REVISION 2

EPRI Guideline

Economic Assessment Methodology for Tidal In-Stream Power Plants

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1. Introduction

To evaluate the economics of tidal in-stream power plants, the Electric Power Research Institute (EPRI) proposes three standard economic assessment methodologies: one for a utility generator (UG), one for a municipal generator (MG), and one for a non-utility generator (NUG). The EPRI Project Team will use these methodologies, and their associated financial assumptions, to evaluate the economics of both a pilot demonstration plant (with a yearly energy produced of the order of 3,000 Mega Watt Hours Electric per Year (MWeh/yr) and a notional commercial scale size plant (sized to extract 15% of the total in stream kinetic energy available at the feasibility study sites).

Taxable regulated utilities (independently owned 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.

Non taxable municipal utilities also set electricity rates that will cover operating costs, however, utility projects are financed by issuing tax-exempt bonds, enabling local governments to access some of the lowest interest rates available

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, and power purchase and contract terms determine project risks and therefore the cost of money.

This regulated UG and MG methodologies are based on a levelized cost approach using real (or constant) dollars with 2005 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 a tidal energy generation project (i.e., a project to engineer, permit, procure, construct, operate and maintain a tidal energy power plant).

The MG methodology includes a special incentive for U.S. municipalities afforded under the Renewable Energy Production Incentive (REPI). This incentive was originally authorized under section 1212 of the Energy Policy Act of 1992, and updated by the Energy Policy Act of 2005, to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. REPI provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Eligible electric production facilities are those owned by State and local government entities (such as municipal utilities) and not-for-profit electric cooperatives.

The Energy Policy Act of 2005 (P.L. 109-58) provides electric cooperatives and public power systems with the ability to issue “Clean Renewable Energy Bonds” (“CREBs”). The CREBs program is further described in Internal Revenue Service (IRS) Notice 2005-98.

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 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 tidal power technology must be made on the basis of large-scale commercial plant economics. A cost estimate of the initial capital cost and the yearly operation and maintenance cost for a future envisioned future commercial plant at a specific site is the initial input into an economic feasibility assessment. The purpose of the commercial scale plant cost of electricity evaluation is to assess the economic viability of a large-scale commercial application of the tidal energy 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 tidal 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 commercial scale tidal in-stream power plant is favorable with respect to alternative renewable generation options, a case can be made for pursuing the development of tidal flow energy conversion technology. If, however, even with the most optimistic assumptions, the economics of a commercial size tidal flow power plant is not favorable and cannot economically compete with the alternatives, a case can be made for not pursuing tidal flow energy conversion technology development.

Relative to the pilot demonstration plant, the decision of whether to fund the Phase II Detailed Design, Permitting and Construction Financing Task will be made at the conclusion of the Phase 1 Feasibility Study in the spring of 2006. 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 work. 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) and Municipal Generator (MG) Cost of Electricity Assessment Methodology and Assumptions

The proposed UG and MG methodology is based on generally accepted regulated utility accounting practices. The 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 COE. It is important to understand that the underlying assumptions must be the same for the different technologies being compared fairly

The methodology is implemented in an excel-spreadsheet solution which allows the analyst to input tidal 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 and MG 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 and MG 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:

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

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:

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

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 specification [(Reference 3)]. Since long-term tidal 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 tidal 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 tidal flow power plant are described in this section. All capital expenditures are defined as installed cost and expressed in constant dollars with 2005 as the reference year. They include shipping and commissioning cost. The first level cost breakdown structure outlined below allows comparing different generation alternatives and identifying sensibilities of a particular tidal power conversion design.

- *Turbine:* All components that are directly responsible for the extraction of energy from tidal flow energy, such as the rotor and its associated controls if any, and the main shaft

- *Extractor Structure:* All structural components such as housings ducts and any other structural components required

- *Power Take Off:* Converts the slow movement of the extraction turbine or similar device via gearing or hydraulics an generator into electricity at grid frequency (50Hz or 60Hz) and transmission voltage (the conversion may be done on shore)

- *Foundation/Mooring/Anchoring:* All components required for holding the tidal flow power conversion device in place.

- *Electrical Interconnection:* All cables required to interconnect the individual tidal flow power conversion units to a common interconnection point in/close to the tidal channel.

- *Grid Interconnection:* All cabling, switchgear, transmission lines and infrastructure required to connect from the common interconnection point of the tidal flow 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 (Tidal Flow Power Plant in this case), for simplicity, 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 tidal channel-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 tidal flow farm and general facilities required for deploying and operating the power plant. This could include necessary dock modifications, maintenance shops, etc. for the deployment and maintenance of the tidal flow 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 tidal flow power 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 tidal flow power 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 tidal flow power conversion turbine and the power take off system

  - Scheduled major overhauls and subsystem replacements of the 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:* 1.5% of TPC

- *Periodic Levelized Overhaul and Replacement Cost (LO&RC):* Depending on the specific manufacturer's design, major overhaul of the 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 US 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: US State and Composite Income Tax Rates

State	State Tax Rate	Composite Rate Assuming 35% Federal Rate [a]
Alaska	9.40 % [b]	41.1 %
California	8.84 % [c]	40.7 %
Maine	8.93 % [d]	40.8 %
Massachusetts	9.50 % [c]	41.2 %
Washington	0.00 % [e]	35.0 %

[a] Since US state income taxes are deductible for federal income taxes purposes, composite rate calculated as follows: [Fed Rate + (State Rate x (1 – Fed Rate))] ((0.35+0.094*(1-0.35))*100 = 41.1%
[b] Assumes top tier tax rate (out of ten tiers) for annual income greater than $90,000
[c] Flat corporate rate
[d] Assumes top tier tax rate (out of four tiers) for annual income greater than $250,000
[e] No state income tax in the state of Washington

For participating Canadian provinces, we assume a Canadian federal corporate tax rate of 22% and provincial tax rates as shown in Table 2.

Table 2: Canadian Province and Composite Income Tax Rates

Province	Provincial	Canadian Federal	Combined Rate [a]

	Tax Rate	Tax Rate	
New Brunswick	16.0% [b]	22%	38.0%
Nova Scotia	16.0% [b]	22%	38.0%

[a] Since provincial corporate income taxes are not deductible for federal corporate income tax purposes (or vice-versa), combined rate is simply Provincial Rate + Federal Rate.
[b] Source: http://www.fin.gc.ca/toce/2002/cantaxadv_e.html

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 3(Reference 4).

Table 3: Applicable Accelerated Tax Depreciation Schedule

Year	Depreciation Rate	
	U.S.	Canadian (declining balance)
1	20.00 %	30%
2	32.00 %	21%
3	19.20 %	14.7%
4	11.52 %	9.4%
5	11.52 %	6.6%
6	5.76 %	4.6% etc

The US Internal Revenue Service explicitly mentions solar, wind, and geothermal as examples of qualifying renewable resources. Since the status of tidal in-stream energy as a renewable energy resource is self-evident, it is reasonable to assume that tidal 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 are 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.

Canadian tax law allows for accelerated depreciation on "electrical generating equipment using wind, solar of geothermal energy" under Capital Cost Allowance (CCA) class 43.1. Since the spirit of the law is to encourage the development of renewable energy resources, we can reasonably assume that tidal in-stream energy would qualify for the same accelerated depreciation treatment. This would allow an accelerated depreciation schedule of 30% declining balance, compared to the baseline depreciation rate of 4% declining balance for this category of equipment.[2] This is referenced in Table 3 above. Natural Resources Canada provides, at no charge, prior opinions on the technical eligibility of proposed projects for this accelerated depreciation treatment.

In addition, the government of Canada has defined Canadian Renewable and Conservation Expenses (CRCE), a category of fully deductible expenditures associated with the start-up of renewable energy and energy conservation projects for which at least 50% of the capital costs of the property would be described in Class 43.1. Under CRCE, eligible expenditures are 100% deductible in the year they are incurred or can be carried forward indefinitely for deduction in later years. Examples of intangible expenses that may be written off in this manner include:

- cost of pre-feasibility and feasibility studies of suitable sites and potential markets
- for projects that will have equipment included in Class 43.1
- costs related to determining the extent, location and quality of energy resources
- negotiation and site approval costs
- certain site preparation costs that are not directly related to the installation of equipment
- service connection costs incurred to transmit power from the project to the electric utility

2.3. Incentives

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

- Renewable Energy Certificates (RECs)
- Production tax credits
- Investment tax credits

These incentives will be analyzed for the commercial scale power plant economics analysis. REC market values and investment and production tax credits for each of the states and provinces are shown in Table 4.

[2] Source: Canadian Department of Finance (http://www.fin.gc.ca/taxexp/1999/taxexp99_5-2e.html)

Table 4: Renewable Energy Certificates and Investment /Production Tax Credits (2005$)

<table>
<tr><th colspan="2"></th><th colspan="2">Investment Tax Credit</th><th colspan="2">Production Tax Credit</th></tr>
<tr><th></th><th>REC</th><th>State</th><th>Federal</th><th>State</th><th>Federal</th></tr>
<tr><td>Alaska</td><td>NA</td><td>NA</td><td rowspan="5">10% of TPI</td><td>NA</td><td rowspan="5">1.8¢ per kWh for the first 10 years and an EPRI assumed escalation of 3% per year</td></tr>
<tr><td>California</td><td></td><td>The lesser of 7.5% or $4.50 per Watt of rated peak generating capacity [a]</td><td>Supplemental Energy Payments (SEPs) for costs above a market price referent [b]</td></tr>
<tr><td>Massachusetts</td><td>$0.05/kWh for entire project life</td><td>Installation cost deductible if installed in Massachusetts</td><td>$0.06 per kWh for up to 3 years [c]</td></tr>
<tr><td>Maine</td><td>$0.012/kW for entire project life [h]</td><td>$50,000 grant [d]</td><td>1.7 - 6.4 cents per kWh [e]</td></tr>
<tr><td>Washington</td><td></td><td>NA</td><td>Sales and Use Tax Exemption [f]</td></tr>
<tr><th></th><th></th><th>Province</th><th>Federal</th><th>Province</th><th>Federal</th></tr>
<tr><td>New Brunswick</td><td>NA</td><td>NA</td><td rowspan="2">35% up to the first $2 million of qualified expenditures; 20% on any excess amount</td><td>NA</td><td rowspan="2">1.0 ¢ (Cdn.) per kWh for Wind for the first 10 years</td></tr>
<tr><td>Nova Scotia</td><td>NA</td><td>NA</td><td>NA</td></tr>
</table>

[a] Corporate tax credit (SB 17x2) currently applies only to PV or wind technologies. Reference: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA33F&state=CA&CurrentPageID=1

[b] Subject to determination by the California Energy Commission. Tidal energy explicitly included as an eligible technology. Reference: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA22F&state=CA&CurrentPageID=1

[c] Mass Energy - Renewable Energy Certificate Incentive. However, PV is the only eligible technology. Reference: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MA10F&state=MA&CurrentPageID=1
The above offer cited is a private offer and not a state program – If private offers are to be included then other products should also be included

[d] Renewable Resources Matching Fund Program provides a grant of up to $50,000 to support renewable resource R&D and community demonstration projects using renewable energy technologies. Eligible technologies include: Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, and Tidal Energy. 100 MW max capacity limit. Reference: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=ME03F&state=ME&CurrentPageID=1

[e] Mainstay Energy Rewards Program - Green Tag Purchase Program provides 1.7 - 6.4 cents/kWh in incentives; which varies by technology, contract length, and payment plan. Intended for commercial and residential projects, not electrical generation facilities, though there is no explicit limit on system size or annual incentive amount. Eligible technologies include: Solar Thermal Electric, Photovoltaics, Wind, Biomass, Geothermal Electric, Small Hydroelectric, Renewable Fuels. Reference: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=ME02F&state=ME&CurrentPageID=1

[f] H.B. 1859, singed into law by Governor on May 8, 2001, expanded the sales and use tax exemption for solar, wind, and landfill gas electric generating facilities to include fuel cells. Does not explicitly include tidal energy.

[g] REC range of $0.015 - $0.05/kWh applies to solar PV in the California wholesale market, and varies based on location and other site-specific attributes. (source: http://www.californiasolarcenter.org/pdfs/forum/2005.2.23-SolarForum_KChristy_SolarRECs_in_CA.pdf) The California RPS calls for renewables to account for 20% of energy by 2017; to be attained in increments of 1% each year beginning in 2003.

[h] Source: National Renewable Energy Lab and EAD Environmental http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

[i] Source: National Renewable Energy Lab and Bonneville Environmental Foundation http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=1

Renewable Portfolio Standard (RPS) and Renewable Energy Credits (REC)

A renewable portfolio standard (RPS) is a state-by-state requirement that a minimum percentage of each electricity generator's or supplier's resource portfolio derive from renewable energy. A RPS creates a minimum commitment to a sustainable energy future for a given state. It builds on and enhances the investment already made in sustainable energy, and it ensures that new electricity markets recognize that clean renewable electricity is worth more than polluting fossil fuel and nuclear electricity. Further, these goals can be accomplished using a market approach that provides the greatest amount of clean power for the lowest price and an ongoing incentive to drive down costs. By using tradable "renewable energy credits" (RECs) to achieve compliance at the lowest cost, the RPS would function much like the Clean Air Act credit-trading system, which permits lower-cost, market-based compliance with air pollution regulations.

Renewable Portfolio Standards (RPS) exist in nineteen states (and may soon exist at a national level) and act as a driver for a REC market. Basically, a generator of renewable non-polluting electricity can have two income streams; the first from the sale of the electricity generated and the second from the sale of renewable energy certificates which are accrued by generating electrical energy without emissions.

Massachusetts RPS - Established as part of the 1997 utility restructuring act, the Massachusetts RPS (225 CMR 14.00) was issued by the state's Division of Energy Resources (DOER). It promotes the deployment of clean energy technologies in a couple of ways. First, it requires all retail suppliers licensed in Massachusetts to buy renewable energy certificates (RECs) produced by generating facilities that meet certain criteria. Second, it creates a new revenue stream for facilities meeting RPS criteria. Facility owners can sell both electricity and RECs, either directly to consumers or to other suppliers. Each megawatt-hour (MWh) of clean energy produced is allocated one REC. These RECs are monitored and traded through the New England Generation Information System (NE-GIS). The value of RECs is currently between 4.5 and 5.0 cents/kWh.

Maine RPS - The State of Maine Public Utility Commission (PUC) adopted a Renewable Resource Portfolio Requirement rule on September 28, 1999 (effective November 4, 1999) pursuant to the state's 1997 electric utility restructuring law. The rule requires electric providers to supply at least 30% of their total retail electric sales in Maine with electricity from eligible renewable resources.

Eligible resources must be a "small power production facility" that produces electricity using only a primary energy source of biomass, waste, renewable resources, or a combination of these resources and has a production capacity of 80 megawatts or less including any other facilities at the same site. A renewable resource may also be a generation facility of 100 MW or less that uses fuel cells, tidal power, solar arrays and installations, wind power installations, geothermal installations, hydroelectric generators, biomass generators, or generators fueled by municipal solid waste in conjunction with recycling. In addition to renewables, the portfolio standard can be met with "efficient resources," specifically, qualified cogeneration facilities.

In June 2003 the PUC adopted an order (Docket No. 2002-494) amending the RPS rule to incorporate the use of NEPOOL Generation Information System certificates (renewable energy credits) to satisfy the portfolio requirement.

California RPS

On September 12, 2002, Governor Gray Davis signed a bill (SB 1078) requiring California to generate 20 percent of its electricity from renewable energy no later than 2017. The 20 percent standard was the most stringent renewables portfolio standard (RPS) to date in the United States. The new law requires sellers of electricity at retail to increase their use of renewable energy by 1 percent per year. Since California already generates about 10 percent of its electricity consumption by renewables, the new law will nearly double the state's existing base of wind, geothermal, biomass and solar energy resources. An estimated 9,000 MW of renewables will be needed.

A June 2005 report for the Energy Commission contains the following update: The state's Energy Action Plan and the California Energy Commission's Integrated Energy Policy Report have since expressed a state goal of accelerating the implementation of the RPS such that the 20-percent goal is met seven years early—by 2010. The Governor has endorsed this accelerated schedule and has set a goal of achieving a 33-percent renewable energy share by 2020 for the state as a whole.

Nova Scotia RPS - The RPS for Nova Scotia calls for 5% of electricity generation from renewable resources by 2006 and 10% by 2011. The percentage is based upon actual power sold and is not based upon installed generation capacity.[3]

New Brunswick RPS - New Brunswick announced an RPS target of 10% additional RE by 2016 (33% in total). http://www.gnb.ca/cnb/news/ene/2005e0788en.htm

Neither **Alaska** nor **Washington** have enacted a RPS.

Renewable Energy Credit (REC)

[3] Source: http://naturalforces.ca/documents/WIND-energy%20submission%20Final.pdf

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. This market applies to Massachusetts and Maine, but it does not apply to either New Brunswick or Nova Scotia which are outside the NE ISO territory.

Renewable Production Tax Credit (PTC)

The U.S. 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 granted 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 tidal energy will be eligible for the PTC

Canada provides a production incentive for wind power under the Wind Power Production Incentive (WPPI). The Federal Government announced a new program in the 2005 budget. It is the Renewable Power Production Incentive. There is also an expansion of WPPI and it will provide 1 cent (Cdn.) per kWh for the first ten years. For projects commissioned after March 31, 2006, this incentive would be 1 ¢ (Cdn.) per kWh for the first 10 years of production, representing in the estimate of the Canadian government about half of the estimated cost premium for wind energy in Canada for facilities with good wind sources. There is no similar explicit production incentive for tidal in-stream developments.[4]

Canada also provides the Scientific Research and Experimental Development (SR&ED) federal tax incentive program to encourage Canadian businesses to conduct research and development in Canada that will lead to new, improved, or technologically advanced products or processes. The SR&ED program is the largest single source of federal government support for industrial research and development. Applicants may claim SR&ED investment tax credits for expenditures such as wages, materials, machinery, equipment, some overhead, and SR&ED contracts. Generally, a Canadian-controlled private corporation can earn an investment tax credit of 35% up to the first $2 million of qualified expenditures for SR&ED carried out in Canada, and 20% on any excess amount. Other Canadian corporations, proprietorships, partnerships, and trusts can earn an investment tax credit of 20% of qualified expenditures for SR&ED carried out in Canada.[5]

To qualify for the SR&ED program, the project must advance the understanding of scientific relations or technologies, address scientific or technological uncertainty, and incorporate a

[4] Source: Canada Ministry of Natural Resources (http://www.canren.gc.ca/programs/index.asp?CaId=107&PgId=622), http://www.fin.gc.ca/budget05/bp/bpc5e.htm#climate

[5] Source: Canada Revenue agency (http://www.cra-arc.gc.ca/taxcredit/sred/aboutus-e.html)

systematic investigation by qualified personnel. Work that qualifies for SR&ED tax credits includes:

- experimental development to achieve technological advancement to create new materials, devices, products, or processes, or improve existing ones
- applied research to advance scientific knowledge with a specific practical application in view
- basic research to advance scientific knowledge without a specific practical application in view
- support work in engineering, design, operations research, mathematical analysis, computer programming, data collection, testing, or psychological research, but only if the work is commensurate with, and directly supports, the eligible experimental development, or applied or basic research

It is reasonable to assume that a pilot-scale tidal in-stream development project would be eligible for the SR&ED tax incentive, and plausible that even *the first* commercial scale plant could be similarly eligible. However, a formal prior opinion from the Canada Revenue Agency would be advisable.

Renewable Energy Production Incentive (REPI) for MGs

MG's are eligible for a production incentive of 1.5 cents per kWh (based on 1993 dollars indexed to inflation) for the first ten years of operation for qualifying facilities installed between October 1, 2005 and October 1, 2016.

Qualifying facilities installed between October 1, 2005 and October 1, 2016 are eligible for annual incentive payments of 1.5 cents per kilowatt-hour (1993 dollars and indexed for inflation) for their first ten years of operation, subject to the availability of annual appropriations in each Federal fiscal year of operation. Criteria for qualifying facilities and application procedures are contained in the rulemaking for this program. Qualifying facilities must use solar, wind, geothermal (with certain restrictions as contained in the rulemaking), biomass (except for municipal solid waste combustion), or landfill gas generation technologies. Although the tidal energy is not explicitly included under the list of examples of qualifying facilities, tidal is explicitly referenced as a renewable resource elsewhere in the Energy Policy Act. It is reasonable to assume that a tidal power plant would be considered a qualifying facility.

Clean Renewable Energy Bonds (CREB)

The Energy Policy Act of 2005 (P.L. 109-58) provides electric cooperatives and public power systems with the ability to issue "Clean Renewable Energy Bonds" ("CREBs"). The CREBs program is further described in Internal Revenue Service (IRS) Notice 2005-98. CREBs deliver an incentive comparable to the Production Tax Credit ("PTC") that is available to private developers and investor owned utilities ("IOUs"). A CREB is a special type of bond, known as a "tax credit bond," that offers cooperatives the equivalent of an interest-free loan for financing qualified energy projects for a limited term.

Renewable energy projects that qualify for the PTC generally qualify for CREB financing. Specifically, these projects include wind, closed-loop biomass, open-loop biomass (including agricultural livestock waste), geothermal, solar, municipal solid waste (including landfill gas and trash combustion facilities), small irrigation power and hydropower. EPRI assumes that Ocean Tidal Power can be a subcategory under hydropower and therefore would apply. The electric cooperative or cooperative lender (“Issuer”) would issue the CREBs and sell them to bondholders. With a conventional bond, the Issuer must pay interest to the bondholder. But with a tax credit bond, the Issuer does not make interest payments. The federal government provides a tax credit to the bondholder in lieu of the Issuer paying interest to the bondholder. Treasury sets the rate of the credit on a daily basis, at a level that permits the issuance of the CREBs without discount and without interest cost to the Issuer. When the bondholder purchases the bond, the credit rate is locked in for the term of the bond. The credit accrues quarterly and is included in gross income of the bondholder (as if it were an interest payment on the bond). The bondholder takes the amount of the tax credit as a credit against its regular income tax liability and alternative minimum tax liability. Repayment of principal to the bondholder occurs on a “level annual repayment” basis, meaning equal payments each year of the term of the bond, commencing in the first year of issuance. The value of the CREB to a bondholder for any year is equal to the credit, less the amount of tax payable on the credit. For example, if the credit amount is $100 and the bondholder is in the 35 percent tax bracket, the credit provides a $65 benefit to the bondholder.

Section 1303 of the Energy Tax Incentives Act of 2005, Pub. L. No. 109-58 (the Act), added section 54 to the Code. In general, section 54 authorizes up to $800,000,000 of tax credit bonds to be issued by qualified issuers to finance certain renewable energy projects described in section 45(d) of the Code.

Section 54(j)(4) defines a “qualified issuer” as: (1) a clean renewable energy bond lender; (2) a cooperative electric company; or (3) a governmental body. Section 54(j)(2) provides that a “clean renewable energy bond lender” is a lender that is: (1) a cooperative that is owned by, or has outstanding loans to, 100 or more cooperative electric companies and was in existence on February 1, 2002; or (2) any affiliated entity controlled by such a lender. Section 54(j)(1) defines the term “cooperative electric company” as a mutual or cooperative electric company described in section 501(c)(12) or section 1381(a)(2)(C), or a not-for-profit electric utility that has received a loan or loan guarantee under the Rural Electrification Act. Section 54(j)(3) defines the term “governmental body” as any State, territory, possession of the United States, the District of Columbia, Indian tribal government, or any political subdivision thereof. Section 54(j)(5) provides that a “qualified borrower” is: (1) a mutual or cooperative electric company described in section 501(c)(12) or 1381(a)(2)(C); or (2) a governmental body.

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 tidal in-stream energy project, we will use the following assumptions:

- 20 year plant life
- All costs in real or constant January 2005 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 [6]

Utility Generator (i.e., independently owned utility (IOU)) assumptions are
- Capital structure of 65% equity and 35% debt [7]
- Distribution of equity: 52% common equity and 13 % preferred equity[8]
- 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 5: Regulated UG 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)

Municipal Utility Generators issue tax-exempt bonds to finance utility projects, enabling local governments to access some of the lowest interest rates available. Financing assumptions are:

- Projects 100% financed by the Bond Market
- Cost of capital = 5% nominal (2% real)
- Not taxable

[6] Source: U.S. Bureau of Labor Statistics, 2004
[7] www.eere.energy.gov/consumerinfo/pfds/financial.pdf
[8] 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 [9]
- 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 6: 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 construction 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.

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 7.

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

Table 7. NUG Income Statement

	Year - 2	…………….	Year N	Total
REVENUES				
Capacity Payments				
Energy Payments				
Renewable Energy Certificates				
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 February 2005 industrial and residential electricity prices by state from the DOE Energy Information Agency, interpreted as wholesale and retail prices respectively, is provided in Table 8:

Table 8: Proxies for Wholesale and Retail Rate by State or Province

State [1] Province	**Wholesale Rate Proxy (Average Industrial Rate)**	**Retail Rate Proxy (Average Residential Rate)**
Alaska	8.63 cents / kWh	12.64 cents / kWh
California	8.15 cents / kWh	11.83 cents / kWh
Maine	5.05 cents / kWh	12.54 cents / kWh
Massachusetts	9.26 cents / kWh	13.43 cents / kWh
Washington	3.86 cents / kWh	6.42 cents / kWh
New Brunswick	4.67 cents (Cdn.) / kWh [2]	8.13 cents (Cdn.) / kWh [2]
Nova Scotia	4.90 cents (Cdn.) / kWh [3]	8.61 cents (Cdn.) / kWh [3]

[1] Source for U.S. state figures, US DOE Energy Information Agency (http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html)

[2] Source: New Brunswick Power, Monthly Electricity Rates as of March 31, 2005. Industrial Service Rate (after first 100 kWh) used as proxy for wholesale rate (does not include base charges or demand charges.) Residential Service Rate (for first 1,300 kWh) used as proxy for retail rate (no demand charges, and excludes base charges). (http://www.nbpower.com/en/customers/policies/2005%20English%20Rate%20Card3.pdf)

[3] Source: Nova Scotia Power, 2005 Rate Case Application, Appendix L. Rates as of August 6, 2004. Large General Rate used as proxy for Wholesale Rate (does not include base charges or demand charges). Domestic Service Rate used as proxy for Retail Rate (does not include base charges; no demand charges). (http://www.nspower.ca/AboutUs/RegulatoryAffairs/RateCase2005/DOCS/AppendixL_ElectricRates_07222004.pdf)

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

- Maine & Massachusetts – 5 cents/kWh in 2004$ from the New England ISO website in October, 2004 for the day ahead market
- California – assume wholesale rate of 8.15 cents / kWh from Table 8.

- Washington – assume wholesale rate of 3.86 cents / kWh from Table 8.
- New Brunswick – assume wholesale rate of 4.67 cents (Cdn.) / kWh from Table 8.
- Nova Scotia – assume wholesale rate of 4.90 cents (Cdn.) / kWh from Table 8.

Electricity Price Forecast

The electricity price forecast from the EIA (Reference 8) is shown graphically in Figure 1 and is as follows *"Average U.S. electricity prices, in real 2003 dollars, are expected to decline by 11 percent, from 7.4 cents per kilowatthour in 2003 to 6.6 cents in 2011 then rise to 7.3 cents per kilowatthour in 2025. Prices follow the trend of the generation cost component of price, which makes up 65 percent of the total price of electricity and changes mainly in response to changes in natural gas prices."*

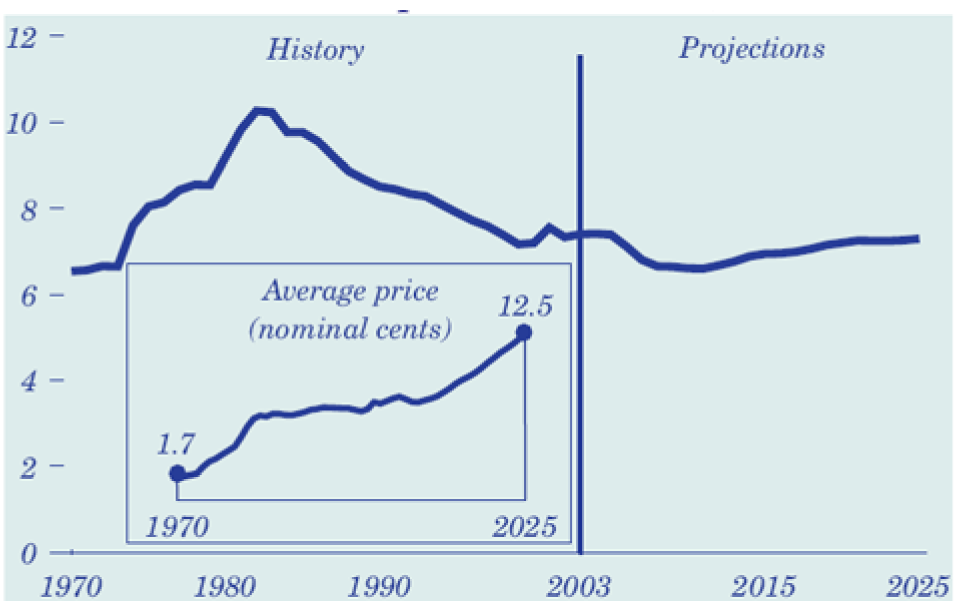

Figure 1. EIA U.S. Retail Electricity Price and Forecast, 1970 – 2025
(2003 Base Year; cents per kilowatt hour)

Most would probably view this 10% increase in electricity prices in constant dollars from 2011 to 2025 to be a conservative forecast. We have chosen to use this forecast as it is consistent with our philosophy throughout the EPRI Ocean Energy feasibility studies of avoiding assumptions which might cause reviewers of this work to perceive EPRI as attempting to make renewable ocean energy look more favorable that it really is.

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 9. 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 9. 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 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 brought back to the same date.

Internal Rate of Return

The internal rate of return (IRR) addresses the profitability of a project. Mathematically, the IRR 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 year. 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 a tidal in-stream power plant has not been accomplished to date, the economics associated with future tidal power are uncertain. Furthermore, we do not know whether tidal in-stream power will ever become cost competitive relative to other energy sources. However, we do believe that tidal in-stream 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 10: 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 1. 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. EPRI will evaluate the economic competitiveness at both the optimistic and pessimistic ends of the uncertainty spectrum.

5. Economic Comparisons

The purpose of this section is to describe how EPRI will compare the economics of Tidal In-Stream Energy Conversion (TISEC) plants to other alternatives such as coal, natural gas, nuclear and other renewable technologies such as wind, solar and geothermal.

5.1. Background

The current capital and O&M costs of commercial scale TISEC plant designs will be estimated in the 2005 EPRI North America Collaborative In Stream Tidal Feasibility Study for sites in New Brunswick, Nova Scotia, Maine, Massachusetts, Alaska, Washington and San Francisco (CA) by the EPRI Project Team. Note that the current capital and O&M costs of commercial scale Wave Energy Conversion (WEC) plant designs were estimated in the 2004 EPRI U.S Collaborative Feasibility Study for sites in Maine, Massachusetts, Hawaii, Oregon and San Francisco (CA) by the EPRI Project Team (see Reference 10).

The current comparative costs of different generation technologies are given in Table 11a for 2010 and Table 11b for 2020 (both in 2004$). Capital costs are given in $/kW. They have wide ranges that depend on the size of the plant and other conditions such as environmental controls for coal and quality of the resource for geothermal. We are using generally accepted average numbers and ranges from EPRI sources (Reference 11).

Table 11a: COE for Alternative Energy Technologies - 2010

2010: Economic Outlook for Various Technologies					
	Efficiency (%)	**Capacity Factor (%)**	**Overnight Capital Cost(1) ($/kW)**	**Cost of Electricity (COE)(1) ($/MWhr)**	**CO2 Emissions (lbs per MWhr)**
Coal(2) PC USC	39	80	1250	41	1757
Coal(2) PC USC w/ CO2 capture	30	80	2100	67	115 (95% Removal)
Coal(2) CFB	36	80	1370	49	1914
IGCC(2) GE – Quench W/O CO2 capture	37	80	1380	47	1887
IGCC(2) GE - Quench w/ CO2 capture	30	80	1780	60	344(3) (85% Removal)
NGCC(4) (@ $7/MM Btu)	46	80(5)	460	63	863
NGCC(4) (@ $5/MM Btu)	46	80(5)	460	47	863

Nuclear Evolutionary (ABWR)	N/A	85-90	1600	46 – 49	None
Nuclear Passive (ESBWR / AP 1000)	N/A	85-90	1400 – 1700	41 - 47	None
Wind (Class 3 to Class 6)	N/A	30-42	1100	46 - 64	None
Solar Thermal (Parabolic Trough)	N/A	33	3150	180	None
Biomass CFB	28	85	2000	62	264[6]

Notes:

1) All costs in 2004$; COE in levelized constant 2004$ and includes capital cost. Capital Cost is overnight, W/O Owner, AFUDC costs.
2) All fossil units about 600 MW capacity; Pittsburgh#8 coal for PC, CFB, IGCC.
3) Based on Gas Turbine technology limitations to handle hydrogen
4) NGCC unit based on GE 7F machine or equivalent by other vendors
5) Represents technology capability 6) Recent market data based on 2004 operation
67) Value shown is 10% emission of total. The remainder is assumed to be absorbed by the biomass plant crop growth cycle

Table 11b: COE for Alternative Energy Technologies - 2020

2020: Economic Outlook for Various Technologies					
	Efficiency (%) Goal	**Capacity Factor (%)**	**Overnight Capital Cost[1] ($/kW)**	**Cost of Electricity (COE)[1] ($/MWhr**	**CO2 Emissions (lbs per MWhr)**
Coal[2] PC First of a Kind USC	46-48	80	1200 – 1500	37 -42	1250 – 1300
Coal[2] PC USC w/ CO2 capture	37-39	80	1600-1900	48-53	85 (95% Removal)
Coal[2] CFB	45-47	80	1250-1550	42-48	1350-1400
IGCC[2] GE Quench W/O CO2 capture	42	80	1130	38	1662
IGCC[2] GE Quench W/ CO2 capture	37	80	1350	50	100 (95% Removal)
NGCC[3] Advanced (@ $7/MM Btu)	54	80[4]	500 – 740	56- 60	660
NGCC[3] Advanced @ $5/MM Btu)	54	80[4]	500 – 740	39-43	660
Nuclear First of a kind (Generation IV)	N/A	70-90	1600 - 1800	46-60	None
Fuel Cell GT Hybrid First of Kind	50 – 55	60-80	1500 - 2000	50-70	600
Wind	N/A	40	660	32	None

Solar Thermal (Parabolic Trough)	N/A	35	2800	160	None
Biomass CFB	34	80	1200	43	220(6)

Notes:
1) All costs in 2004$; COE in levelized constant 2004$ and includes capital cost. Capital Cost is overnight, W/O Owner, AFUDC costs
2) All fossil units about 600 MW capacity; Pittsburgh#8 coal for PC, CFB, IGCC. Advancements in CFB in larger sizes and higher efficiency are being carried out. PC USC is 5000 psi 1112-1292F
3) NGCC unit based on GE H Type or equivalent by other vendors
4) Represents technology capability
5) Recent market data based on 2004 operation
6) Value shown is 10% emission of total. The remainder is assumed to be absorbed by the biomass plant crop growth cycle

The fuel cost for coal and natural gas (NG) is the price of fuel (in $ per Mbtu), times the heat rate (BTUs needed to generate a kWh of electricity – 10,000 for PC Coal, 9,000 for IGCC, 12,000 for Gas CT and 7,000 for NG CC), divided by 10,000.

New Brunswick Power expects any new coal plants after 2010 will use super critical technologies; therefore the heat rates and efficiencies should be better than those shown in the previous paragraph. In addition, climate change initiatives will push New Brunswick Power to use the best new technologies available after 2008; therefore, New Brunswick Power expects to use the best new technologies available after 2010 and CO2 capture will happen after 2012/2013. (Currently IGCC capture is ready)

5.2. Key Assumptions

All costs are calculated without government subsidies or incentives. The following is a list of the key assumptions, which form the basis of the numbers stated in this report.

1. 2005 base year – expressed in current year dollars
2. Book life/Tax life
3. Federal Tax rate
4. State Tax rates
5. Depreciation schedule
6. Government incentives applied (should be none)
7. Capital financing structure (% common equity, preferred equity and debt)
8. Financing rates (common equity, preferred equity and debt) – expressed in nominal rates)

Table 12: Assumptions forming the Basis for COE for Alternative Energy Technologies

	Book Life/ Tax life)	Fed Tax Rate	State Tax Rate	Dep Sch	% Equity UG/ NUG/ Public	Equity Disc't Rate (Real) UG/NUG	% Debt UG/ NUG/ Public	Debt Disc't Rate (Real) UG/NUG/ Public	Inflation Rate
Coal[(2)] PC First of a Kind USC	30/ 20	35	6.5	ACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Coal[(2)] PC USC w/ CO2 capture	30/ 20	35	6.5	ACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Coal[(2)] CFB	30/ 20	35	6.5	ACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
IGCC[(2)] GE Quench W/O CO2 capture	30/ 20	35	6.5	ACRS	45/ 30/ 00	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
NGCC[(3)] Advanced (@ $7/MM Btu)	30/ 20	35	6.5	ACRS	45/ 30/ 00	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
NGCC[(3)] Advanced @ $5/MM Btu)	30/ 20	35	6.5	ACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Nuclear First of a kind (Gen IV)	30/ 20	35	6.5	ACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Fuel Cell GT Hybrid First of Kind	30/ 20	35	6.5	MACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Wind	30/ 20	35	6.5	MACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Solar Thermal (Parabolic Trough)	30/ 20	35	6.5	MACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Biomass CFB	30/ 20	35	6.5	MACRS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Wave (1)	20/ 20	35	8.93 (2)	MACRS	65/ 30	9.4/ 13.6	35/ 70	4.4/ 4.9	3

(1) EPRI 2004 Wave Energy Feasibility Definition Study
(2) Maine

5.3. Form of Expected Results

As described in section 4.2 on learning curves, there is a negative exponential relationship between price and the total amount of cumulative capacity sold. In other words, with each doubling of cumulative capacity, the cost drops a fixed amount: the 32nd cumulative MW of say, PV capacity installed will be x% cheaper than the 16th, and the 64th cumulative MW will be x% cheaper than the 32nd. This relationship is found to apply to most power technologies, both mature and emerging, but the progress quotient (value of "x") differs among technologies, with fossil fuel technologies having a lower progress quotient than for renewable technologies. For this reason, it makes sense to compare the cost of an emerging power technology against each other and against mature technologies as a function of cumulative production volume.

Fossil fuel technology cost have a fuel cost component whereas renewable technologies do not. Therefore, it makes sense to compare the COE of TISEC against the fossil fuel technologies as a function of the coal and NG fuel price.

Lastly, as governments subsidize (by providing incentives such as investment tax credits, production tax credits and establishing a renewable energy certificate market driven by renewable portfolio standards) certain technologies deemed to be in the public good, it makes sense to analyze the effects of these incentives.

The list of expected economic comparison is as follows:

1. TISEC COE vs Wind
2. TISEC COE vs Solar PV and Solar Thermal
3. TISEC COE vs PC Coal = function of fuel prices
4. TISEC COE vs IGCC Coal = function of fuel prices
5. TISEC COE vs NG CT = function of fuel prices
6. TISEC COE vs NG CC = function of fuel prices a
7. TISEC COE vs Geothermal
8. TISEC COE vs Nuclear
9. TISEC COE vs WEC
10. TISEC COE vs all alternatives = function of (subsidies and incentives)
11. TISEC COE vs all alternatives = function of (CO2 regulations)

References

(1) National Wind Coordinating Council, *"Wind Energy Costs"*, Wind Energy Series 11, January 1997

(2) *"EPRI Specification of the Tidal Flow Resource and a Guideline for the Preliminary Estimation of the Power produced by an Tidal Flow Power Plant"*. May 30, 2005.

(3) *"How to Depreciate Property". Internal Revenue Service Publication 946, 2003 Table A-1*

(4) "Experience Curves for Energy Technology Policy". IEA, 2000

(5) Why Invest in Uneconomic Renewable Power Generation Technology' John Aldersey-Williams, 2002

(6) "Facilitating Widespread Deployment of Wind and Photovoltaic Technologies" Robert Williams, Princeton Environmental Institute, February 2002

(7) Investment and Production Tax Credits for Each State http://www.dsirusa.org

(8) DOE EIA Website dated January 2005 http://www.eia.doe.gov/oiaf/aeo/electricity.html

(9) Massachusetts State Income Tax http://www.dor.state.ma.us/

(10) Final Summary Report, EPRI offshore Wave Energy Feasibility Definition Study, EPRI WP 009-US, Jan 2005

(11) EPRI Summer Session August 2005

Appendix A UG Worksheet

The UG Economic Assessment Calculations are is implemented as an Excel Workbook with Nine (9) tabs or sheets and calculates the cost of electricity (COE) for a regulated utility generator (UG). The capital cost and O&M cost numbers shown in this worksheet are for illustrative purposes; they DO NOT represent the cost of a tidal plant in any particular state or province.

Instructions

Tab 1. Instructions

Tab 2. Total Production Cost (TPC) and Annual Operation and Maintenance Cost

Tab 3. Assumptions

Tab 4. Net present Value (NPV)

Tab 5. Capital Recovery Rate (CR)

Tab 6. Fixed Charge Rate (FCR)

Tab 7. Cost of Electricity (COE)

INSTRUCTIONS		
		Indicates Input Cell (either input or use default values)
		Indicates a Calculated Cell (do not input any values)
Sheet 1.	**TPC/TPI (Total Plant Cost/Total Plant Investment)**	
	a)	Enter Component Unit Cost and No. of Units per System
	b)	Worksheet sums component costs to get TPC
	c)	Adds the value of the construction loan payments to get TPI
	d)	Enter Annual O&M Type including annualized overhaul and refit cost
	c)	Worksheet Calculates insurance cost and Total Annual O&M Cost
Sheet 2.	**Assumptions (Financial)**	
	a)	Enter project and financial assumptions or leave default values
Sheet 3.	**NPV (Net Present Value)**	
	A	Gross Book Value = TPI
	B	Annual Book Depreciation = Gross Book Value/Book Life
	C	Cumulative Depreciation
	D	MACRS 5 Year Depreciation Tax Schedule Assumption
	E	Deferred Taxes = (Gross Book Value X MACRS Rate - Annual
		Book Depreciation) X Debt Financing Rate
	F	Net Book Value = Previous Year Net Book Value - Annual Book
		Depreciation - Deferred Tax for that Year
Sheet 4.	**CRR (Capital Revenue Requirements)**	
	A	Net Book Value for Column F of NPV Worksheet
	B	Common Equity = Net Book X Common Equity Financing
		Share X Common Equity Financing Rate
	C	Preferred Equity = Net Book X Preferred Equity Financing
		Share X Preferred Equity Financing Rate
	D	Debt = Net Book X Debt Financing Share X Debt Financing Rate
	E	Annual Book Depreciation = Gross Book Value/Book Life
	F	Income Taxes = (Return on Common Equity + Return of Preferred Equity -
		Interest on Debt + Deferred Taxes) X (Comp Tax Rate/(1-Comp Tax Rate
	G	Property Taxes and Insurance Expense =
	H	Calculates Investment and Production Tax Credit Revenues
	I	Capital Revenue Req'ts = Sum of Columns B through G
Sheet 5.	**FCR (Fixed Charge Rate)**	
	A	Nominal Rates Capital Revenue Req'ts from Columnn H of Previous Worksheet
	B	Nominal Rate Present Worth Factor = 1 / (1 + After Tax Discount Rate)
	C	Nominal Rate Product of Columns A and B = A * B
	D	Real Rates Capital Revenue Req'ts from Columnn H of Previous Worksheet
	E	Real Rates Present Worth Factor = 1 / (1 + After Tax Discount Rate - Inflation Rate)
	F	Real Rates Product of Columns A and B = A * B
Sheet 6.	**Calculates COE (Cost of Electricity)**	
	COE = ((TPI * FCR) + AO&M) / AEP	
	In other words…The Cost of Electricity =	
		The Sum of the Levelized Plant Investment + Annual O&M Cost including Levelized
		Overhaul and Replacement Cost Divided by the Annual Electric Energy Consumption

TOTAL PLANT COST (TPC) - 2005$

TPC Component	Unit	Unit Cost	Total Cost (2005$)
Procurement			
Power Conversion System	40	$799,712	$31,988,480
Structural Elements	40	$747,281	$29,891,240
Subsea Cables	Lot	$2,984,000	$2,984,000
Turbine Installation	40	$358,862	$14,354,480
Subsea Cable Installation	Lot	$10,492,000	$10,492,000
Onshore Grid Interconnection	Lot	$500,000	$500,000
TOTAL			$90,210,200

TOTAL PLANT INVESTMENT (TPI) - 2005 $

End of Year	Total Cash Expended TPC (2005$)	Before Tax Construction Loan Cost at Debt Financing Rate	2005 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT 2005$
2007	$45,105,100	$3,382,883	$2,758,033	$47,863,133
2008	$45,105,100	$3,382,883	$2,490,323	$47,595,423
Total	$90,210,200	$6,765,765	$5,248,356	$95,458,556

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2005$

Costs	Yrly Cost	Amount
Labor and Parts	$2,212,644	$2,212,644
Insurance (1.5% of TPC)	$1,353,153	$1,353,153
Total		$3,565,797

FINANCIAL ASSUMPTIONS			
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	40	MW
2	Annual Electric Energy Production (AEP)	131,500	MWeh/yr
	Therefore, Capacity Factor	37.50	%
3	Year Constant Dollars	2005	Year
4	Federal Tax Rate	35	%
5	State	Example State	
6	State Tax Rate	8.84	%
	Composite Tax Rate (t)	0.40746	
	t/(1-t)	0.6876	
7	Book Life	20	Years
8	Construction Financing Rate	7.5	
9	Common Equity Financing Share	52	%
10	Preferred Equity Financing Share	13	%
11	Debt Financing Share	35	%
12	Common Equity Financing Rate	13	%
13	Preferred Equity Financing Rate	10.5	%
14	Debt Financing Rate	7.5	%
	Nominal Discount Rate Before-Tax	10.75	%
	Nominal Discount Rate After-Tax	9.68	%
15	Inflation Rate = 3%	3	%
	Real Discount Rate Before-Tax	7.52	%
	Real Discount Rate After-Tax	6.49	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 years
18	State Investment Tax Credit	7.5	% of TPI
19	State Investment Tax Credit Limit	None	Credit - 1st year only for ≥ $10M plant
20	Renewable Energy Certificate	0	$/kWh
21	State Tax Depreciation	0	Installation Cost

NET PRESENT VALUE (NPV) - 2005 $						
TPI =	$95,458,556					
Year	**Gross Book**	**Book Depreciation**		**Renewable Resource MACRS Tax Depreciation**	**Deferred**	**Net Book**
End	**Value**	**Annual**	**Accumulated**	**Schedule**	**Taxes**	**Value**
	A	**B**	**C**	**D**	**E**	**F**
2008	**95,458,556**					**95,458,556**
2009	95,458,556	4,772,928	4,772,928	0.2000	5,834,331	84,851,297
2010	95,458,556	4,772,928	9,545,856	0.3200	10,501,797	69,576,572
2011	95,458,556	4,772,928	14,318,783	0.1920	5,523,167	59,280,477
2012	95,458,556	4,772,928	19,091,711	0.1152	2,535,989	51,971,560
2013	95,458,556	4,772,928	23,864,639	0.1152	2,535,989	44,662,643
2014	95,458,556	4,772,928	28,637,567	0.0576	295,606	39,594,109
2015	95,458,556	4,772,928	33,410,495	0.0000	-1,944,777	36,765,958
2016	95,458,556	4,772,928	38,183,422	0.0000	-1,944,777	33,937,808
2017	95,458,556	4,772,928	42,956,350	0.0000	-1,944,777	31,109,657
2018	95,458,556	4,772,928	47,729,278	0.0000	-1,944,777	28,281,506
2019	95,458,556	4,772,928	52,502,206	0.0000	-1,944,777	25,453,356
2020	95,458,556	4,772,928	57,275,134	0.0000	-1,944,777	22,625,205
2021	95,458,556	4,772,928	62,048,061	0.0000	-1,944,777	19,797,054
2022	95,458,556	4,772,928	66,820,989	0.0000	-1,944,777	16,968,904
2023	95,458,556	4,772,928	71,593,917	0.0000	-1,944,777	14,140,753
2024	95,458,556	4,772,928	76,366,845	0.0000	-1,944,777	11,312,603
2025	95,458,556	4,772,928	81,139,773	0.0000	-1,944,777	8,484,452
2036	95,458,556	4,772,928	85,912,700	0.0000	-1,944,777	5,656,301
2027	95,458,556	4,772,928	90,685,628	0.0000	-1,944,777	2,828,151
2028	95,458,556	4,772,928	95,458,556	0.0000	-1,944,777	0

TPI :	$95,458,556							
End of Year	**Net Book**	**Returns to Equity Common**	**Returns to Equity Pref**	**Interest on Debt**	**Book Dep**	**Income Tax on Equity Return**	**Fed PTC and REC**	**Capital Revenue Req'ts**
	A	**B**	**C**	**D**	**E**	**F**	**H**	**I**
2009	84,851,297	5,735,948	1,158,220	2,227,347	4,772,928	7,221,115	4,266,240	16,849,318
2010	69,576,572	4,703,376	949,720	1,826,385	4,772,928	9,852,995	4,266,240	17,839,165
2011	59,280,477	4,007,360	809,179	1,556,113	4,772,928	6,040,036	4,266,240	12,919,375
2012	51,971,560	3,513,277	709,412	1,364,253	4,772,928	3,709,475	4,266,240	9,803,106
2013	44,662,643	3,019,195	609,645	1,172,394	4,772,928	3,433,047	4,266,240	8,740,969
2014	39,594,109	2,676,562	540,460	1,039,345	4,772,928	1,700,752	4,266,240	6,463,806
2015	36,765,958	2,485,379	501,855	965,106	4,772,928	53,190	4,266,240	4,512,218
2016	33,937,808	2,294,196	463,251	890,867	4,772,928	-53,773	4,266,240	4,101,229
2017	31,109,657	2,103,013	424,647	816,628	4,772,928	-160,735	4,266,240	3,690,241
2018	28,281,506	1,911,830	386,043	742,390	4,772,928	-267,698	4,266,240	3,279,252
2019	25,453,356	1,720,647	347,438	668,151	4,772,928	-374,661	1,939,200	5,195,303
2020	22,625,205	1,529,464	308,834	593,912	4,772,928	-481,624	1,939,200	4,784,314
2021	19,797,054	1,338,281	270,230	519,673	4,772,928	-588,586	1,939,200	4,373,325
2022	16,968,904	1,147,098	231,626	445,434	4,772,928	-695,549	1,939,200	3,962,336
2023	14,140,753	955,915	193,021	371,195	4,772,928	-802,512	1,939,200	3,551,347
2024	11,312,603	764,732	154,417	296,956	4,772,928	-909,475	1,939,200	3,140,358
2025	8,484,452	573,549	115,813	222,717	4,772,928	-1,016,437	1,939,200	2,729,369
2026	5,656,301	382,366	77,209	148,478	4,772,928	-1,123,400	1,939,200	2,318,380
2027	2,828,151	191,183	38,604	74,239	4,772,928	-1,230,363	1,939,200	1,907,391
2028	0	0	0	0	4,772,928	-1,337,326	1,939,200	1,496,402
Sum of Annual Capital Revenue Requirements								121,657,203

FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED - 2005$

TPI = $95,458,556

End of Year	Capital Revenue Req'ts Nominal A	Present Worth Factor Nominal B	Product of Columns A and B C	Capital Revenue Req'ts Real D	Present Worth Factor Real E	Product of Columns D and E F
2009	16,849,318	0.6910	11,643,028	14,970,400	0.7777	11,643,028
2010	17,839,165	0.6300	11,239,035	15,388,220	0.7304	11,239,035
2011	12,919,375	0.5744	7,421,077	10,819,773	0.6859	7,421,077
2012	9,803,106	0.5237	5,134,049	7,970,822	0.6441	5,134,049
2013	8,740,969	0.4775	4,173,754	6,900,201	0.6049	4,173,754
2014	6,463,806	0.4353	2,814,016	4,953,969	0.5680	2,814,016
2015	4,512,218	0.3969	1,791,015	3,357,514	0.5334	1,791,015
2016	4,101,229	0.3619	1,484,205	2,962,815	0.5009	1,484,205
2017	3,690,241	0.3300	1,217,603	2,588,260	0.4704	1,217,603
2018	3,279,252	0.3008	986,499	2,233,011	0.4418	986,499
2019	5,195,303	0.2743	1,424,963	3,434,707	0.4149	1,424,963
2020	4,784,314	0.2501	1,196,419	3,070,869	0.3896	1,196,419
2021	4,373,325	0.2280	997,117	2,725,311	0.3659	997,117
2022	3,962,336	0.2079	823,676	2,397,278	0.3436	823,676
2023	3,551,347	0.1895	673,084	2,086,042	0.3227	673,084
2024	3,140,358	0.1728	542,658	1,790,902	0.3030	542,658
2025	2,729,369	0.1575	430,012	1,511,185	0.2846	430,012
2026	2,318,380	0.1436	333,023	1,246,244	0.2672	333,023
2027	1,907,391	0.1310	249,804	995,453	0.2509	249,804
2028	1,496,402	0.1194	178,681	758,215	0.2357	178,681
	121,657,203		54,753,718	92,161,195		54,753,718

	Nominal $		Real $
1. The present value is at the beginning of 2006 and results from the sum of the products of the annual present value factors times the annual requirements	54,753,718		54,753,718
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.68%		6.49%
4. Capital recovery factor value = i(1+i)"/(1+i)"-1 where book life = n and discount rate = i	0.1149079		0.090654358
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	6,291,635		4,963,663
6. Booked Cost	95,458,556		95,458,556
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0659**		**0.0520**

LEVELIZED COST OF ELECTRICITY CALCULATION - UTILITY GENERATOR - 2005$			
COE = ((TPI * FCR) + AO&M + LO&R) / AEP			
In other words…			
The Cost of Electricity =			
The Sum of the Levelized Plant Investment + Annual O&M Cost + Levelized Overhaul and Replacement Cost			
Divided by the Annual Electric Energy Consumption			
NOMINAL RATES			
	Value	**Units**	**From**
TPI	$108,715,629	$	From TPI
FCR	9.08%	%	From FCR
AO&M	$4,549,205	$	From AO&M
LO&R = O&R/Life	$0	$	From LO&R
AEP =	131,500	MWeh/yr	From Assumptions
COE - TPI X FCR	7.51	cents/kWh	
COE - AO&M	3.46	cents/kWh	
COE - LO&R	0.00	cents/kWh	
COE	$0.1097	$/kWh	Calculated
COE	**10.97**	cents/kWh	Calculated
REAL RATES			
TPI	$108,715,629	$	From TPI
FCR	6.56%	%	From FCR
AO&M	$4,549,205	$	From AO&M
LO&R = O&R/Life	$0	$	From LO&R
AEP =	131,500	MWeh/yr	From Assumptions
COE - TPI X FCR	5.42	cents/kWh	
COE - AO&M	3.46	cents/kWh	
COE - LO&R	0.00	cents/kWh	
COE	$0.0888	$/kWh	Calculated
COE	**8.88**	cents/kWh	Calculated

Appendix B MG Worksheet

The MG Economic Assessment Calculations are is implemented as an Excel Workbook with Nine (9) tabs or sheets and calculates the cost of electricity (COE) for a regulated municipal generator (MG). The capital cost and O&M cost numbers shown in this worksheet are for illustrative purposes; they DO NOT represent the cost of a tidal plant in any particular state or province.

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INSTRUCTIONS		
		Indicates Input Cell (either input or use default values)
		Indicates a Calculated Cell (do not input any values)
Sheet 1.	**TPC/TPI (Total Plant Cost/Total Plant Investment)**	
	a)	Enter Component Unit Cost and No. of Units per System
	b)	Worksheet sums component costs to get TPC
	c)	Adds the value of the construction loan payments to get TPI
	a)	Enter Labor Hrs and and Parts Cost by O&M inc overhaul and refit
	c)	Worksheet Calculates Insurance and Total Annual O&M Cost
Sheet 3.	**O&R (Overhaul and Replacement Cost)**	
	a)	Enter Year of Cost and O&R Cost per Item
	b)	Worksheets calculates the present value of the O&R costs
Sheet 4.	**Assumptions (Financial)**	
	a)	Enter project and financial assumptions or leave default values
Sheet 5.	**NPV (Net Present Value)**	
	A	Gross Book Value = TPI
	B	Annual Book Depreciation = Gross Book Value/Book Life
	C	Cumulative Depreciation
	D	~~MACRS 5 Year Depreciation Tax Schedule Assumption~~
	E	~~Deferred Taxes = (Gross Book Value X MACRS Rate - Annual~~
		~~Book Depreciation) X Debt Financing Rate~~
	F	Net Book Value = Previous Year Net Book Value - Annual Book
		Depreciation - Deferred Tax for that Year
Sheet 6.	**CRR (Capital Revenue Requirements)**	
	A	Net Book Value for Column F of NPV Worksheet
	B	Common Equity = Net Book X Common Equity Financing
		Share X Common Equity Financing Rate
	C	Preferred Equity = Net Book X Preferred Equity Financing
		Share X Preferred Equity Financing Rate
	D	Debt = Net Book X Debt Financing Share X Debt Financing Rate
	E	Annual Book Depreciation = Gross Book Value/Book Life
	F	~~Income Taxes = (Return on Common Equity + Return of Preferred Equity -~~
		~~Interest on Debt + Deferred Taxes) X (Comp Tax Rate/(1-Comp Tax Rate))~~
	G	Property Taxes and Insurance Expense =
	H	Calculates Investment and ~~Production Tax Credit Revenues~~
	I	Capital Revenue Req'ts = Sum of Columns B through G
Sheet 7.	**FCR (Fixed Charge Rate)**	
	A	Nominal Rates Capital Revenue Req'ts from Columnn H of Previous Worksheet
	B	Nominal Rate Present Worth Factor = 1 / (1 + After Tax Discount Rate)
	C	Nominal Rate Product of Columns A and B = A * B
	D	Real Rates Capital Revenue Req'ts from Columnn H of Previous Worksheet
	E	Real Rates Present Worth Factor = 1 / (1 + After Tax Discount Rate - Inflation Rate)
	F	Real Rates Product of Columns A and B = A * B
Sheet 8.	**Calculates COE (Cost of Electricity)**	
	COE = ((TPI * FCR) + AO&M + LO&R) / AEP	
	In other words…The Cost of Electricity =	
		The Sum of the Levelized Plant Investment + Annual O&M Cost including Levelized
		Overhaul and Replacement Cost Divided by the Annual Electric Energy Consumption

TOTAL PLANT COST (TPC) - 2005$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	
Procurement				
Power Conversion System	40	$799,712	$31,988,480	
Structural Elements	40	$747,281	$29,891,240	
Subsea Cables	Lot	$2,984,000	$2,984,000	
Turbine Installation	40	$358,862	$14,354,480	
Subsea Cable Installation	Lot	$10,492,000	$10,492,000	
Onshore Grid Interconnection	Lot	$500,000	$500,000	
TOTAL			$90,210,200	

TOTAL PLANT INVESTMENT (TPI) - 2005 $

End of Year	Total Cash Expended TPC (2005$)	Before Tax Construction Loan Cost at Debt Financing Rate	2005 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT 2005$
2007	$45,105,100	$2,255,255	$2,045,583	$47,150,683
2008	$45,105,100	$2,255,255	$1,948,174	$47,053,274
Total	$90,210,200	$4,510,510	$3,993,757	$94,203,957

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2005$

Costs	Yrly Cost	Amount	
Labor and Parts	$2,212,644	$2,212,644	
Insurance (1.5% of TPC)	$1,353,153	$1,353,153	
Total		$3,565,797	

FINANCIAL ASSUMPTIONS			
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	45.7	MW
2	Annual Electric Energy Production (AEP)	119,700	MWeh/yr
	Therefore, Capacity Factor	29.88	%
3	Year Constant Dollars	2004	Year
4	Federal Tax Rate	0	%
5	State	Example State	
6	State Tax Rate	0	%
	Composite Tax Rate (t)	0	
	t/(1-t)	0.0000	
7	Book Life	20	Years
8	Construction Financing Rate	5	
9	Common Equity Financing Share	0	%
10	Preferred Equity Financing Share	0	%
11	Debt Financing Share	100	%
12	Common Equity Financing Rate	0	%
13	Preferred Equity Financing Rate	0	%
14	Debt Financing Rate	4.1	%
	Nominal Discount Rate Before-Tax	4.1	%
	Nominal Discount Rate After-Tax	4.1	%
15	Inflation Rate = 3%	3	%
	Real Discount Rate Before-Tax	1.07	%
	Real Discount Rate After-Tax		%
16	Federal Investment Tax Credit	0	% 1st year only
17	Federal Production Tax Credit	0	$/kWh for 1st 10 years
18	State Investment Tax Credit	0	% of TPI up to $2.5M
19	State Investment Tax Credit Limit	0	Credit - 1st year only for ≥
20	State Production Tax Credit	0	$/kWh for 1st 10 years
21	REPI or CREB	0.0173	$/kWh for 1st 10 years for l
22	Renewable Energy Credit	0.0250	$/kWh

REPI Calculation Area

PPI Change in inflation

http://www.gpec.org/InfoCenter/Topics/Economy/USInflation.html

			REPI incentive	
		1993	1.50	cents/kWh
1994	130%	1994	1.52	cents/kWh
1995	3.60%	1995	1.57	cents/kWh
1996	2.40%	1996	1.61	cents/kWh
1997	-0.10%	1997	1.61	cents/kWh
1998	-2.50%	1998	1.57	cents/kWh
1999	0.90%	1999	1.58	cents/kWh
2000	5.70%	2000	1.67	cents/kWh
2001	110%	2001	1.69	cents/kWh
2002	-2.30%	2002	1.65	cents/kWh
2003	5.30%	2003	1.74	cents/kWh
2004	-0.70%	2004	1.73	cents/kWh

Post 2004, assume inflation rate of line 15

NET PRESENT VALUE (NPV) - 2005 $

TPI = $94,203,957

Year End	Gross Book Value	Book Depreciation Annual	Book Depreciation Accumulated	Renewable Resource MACRS Tax Depreciation Schedule	Deferred Taxes	Net Book Value
	A	B	C	D	E	F
2008	**94,203,957**					**94,203,957**
2009	94,203,957	4,710,198	4,710,198	0	0	89,493,759
2010	94,203,957	4,710,198	9,420,396	0	0	84,783,561
2011	94,203,957	4,710,198	14,130,594	0	0	80,073,363
2012	94,203,957	4,710,198	18,840,791	0	0	75,363,165
2013	94,203,957	4,710,198	23,550,989	0	0	70,652,968
2014	94,203,957	4,710,198	28,261,187	0	0	65,942,770
2015	94,203,957	4,710,198	32,971,385	0	0	61,232,572
2016	94,203,957	4,710,198	37,681,583	0	0	56,522,374
2017	94,203,957	4,710,198	42,391,781	0	0	51,812,176
2018	94,203,957	4,710,198	47,101,978	0	0	47,101,978
2019	94,203,957	4,710,198	51,812,176	0	0	42,391,781
2020	94,203,957	4,710,198	56,522,374	0	0	37,681,583
2021	94,203,957	4,710,198	61,232,572	0	0	32,971,385
2022	94,203,957	4,710,198	65,942,770	0	0	28,261,187
2023	94,203,957	4,710,198	70,652,968	0	0	23,550,989
2024	94,203,957	4,710,198	75,363,165	0	0	18,840,791
2025	94,203,957	4,710,198	80,073,363	0	0	14,130,594
2036	94,203,957	4,710,198	84,783,561	0	0	9,420,396
2027	94,203,957	4,710,198	89,493,759	0	0	4,710,198
2028	94,203,957	4,710,198	94,203,957	0	0	0

CAPITAL REVENUE REQUIREMENTS - 2005$								
TPI =	$94,203,957							
End of Year	**Net Book**	**Returns to Equity Common**	**Returns to Equity Pref**	**Interest on Debt**	**Book Dep**	**Income Tax on Equity Return**	**REPI**	**Capital Revenue Req'ts**
	A	**B**	**C**	**D**	**E**	**F**	**H**	**I**
2009	89,493,759	0	0	4,474,688	4,710,198	0	3,878,400	5,306,486
2010	84,783,561	0	0	4,239,178	4,710,198	0	3,878,400	5,070,976
2011	80,073,363	0	0	4,003,668	4,710,198	0	3,878,400	4,835,466
2012	75,363,165	0	0	3,768,158	4,710,198	0	3,878,400	4,599,956
2013	70,652,968	0	0	3,532,648	4,710,198	0	3,878,400	4,364,446
2014	65,942,770	0	0	3,297,138	4,710,198	0	3,878,400	4,128,936
2015	61,232,572	0	0	3,061,629	4,710,198	0	3,878,400	3,893,426
2016	56,522,374	0	0	2,826,119	4,710,198	0	3,878,400	3,657,917
2017	51,812,176	0	0	2,590,609	4,710,198	0	3,878,400	3,422,407
2018	47,101,978	0	0	2,355,099	4,710,198	0	3,878,400	3,186,897
2019	42,391,781	0	0	2,119,589	4,710,198	0	1,939,200	4,890,587
2020	37,681,583	0	0	1,884,079	4,710,198	0	1,939,200	4,655,077
2021	32,971,385	0	0	1,648,569	4,710,198	0	1,939,200	4,419,567
2022	28,261,187	0	0	1,413,059	4,710,198	0	1,939,200	4,184,057
2023	23,550,989	0	0	1,177,549	4,710,198	0	1,939,200	3,948,547
2024	18,840,791	0	0	942,040	4,710,198	0	1,939,200	3,713,037
2025	14,130,594	0	0	706,530	4,710,198	0	1,939,200	3,477,528
2026	9,420,396	0	0	471,020	4,710,198	0	1,939,200	3,242,018
2027	4,710,198	0	0	235,510	4,710,198	0	1,939,200	3,006,508
2028	0	0	0	0	4,710,198	0	1,939,200	2,770,998
Sum of Annual Capital Revenue Requirements								80,774,836

FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED - 2005$						
TPI =	$94,203,957					
End of Year	Capital Revenue Req'ts Nominal A	Present Worth Factor Nominal B	Product of Columns A and B C	Capital Revenue Req'ts Real D	Present Worth Factor Real E	Product of Columns D and E F
2009	5,306,486	0.8227	4,365,659	4,714,744	0.9260	4,365,659
2010	5,070,976	0.7835	3,973,242	4,374,268	0.9083	3,973,242
2011	4,835,466	0.7462	3,608,299	4,049,627	0.8910	3,608,299
2012	4,599,956	0.7107	3,269,103	3,740,185	0.8740	3,269,103
2013	4,364,446	0.6768	2,954,029	3,445,334	0.8574	2,954,029
2014	4,128,936	0.6446	2,661,549	3,164,486	0.8411	2,661,549
2015	3,893,426	0.6139	2,390,226	2,897,075	0.8250	2,390,226
2016	3,657,917	0.5847	2,138,708	2,642,557	0.8093	2,138,708
2017	3,422,407	0.5568	1,905,724	2,400,407	0.7939	1,905,724
2018	3,186,897	0.5303	1,690,079	2,170,122	0.7788	1,690,079
2019	4,890,587	0.5051	2,470,079	3,233,254	0.7640	2,470,079
2020	4,655,077	0.4810	2,239,172	2,987,917	0.7494	2,239,172
2021	4,419,567	0.4581	2,024,655	2,754,128	0.7351	2,024,655
2022	4,184,057	0.4363	1,825,490	2,531,423	0.7211	1,825,490
2023	3,948,547	0.4155	1,640,703	2,319,355	0.7074	1,640,703
2024	3,713,037	0.3957	1,469,375	2,117,493	0.6939	1,469,375
2025	3,477,528	0.3769	1,310,644	1,925,423	0.6807	1,310,644
2026	3,242,018	0.3589	1,163,697	1,742,744	0.6677	1,163,697
2027	3,006,508	0.3418	1,027,774	1,569,074	0.6550	1,027,774
2028	2,770,998	0.3256	902,157	1,404,042	0.6425	902,157
	80,774,836		45,030,365	56,183,658		45,030,365

	Nominal $		Real $
1. The present value is at the beginning of 2006 and results from the sum of the products of the annual present value factors times the annual requirements	45,030,365		45,030,365
2. Escalation Rate	3%		3%
3. Discount Rate = i	5.00%		1.94%
4. Capital recovery factor value = i(1+i)"/(1+i)"-1 where book life = n and discount rate = i	0.08024259		0.060813464
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	3,613,353		2,738,452
6. Booked Cost	94,203,957		94,203,957
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0384**		**0.0291**

LEVELIZED COST OF ELECTRICITY CALCULATION - MUNICIPAL GENERATOR - 2005$			
COE = ((TPI * FCR) + AO&M) / AEP			
In other words…			
The Cost of Electricity =			
The Sum of the Levelized Plant Investment + Annual O&M Cost + Levelized Overhaul and Replacement Cost			
Divided by the Annual Electric Energy Consumption			
NOMINAL RATES			
	Value	**Units**	**From**
TPI	$94,203,957	$	From TPI
FCR	3.84%	%	From FCR
AO&M	$3,565,797	$	From AO&M
AEP =	129,280	MWeh/yr	From Assumptions
COE - TPI X FCR	2.79	cents/kWh	
COE - AO&M	2.76	cents/kWh	
COE	$0.0555	$/kWh	Calculated
COE	**5.55**	cents/kWh	Calculated
REAL RATES			
TPI	$94,203,957	$	From TPI
FCR	2.91%	%	From FCR
AO&M	$3,565,797	$	From AO&M
AEP =	129,280	MWeh/yr	From Assumptions
COE - TPI X FCR	2.12	cents/kWh	
COE - AO&M	2.76	cents/kWh	
COE	$0.0488	$/kWh	Calculated
COE	**4.88**	cents/kWh	Calculated

Appendix C NUG IRR Worksheet

The NUG Economic Assessment Calculations are is implemented as an Excel Workbook with seven (7) tabs or sheets and calculates the net internal rate of return (IRR) for a non regulated merchant non utility generator (NUG). The capital cost and O&M cost numbers shown in this worksheet are for illustrative purposes; they DO NOT represent the cost of a tidal plant in any particular state or province.

Instructions

Tab 1. Instructions

Tab 2. Total Production Cost (TPC) and Annual Operation and Maintenance Cost

Tab 3. Assumptions

Tab 4. Income

Tab 5. Cash Flow and Net Internal Rate of Return (IR)

INSTRUCTIONS		
Fill in first four worksheets (or use default values) - the last two worksheets are automatically calculated. Refer to EPRI Economic Methodology Report 002		
(pink cell)		Indicates Input Cell (either input or use default values)
(outlined cell)		Indicates a Calculated Cell (do not input any values)
Sheet 1.	**Total Plant Cost/Total Plant Investment (TPC/TPI) - 2005$**	
	1	Enter Component Unit Cost and No. of Units per System
	2	Worksheet sums component costs to get TPC
	3	Worksheet adds the value of the construction loan payments to get TPI
Sheet 2.	**AO&M (Annual Operation and Maintenance Cost) - 2005$**	
	1	Enter Labor Hrs and Cost by O&M Type)
	2	Enter Parts and Supplies Cost by O&M Type)
	3	Worksheet Calculates Total Annual O&M Cost
Sheet 3.	**O&R (Overhaul and Replacement Cost) - 2005$**	
	1	Enter Year of Cost and O&R Cost per Item
	2	Worksheet calculates inflation to the year of the cost of the O&R
Sheet 4.	**Assumptions (Project, Financial and Others)**	
	1	Enter project, financial and other assumptions or leave default values
Sheet 5.	**Income Statement - Assuming no capacity factor income - Current $**	
	1	2008 1st Year Energy payments = AEP X 2005 wholesale price X 97.18% (to adjust price
		from 2005 to 2008 (an 2.82% decline) X Inflation from 2005 to 2008
		2009-2011 Energy payments = AEP X Previous Year Elec Price X Annual Price
		de-escalation of -1.42% X Inflation
		2012-2025 Energy payments = AEP X Previous Year Elec Price X 0.72% Price
		escalation X Inflation
	2	Calculates State Investment and Prodution tax credit
	3	Calculates Federal Investment and Production Tax Credit
	4	Scheduled O&M from TPC worksheet with inflation
	5	Scheduled O&R from TPC worksheet with inflation
	8	Earnings before EBITDA = total revenues less total operating costs
	9	Tax Depreciation = Assumed MACRS rate X TPI
	10	Interest paid = Annual interest given assumed debt interest rate and life of loan
	11	Taxable earnings = Tax Depreciation + Interest Paid
	12	State Tax = Taxable Earnings x state tax rate
	13	Federal Tax = (Taxable earnings - State Tax) X Federal tax rate
	14	Total Tax Obligation = Total State + Federal Tax
Sheet 6.	**Cash Flow Statement - Current $**	
	1	EBITDA
	2	Taxes Paid
	3	Cash Flow From Operations = EBITDA - Taxes Paid
	4	Debt Service = Principal + Interest paid on the debt loan
	5	Net Cash Flow after Tax
		Year of Start of Ops minus 1 = Equity amount
		Year of Start of Ops = Cash flow from ops - debt service
		Year of Start of Ops Plus 1 to N = Cash flow from ops - debt service
	6	Cum Net Cash Flow After Taxes = previous year net cash flow + current year net cash flow
	7	Cum IRR on net cash Flow After Taxes = discount rate that sets the present worth
		of the net cash flows over the book life equal to the equity investment at the
		commercial operations

TOTAL PLANT COST (TPC) - 2005$

TPC Component	Unit	Unit Cost	Total Cost (2005$)	Notes and Assumptions
Procurement				
Power Conversion System	40	$799,712	$31,988,480	
Structural Elements	40	$747,281	$29,891,240	
Subsea Cables	Lot	$2,984,000	$2,984,000	
Turbine Installation	40	$358,862	$14,354,480	
Subsea Cable Installation	Lot	$10,492,000	$10,492,000	
Onshore Grid Interconnection	Lot	$500,000	$500,000	
TOTAL			$90,210,200	

TOTAL PLANT INVESTMENT (TPI) - 2005 $

End of Year	Total Cash Expended TPC ($2005)	Before Tax Construction Loan Cost at Debt Financing Rate	2005 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT (TPC + Loan Value) ($2005)
2006	$45,105,100	$4,059,459	$3,312,630	$48,417,730
2007	$45,105,100	$4,059,459	$2,992,439	$48,097,539
Total	$90,210,200	$8,118,918	$6,305,069	$96,515,269

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2005$

Costs	Yrly Cost	Amount	
Labor and Parts	$2,212,644	$2,212,644	
Insurance (1.5% of TPC)	$1,353,153	$1,353,153	
Total		$3,565,797	

FINANCIAL ASSUMPTIONS			
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	100	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	34.22	%
3	Year Constant Dollars	2005	Year
4	Federal Tax Rate	35	%
5	State	Example State	
6	State Tax Rate	9.5	%
	Composite Tax Rate (t)	0.41175	%
	t/(1-t)	0.7000	
7	Book Life	30	Years
8	Construction Financing Rate	9	
9	Common Equity Financing Share	30	%
10	Preferred Equity Financing Share	0	%
11	Debt Financing Share	70	%
12	Common Equity Financing Rate	17	%
13	Preferred Equity Financing Rate	0	%
14	Debt Financing Rate	8	%
	Current $ Discount Rate Before-Tax	10.7	%
	Current $ Discount Rate After-Tax	8.39	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.019	$/kWh for 1st 10 yrs
18	State Investment Tax Credit		% 1st year only
			% of TPI up to $2.5M
19	State Production Tax Credit	0	
20	Wholesale electricity price - 2005$	0.0926	$/kWh
21	Decline in wholesale elec. price from 2005 to 2008	4.20	%
22	Annual decline in wholesale price, 2009 - 2011	1.42	%
23	Annual increase in wholesale price, 2012 - 2025	0.72	%
24	Yearly Unscheduled O&M	5	% of Sch O&M cost
25	MACRS Year 1	0.2000	
26	MACRS Year 2	0.3200	
27	MACRS Year 3	0.1920	
28	MACRS Year 4	0.1152	
29	MACRS Year 5	0.1152	
30	MACRS Year 6	0.0576	
31	REC Rate	0.0576	$/kWh for Project Life

Electricity Price Forecast Area

The electricity price forecast from the EIA (Doc 002, Reference 8):

"Average U.S. electricity prices, in real 2003 dollars, are expected to decline by 11% from 7.4 cents/kWh in 2003 to 6.6 cents in 2011, then rise to 7.3 cents/kWh in 2025."

	2003	7.4	7.4		
	2004		7.29		
Base	2005		7.19		
	2006		7.09		
	2007		6.99		
	2008		6.89	-4.20%	Decline (2005 - 2008)
	2009		6.79		
	2010		6.7		
	2011	6.6	6.6	-1.42%	Annual Decline (2009 - 2011)
	2012		6.65		
	2013		6.7		
	2014		6.74		
	2015		6.79		
	2016		6.84		
	2017		6.89		
	2018		6.94		
	2019		6.99		
	2020		7.04		
	2021		7.09		
	2022		7.14		
	2023		7.2		
	2024		7.25		
	2025	7.3	7.3	0.72%	Annual Increase (2012 - 2025)

INCOME STATEMENT ($)		**CURRENT DOLLARS**						
Description/Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
REVENUES								
Energy Payments	11,029,802	11,199,379	11,371,564	11,546,396	11,978,729	12,427,250	12,892,565	13,375,303
REC income	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200
State ITC	17,373							
Federal ITC	0							
Fedaral PTC	2,327,040	2,396,851	2,468,757	2,542,819	2,619,104	2,697,677	2,778,607	2,861,966
TOTAL REVENUES	12,986,375	13,138,579	13,310,764	13,485,596	13,917,929	14,366,450	14,831,765	15,314,503
AVG $/KWH	0.100	0.102	0.103	0.104	0.108	0.111	0.115	0.118
OPERATING COSTS								
Scheduled and Unscheduled O&M	3,565,797	3,672,771	3,782,954	3,896,443	4,013,336	4,133,736	4,257,748	4,385,481
Other	0	0	0	0	0	0	0	0
TOTAL	3,565,797	3,672,771	3,782,954	3,896,443	4,013,336	4,133,736	4,257,748	4,385,481
EBITDA	9,420,578	9,465,809	9,527,810	9,589,154	9,904,593	10,232,714	10,574,017	10,929,022
Tax Depreciation	19,303,054	30,884,886	18,530,932	11,118,559	11,118,559	1,447,729	0	0
Interest Paid	5,404,855	5,286,747	5,159,190	5,021,429	4,872,647	4,711,962	4,538,423	4,351,000
TAXABLE EARNINGS	-15,287,331	-26,705,825	-14,162,312	-6,550,834	-6,086,613	4,073,023	6,035,594	6,578,022
State Tax	-1,351,400	-2,360,795	-1,251,948	-579,094	-538,057	360,055	533,547	581,497
Federal Tax	-4,877,576	-8,520,760	-4,518,627	-2,090,109	-1,941,995	1,299,539	1,925,717	2,098,784
TOTAL TAX OBLIGATIONS	-6,228,976	-10,881,555	-5,770,576	-2,669,203	-2,480,051	1,659,594	2,459,263	2,680,281

2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
13,876,116	14,395,681	14,934,700	15,493,901	16,074,041	16,675,903	17,300,301	17,948,078	18,620,110	19,317,305	20,040,605	20,790,987
1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200	1,939,200
2,947,825	3,036,259										
15,815,316	16,334,881	16,873,900	17,433,101	18,013,241	18,615,103	19,239,501	19,887,278	20,559,310	21,256,505	21,979,805	22,730,187
0.122	0.126	0.131	0.135	0.139	0.144	0.149	0.154	0.159	0.164	0.170	0.176
4,517,045	4,652,556	4,792,133	4,935,897	5,083,974	5,236,493	5,393,588	5,555,396	5,722,057	5,893,719	6,070,531	6,252,647
0	0	0	0	0	0	0	0	0	0	0	0
4,517,045	4,652,556	4,792,133	4,935,897	5,083,974	5,236,493	5,393,588	5,555,396	5,722,057	5,893,719	6,070,531	6,252,647
11,298,271	11,682,324	12,081,767	12,497,204	12,929,267	13,378,610	13,845,913	14,331,883	14,837,253	15,362,786	15,909,274	16,477,541
0	0	0	0	0	0	0	0	0	0	0	0
4,148,584	3,929,974	3,693,876	3,438,889	3,163,504	2,866,088	2,544,879	2,197,973	1,823,314	1,418,683	981,681	509,719
7,149,687	7,752,350	8,387,891	9,058,315	9,765,763	10,512,522	11,301,034	12,133,910	13,013,939	13,944,103	14,927,593	15,967,822
632,032	685,308	741,490	800,755	863,293	929,307	999,011	1,072,638	1,150,432	1,232,659	1,319,599	1,411,555
2,281,179	2,473,465	2,676,240	2,890,146	3,115,864	3,354,125	3,605,708	3,871,445	4,152,227	4,449,006	4,762,798	5,094,693
2,913,211	3,158,773	3,417,730	3,690,901	3,979,158	4,283,432	4,604,719	4,944,083	5,302,659	5,681,664	6,082,397	6,506,249

CASH FLOW STATEMENT							
Description/Year	2007	2008	2009	2010	2011	2012	2013
EBITDA			9,420,578	9,465,809	9,527,810	9,589,154	9,904,593
Taxes Paid			-6,228,976	-10,881,555	-5,770,576	-2,669,203	-2,480,051
CASH FLOW FROM OPS			15,649,554	20,347,364	15,298,386	12,258,357	12,384,645
Debt Service			-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205
NET CASH FLOW AFTER TAX		-28,954,581	8,768,348	13,466,158	8,417,180	5,377,151	5,503,439
CUM NET CASH FLOW		-28,954,581	-20,186,232	-6,720,074	1,697,106	7,074,258	12,577,697

2014	2015	2016	2017	2018	2019	2020	2021
10,232,714	10,574,017	10,929,022	11,298,271	11,682,324	12,081,767	12,497,204	12,929,267
1,659,594	2,459,263	2,680,281	2,913,211	3,158,773	3,417,730	3,690,901	3,979,158
8,573,120	8,114,754	8,248,742	8,385,059	8,523,552	8,664,037	8,806,303	8,950,110
-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205
1,691,915	1,233,549	1,367,536	1,503,854	1,642,347	1,782,831	1,925,098	2,068,904
14,269,612	15,503,161	16,870,697	18,374,551	20,016,898	21,799,729	23,724,827	25,793,731

2022	2023	2024	2025	2026	2027	2028
13,378,610	13,845,913	14,331,883	14,837,253	15,362,786	15,909,274	16,477,541
4,283,432	4,604,719	4,944,083	5,302,659	5,681,664	6,082,397	6,506,249
9,095,178	9,241,194	9,387,800	9,534,593	9,681,121	9,826,877	9,971,292
-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205	-6,881,205
2,213,973	2,359,988	2,506,594	2,653,388	2,799,916	2,945,672	3,090,087
28,007,704	30,367,692	32,874,287	35,527,675	38,327,591	41,273,262	44,363,349
			IRR ON NET CASH FLOW AFTER TAX			20.8%