EPRI Global E2I Guideline

Economic Assessment Methodology for Offshore Wave Power Plants

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1. Introduction

The Electricity Innovation Institute (E2I) and the Electric Power Research Institute (EPRI) propose two standard cost estimate methodologies, a utility generator (UG) and a non utility generator (NUG) methodology, including a set of financial assumptions, to evaluate the economics of offshore wave power plants. The E2I EPRI Project Team will use these methodologies to evaluate the economics of both a 1,500 Mega Watt Hours Electric per Year (MWeh/yr) pilot plant and a 300,000 MWeh/yr commercial size plant (500 kW and 100 MW at 40 capacity factor respectively).

Regulated utilities are permitted to set electricity rates (i.e., collect revenue) that will cover operating costs and provide an opportunity to earn a reasonable rate of return on the property devoted to the business. This return must enable the UG to maintain its financial credit as well as to attract whatever capital may be required in the future for replacement, expansion and technological innovation and must be comparable to that earned by other businesses with corresponding risk.

Because the risks associated with private ownership are generally considered to be greater than utility ownership, the return on equity must be potentially higher in order to justify the investment. However, it is important to understand that there is no single right method to model an independently owned and operated NUG renewable power plant. Considerations such as an organization's access to capital, project risks, power purchase and contract terms determine project risks and therefore the cost of money.

This regulated UG methodology is based on a levelized cost approach using real (or constant) dollars with 2004 as the reference year and a 30 year book life. The purpose of this standard methodology is to provide a consistent, verifiable and replicable basis for computing the cost of electricity (COE) of an offshore wave energy generation project (i.e., a project to engineer, permit, procure, construct, operate and maintain an offshore wave energy power plant).

The NUG methodology is based on a cash flow analysis and projections of market electricity prices. This allows a NUG to estimate how quickly an initial investment is recovered and how returns change over time.

A cost estimate of the initial capital cost and the yearly operation and maintenance cost will be developed for both the pilot plant of immediate interest and an envisioned future commercial plant at the same site. A small-scale pilot plant with little cumulative production experience cannot be expected to be economically competitive with large-scale commercial technologies with high cumulative production experience. Therefore, decisions on the economic viability of offshore wave power technology must be made on the basis of large-scale commercial plant economics. The purpose of the notional 300,000 MWeh/yr plant cost of electricity evaluation is to assess the economic viability of a large-scale commercial application of the offshore wave technology and to allow a comparison against other large-scale commercial renewable generation options.

The results of this economic evaluation will help government policy makers determine the public benefit of investing public funds into building the experience base of wave energy to transform the market to the point where private investment will take over and sustain the market. Such technology support is typically done through funding R&D and through incentives for the deployment of targeted renewable technologies.

If the economics of the notional 300,000 MWeh/yr commercial off shore wave power plant is favorable with respect to alternative renewable generation options, a case can be made for pursuing the development of that offshore wave energy technology. If, however, even with the most optimistic assumptions, the economics of a commercial size offshore wave power plant is not favorable and cannot economically compete with the alternatives, a case can be made for not pursuing the offshore wave power technology development.

Relative to the pilot plant, the decision of whether to fund the Phase IB Implementation Planning task will be made in the fall of 2004 and the decision point of whether to fund the Phase II Detailed Design, Permitting and Construction Financing Task will be made in the winter of 2004. A key factor in those decisions is the cost to design, build and test the pilot plant. The initial capital cost required to build the pilot plant will be estimated as part of this Phase IA work this summer. Of particular importance is our emphasis on identifying unique opportunities that will enable a pilot plant to be built at an affordable cost.

2. Regulated Utility Generator (UG) Cost of Electricity Assessment Methodology and Assumptions

The proposed UG methodology is based on generally accepted regulated utility accounting practices. The cost of electricity (COE) is computed by levelizing a power plant's annual revenue requirements over the service life of the plant and dividing it by the plant's annual output. This makes it possible to compare alternative designs or technologies in terms of a single index – the levelized cost of electricity (COE). It is important to understand that in order to make such cost comparisons, the underlying assumptions must be the same for the different technologies being compared.

The methodology is implemented in an excel-spreadsheet solution which allows the analyst to input wave power plant component costs, power production, and financing assumptions in order to calculate the COE.

The following paragraphs provide a short outline of the steps and associated formulations used to calculate the COE:

- Determine Annual Revenue Requirements

  Annual revenue requirements are equal to the cost that the project incurs each year. We assume that the project will be financed with a debt/equity finance structure. Annual costs are determined by the following components: Debt Principal, Debt Interest, Return on Equity, State Taxes, Federal Taxes, State Tax Incentives, Federal Tax Incentives, Accelerated Depreciation, Property Taxes and Insurance. Over the life of the project, these revenue requirements change and need to be brought back to Net Present Value (NPV) in order to properly levelize the annual cost.

In a regulated UG framework, the annual cost to operate the power plant is defined as its “annual revenue requirement”, i.e., the equivalent in revenue that would make the project break-even. In a regulated market, the UG can adjust its rates to provide cost recovery for its assets with a stipulated return.

- Levelizing Annual Revenue Requirements

Annual incurred costs are levelized by summating the NPVs for each year. The NPV is calculated using a discount rate that is determined by the cost of money. In this case, it is the capital finance structure (i.e. mix of equity and debt) that is used to calculate the pre-tax discount rate applicable to this project. Using this pre-tax discount rate and the applicable composite tax rate (i.e., a single value for the combined state and federal tax), the after tax discount rate can be determined and is used to calculate the NPV.

- Calculating the Fixed Charge Rate

The fixed charge rate is the percentage of the total plant cost that is required over the project life per year to cover the minimal annual revenue requirements. This fixed charge rate concept can be compared to a fixed rate home mortgage where a fixed annual payment will pay off the principal and interest over a period of time. It is calculated in three steps:

1) Calculate Capital Recovery Factor (CRF) as follows:

$$\text{CRF} = \left[\frac{\text{Discount Rate}}{(1 + \text{Discount Rate})^{\text{Book Life}} - 1} + \text{Discount Rate} \right] \quad \text{(Equation 1)}$$

Please note from the formula above that the capital recovery factor is a direct function of the Discount Rate (yearly cost of money) and the Book Life (Project Duration in number of years).

2) Calculate the levelized annual charges by simply multiplying the capital recovery factor by the net present value.

3) Calculate the Levelized Annual Fixed Charge Rate by dividing the levelized annual charges by the Total Plant Investment (Booked Cost).

- Calculating the Cost of Electricity

The levelized cost of electricity is calculated by dividing the annual cost of the power plant by the Annual Energy Production. Because O&M and Levelized Overhaul and Replacement Costs were not previously considered, they are found in the formula below. The formula for computing the levelized cost of electricity (COE) is:

$$COE = \frac{(TPIxFCR) + (O\,\&\,M) + (LO\,\&\,R)}{AEP} \qquad \text{(Equation 2)}$$

where:

TPI = Total Plant Investment
FCR = Fixed Charge Rate (percent)
O&M = Annual Operating and Maintenance Cost
LO&R = Periodic Levelized Overhaul and Replacement Cost
AEP = Annual Energy Production at Busbar

The annual energy production (AEP) calculation methodology is described in a separate E2I EPRI Offshore Wave Energy Project Standard [Reference 3]. Since long-term wave measurement data is averaged in order to come up with appropriate power generation values, the annual energy output is assumed to be constant over the life of the project..

The following sections discuss the core issues associated with this proposed methodology:

- Cost Components of a wave power plant (section 2.1)
- Taxation and Tax Incentives offered for renewable power plants (section 2.2)
- Cost Levelizing Procedures (section 2.3)
- Real and Nominal Energy Costs (section 2.4)
- Financing Assumptions (section 2.5)

2.1. Cost Components

The elements of the cost breakdown for a typical offshore wave power plant are described in this section. All capital expenditures are defined as installed cost and expressed in constant dollars with 2004 as the reference year. Being the installed cost, they include shipping and commissioning cost elements. The first level cost breakdown structure outlined below allows comparing different generation alternatives and identifying sensibilities of a particular wave power conversion design. This breakdown will also be useful for parametric optimization of a wave power plant s.

- *Absorber Structure:* All structural components that are directly responsible for the absorption of energy from ocean waves such as capture chamber, counter reacting mass absorber buoy, etc.

- *Power Take Off:* Turbo-machinery converts the slow oscillating movement of a prime-mover (mechanical motion of buoy, oscillating air-flow or water pressure in overtopping system) into electricity at grid frequency (50Hz or 60Hz) and transmission voltage.

- *Mooring:* All components required for holding the wave power conversion device in place.

- *Electrical Interconnection:* All cables required to interconnect the individual units to a common offshore interconnection point.

- *Grid Interconnection:* All cabling, switchgear, transmission lines and infrastructure required to connect the offshore wave farm to a nearby land-based grid interconnection point.

- *Substation to Substation Upgrade Cost:* The initial capital cost for any required distribution/transmission substation to substation cost will be included in the cost estimate, however, since that cost is credited back with interest within the first 5 years of operation to the Interconnection Customer (Wave Power Plant in this case), for simplicity reasons, that cost will not be factored into the cost of electricity or internal rate of return calculations

- *Communication, Command and Control:* All equipment and infrastructure required to establish a two way link from land-based to sea-based systems for purposes of communication, command and control.

- *Installation Cost* = the costs required to transport the system from its safe harbor assembly location to its deployment site and complete all interconnections and checkout to the point where the system is ready to begin official commissioning procedures.

- *Owner's Development Cost* = assume 5% of the costs through installation above

- *Spares Provisioning*: 2% of the hardware cost above

- *General Facilities and Engineering:* Engineering cost associated with the planning of a wave farm and general facilities required for deploying and operating the wave power plant. This could include necessary dock modifications, maintenance shops, etc. for the deployment and maintenance of the offshore wave farm as well as mobilization of the O%M itself..

- *Financial Fees:* 2% of the 1st year of debt with the cost occurring in the 2nd year of the two year construction period..

- *Commissioning:* The process, inspection and testing required to turn over the system from the general contactor to the owner/operator.

- *Total Plant Cost (TPC):* This is the total installed and commissioned cost of the power plant and consists of the abovementioned cost elements.

- *Interest during Construction:* Interest paid for the two-year construction loan (assumes two loans, one at the beginning of each year)

- *Total Plant Investment (TPI):* Total Plant Investment is the amount of capital required to build the power plant. TPI = TPC + Interest during Construction (called allowance for funds used during construction (AFUDC) in the regulated world).

- *Annual Scheduled O&M Cost:* The components of O&M costs are insurance, labor and parts. Labor includes equipment such as barges, dive boats, etc. to carry out O&M operations. Parts are simply replacement items. The O&M costs do NOT include the infrequently incurred costs of major overhauls of wave energy conversion devices or other components. These costs are included in the levelized replacement cost (LRC). Expenses are annual payments associated with plant operations and maintenance (O&M), and include recurring O&M and non-recurring O&M (which is estimated for the economic analysis based on related infrastructure projects from the offshore industry). The majority of the O&M costs associated with the wave energy conversion devices can be grouped into three categories:

  - Unscheduled maintenance to carry out repairs, typically occurring after a violent storm
  - Scheduled preventive maintenance for the wave energy conversion turbine and the power take off system
  - Scheduled major overhauls and subsystem replacements of the WEC device

- *Annual Unscheduled O&M Cost:* A provision for unscheduled maintenance is estimated at x% of the annual scheduled O&M cost.

- *Annual Insurance Cost:* 2% of TPC

- *Periodic Levelized Overhaul and Replacement Cost (LO&RC):* Depending on the specific manufacturer's design, major overhaul of the WEC device and mooring system is scheduled to occur every 5, 10 or 15 years. These major overhauls may address gears, bearings, seals and other moving parts as well as the mooring cable and components. Because these costs are incurred at intervals of several years and not routinely during each year, correct accounting for their costs requires an annual accrual of funds. The objective of this accrual is to have the funds available when the need for overhaul or replacement occurs. The accrual involves a net present value calculation to level or apportion the overhaul and replacement costs to an annualized basis consistent with the other cost elements. Because they are treated as investments, they are eligible for investment tax credits.

2.2. Income Taxation

For this project, we assume a federal rate of 35% and a state rate as shown in Table 1. The calculation of composite tax rate (i.e., federal and state) reflects the fact that state income taxes are deductible from federal taxes.

Table 1: State and Composite Income Tax Rates

State	State Tax Rate	Composite Rate Assuming 35% Federal Rate
CA	8.84 %	40.7 %
HI	6.02 %	38.9 %
MA	9.50 %	41.2 %
ME	8.93 %	40.8 %
OR	6.60 %	39.3 %
WA	0.00 %	35.0 %

Power plants that generate electricity from renewable energy resources qualify under IRS guidelines for an accelerated cost recovery period under the Modified Accelerated Cost Recovery (MACR) depreciation schedule as shown in Table 2[Reference 4].

Table 2: Applicable Accelerated Tax Depreciation Schedule

Year	Depreciation
1	20.00 %
2	32.00 %
3	19.20 %
4	11.52 %
5	11.52 %
6	5.76 %

The IRS explicitly mentions solar, wind, and geothermal as examples of qualifying renewable resources. Insofar as offshore wave energy is a derivative of solar and wind energy (i.e., the sun produces winds, and winds over the ocean produce waves) and its status as a renewable energy resource is self-evident, it is reasonable to assume that wave conversion plants would be eligible for the same depreciation treatment, as well as investment and production tax credits as described in the next section..

Tax-filing entities such as corporations are allowed to employ different tax depreciation assumptions for financial accounting (i.e. book) versus tax accounting purposes – so long as all assumptions conform to Generally Accepted Accounting Principles (GAAP). Accordingly, entities tend to apply more conservative depreciation assumptions (such as straight line depreciation) for financial accounting purposes to accentuate earnings, whereas they apply more accelerated depreciation assumptions for tax accounting to defray taxable income. This difference between the effective book and tax depreciation rates results in an annual variance between income taxes actually paid and those that would have been paid under book depreciation assumptions over the book life of the plant. The difference is referred to as deferred income tax. A utility is not allowed to earn a rate of return on deferred taxes. A renewable energy project will show negative taxes in the first couple of years of operation (mainly because of accelerated depreciation). If a renewable energy project were treated as individual entity, the negative values would need to be carried forward to future years (because there is no other tax obligations against which such deductions could be made in the present year). If a renewable energy project is a part of a utility's generation assets, it is likely that tax deductions will have a significant net impact on the bottom-line of a utility or IPP in the early years of operation. For the purpose of this project, such tax incentives are treated as direct benefits to the project in the year they occur.

2.3. Incentives

Federal and State government organizations are providing incentives for renewable energy projects in the form of tax credits and renewable portfolio standards and renewable energy certificates. The three main categories that have an impact on the economic feasibility on a renewable power plant are:

- Investment tax credits
- Production tax credits
- Renewable Portfolio Standards (RPS)/Renewable Energy Certificates (RECs)

These incentives will be analyzed for the commercial scale power plant economics analysis. The incentives occur in the early years of a wave power plant and have a positive impact on the NPV of a project.

The Federal Government provides a production tax credit (PTC) as an incentive for development of clean, renewable, domestic wind energy. Originally introduced through the Energy Policy Act of 1992, the PTC grants 1.5¢ per kilowatt-hour for the first ten years of operation to wind plants brought on line before June 30, 1999. The credit was then extended at 1.8¢ per kilowatt-hour for the first ten years of operation to wind plants brought on line before Dec 31, 2003. The PTC was again extended in late 2004 to Dec 31, 2005. We assume that the federal PTC for wind energy will be extended to ensure continued strong growth of America's renewable energy capabilities, and that wave energy will be eligible for the PTC

Investment and production tax credits for each of the states are shown in Table 3.

Table 3: Investment Production Tax Credits

	Investment Tax Credit		Production Tax Credit	
	State	**Federal**	**State**	**Federal**
CA	Credit of 6% of qualified costs paid or incurred for the acquisition or construction of qualified property (machinery, equipment, or capitalized labor) for manufacturing activities	10% of TPI		1.8¢ per kWh for the first 10 years
HI		10% of TPI		1.8¢ per kWh for the first 10 years
MA	Installation cost deductible if installed in Massachusetts	10% of TPI		1.8¢ per kWh for the first 10 years
ME		10% of TPI		1.8¢ per kWh for the first 10 years
OR	Business Energy Tax - Credit 25 % of project cost, up to $10M credit in 1st Year	10% of TPI		1.8¢ per kWh for the first 10 years
WA		10% of TPI		1.8¢ per kWh for the first 10 years

The New England Interconnection System Operator (NE-ISO) has created a market for renewable energy certificates. The value of RECs is currently about 2.5 cents/kWh.

2.4. Levelizing Costs

Levelized cost, which is intimately related to present value, is the uniform annual cost with the same present value as the actual annual cost.

Book depreciation and periodic investment in replacement equipment will cause a project's revenue requirements to change from year to year. The first step in calculating the levelized revenue requirement is to discount the time-varying cash flow for a particular reference year. The second step is to compute the equivalent payment (or annuity) that would have the same cumulative present value as the time-varying cash flow over the project's life.

Mathematical formulas for these two steps are described in any standard economics textbook.

The discount rate is the cost of money needed to finance an investment project. In this analysis, we use the after-tax cost of money. The discount rate that is applicable to this analysis is based on a corporation's access to the financial markets and will reflect a certain proportion of debt and equity financing for capital projects. This discount rate is dependent on whether ownership is a regulated utility or independent power producer.

2.5. Constant Dollar vs. Current Dollar Energy Costs

Energy costs can be computed in either constant dollars, which do not include the effects of inflation, or in current dollars, which do.

Please note that when comparing different investment alternatives, the most economical option will not change regardless of whether constant or current dollars are used. Even so, when presenting the results of such studies, the type of dollar used should be indicated, as should the reference year for input cost data, and in the case of a current dollar analysis, the assumed inflation rate.

When working with constant dollars, real interest rates are used, whereas when working with current dollars, nominal interest rates are used. As a simple example, if a homeowner's fixed rate mortgage is a nominal rate of 6% and inflation is 3%, the real rate, i.e., adjusted for inflation is 2.9% (real rate = ((1 + nominal rate)/(1 + inflation rate)) - 1).

2.6. Financing Assumptions

The four key assumptions that underpin the calculation of levelized cost are:

(1) The period over which the annual costs are incurred;
(2) The reference year dollar in which the annual costs are expressed;
(3) Whether the levelized costs are in constant or current terms;
(4) The discount rate, which is based on the capital structure (equity and/or debt) used to finance the project as well as the perceived risk of the project.

For this offshore wave energy project, we will use the following assumptions:

- 20 year plant life
- All costs in real or constant January 2004 dollars
- Commercial plant start date = January 2008 (plant design, permitting and financing in 2005, plant construction in 2006 and 2007)
- Inflation rate of 3.0%, based on the U.S. Producer Price Index for 2003 [1]

[1] Source: U.S. Bureau of Labor Statistics, 2004

Utility Assumptions

- Capital structure of 65% equity and 35% debt [2]
- Distribution of equity: 52% common equity and 13 % preferred equity[3]
- Cost of common equity of 13% (nominal) [2]
- Cost of debt before taxes of 7.5% (nominal) [2]
- Cost of preferred equity (nominal) of 10.5%, representing the average of the cost of common equity and cost of debt

Table 4: Example Regulated Utility Financing Assumption

	Percent	**Nominal Rate**	**Real Rate(1)**
Capital Structure (%)			
Common Equity	52	13.0 %	9.7 %
Preferred Equity	13	10.5 %	7.3 %
Long-Term Debt	35	7.5 %	4.4 %
Income Tax Rates			
Federal		35.0 %	35.0 %
State (generic @ 4.0%)		4.0 %	4.0 %
Composite (21)		37.6 %	37.6 %
Discount Rate (before tax)(3)		10.75 %	7.5 %
Discount Rate (after tax) (4)		9.72 %	6.5 %

(1) Real rate = (((1 + nominal rate)/(1 + inflation rate))-1)
(2) State income tax is deductible, so the composite rate is (0.35+0.040*(1-0.35))*100 = 37.6%
(2) The weighted cost of money or before-tax discount rate = Common equity share *interest rate + preferred equity share * interest rate + long-term debt share * interest rate
(3) The after-tax discount rate = Common equity share *interest rate + preferred equity share * interest rate + long-term debt share * interest rate * (1-composite tax rate)

[2] www.eere.energy.gov/consumerinfo/pfds/financial.pdf
[3] Consistent with historical 4:1 ratio between common and preferred stock in the Composite Balance Sheet for Major U.S. Investor-Owned Electric Utilities, 1996 – 2000 compiled by the Energy Information Administration (http://www.eia.doe.gov/cneaf/electricity/invest/t8.txt).

3. Non Utility Generator (NUG) Cost of Electricity Assessment Methodology and Assumptions

The key differences between UG and NUGs are:

- Obligation to Serve – UG's have traditionally had an obligation to serve and to provide reliable electric service. NUG's develop a project for its potential economic rewards and have the option to sell their power on a wholesale basis to a utility, on a retail basis to the customer, or directly to a power pool.

- Rates/Prices – Rates for UGs are usually set using the revenue requirements approach. NUGs typically attempt to set the prices as high as the market will allow.

- Risks and benefits – Customers of UGs bear the risks associated with prudent investments. Since customer, not utilities, bear the risk, UGs earn a lower rate of return on investments associated with a monopoly. NUGs bear the risks associated with their investments but can mitigate them to an extent that they negotiate contracts for energy sales.

NUGs can be classified into different types; however, for purpose of this analysis, we assume that the NUG is a Merchant Power Plant. Merchant plants are generally characterized as those that have substantial commodity risks for electricity sales (i.e., a substantial portion of their electricity sales is not fully committed to long term power sales agreements). The power will either be sold on a spot market basis to a power pool or under contracts with varying terms to utilities.

3.1. Development of an Economic Pro Forma for a NUG

While there are a variety of methods to evaluate NUG power projects, all methods depend on calculating cash flows. The cash flows represent all revenues from the sale of electricity less the sum of all expenses, debt service and income taxes. The net cash flow represents cash available to equity holders.

Cost Components, Income Taxation, and Investment/Production Tax Credits

The cost component, income taxation and investment/production tax credits are the same for UGs as described in section 2.1, 2.2 and 2.3 respectively

Constant Dollar vs. Current Dollar Energy Costs

Energy costs can be computed in either constant dollars, which do not include the effects of inflation, or in current dollars, which do. Please note that when comparing different investment alternatives, the most economical option will not change regardless of whether real or nominal dollars are used. Even so, when presenting the results of such studies, the type of dollar used should be indicated, as should the reference year for input cost data.

Financing Cost

- Capital structure of 30% equity and 70% debt [4]
- Cost of equity of 17.0% (nominal), a premium over the utility cost of equity due to higher inherent risk [4]
- Cost of debt of 8% (nominal) [4]
- Interest rate on construction loan assumed equivalent to cost of debt: 8% (interest)
- Financial fees of 2% of the loan amount and
- Debt service reserve of 6 months of debt service

Table 5: Example Independent Power Producer Financing Assumptions

	Percent	Rate Nominal	Rate Real
Scenario 2: Long-term (30 year) Capital Structure (%)			
Equity	30	17.0 %	13.60 %
Debt	70	8.0 %	4.9 %
Income Tax Rates			
Federal		35.0 %	35.0 %
State (generic @ 4.0%)		4.0 %	4.0 %
Composite		37.6 %	37.6 %
Discount Rate (before tax)		10.7 %	7.5 %
Discount Rate (after tax)		8.5 %	5.3 %

Development Cost

Development costs include a variety of costs that a NUG incurs to develop a project. Examples include security deposits, permitting (including constriction permits and environmental permits), owner's engineering and general and administrative costs, development fees, legal fees and easements and rights of way. These costs can vary widely depending on the specific project. For purposes of this analysis, we assume a cost allowance of 5% of the TPC.

[4] www.eere.energy.gov/consumerinfo/pfds/financial.pdf

3.2. Income Statement

The income statement summarizes the revenues and expenses for each year of the project. A layout of a typical income statement is shown in Table 6.

Table 6. NUG Income Statement

	Year - 2	…………….	Year N	Total
REVENUES				
Capacity Payments				
Energy Payments				
Federal Production Tax Credit				
TOTAL REVENUES				
Avg Electricity Revenues (cents/kWh)				
VARIABLE OPERATING EXPENSES				
Supplies and Consumables				
Unscheduled Operation and Maintenance				
TOTAL				
FIXED OPERATING EXPENSES				
Scheduled Operation and Maintenance				
Scheduled Overhaul/Replacement				
Insurance				
TOTAL				
TOTAL OPERATIG EXPENSES				
EARNINGS BEFORE INTEREST, DEPREC, TAXES, AND AMORTIZATION (EBIDTA)				
INCOME TAX				
Tax Depreciation				
EARNINGS BEFORE INCOME / TAXES				
Interest paid				
Total Interest Received (5% per year)				
NET OPERATING INCOME (LOSS)				
TAXABLE EARNINGS				
State Tax				
Federal Tax				
TOTAL TAX OBLIGATION				
NET EARNINGS AFTER TAXES				

3.3. Revenues

The forecast of revenues over the service life of a merchant power plant is one of the most critical aspects of the economic analysis. The analysis requires a forecast of market prices. In a deregulated market, prices need to be forecast by time-of-day and time of year and gets very complex very quickly. For simplicity of analysis and understanding, this methodology assumes only an energy component (the capacity component shown in Table 6 is zero) and an average power sales price as a function of state. Two electricity price indicators; industrial price and avoided cost, on a state-by-state basis, and one forecast model is used

Industrial Price.

The 2002 industrial and residential electricity prices by state from the DOE Energy Information Agency[5]), interpreted as wholesale and retail prices respectively, is as follows:

- CA – 10.8 and 12.9 cents/kWh in January 2002
- WA – 4.6 and 6.3 cents/kWh in January 2002
- OR – 4.7 and 7.1 cents/kWh in January 2002
- HI - 11 and 15.5 cents/kWh in January 2002
- MA – 8.8 and 11 cents/kWh in January 2002
- ME[6] – 6.5 and 10 cents/kWh in January 2002

Avoided Cost

Avoided cost is defined as the incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from a qualifying facility, the utility would generate itself or purchase from another source. Analyses may be conducted where the avoided cost is the selling price that a generator receives from a grid operator, retailer or marketing agency. The avoided cost by state is as follows

- CA – 5.4 cents/kWh in 2004$ for Northern California from E3 and the CA PUC[7]
- HI – 8.69 cents/kWh in 2004$ from personnel communication from Darren Ishimura of HECO[8]
- OR - 4.91 cents/kWh in 2004$ from Portland General filing with the PUC of Oregon
- MA & ME – 5 cents/kWh in 2004$ from the New England ISO website in October, 2004 for the day ahead market

[5] http://www.eia.doe.gov/cneaf/electricity/st_profile/maine.pdf or replace Maine with state of concern
[6] EIA 2002 industrial and residential electricity prices for Maine is 11.2 and 12 cents/kWh respectively. At the direction of the Maine Project Advisors, we are using 6.5 and 10 cents/kWh for wholesale and retail prices
[7] "Avoided Cost Estimation" www.ethre.com/avoidedcosys.html Energy and Environmental Economics for the California PUC
[8] Darren Ishimura Personnel communication, 4th Quarter 2004 for over 100 kW for Oahu Hawaii 9.64 cents/kWh (on-peak: 7 am to 9 pm) and 7.37 cents/kW/h (off-peak: 9 pm to 7 am). Weighted average = 8.69 cents/kWh

Electricity Price Forecast

The electricity price forecast from the EIA (Reference 11) is shown graphically in Figure 1 and is as follows *"Average U.S. electricity prices, in real 2002 dollars, are expected to decline by 8 percent, from 7.2 cents per kilowatthour in 2002 to 6.6 cents in 2008 (Figure 74), and to remain relatively stable until 2011. From 2011 they are projected to increase gradually, by 0.3 percent per year, to 6.9 cents per kilowatthour in 2025, generally following the trend of the generation component of electricity price, which currently makes up 64 percent of electricity prices."*

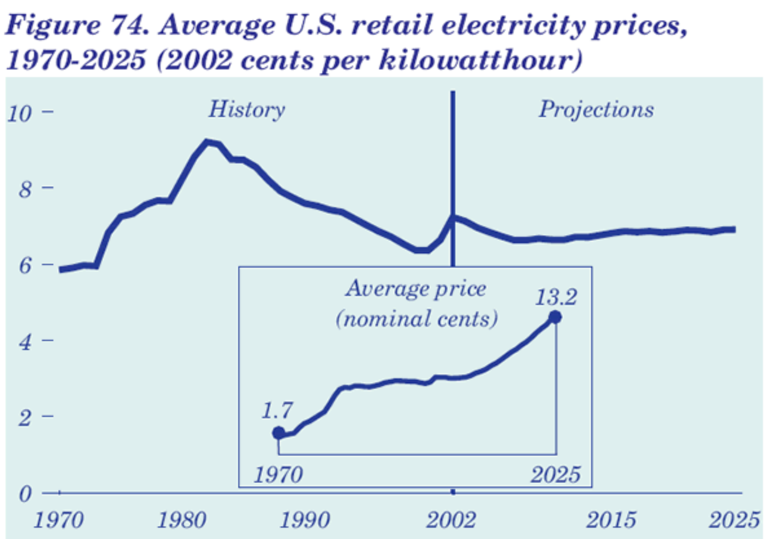

Figure 1. EIA retail electricity price from 1970 with projections to 2025

An alternative to using the industrial price as the basis for competitive price of electricity is to use marginal costs for that basis. Economic theory states that competition drives prices to marginal costs if there are many producers and many consumers. For electricity, this means that the competitive prices for generation services would be based on the cost of producing the last kWh of electricity (marginal costs is defined as the cost to the utility of providing the last (marginal) kilowatthour of electricity, irrespective of sunk costs). This method of pricing is different from the cost-of-service regulatory practice (explained in section 2 of this report), which uses average costs (total costs divided by total sales) as the basis for prices. The application of market costs as the basis of prices assumes that no producer or consumer exercises market power.

The avoided cost data for the Oahu Hawaii data (4th quarter of 2004) was provided by HECO. It is 9.64 cents/kWh on-peak (7 am to 9 pm) and 7.37 cents/kWh off-peak (9 pm to 7 am). This reduces to an average hourly avoided cost of 8.69 cents/kWh

3.4. Cash Flow Statement

A cash flow statement calculates the after tax net cash flow for the project. A layout of a typical cash flow statement is shown in Table 7. The cash flow statement begins with the EBITDA as brought forward from Table 6 and includes the following adjustments:

- Less income Taxes
- Less debt service (principal + interest for the loan)
- Plus interest received from the debt reserve fund
- Less any new contributions to reserve
- Plus return of the reserves at the end of the debt service term
- Less any adjustments to working capital
- Less equity investment during constriction

Table 7. NUG Cash Flow Statement

	Year - 2	…………….	Year N	Total
EBITDA				
Taxes Paid				
CASH FLOW FROM OPERATIONS				
Debt Service				
Interest Received				
Contribution to Reserves				
Disbursement of Reserves				
ADDITIONS TO WORKING CAPITAL				
Accounts Receivable				
Spare Parts				
CAPITALIZED REFURBISHMENTS				
CONTRIBUTED CAPITAL				
NET CASH FLOW BEFORE TAX				
CUM NET CASH FLOW BEFORE TAX				
NET CASH FLOW AFTER TAX				
CUM NET CASH FLOW AFTER TAX				
CUM IRR ON AFTER TAX NET CASH FLOW				

3.5. Economic Indicators

The net present value (NPV) and the internal rate of return (IRR) are economic measures of the project that reflect the present worth of profit over the service life and the profitability of the project, respectively.

Net Present Value

The net present value represents the present value (or present worth) of profit using the time value of money. This calculation results from discounting the net cash flows at the minimum acceptable rate of return for the equity investor. The method is also referred to as the discounted cash flow method.

The net present value must be defined at a certain point in time. Frequently, the NPV is calculated at the commercial operation date. In this case, the total capital requirement (at the commercial operation date) is subtracted from the net cash flows that are discounted or brought back to the same date.

Internal Rate of Return

The internal rate of return (IRR) addresses the profitability of a project. Mathematically, the IRRT is defined as the discount rate that sets the present worth of the net cash flows over the service life equal to the equity investment at the commercial operating date.

An IRR of 20% does not necessarily mean that the net cash flows will represent 20% of the equity investment for each and every year of the service life. However, an IRR of 20% does mean that the equity investor will earn an equivalent of 20% of the outstanding balance each yea, The balance will be reduced in some fashion over the life of the plant.

Many companies have a minimally acceptable IRR that must be met before a potential project is seriously considered. The minimum acceptable rate is known as the hurdle rate. It can be used to screen potential projects based on their IRR

There are several caveats to be aware of when calculating the IRR:

- The IRR solution is a trial and error solution that is typically solved by a convergence routine available in spreadsheet software

- The solution is based on solving an “n-th” degree polynomial that may have multiple real positive roots. More that one change in the sign of the coefficients of the net cash flows is an indication of multiple positive roots. A standard engineering economics should be consulted for situations where multiple roots are suspected.

- Changes in the IRR are not scalar and a small change in the cash flows can have a large effect on the IRR

- Comparisons of the IRR may be misleading. While the IRR allows investors to rank options based on their potential rate of return, it does not take into account a project's size. For example, it does not allow an analyst to capture a $1 million project with a 25% IRR and a $10 million alternative having a 20% IRR. An incremental analysis may be required. A standard engineering economics should be consulted for these situations.

Discounted Payback Period

The discounted payback period (DPP) represents the number of years for the present worth of net cash flows to recover the capital investment. Time value of money considerations are considered (as opposed to a simple payback period in which the time value of money is not considered).

4. General Considerations

4.1. Cost Accuracy

Since commercial-scale demonstration of an offshore wave power plant has not been accomplished to date, the economics associated with future wave power are uncertain. Furthermore, we do not know whether wave power will ever become cost competitive relative to other energy sources. However, we do believe that wave power is an energy resource that is too important to overlook and therefore needs to be developed to the point where the economics are well enough understood so there can be a determination of future cost competitiveness. In order to quantify the accuracy of the cost estimates to be made in this project, we use the accuracy versus cost estimate rating and stage of development relationship as shown in the following table:

Table 8: Accuracy Range for Cost Data

Cost Estimate Rating	A Mature	B Commercial	C Demonstration	D Pilot	E Conceptual (Idea or Lab)
A. Actual	0	-	-	-	-
B. Detailed	-5 to +5	-10 to +10	-15 to +20	-	-
C. Preliminary	-10 to +10	-15 to +15	-20 to +20	-25 to +30	-30 to +50
D. Simplified	-15 to +15	-20 to _20	-25 to +30	-30 to +30	-30 to +80
E. Goal	-	-30 to +70	-30 to +80	-30 to +100	-30 to +200

- A – Actual – Data on detailed process and mechanical designs with historical data from existing units
- B – Detailed – Detailed process and mechanical design and cost estimate but no historical data
- C – Preliminary – Preliminary process and mechanical design
- D- Simplified - Simplified process and mechanical design
- E – Goal – Technical design/cost goal or cost estimate developed from literature data

Using this table, the accuracy of the cost estimates for this project during the Phase 1A Project Definition Study are expected to be:

- Initial capital cost = -30 to +30% accurate based on the existence of prototypes and the simplified cost estimate level of detail for this project

- Replacement and overhaul capital cost and O&M = -30 to +80% accurate based on the lack of existence of any experience with periodic replacement and overhaul and O&M

The estimates will have a relatively high degree of uncertainty, particularly in the O&M and LO&RC area. E2I EPRI will evaluate the economic competitiveness at both the optimistic and pessimistic ends of the uncertainty spectrum.

4.2. Experience Curves

When comparing an emerging technology such as wave power to other generation options, it is important to understand that cost reduction of a commercial technology are achieved through experience as installed capacity or production volume grows. This relationship between cost and experience is represented by the experience curve illustrated in Figure 2 below where both axes are on a logarithmic scale.

4.2.1.The Experience Curve Equation

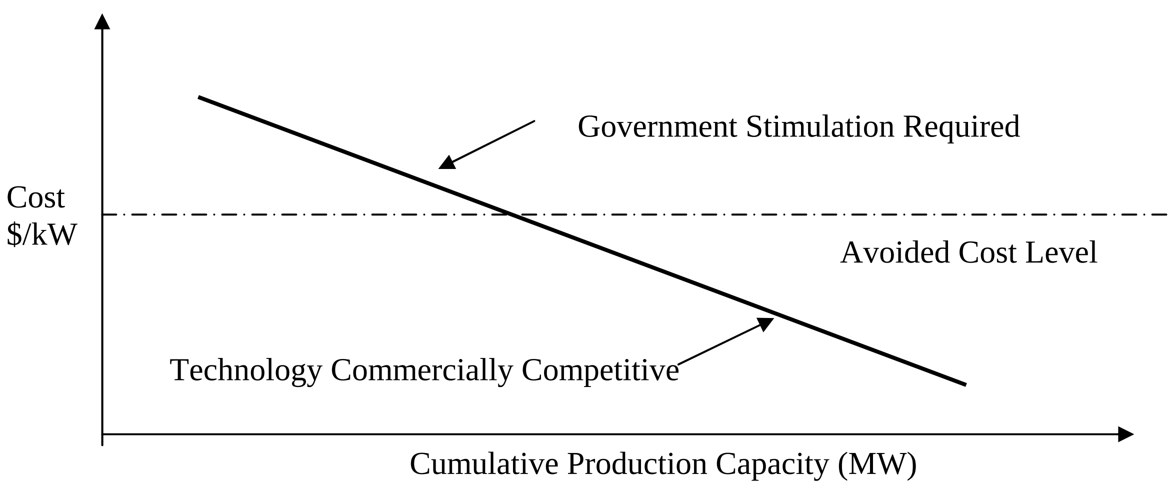

Figure 2 – A Typical Renewable Energy Technology Experience Curve

The above illustration shows the development of a typical power generation option. Initial capital costs are high and cost reductions start to occur as the technology matures and the installed capacity base grows. In order to bring any renewable resource into the market place, government stimulation is required in the early stage of production. Mechanisms to stimulate the adoption of technologies can be production credits, investment credits or a mandated purchase of a certain amount of energy from a specific resource option. As the installed capacity base grows, the cost of power generation comes down. Once it becomes commercially competitive (generation costs are falling below avoided cost levels), government incentives are no longer required and the market will adopt more capacity because the specific resource option is competitive without any subsidies.

The progress ratio and the learning rate are the same for any part of the simple experience curve in Figure 1. This means that young technologies learn faster from market experience than old technologies with the same progress ratios. Market expansion from 1 to 2 MW reduces prices by 18% in the example in Figure1, but, at a volume of 1000 MW, the market has to deploy another 1000 MW to obtain another 18% price reduction.

The curve in Figure 2 is commonly referred to as the "experience curve." The curve is described by:

$$\text{Price at year } t = Po * X\text{-}E \qquad \text{(Equation 3)}$$

where:

- Po = a constant equal to the price at one unit of cumulative production
- X = the cumulative production in year t
- E = the positive experience factor which characterizes the inclination of the curve.

Large value if E indicate a steep curve with a high learning rate. The relation between the progress ratio PR and the experience factor is

$$PR = \{Po * (2X)^{-E}\} / (Po * X^{-E}\} = 2^{-E} \qquad \text{(Equation 4)}$$

The experience parameter for the curve of Figure 1 is E = 0.29 which gives a Progress ratio $PR = 2^{-0.29} = 0.82 = 82\%$

The empirical and theoretical bases for expecting a reduction in unit cost with increased volume are well established. A recent paper [Reference 6] analyzed two business sectors closely related to offshore wave (and wind) farm costs, namely, oil and gas developments, and showed significant cost reductions were achieved with increasing experience with these technologies. The paper concludes that technological similarities with offshore wave energy renewable technologies indicate that it is reasonable to expect similar cost effects.

4.2.2. The PV Experience Curve

Figure 4 shows the experience curve for photovoltaic modules on the world Market [Reference 5] for the period 1976 to 2002. The data indicates a steady, progressive decrease in prices through cumulative sales that are used as the measure of the experience accumulated within the industry. The relationship remains the same over three orders of magnitude. The data are presented in a double logarithmic diagram. With this representation, it is possible to follow the experience effect over many orders of magnitude of production volume with a straight-line representation, making it easy to identify the experience effect.

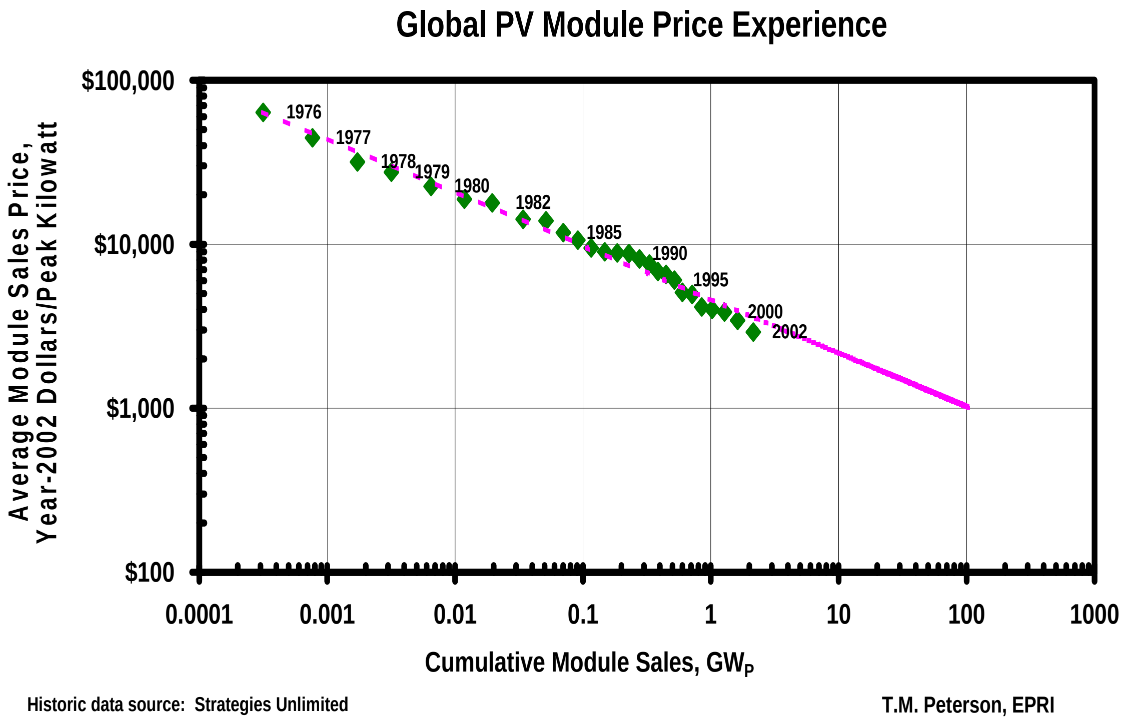

Figure 3. PV Experience Curve

The experience curve for PV shown in Figure 3 has a progress ration PR = 82% meaning that the price is reduced by 0.82 of its previous level after a doubling of cumulative sales.

4.2.3. The Wind Technology Experience Curve

Wind energy system costs have decreased significantly over the past couple of decades [Reference 7]. The initial capital cost per kW in 1980 is quoted at about $2,800/kW and this decreased to about $1,000/kW in 1995.

Worldwide, installed wind capacity has grown an average of 25% per year since 1990 [Reference 5]. By the end of 2000 it reached 17.0 GW. In the U.S., average wind energy cost of electricity (year 2000 dollars) fell from 47 cents/kWh in 1981 to 5.1 cents/kWh in 1995 as installed wind power capacity expanded to about 1.5 GWe. Historically, progress curve rates are about 80% in the U.S. for wind, PV, and gas turbine technology [Reference 6]. In Europe, similar 80% progress rate curves have been seen. [Reference 7 Figure 3.3]

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