equity and the cost of debt. The equation for the WACC is

$$WACC = \left(\frac{E}{E+D} \right) i_e + \left(\frac{D}{E+D} \right) i_{dt} \quad (5.21)$$

where E is the equity amount, D is the debt amount (for a special purpose company with a single project $E+D$ is approximately equal to the total CapEx of the project), i_{dt} is the tax adjusted interest rate and i_e is the cost of equity. Equation (5.21) is sometimes modified for more than one type of equity each with a potentially different cost of equity. The tax adjusted interest rate is calculated from

$$i_{dt} = i(1 - t) \quad (5.22)$$

where i is the interest rate and t is the tax rate. For an established company the cost of capital can be established by comparing historical returns to a market average using the Capital Asset Pricing Model (CAPM). Alternatively, the cost of equity may be calculated from a theory known as the dividend growth model

$$i_e = \frac{V_1}{P} + g \quad (5.23)$$

where V_1 is the expected dividend in the first year, P is the value of the company and g is the growth rate of the dividend.

Debt is generally cheaper than equity so a company will usually have a high debt to equity ratio, perhaps 4:1. However loan repayments are a fixed cost that makes a company vulnerable to interruptions in revenue so debt levels very much above this, called high leverage or gearing, may not be sound business practice. The WACC may be used directly in the discounted cash-flow calculations as the discount rate. Alternatively the Risk Adjusted Discount Rate (RADR) is

$$RADR = WACC + Project Risk Premium \quad (5.24)$$

A survey of companies shows that most companies use the WACC as the discount rate and that most companies do not adjust the WACC for project risk i.e. the WACC is preferred over the RADR [14]. However, in a new industry such as wave energy, even though the WACC is likely to be higher than for other projects using more proven technology, a project risk premium is almost certainly appropriate.

The Carbon Trust's Marine Energy Challenge study [1] used discount rates in the range from 15 % for the first commercial wave energy devices to 8 % for wave energy when it is an established technology. The WaveNet European Commission Thematic Network [2] recommends a discount rate of 10 %, this is arrived at through use of the CAPM methodology. For comparison NREL recommendations for early (1995) onshore wind, in the absence of investment specific data, were rates of 3 % for government, 10 % for industry and 5 % for utilities [18].

As a closing point on selection of discount rate it is interesting to reflect on the implicit discount rate that individuals and households use when making non-business purchasing decisions. In general, consumers appear to apply much higher discount rates in their own lives than investors apply in infrastructure projects. Research by Hausman [8] and further research by Houston [9] found that households intuitively applied a discount rate of about 20 % when purchasing energy saving appliances. So it appears that private individuals can be more demanding investors than companies are.

5.3.7 *Economic Decision Making—Which Metric to Use?*

There are several types of decisions that should take economic assessments into consideration; these are not all in the deployment of large wave farms, some come much earlier in product development and R&D phase of a wave energy conversion technology. Selection of a metric to support decision making depends on the nature of the decision to be made and on the information available. The types of decisions that might be made with input from economic metrics include:

- Product development:
 - R&D management; allocate resources to competing sub-projects—which one will lead to a more competitive technology given available resources and timescale
 - Design decisions; choose between alternative design concepts- which one will lead to a more competitive technology with available resources and timescale
- Investment in WEC technology company:
 - Is the technology developed by the company competitive? The competitiveness of the technology is an important, if not the most important, component of the value of the company.
- Investment in wave-farm:
 - Is a particular wave-farm an attractive investment; on its own merits? Compared to other wave energy? Compared to other renewable energy? Compared to other electricity generation? Compared to any other investment?
 - Given a particular location is technology A or technology B more attractive?
 - Given a particular technology is location X or location Y more attractive? (Differences between location X and Y might not only be physical but may also be financial or political e.g. different energy prices, tax rates, insurance costs, permitting effort etc.)

Of key importance in determining which metric to use is the availability of the required input data. Critical, in this regard, is knowledge of the power purchase price. If the power purchase price is known then all of the metrics introduced in the previous sections are potentially available to the decision making process. If the power purchase price is not known then the revenue cannot be calculated and the LCoE is the most sophisticated economic metric that is available to decision makers.

In R&D management, especially in early stages of R&D, the decision is likely to be linked to a generic type of deployment location rather than a specific location with a known wave resource. It is also likely that the analysis should not be country specific but applicable to a wide range of markets. As a result the energy yield and the revenue are unknown or are subject to increased uncertainty and a cash flow based assessment is not appropriate, in this case a simplified LCoE assessment is recommended. It should be noted that in R&D and product development the immediate entrepreneurial goal might not be discovery of the technical configuration that will ultimately allow maximisation of NPV or IRR, it may instead be a minimum viable product.

In valuation of a company that produces wave energy conversion technology the competitiveness of the WEC technology is of critical importance. Similarly to the R&D decision making an assessment of a technology for company valuation should not be location specific or jurisdiction specific. It follows that LCoE is again an

appropriate metric. Alternatively, the NPV could be calculated for a representative range of ocean locations and financial and regulatory environments.

In planning of large scale wave farm deployments the investment required is tens of millions of pounds or euro upwards. To attract this level of investment the project return must be attractive when compared to other investment opportunities that are available. If very large wave energy installations are to be privately financed then this will involve pension funds and other very large investment funds and these investors will compare wave energy to other investment opportunities outside the power generation sector. In this case NPV or IRR should be preferred over LCoE.

In principle the objective in investment decision making is maximisation of shareholder value. Crundwell (2008) notes that, maximising NPV maximises shareholder value while maximising PI maximises capital efficiency. If money and other resources were no object then it would be logical for all viable projects ($NPV > 0$, $PI > 1$) to proceed and in this case project assessment would be on project by project basis. However, in the real world resources and capital are constrained so making an investment decision is always done on the basis of ranking and choosing between alternatives. Even if only one project is proposed then in principle it should be compared to putting the investment amount on deposit.

In summary, LCoE is more likely to be independent of the financial/legal/taxation environment than NPV and conversely NPV is better able to reflect the effects of financial/legal/taxation issues than LCoE. If an assessment is technology focused then LCoE may be a better option than NPV. If the assessment is an investment focused on a specific deployment in a specific territory/location with known tariff/subsidy/tax/insurance conditions then NPV is a better choice than LCoE.

As final note, readers should be aware that while maximising NPV might maximise shareholder value, it is also true that NPV ignores external benefits (and potentially external costs) such as benefits of decarbonising electricity supply, reducing dependence on imported energy and other wider societal benefits such as providing employment [6]. An example of the need to take these wider benefits into account is the need for strategic government support for pioneering projects that allow projects with low NPV to proceed and facilitate learning that will drive costs down so that a new industry gains a foothold and projects with higher NPV and ever lower support requirements may follow.

5.3.8 Expert Oversight and Independent Review

The Electric Power Research Institute (EPRI) [4] correctly identify that it is possible to get almost any desired answer by making different assumptions. Similarly Stallard et al. [26] state that headline figures (e.g. €/kW or €/kWh) are useless unless the inputs and assumptions employed are clearly stated. It is therefore vital for WEC development companies to regularly receive an independent critique of their own

projections of the cost of energy that their device might deliver. And for potential investors, customers and government sponsors to seek independent scrutiny of any estimates produced by a technology or project development company.

5.4 Economic Analysis in Technology R&D

Most energy utilisation is technologically intensive and all electrical energy generation and utilisation are technologically intensive. In the public consciousness energy and technology are often confused and the fact that energy and technology are not the same is often overlooked [22]. While energy is conserved, it is neither created nor destroyed. In contrast, the technology of energy conversion must be invented, researched, designed, manufactured, tested, refined etc. In other words research and development (R&D) is necessary. This section explores the importance of economic analysis in the innovation and R&D process.

Wave energy looks set to follow the industry structure of wind and solar PV energy, both have two intertwined businesses, one primarily concerned with energy and a second primarily concerned with technology.

- The *technology business* is concerned with the sale of energy conversion technology and the related activities of invention, research, development, design, demonstration and manufacture.
- The *energy business* is concerned with the sale of energy and the related activities of deploying, owning and operating the energy conversion technology and farm/facility.

(Each *business* is usually more than one company) Discussion of economics in renewable energy often focuses exclusively on the *energy business*, and economic analysis is usually focused on analysis to support project level go/no-go decisions. A tacit assumption underlying such discussion is that the energy conversion technology is available and mature. A second point that is ignored by focusing on the *energy business* is that R&D and other decision making within the *technology business* also needs to be supported by (very similar) economic analysis.

In wave energy some technologies have recently become available but are not yet mature. Wave energy economics must address the interlinked requirements of R&D in the technology business and project developments in the energy business. This link between the economics of these two businesses can be summarised as:

- Financing of R&D activities in the *technology business* relies on accurate and verifiable projections of attractive future project developments i.e. visibility of a future market for the technology.
- Project developments, and ultimate energy delivery, in the *energy business* rely on successful execution of product R&D and credible/verifiable analysis of technology performance.

5.5 Techno-Economic Assessment and Optimisation

The benefits of computer aided assessment of levelised cost of energy have long been recognised, for example the Carbon Trust and NREL both recommend Monte Carlo simulation as a tool for quantification of uncertainty in the LCoE. Farrell [7] and Dalton [13] separately demonstrate the use of Monte Carlo simulation in the economic assessment of wave energy projects.

Weber et al. [10] anticipates that techno-economic optimisation will form a crucial part of a successful performance before readiness product development. Effective implementations of integrated techno-economic optimisation have been demonstrated by [5, 16, 17] and this software is now becoming commercially available.

Figure 5.2 shows the structure of an integrated techno economic optimisation, courtesy of Wave Venture Ltd. The components of this particular integrated analysis are a physical model, an operational model, a cost model and a financial

Fig. 5.2 Schematic of the information flow in an integrated techno-economic optimisation. A techno-economic assessment follows the same structure but without the numerical optimisation step which closes the loop. FMEA is Failure Modes Effects Analysis. Courtesy of Wave Venture Ltd

model. Part of the strength on the approach is its amenability to combine with numerical optimisation.

The physical model simulates the hydrodynamic interaction of the wave environment and the wave energy converter along with the performance of the devices power take off and power conversion chain, a so called wave-to-wire model. The input to the physical model is the system design and output is a characterisation of power performance and other engineering quantities of interest.

The operational model simulates the logistics of wave farm installation, operation and maintenance and ultimately decommissioning. The inputs of the operational model are the power characterisation calculated in the physical model, environmental data necessary to calculate weather windows and the system energy productivity and a characterisation of system reliability in the form of a failure mode effects analysis (FMEA). The outputs are estimates of the energy productivity and the operational expenditure. The advantages of this approach are that the availability and the operational expenditure are calculated by the simulation based on testable inputs instead of assuming an arbitrary percentage availability and an arbitrary operational cost based on experience in other sectors which might not relate to wave energy.

The cost model is formed from a suitable structure as introduced in the next section and is linked to the system design parameters so as quantities change the capital cost can be automatically updated.

The economic model generates a simulated discounted cash flow analysis which can be used to calculate any of the economic metrics introduced earlier in this chapter and potentially many more. A key advantage of the approach is that the economic value of a system design can be assessed without any third party data, especially third party performance data.

5.6 WEC Cost-of-Energy Estimation Based on Offshore Wind Energy Farm Experience

5.6.1 Introduction

Estimating the LCoE for a WEC array requires a lot of detailed information, which often can only be obtained after having completed several similar projects. However, valuable information on many of these specific topics can also be obtained by looking at the LCoE breakdown of offshore wind energy farms, which is now done in this section.

The structure of this LCoE calculations is following the document: “Value breakdown for the offshore wind sector” prepared by BVG Associates for the Renewables Advisory Board of the UK government [1]. The cost breakdown is done for a whole wind energy farm, not only for the wind energy technology itself. This document presents the relative cost of all main categories that are present in a 90 MW offshore wind farm in less than 20 m of water depth and a lifetime of 20 years, based on information provided by key industry players. These (sub-) categories and related

cost, can be used to guide the cost of energy calculation for a similar WEC farm and help to estimate some of the sub-categories, which are too difficult/impossible to estimate with a reasonable accuracy for a WEC array at this point of time.

In addition, a presentation by Siemens Wind Power in late 2014 covering their actual LCoE and a related document by the International Renewable Energy Agency that covers the cost of renewable energy have been used [2, 14] to indicate reasonable level of costs of certain parameters.

5.6.2 Definition of the Categories

The definition of the (sub-) categories is taken directly from the value breakdown document (not everything has been reproduced here), and are thereby directly linked to an offshore wind energy project. The categories are as follow:

Development and consenting includes the multifaceted process of taking a wind farm from inception through to the point of financial close or commitment to build, depending on the contracting model, including Environmental Impact Assessment, planning, Front End Engineering Design studies and contract negotiation.

Turbine excluding tower includes supply of all components (including turbine transformers) upwards from (but excluding) the transition piece/foundation and in this case also excluding the tower structure. This includes delivery to a port (which may not be the port used for storage and pre-assembly of components before transfer to the wind farm site).

Balance of plant (BoP) includes detailed infrastructure design and supply of all parts of the wind farm except turbines, including tower, foundations, buildings, electrical systems between turbine and the onshore demarcation point between the farm and grid. Conventionally, the tower is seen as part of the scope of supply of the turbine. In this case, due to the synergies of manufacture of the tower and typical steel foundation, it has been incorporated here.

Installation and commissioning includes installation of turbines and balance of plant on site and commissioning of these to a fully operational state, up to point of issue of any take over certificate.

Operation and maintenance (O&M) starts from take-over, on completion of building and commissioning of all or part of a farm. It includes servicing of turbines and other parts including electrical grid connection. Whilst it does include insurance for the replacement of faulty/broken components or defective work it does not include coverage of this by warranties.

In addition, the following definitions are used:

Capital Expenditure (CapEx) includes all one-time expenditure associated with farm development, deployment and commissioning up to the point of issue of a takeover certificate.

Operating Expenditure (OpEx) includes all expenditure occurring from immediately after point of takeover, whether one-time or recurring, related to the wind farm, measured on an annual basis. Excluded are expenses inherent to the

operation of the operators business but not directly related to the operation and management of the wind farm.

Grid connection includes the dedicated cables and other costs associated with connecting the farm to the National Grid, including any isolators and switchgear under the control of the onshore network operator.

Note that Project management, insurance and other costs relevant to many activities across the life of the farm have been included in these activities, rather than been separated out.

5.6.3 Wind Energy Project Case

5.6.3.1 Introduction

Some reference values need to be chosen, such as the kW price and the capacity factor of an offshore 3.6 MW wind turbine, as the relative cost of the sub-categories is given. The corresponding values depend on many factors (e.g. environmental resource and others), which is also reflected in the huge variation in their values that can be found in related literature. In order to give an example, an extract of the weighted average CapEx cost per kW provided by IRENA is given in Fig. 5.3.

By considering different sources in literature, under which a recent presentation by Siemens Wind Power [2], a CapEx price per MW of 4.5 m€ was chosen at a capacity factor of 30 %, a lifetime of 20 years and a discount rate of 10 %.

Fig. 5.3 Weighted average total investment for commissioned and proposed offshore wind energy projects 2000–2020, Courtesy of IRENA [14]

A ratio between CapEx and discounted OpEx of 73 % against 27 % is given by Siemens for a 1000 MW project of 6 MW turbines at 30 m of water depth. They also state a current LCoE of 0.145 € per kWh (in 2010) as the baseline for such kind of project [2]. This is quite high (much higher than is found in general literature), as it is for such a large farm with such large turbines, which should bring the cost down. Their additional cost, most likely arises from the additional water depth, which will be attempted to be taken into consideration as well.

5.6.3.2 Categories Cost Breakdown

Table 5.2 presents a typical cost breakdown of offshore wind turbines. The costs are divided over the main different cost categories, which was done following [1].

Table 5.2 Overview of the cost breakdown of a 3.6 MW offshore wind turbine [1]

Case specifications:

Turbine capacity [MW]	3.6
Total installed capacity [MW]	90
Amount of turbines	25.0
CAPEX/MW [m€/MW]	4.5
CAPEX/turbine [m€/turbine]	16
yearly OPEX/MW [k€/MW/y]	200
yearly OPEX/turbine [k€/turbine/y]	720
=> discounted OPEX [m€/MW]	1.7

lifetime of a windturbine:	20
Discount rate [%]:	10%
Capacity factor [%]	30%

CapEx breakdown/ Wind turbine

Category	Category cost	
	[%]	[k€]
Development & Consent	4.0	648
Turbine - WEC	32.6	5281
Balance of plant	36.6	5929
Installation & Commissioning	25.7	4163
Total	98.9	16022

Annual OpEx cost breakdown / Wind turbine

Category	Category cost	
	[%]	[k€]
Operation - remote	7.5	54
Operation - local	7.5	54
Maintenance - remote	11.6	84
Maintenance - local	26.6	192
Port activities - remote	8.0	58
Port activities - local	23	166
License fees	3.8	27
Other costs	12.0	86
Total	100.0	720

Development & Consent	[%]	[k€]
Environmental survey	0.3	49
Sea bed survey - Geophysical	0.1	16
Sea bed survey - Geotechnical	0.5	81
MetMast	0.3	49
Development services - engineering	0.9	146
Development services - other	1.9	308
Total	4.0	648
Turbine	[%]	[k€]
Blades	7	1134
Hub assembly	3.6	583
Gearbox	9.2	1490
Electrical system	8.2	1328
Other systems	4.6	745
Total	32.6	5281
Balance of Plant	[%]	[k€]
Tower	6	972
Foundations	16	2592
Cables - Inter array	1.4	227
Cables - Export	4.1	664
Offshore Substations - electrical	5	810
Offshore Substations - other	1.4	227
Onshore electrical - electrical	2	324
Onshore electrical - other	0.7	113
Total	36.6	5929
Installation and commissioning	[%]	[k€]
Foundations	7	1134
Cables	9	1458
Turbines	9	1458
Offshore substations	0.7	113
Total	25.7	4163

The general development, infrastructure and commissioning cost of a wind turbine in a project, thereby excluding the technology itself, is in the range of 7,2 million Euros, corresponding to about 45 % of the CapEx. This includes the development and consent, the installation and commissioning and a part of the balance of plant category (excluding the tower and foundations of the BoP).

5.6.3.3 Levelized Cost of Energy Estimation

The CapEx and OpEx were obtained following some assumptions on their cost and on the capacity factor, which were based on different sources of available literature. This cost breakdown was done for an offshore wind farm at 20 m of water depth. It seems to be more relevant to compare both case at 30 m of water depth, which correspond to the case of Siemens, which is stating a LCoE of 0.145 €/kWh. Therefore, an additional cost of 50 % was added to the tower and foundation (and its installation), to take this additional depth into account, which is (off course very simplistic but) considered to be conservative (Table 5.3).

Table 5.3 LCoE estimation for an offshore wind turbine

Cost		20 m water depth		30 m water depth	
			Ratio		Ratio
CapEx	(k€)	16022	72 %	16022	65 %
50 % extra cost on tower and foundation (part + installation)				2349	10 %
Discounted OpEx	(k€)	6130	28 %	6130	25 %
Total project cost	(k€)	22152		24501	
<i>Revenue</i>					
Power	(kW)	3600		3600	
Capacity factor	(%)	30 %		30 %	
Annual energy production	(MWh)	9467		9467	
<i>Levelized cost of energy</i>					
LCoE	(€/kWh)	0.117		0.129	

For the wind energy case at a water depth of 30 m a LCoE of 0.129 €/kWh is calculated. This seems to be reasonable when looking at most literature, however appears to be approx. 12 % lower then what Siemens estimates (LCoE of 0.145 €/kWh) for a much larger wind farm (1000 MW against 90 MW) and with larger turbines (6 MW against 3.6 MW). An additional factor of 50 % on the tower and foundation was maybe not sufficient, or it might maybe also affect other sub-categories which were not updated correspondingly (Fig. 5.4).

Fig. 5.4 Illustration of the relative cost of the different sub-categories of an offshore wind turbine at 30 m of water depth

5.6.4 Wave Energy Case

5.6.4.1 Introduction

The same analysis can be done for a 90 MW WEC farm at 30 m water depth (or deeper). The same categories are maintained, with just some few adaptations into the sub-categories. The main adaptations, in order for it to fit the case of a floating WEC, are:

- The turbine category corresponds here to the WEC category. It aims at including the same scope, thereby excluding the mooring system.
- The mooring system is interpreted to correspond to the tower and foundation of the wind turbine and thereby put in the Balance of Plant category.

The resulting values relative to the WEC, have to come from a broad range of test and development efforts. The size and weight of the structure and sub components can be based on scaling, while the cost of materials and of components should be based on discussion with suppliers and quotations.

A cost breakdown of a 90 MW WEC array is made for two different sizes of WECs, 0.75 MW and 3.6 MW, based on the information of this offshore wind turbine case. The analysis aims to be generic and thereby no specific WEC technology is considered. The analysis assumes that the area required for a 90 MW array with types of WEC types is the same. General information regarding the cost of WECs can be found in e.g. [18].

5.6.4.2 Category: Development and Consent

The development and consent expenses of a wind energy farm are considered quite representative for a wave energy farm, as they both assess an offshore environment of somewhat the same specifications (water depth, project area, distance to shore and same objective to produce electricity). However, some of these expenses are to a certain extent dependent on the amount of WECs (how many detailed investigations need to be made e.g. on the soil) and on the technology (how detailed does some information need to be e.g. the seabed).

For a WEC array of 90 MW being deployed in about 30 m water depth, the overall survey costs are believed to be approximately the same, for large as well as for small WECs, as they will require approximately the same area, on the exception of the geotechnical sea bed survey. As this depends on the amount of systems to be installed (each one needs an analysis) and on the level of detail that is required (offshore wind requires much more detailed analysis). Therefore, the cost for small and large WECs have been reduced to 20 % relative to offshore wind value. All the other category costs have been divided amongst the amount of WECs that are required to make a 90 MW farm.

The development services cost are linked to the size of the project (same for all) and to some extent to the amount of systems to be installed (more cable routes, WEC positions and others to be analysed). Here, the same cost per large WEC as for wind turbines has been used, while for small WECs, the cost per WEC has been halved (Table 5.4).

Table 5.4 Overview of the development and consent costs (per unit) for a 90 MW farm of 25×3.6 MW WT and WECs and of 120×0.75 MW WECs

Category and sub-category	3.6 MW Wind (k€)	3.6 MW WEC (k€)	0.75 MW WEC (k€)
<i>Survey</i>			
Environmental survey	49	49	10.2
Sea bed survey-Geophysical	16	16	3.3
Sea bed survey-Geotechnical	81	20	20.0
MetMast	49	49	10.2
<i>Development services</i>			
Engineering	146	146	73.0
Other	308	308	154.0
Total cost	649	588	271

5.6.4.3 Category: Wave Energy Converter

This category corresponds to the main part of delivery by the wave energy developer, together with some few sub-categories in the Balance of Plant category, such as the mooring system. None of these values can thereby be taken from the offshore wind turbine case, as all of these are WEC technology dependant. The

Fig. 5.5 Generic high level WEC design breakdown [9]

overall turbine category cost for a 3.6 MW offshore wind turbine (WT) has been estimated to be 5281 kEuro, corresponding to 33 % of the overall CapEx.

It is suggested to use the same sub-categories as proposed by DNV, which can be seen as a generic platform for the establishment of generic failure mode and effects analysis (FMEA) for WECs [8, 9] (Fig. 5.5).

All these categories contain different sub-categories dependant on the technology. A possible overview of this is given in Table 5.5.

Table 5.5 Overview of the possible cost breakdown for WECs

Category and sub-category	Weight or amount	Unit	Price/unit (k€)	Sub-category (k€)	Category cost (k€)
<i>Reaction sub-system</i>					
steel (painted, welded,...)	X	ton	X	X	
Concrete	X	ton	X	X	
Ballast	X	ton	X	X	
Others and extras				X	
				sub-total:	X
<i>Hydrodynamic subsystem</i>					
Steel	X	ton	X	X	
Concrete	X	ton	X	X	
Ballast	X	ton	X	X	
Others and extras				X	
				sub-total:	X

(continued)

Table 5.5 (continued)

Category and sub-category	Weight or amount	Unit	Price/unit (k€)	Sub-category (k€)	Category cost (k€)
<i>PTO subsystem</i>					
PTO unit	X	#	X	X	
Generator(s)	X	#	X	X	
Power electronics	X	#	X	X	
Others and extras				X	
				sub-total:	X
<i>Instrumentation and control</i>					
Cooling system	X	#	X	X	
Others (insulation, drain, wiring, ...)	X	#	X	X	
PLC-SCADA	X	#	X	X	
Instrumentation and communication	X	#	X	X	
Others and extras				X	
				sub-total:	X
<i>R&D</i>					X
<i>Management</i>					X
<i>Contingency</i>					X
<i>Profit</i>					X
				Total cost/WEC:	X

5.6.4.4 Category: Balance of Plant

The Balance of Plant (BoP) includes detailed infrastructure design and supply of all parts of the farm except for the WEC, including, foundations, buildings, electrical systems between WEC and the onshore demarcation point between the farm and grid.

Some of the costs here are very specific to the technology (mooring and foundations) and are thereby left blank for the WECs (noted with an “X”), while others can directly be taken over. The same cost for all the sub-categories has been maintained as for offshore wind (the total cost has been divided by the amount of WECs), except for the substation category, where the cost for small WECs is estimated to be a third than that of large WECs (although sharing the same platform, still requires more cable connections, routes and others) (Table 5.6).

Table 5.6 Overview of the balance of plants costs (per unit) for a 90 MW farm of 25×3.6 MW WT and WECs and of 120×0.75 MW WECs

Category and sub-category	3.6 MW wind (k€)	3.6 MW WEC (k€)	0.75 MW WEC (k€)
<i>Tower/Mooring</i>	972	X	X
<i>Foundations</i>	2592	X	X
<i>Cables</i>			
Inter array	227	227	47
Export	664	664	138
<i>Offshore substation</i>			
electrical	810	810	270
Other	227	227	47
<i>Onshore electrical</i>			
Electrical	324	324	68
Other	113	113	24
Total	5929	2365 + X	594 + X

5.6.4.5 Category: Installation and Commissioning

The cost of all the related sub-categories are case/technology dependant and can thereby not easily be derived from the wind energy project case. However, they can be used as inspirations and in the case where less work has to be performed at sea (more of the work can be done in the harbour); they can be assumed to be lower. Therefore, the overall cost for the installation of the cables and offshore substation is expected to be the same, while the work on the installation and commissioning of the foundations and WEC are expected to be significantly lower for WECs, thereby they have been reduced by 75 %.

However, you would expect that many of the costs would be roughly the same per all WECs, independently of the generator size, e.g. installation and commissioning of the WEC, electrical connections and installation of foundations etc. Thereby the cost per unit has been assumed to be 50 % lower for small WECs compared to large WECs, for all categories except for the substation (where the overall cost has been divided by the amount of WECs) (Table 5.7).

Table 5.7 Overview of the installation and commissioning costs (per unit) for a 90 MW farm of 25×3.6 MW WT and WECs and of 120×0.75 MW WECs

Category name	3.6 MW wind (k€)	3.6 MW WEC (k€)	0.75 MW WEC (k€)
Foundations	1134	284	142
WEC	1458	365	182
Cables	1458	1458	729
Offshore substation	113	113	24
Total cost	4163	2219	1077

5.6.4.6 Category: Operation and Maintenance (OpEx)

The operation and maintenance costs for large WECs are kept identical to the wind energy project, as there are various arguments that point in both directions. Some of the arguments in favour are that the WEC might be able to be decoupled and brought back to a harbour for maintenance, making large maintenance much easier. However, some parts of the device might be more difficult of access and there are more moving parts that are in contact with water (or being submerged). However, for WECs having most of their essential parts being submerged, the relative OpEx are expected to be much higher. For the WEC project, based on small WECs, it is expected that the relative OpEx will be significantly higher for several reasons, such as:

- The same effort (and thereby cost) is required to access or retrieve a large or a small WEC, this makes the relative cost higher for small WECs.
- The project made out of small WECs consists out of many more WECs (120 against 25). This means that in total many more sub-systems (each system requires a PTO, generator, mooring system, ...) need to be serviced and maintained, which increases significantly the relative OpEx costs.

The OpEx cost for small WECs (with vital parts, such as PTO, not being submerged) is thereby assumed to be 50 % lower than that of large WECs, which is still assumed to be conservative (Table 5.8).

Table 5.8 Overview of the yearly operation and maintenance costs (per unit) for a 90 MW farm of 25×3.6 MW WT and WECs and of 120×0.75 MW WECs

Category and sub-category	3.6 MW Wind (k€)	3.6 MW WEC (k€)	0.75 MW WEC (k€)
<i>Operation</i>			
Remote	54	54	27
Local	54	54	27
<i>Maintenance</i>			
Remote	84	84	42
Local	192	192	96
<i>Port activities</i>			
Remote	58	58	29
Local	166	166	83
License fees	27	27	14
Other costs	86	86	43
Total annual cost	721	721	361

5.6.4.7 Overview and Levelized Cost of Energy Estimation

The mean annual energy production (MAEP), which is the multiplication of the capacity factor of the device times the installed capacity, is expected to be in the

same range for a large WEC as for an offshore wind turbine. An average capacity factor (including the availability of the device) of 30 % has been assumed. This is expected to be significantly lower under certain circumstances, for small devices because their max-to-mean ratios of the absorbed power are much larger and their power smoothening capabilities are generally much lower. Their capacity factor (including availability) has thereby be assumed to be of 20 %, which is assumed to be reasonably conservative as a long-term projection.

In Table 5.9, an overview of the costs and energy production is given together with the LCoE. The total cost, corresponds to a “base” CapEx and discounted OpEx, while no specific cost for the WEC has been included (thereby marked by “X”). This base cost can also be set in terms of LCoE, and thereby represents the base electricity cost, not including the technology itself.

Table 5.9 Overview of the cost breakdown together with the base LCoE for a 90 MW farm of 25×3.6 MW WT and WECs and of 120×0.75 MW WECs

Costs	3.6 MW Wind (k€)	3.6 MW WEC (k€)	0.75 MW WEC (k€)
Development and consent	649	588	271
Turbine/WEC	5281	X	X
Balance of plant	5929	2365 + X	594 + X
Installation and commissioning	4163	2219	1077
Total CapEx	16022	5822 + X	1941 + X
Annual OpEx	721	721	361
Discounted OpEx (20 years)	6138	6138	3069
Total (CapEx & OpEx) costs	22160	11960 + X	5010 + X
<i>Revenue</i>			
Approx. capacity factor (%)	30	30	20
Mean annual energy production (MWh)	9467	9467	1315
Levelized cost of energy	(€/kWh)	(€/kWh)	(€/kWh)
Base LCoE (without OpEx)	0.085	0.031 + X	0.074 + X
Total LCoE	0.117	0.063 + X	0.191 + X

The total CapEx cost is composed of a “base” cost and a technology cost (marked by “X” for the WECs). This base cost is relatively independent of the technology, as it is mostly related to the project development, infrastructure and commissioning, while it is to some extent dependant on the generator size of the technology. The base cost is about 5.8 million Euros for a 3.6 MW WEC, while about a third of that for a 0.75 MW WEC. This corresponds to a base LCoE of 0.031 and 0.074 Euro/kWh for large and small WECs respectively. This means that the general development, infrastructure and commissioning costs weigh about 2.5 times higher on small than on large WECs.

When adding the OpEx cost to the base cost, the amount rises to 12 and 5 million Euros for the large and small WECs. This corresponds to a LCoE over the

lifetime of the WEC, excluding the CapEx for the technology itself of 0.063 and 0.191 Euro/kWh for large and small WECs.

These results indicate clearly the economic advantage of large WECs. This is mainly because some of the costs are independent of the generator capacity of the WECs and that the capacity factor of a WEC usually increases with its physical size. It is thereby strongly beneficial to have a few large WECs instead of many small WECs in an array.

In order to be able to even further significantly reduce the base costs in the future, the scaling possibilities of a WEC technology are of very large importance.

5.6.5 Cost Reduction

Table 5.10 shows target costs for wave energy projects produced by Fitzgerald [33]. The table gives the OpEx in €/MW/year and the CapEx in €/MW that are necessary to give a 10 % IRR assuming a 160 €/MWh tariff. Different CapEx and OpEx values are given for a range of capacity factors (rows) and annual OpEx to CapEx ratios (columns).

Table 5.10 Affordable investment costs for generation projects [33]

Affordable investment costs for generation projects						
OpEx €/MW/year			Annual OpEx as % of CapEx			
CapEx €/MW			2 %	4 %	6 %	8 %
Capacity factor	20 %	OpEx	0.04	0.07	0.10	0.12
		CapEx	2.15	1.87	1.65	1.47
	25 %	OpEx	0.05	0.09	0.12	0.15
		CapEx	2.69	2.33	2.06	1.84
	30 %	OpEx	0.06	0.11	0.15	0.16
		CapEx	3.23	2.80	2.47	2.21
	35 %	OpEx	0.08	0.13	0.17	0.21
		CapEx	3.77	3.27	2.88	2.58
	40 %	OpEx	0.09	0.15	0.20	0.24
		CapEx	4.31	3.73	3.29	2.95
	45 %	OpEx	0.10	0.17	0.22	0.27
		CapEx	4.85	4.20	3.71	3.32

To yield a 10 % IRR for a 25 year Project life where a tariff of 160€/MWh is payable

The ratio of annual OpEx to CapEx increases column-wise from left to right and as a result the allowable CapEx to achieve the target IRR decreases from left to right. The capacity factor increases row-wise from top to bottom so that the allowable CapEx and OpEx to achieve the target IRR also increases from top to

bottom. The annual energy yield and the project revenue can be expected to increase with the capacity factor.

In general costs may be expected to decrease as the number of units and the total installed capacity increases over time. This effect, known as the learning rate, was initially found to apply to aircraft and aerospace components and has since been confirmed to apply in many industries. Learning rates imply a pattern where each doubling of the capacity is accompanied by a consistent reduction in the unit price.

Figure 5.6, taken from the International Energy Agency report “Experience Curves for Energy Technology Policy” [34] shows the progress in cost of energy reductions as cumulative electricity production increased for a range of technologies. The percentages in braces in Fig. 5.6 are the “progress ratios”, the ratio of price after to price before a doubling of capacity, e.g. wind power progress ratio is 82 %.

Fig. 5.6 Learning rates for different power generating technologies [34]

The learning curve theory does not propose any hypothesis for how the price reductions are actually achieved it treats the technology production system as a black box and only models an external view of the pattern of price over time. It is important to ask where price reductions might come from in wave energy.

Areas for further research in cost reduction in wave energy were investigated by the SI ocean project [39] and the recommendations include:

- Material optimisation
- Up-scaling of devices
- Batch and serial production
- Reduced levels of over engineering
- Improved moorings
- Improved foundations
- Cost effective anchors for all sea bed conditions

- Reduced cost of subsea electrical hubs/substations
- Optimisation of array electrical system and offshore grid
- Specialist installation vessels
- Improvements in weather forecasting
- Economic installation methods, e.g. fast deployment
- Improved ROV and autonomous vehicles

5.6.6 Revenue and Energy Yield

The final piece of the economics picture is annual revenue, which is directly proportional to annual energy yield. Other chapters in this book deal with wave resource characterisation and calculating and measuring the power absorption and power take off performance of WEDs in given wave conditions. This section will give only a brief discussion of the relation of these results to economic analysis.

Estimation of the annual energy yield must consider all of; wave resource, device power absorption performance, device power conversion/transmission efficiency and also availability. A key point in making an assessment of a wave energy project is that the energy sold to the electricity grid will be less than the energy absorbed by the wave energy device under continuous normal operation. The two principal reasons for this are firstly that there are losses involved in the power conversion and transmission steps that take power from the point of absorption to the point of metering and secondly that continuous operation of each device in the wave farm is unlikely. The implication of this is that a conservative assessment must allow for losses in the power take off and electrical power transmission and must also account for an availability that is less than 100 %.

Estimation of the annual revenue should consider annual energy production and the effective energy price including subsidisations and strategic supports, however the nature of subsidisation and strategic supports is varied and sometimes complex so the assessment may be as straightforward as calculating the product of annual productivity and effective price or it may be more involved. The next section will give a discussion of strategic support mechanisms.

5.7 Strategic Support Mechanisms

At any given time and place one form of electricity generation will provide cheaper electricity than all others. It stands to reason that all other forms of electricity generation are then more expensive or less attractive. If market forces alone decide investment in generation capacity then only power stations that use the most attractive technical solution will ever be built. Some form of market distortion or

intervention is necessary to cause any technical solution other than the least expensive to be used. Reasons for making such an intervention include:

- Promotion of diversity of supply (and diversity related security of supply),
- Reduction of costs over a longer time horizon than considered by individual investors,
- Encouragement of (new) technologies with desirable characteristics
- Discouragement of (old) technologies with undesirable characteristics

Beyond energy related motivations policy related motivations² may include

- Protection of an established or domestic industry against encroachment of new or foreign industries
- Promotion or creation of a new or domestic industry in preference to older or foreign industries

Interventions are often targeted at influencing the decision to use a particular, already mature, technology, i.e. choice of technology at the pre-construction project planning stage, other interventions are targeted at increasing R&D investment in new technologies and a minority are targeted at influencing operational decisions e.g.: fuel-mix in co-firing or CHP operations management (see CHPQA). Interventions can take the form of regulations that discourage or effectively block a particular technology but more often interventions are structured as strategic support mechanisms that encourage a particular technology or behaviour.

Strategic support mechanisms maybe categorised as one of either **Market Pull** or **Technology Push**. Market pull is usually related to production incentives while technology push is related to either installation incentives or to research and development funding. Market pull type support mechanisms are effective in encouraging technology that is either already mature or can be made sufficiently mature with private investment, it is intended to heighten the price signal that activates private investment. Technology push, on the other hand, is effective in encouraging research in technologies that are not yet sufficiently close to commercialisation to benefit from price signals or market pull type supports. Technology push can also activate private investment through matched funding requirements.

Strategic supports whether market pull or technology push may take the form of

- Direct payments e.g.: feed in tariff, research grants, government contracts.
- Tax credits e.g.: production tax credit, installation tax credit, accelerated depreciation, R&D tax credit.

²In addition, but arguably less relevant to this discussion, a policy related motivation for intervention that is prevalent in some developing countries is reduction of consumer energy bills for welfare (or electoral) purposes. Such policies are a distortion that blocks price signals and discourages energy efficiency [35].

- In-kind or preferential provision of goods or infrastructure e.g.: access to materials, technology, natural resources, sea-bed lease, port construction, road construction.
- In-kind or preferential provision of services, especially services that transfer risk from investors to government e.g.: Loan guarantees, construction cost guarantees, demand guarantee, price regulation, market access regulations, favourable licensing and permitting.

Some governments have a philosophical objection to distorting free markets, but experience from studies of the nuclear industry and to a lesser extent the petrochemical industry has shown that this objection only leads to subsidies becoming hidden and more subtle. A consequence of the hidden nature of such subsidies is that they are sometimes so inscrutable that they can be denied. Proponents the nuclear energy often claim that nuclear energy receives no subsidisation when in fact it benefits massively from favourable long term power purchase agreements and from large scale transfers of risk and liability from the operators to the state [36].

Both market pull and technology push type strategic incentives are now needed to attract sufficient private finance to wave energy development. There are three key challenges that must be overcome by the wave energy industry and strategic incentives can play a role in addressing each, these key challenges are:

- Identify and develop those WEC concepts that are capable of reaching TRL9 i.e. have sufficiently high TPL and sufficiently lean/affordable development trajectory.
- Facilitate finance of the latter phases of development, demonstration and risk reduction (from TRL 6 to TRL8/9) where product development becomes too expensive for the SME's that typically initiate new and innovative technologies.
- Facilitate insurance against warranty claims after the start of volume sales.

Technology push type incentives and application of advanced R&D management techniques such as the Weber matrix as introduced in Chap. 4 will assist with the first of these challenges. A combination of market pull type incentives such as long term price supports, capital grants and crucially risk sharing such as loan guarantees and insurance initiatives such as government underwriting of project risk will assist with the second and third challenges.

References

1. BVG Associates for the Renewables Advisory Board.: Value breakdown for the offshore wind sector (2010)
2. Christensen, B.: Den nødvendige indsats i offshore vindindustrien—Siemens Wind Power. aarsmoedet 2014 i offshoreenergy.dk (2014)

3. Costello, R., Teillant, B., Weber, J., Ringwood, J.V.: Techno-economic optimisation for wave energy converters. In: International Conference on Ocean Energy, Dublin (2012)
4. Crundwell, F.K.: Finance for Engineers, Evaluation and Funding of Capital Projects. Springer, London (2008)
5. Farrell, Niall, O'Donoghue, Cathal, Morrissey, Karyn: Quantifying the uncertainty of wave energy conversion device cost for policy appraisal: An Irish case study. *Energy Policy* **78**, 62–77 (2015)
6. Future Marine Energy.: Results of the marine energy challenge: cost competitiveness and growth of wave and tidal stream energy. J. Callaghan, R. Boud—Carbon Trust (2006)
7. Fitzgerald, J.: Financing Ocean Energy Technology Development. ESBI 2012. <http://www.ucc.ie/en/media/research/hmrc/forums/thirdforumoneconomicsofmarinerenewableenergy2012/JohnFitzgeraldOceanEnergyFinance-ESBPresentation.pdf>
8. Hamedni, B., Ferreira, C.B.: Generic WEC risk ranking and failure mode analysis generic WEC risk ranking and failure mode analysis (2014)
9. Hamedni, B., Ferreira, C.B., Cocho, M.: Generic WEC system breakdown (2014)
10. Hardisty, P.E.: Environmental and Economic Sustainability, Environmental and Ecological Risk Assessment. CRC Press (2010)
11. Hausman, J.: Individual discount rates and the purchase and utilization of energy-using durables. *Bell J. Econ.* (1979)
12. Houston, D.A.: Implicit discount rates and the purchase of untried, energy-saving durable goods. *J. Consumer Res.* **10**. (1983)
13. International Energy Agency.: Experience Curves for Energy Technology Policy (2000)
14. International Renewable Energy Agency (IRENA).: Renewable power generation costs in 2014 (2015)
15. Koplow, D.: Nuclear Power: Still Not Viable without Subsidies. Union of Concerned Scientists (2011)
16. Kunstler, J.: The Long Emergency: Surviving the End of Oil, Climate Change, and Other Converging Catastrophes of the Twenty-First Century. ISBN-155584670X, 9781555846701. Grove/Atlantic, Inc. (2007)
17. Madlener, R., Ortlieb, C.: An Investigation of the Economic Viability of Wave Energy Technology: The Case of the Ocean Harvester,” FCN Working Paper No. 9/2012, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University (2012)
18. Ocean Energy Systems (OES).: International levelised cost of energy for ocean energy technologies (2015)
19. Ocean Energy: Cost of Energy and Cost Reduction Opportunities.: SI-Ocean Project. May 2013. http://si-ocean.eu/en/upload/docs/WP3/CoE%20report%203_2%20final.pdf
20. Padeletti, D., Costello, R., Ringwood, J.V.. A multi-body modelling approach for wave energy converters employing nonlinear joint representation. In: Proceedings of the OMAE, San Francisco (2014)
21. Previsic, M., Siddiqui, O., Bedard, R.: EPRI Global E2I Guideline. Economic Assessment Methodology for Offshore Wave Power Plants. E2I EPRI WP-US—002 Rev 4 (2004)
22. Short, W., Packey, D.J., Holt, T.: A manual for the economic evaluation of energy efficiency and renewable energy technologies. NREL/TP-462-5173 (1995)
23. Stallard, T., et al.: Economic assessment of marine energy schemes. In: Proceedings of the 8th European Wave and Tidal Energy (EWTEC) Conference, Uppsala, Sweden (2009)
24. Tegen, S., Hand, M., Maples, B., Lantz, E., Schwabe, P., Smith, A.: 2010 Cost of Wind Energy Review. NREL/TP-5000-52920 (2012)

25. Teillant, B., Costello, R., Weber, J., Ringwood, J.V.: Productivity and economic assessment of wave energy projects through operational simulations. *Renew. Energy* **48**, 220–230 (2012)
26. VV.AA.: WaveNet: Full report (2003). [www.wave-energy.net/Library/WaveNetFullReport\(11.1\).pdf](http://www.wave-energy.net/Library/WaveNetFullReport(11.1).pdf)
27. Weber, J., Costello, R., Ringwood, J.V.: WEC technology performance levels (TPLs)—metric for successful development of economic WEC technology. In: *Proceedings of the European Wave and Tidal Energy Conference (EWTEC)*, Aalborg (2013)

Open Access This chapter is distributed under the terms of the Creative Commons Attribution-Noncommercial 2.5 License (<http://creativecommons.org/licenses/by-nc/2.5/>) which permits any noncommercial use, distribution, and reproduction in any medium, provided the original author(s) and source are credited.

The images or other third party material in this chapter are included in the work's Creative Commons license, unless indicated otherwise in the credit line; if such material is not included in the work's Creative Commons license and the respective action is not permitted by statutory regulation, users will need to obtain permission from the license holder to duplicate, adapt or reproduce the material.