System Level Design, Performance, Cost and Economic Assessment – Maine Western Passage Tidal In-Stream Power Plant

Report: EPRI – TP - 006 - ME
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1. Introduction and Summary

Western Passage is the western conduit for waters from the St. Croix River and Passamaquoddy Bay. The US – Canada border lies within the waters of the Western Passage. It is known for its strong currents. In average 104MW of power is embodied in the tidal stream at the Dog Island transect, of which about 15MW could be extracted without any negative impact on the environment. A plant of that scale could reach an electrical output of about 45MW at peak.

This document describes the results of a system level design, performance and cost study for both a demonstration pilot plant and an economics assessment of a commercial size in-stream tidal power plant installed at the Dog Island transect in the Western Passage. The primary purpose of this design study was to identify and quantify the risks and benefits of using TISEC technology at this site. As such it addresses the technology, energy production, cost of a pilot and commercial power plant system and cost of electricity.

The study was carried out using the methodology and standards established in the Design Methodology Report [5], the Power Production Performance Methodology Report [2] and the Cost Estimate and Economics Assessment Methodology Report [2].

For purposes of this design study, the Maine stakeholders and EPRI decided to work with three TISEC device developers: Lunar Energy, Marine Current Turbines (MCT) and Verdant Power. Lunar Energy's RTT 2000 is a fully submersed ducted turbine with the power conversion system (containing rotors and power generation equipment) inserted in a slot in the duct as a cassette. This allows the critical components to be recovered for operation and maintenance without having to remove the whole structure. MCT's SeaGen consists of two horizontal-axis rotors and power trains (gearbox, generator) attached to a supporting monopile by a cross-arm. The monopile is surface piercing and includes an integrated lifting mechanism to pull the rotors and power trains out of the water for maintenance access. MCT also offered information on their conceptual fully submersed design, which consists of 6 rotors mounted on a single structure, which can be raised to the surface for maintenance using an integrated lifting mechanism. Verdant Power's turbine was designed for the East River in New York and is 5 meters in diameter. This design was believed to be too small for the Western Passage site and our ability to scale up the design with high confidence was judged to be poor. Therefore, EPRI did not conceptualize a design with the Verdant Power turbine.

The purpose of working with two TISEC device developers was to provide a redundant check of the performance and cost design points and to increase the confidence level of the assessment work. There is no intend to compare the two device developers nor their technology. At this nascent stage of TISEC development, a pursuit towards the development and demonstration off as many good ideas as possible is warranted.

It became clear during the study that a TISEC array would have to be placed directly below the navigation channel at the site. As such only fully submersible technology could be used at the site, which is the RTT2000 and MCTs second generation technology. However, only MCTs surface piercing SeaGen offered sufficiently solid engineering specifications at this time (January through March 2006) to perform an independent cost assessment. SeaGen was therefore used to establish relevant performance and cost estimates. Given the similar scale and technology used on MCT's fully submersed technology it is likely that cost and performance will be similar to the surface piercing SeaGen. In order to extract a meaningful amount of energy at the Golden Gate site, a technology needs to be sufficiently large in scale to extract a meaningful amount of energy and be completely submersed to avoid interference with shipping traffic. Both MCTs second generation technology and Lunar Energy's RTT2000 satisfy these criteria. It is unlikely that MCTs second generation technology would be ready for commercial pilot demonstration within the next two years as a proof of high reliability with SeaGen is a prerequisite.

A pilot consisting of a single SeaGen unit would cost \$4.7M to build and would produce an estimated 3,335 MWh per year. This cost reflects only the capital needed to purchase a SeaGen unit, install it on site, and connect it to the grid. Therefore, it represents the installed capital cost, but does not include detailed design, permitting and construction financing, yearly O&M or test and evaluation costs.

A commercial scale tidal power plant at the same location was also evaluated to establish a base case from which economic comparisons to other renewable and non renewable energy systems could be made. While the potential to harness energy at the site is limited to about 15% to assure that the system produces no significant or noticeable ecological or environmental effects, it became clear during this design study that the combination of the shortness of the length of the constricted zone at the site (i.e., high velocity flow) and the current technology would further limit the amount of energy that could be extracted at the site to about 5-7%. This is based on conservative assumptions and further detailed study of required device spacing, increasing rotor size, developing stackable rotor structures and detailed resource modeling could reveal different findings.

The yearly electrical energy produced and delivered to bus bar is estimated to be 40,024 MWh/year for an array consisting of 12 dual-rotor MCT turbines. These turbines have a combined installed capacity of 9.9MW, and on average extract 5.3 MW of kinetic power from the tidal stream, which is roughly 5% of the total kinetic energy at the site. The elements of cost and economics (in 2005$) for MCT's SeaGen are:

- Utility Generator (UG) Total Plant Investment = $23.6 million
- Annual O&M Cost = $0.98 million
- UG Levelized Cost of Electricity (COE) = 5.6 (Real) – 6.5 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology
- Municipal Generator (MG) Levelized Cost of Electricity (COE) = 4.2 (Real) – 4.8 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology
- Nun Utility Generator (Independent Power Producer) Internal Rate of Return on net cash flows after tax is 34%

While being limited in size, this resource should be tapped strategically as it will contribute to a balanced energy supply system. In order to tap into it, further work needs to be carried out to better quantify and qualify the resource, address consenting issues and continue to work with device developers and help them apply their technology to the site and it's unique requirements. The next immediate step is to work towards the implementation of a pilot and demonstration system. A pilot system is an important intermediary step before proceeding to a commercial installation and is used to:

- Proof technology reliability and performance at the site and reduce commercial risks
- Measure and quantify environmental impacts
- Focus the consenting process for a commercial installation

Before proceeding with the installation of a pilot plant, remaining uncertainties need to be addressed. Some of these uncertainties include:

- Tidal velocity distribution at the site
- Seabed geology required for detailed foundation design
- Ownership issues
- Consenting issues
- Political and public education issues

In order to promote development of TISEC, EPRI recommends that stakeholders build collaboration within California and with other State/Federal Government agencies by forming a state electricity stakeholder group and joining a TISEC Working Group to be formed by EPRI to be called "OceanFleet.". Additional, EPRI encourages the stakeholders to support related R&D activities at a state and federal level and at universities in the region. This would include:

- Implement a national ocean tidal energy program at DOE
- Operate a national in stream tidal energy test facility
- Promote development of industry standards
- Continue membership in the IEA Ocean Energy Program
- Clarify and streamline federal, state and local permitting processes
- Study provisions for tax incentives and subsidies needed to incentivice potential investors and owners to bring this technology to the marketplace

- Ensure that the public receives a fair return from the use of tidal energy resources
- Ensure that development rights in state waters are allocated through a fair and transparent process that takes into account state, local, and public concerns.

2. Site Selection

The Maine electricity stakeholders selected the Western Passage for an assessment of in stream tidal power. Fabrication, assembly, installation, operation and maintenance would be performed out of Eastport. Grid interconnection would be at a substation in Eastport. Figure 1 shows a Google Earth depiction of the region. Site selection is determined by the following primary considerations:

- Good tidal energy resource
- Ease of interconnection and accessibility to an electrical demand
- Proximity to major port with marine infrastructure

The Western Passage satisfies these considerations.

Western Passage cuts between Moose Island on the U.S. side and Deer Island, the next large Canadian island northwest of Campobello Island, and connects Friar Roads with Passamaquoddy Bay. It is entered between Deer Island Point, which is at the south end of Deer Island, and Dog Island, which lies off the east side of Moose Island.

Western Passage is the western conduit for waters from the St. Croix River and Passamaquoddy Bay. As such, it is known for its strong currents and eddies, including "Old Sow," the largest tidal whirlpool in the Western Hemisphere.

The following figures provide an overview of the site location, relevant transects, a flow simulation of the area and bathymetry charts to provide the reader with an overview.

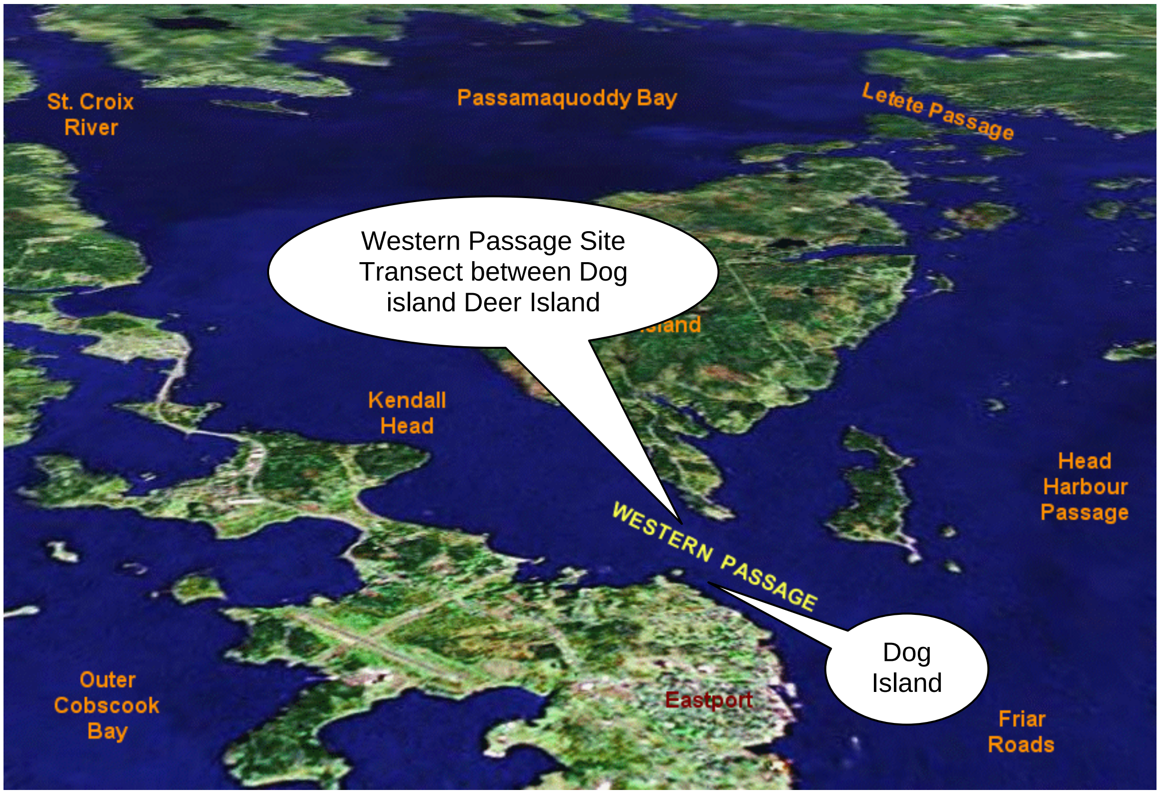


Figure 1 - Site Overview

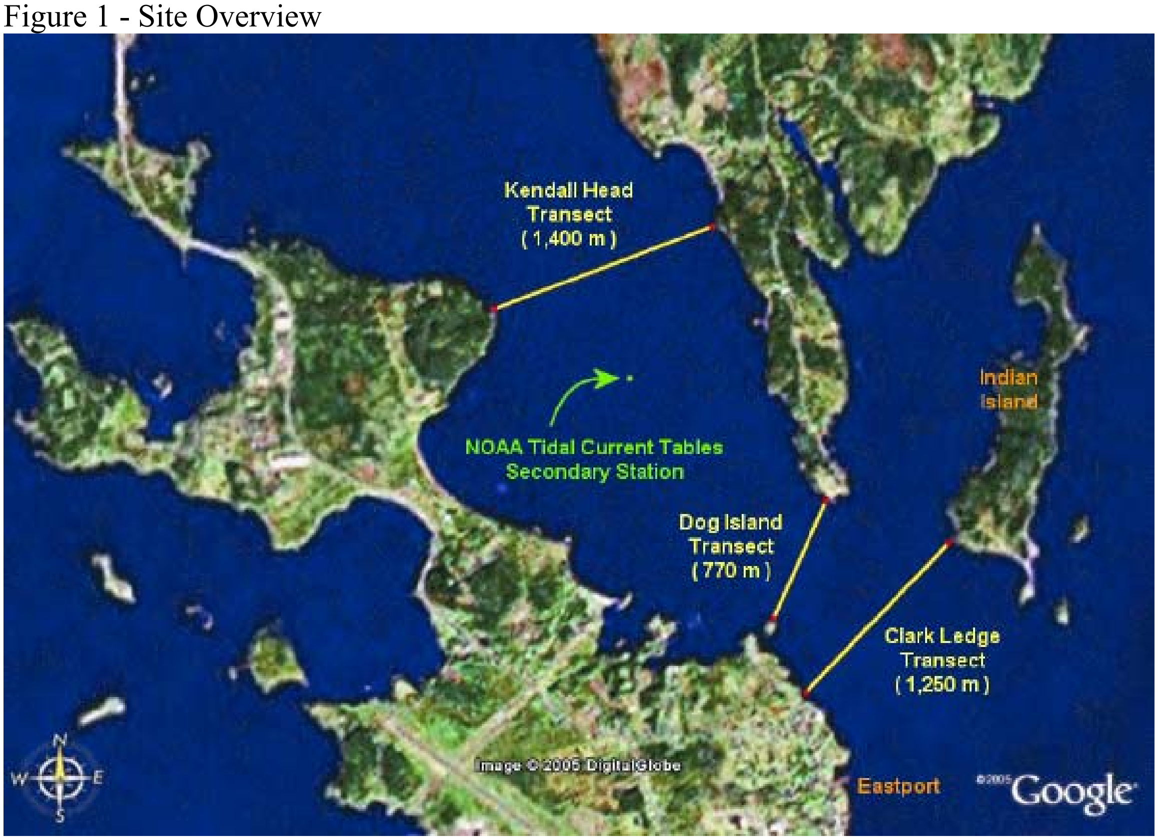


Figure 2 - Transects at the Western Passage

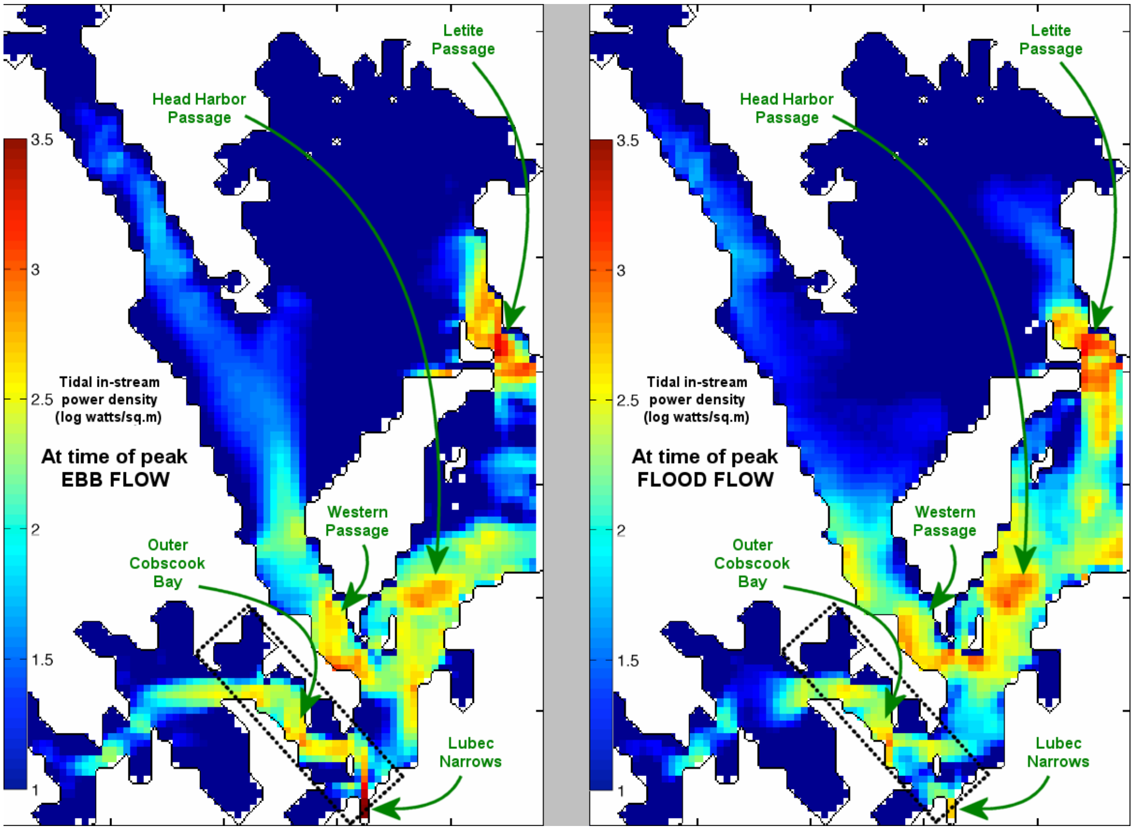


Figure 3 - Regional Simulation of Tidal Flows

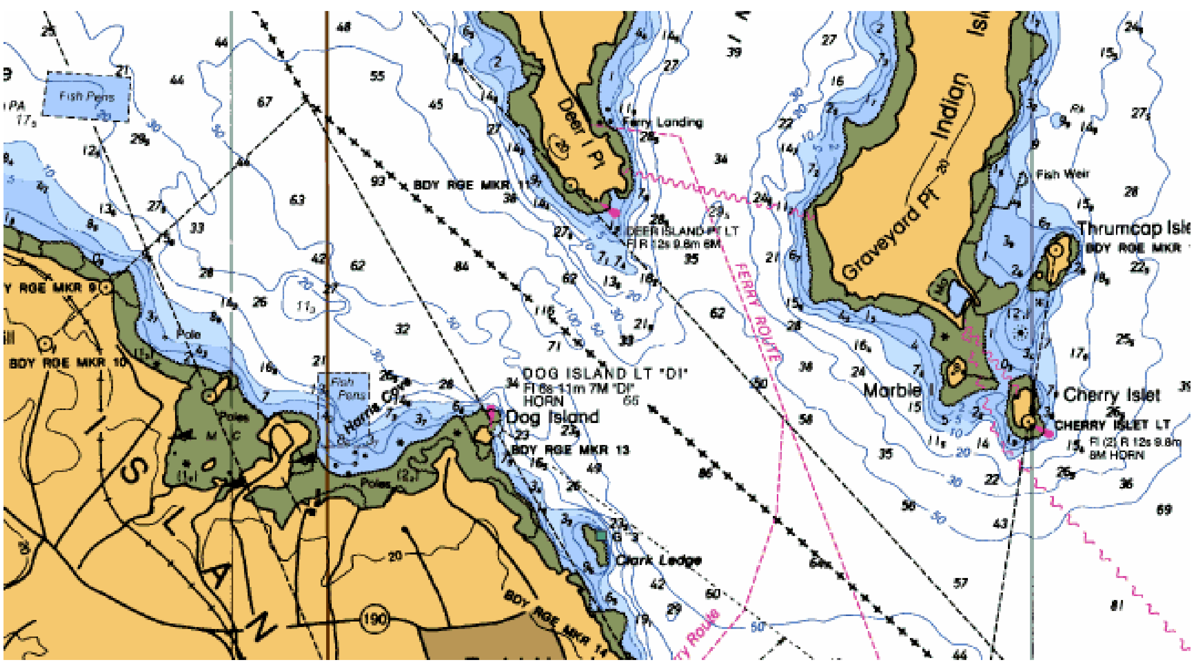


Figure 4 - Nautical Chart of the area of interest. Blue depth contours shown are in meters.

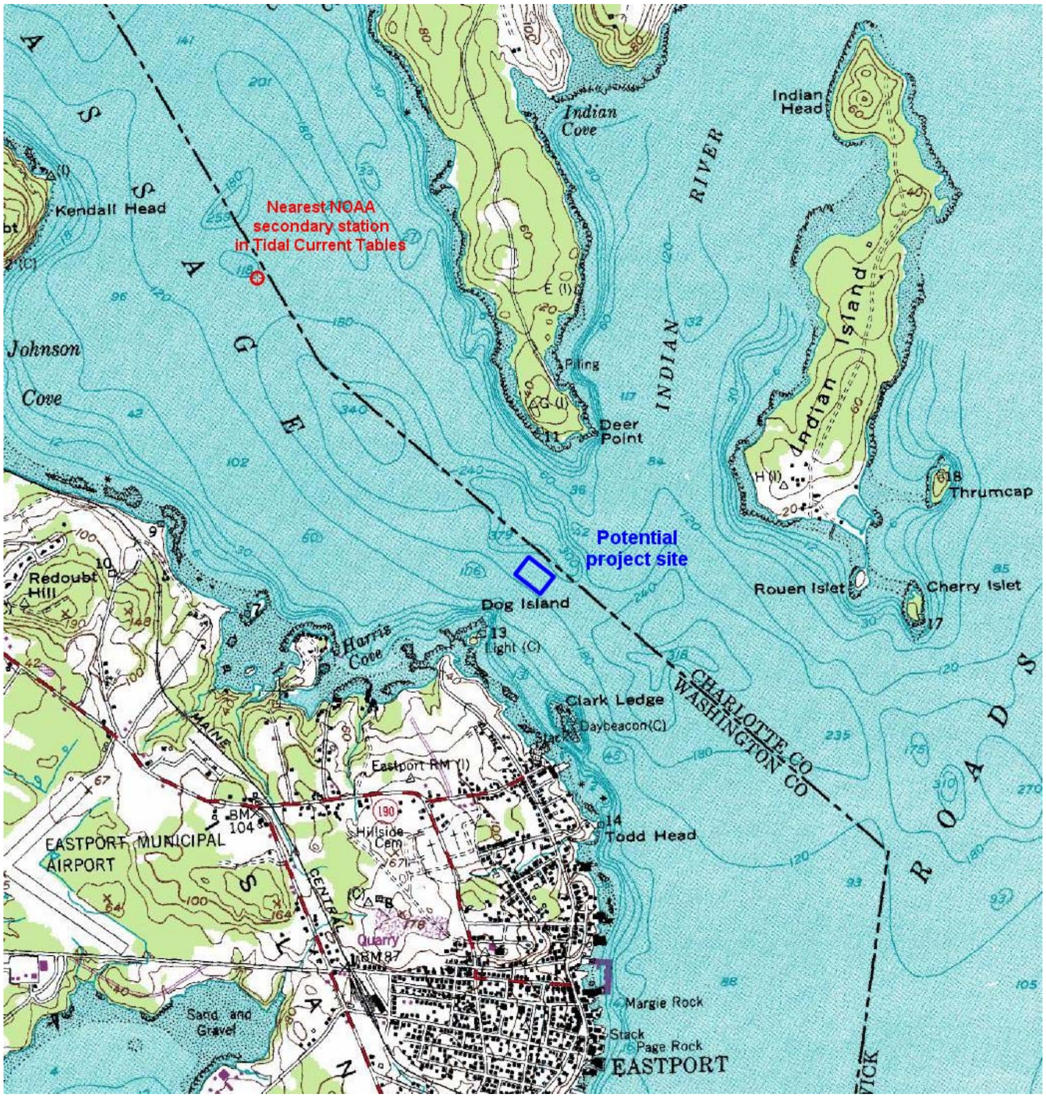


Figure 5: Minas Passage Site overview

Tidal Energy Resource

Table 1 and Figure shows the depth-averaged velocity distribution at the narrowest transect. The nearest NOAA secondary (predicted) tidal current station and the selected project site is shown on Figure 3. This data is later used to calculate the annual performance of the device in the site.

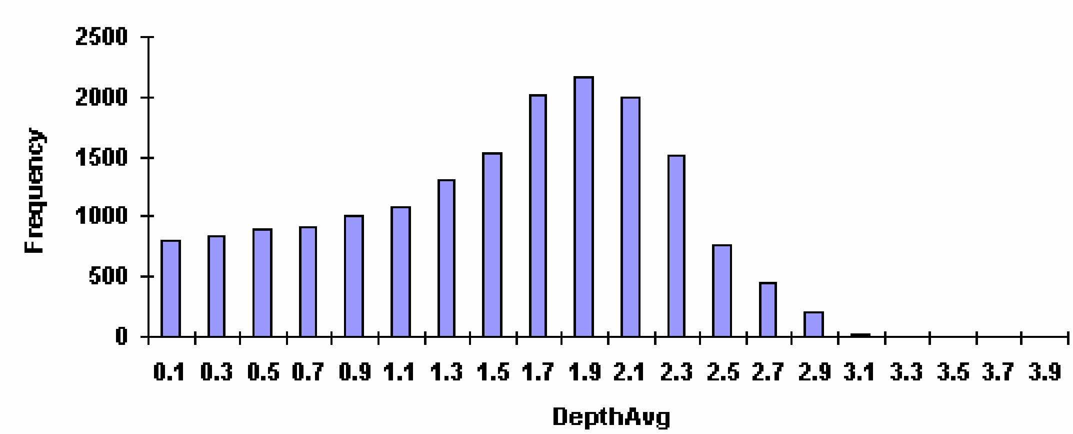


Figure 6: Depth averaged velocity distribution at the target site. Velocity shown is in m/s

Table 1 - Depth averaged velocity distribution at Dog island transect

Velocity (m/sec)	Power Density kW/m^2	Number of Cases	Percentage of Cases	Number of Hours	Energy Density (kWh/sq.m)
0.1	0.0	804	4.6%	402.0	0.2
0.3	0.0	838	4.8%	419.0	5.8
0.5	0.1	896	5.1%	448.0	28.7
0.7	0.2	911	5.2%	455.5	80.1
0.9	0.4	1005	5.7%	502.5	187.7
1.1	0.7	1083	6.2%	541.5	369.4
1.3	1.1	1299	7.4%	649.5	731.3
1.5	1.7	1536	8.8%	768.0	1,328.4
1.7	2.5	2015	11.5%	1007.5	2,536.8
1.9	3.5	2163	12.3%	1081.5	3,801.7
2.1	4.7	2005	11.4%	1002.5	4,758.1
2.3	6.2	1520	8.7%	760.0	4,739.0
2.5	8.0	770	4.4%	385.0	3,083.0
2.7	10.1	451	2.6%	225.5	2,274.7
2.9	12.5	200	1.1%	100.0	1,249.9
3.1	15.3	24	0.1%	12.0	183.2
3.3	18.4	0	0.0%	0.0	0.0
3.5	22.0	0	0.0%	0.0	0.0
3.7	26.0	0	0.0%	0.0	0.0
Average		17520	1	8760	25,358.2

Average Power Density	2.9 kW/m^2
Channel Cross Sectional Area	3,600 m^2
Total Resource Base	104 MW
Average extractable resource (15%)	15.6 MW

The following charts show the depth-averaged resource variability and magnitude over time. All of these resource profiles are based on a preliminary extrapolation, which was used for this study. Detailed 3-dimensional theoretical modeling and measurements should be carried out in a detailed design phase to properly quantify the resource and show cross-sectional variability as well as potential resource stratification, which may occur at the site and can have a critical impact on the device deployment location as well as device cost and economics.

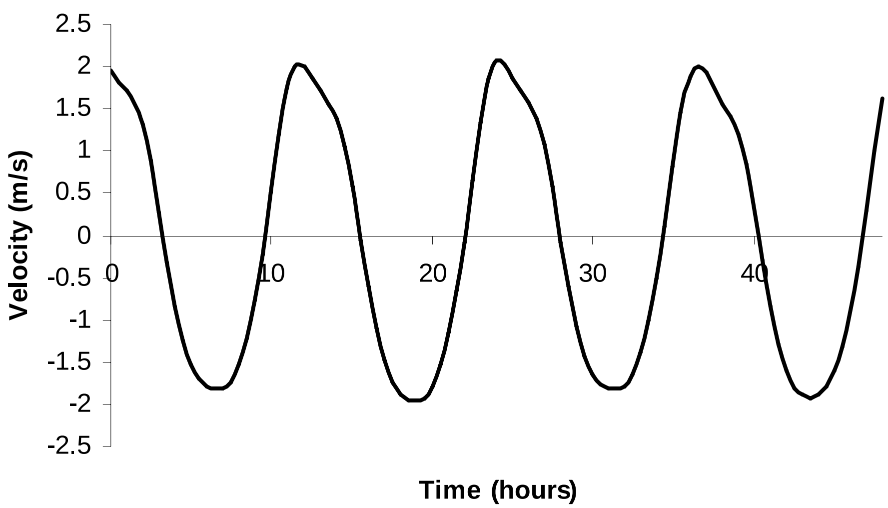


Figure 7 - Typical depth-averaged velocity profile over a 48 hour period

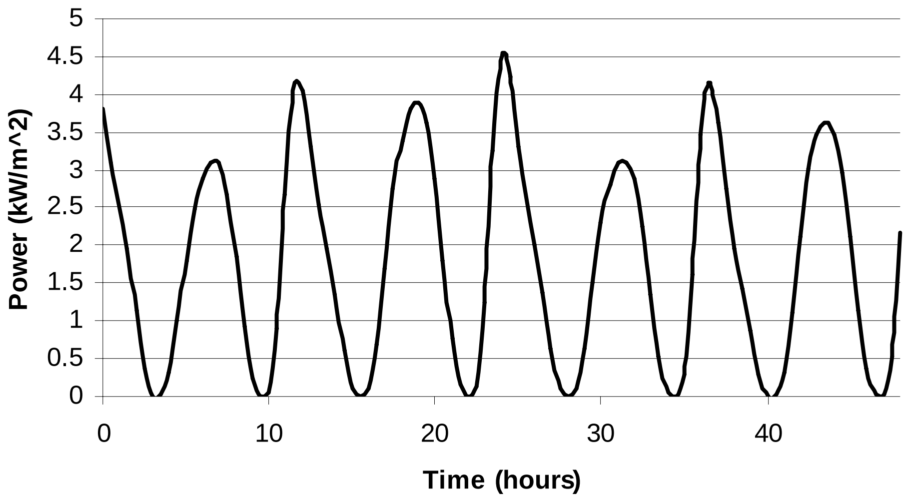


Figure 8 - Typical depth-averaged power variation over a 48-hour period

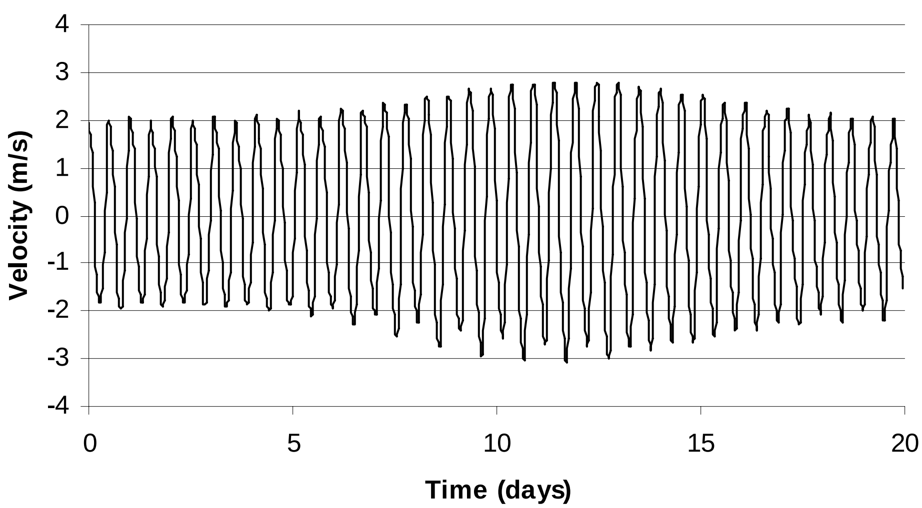


Figure 9 - Velocity profile over a 20 day period covering more then a full lunar cycle

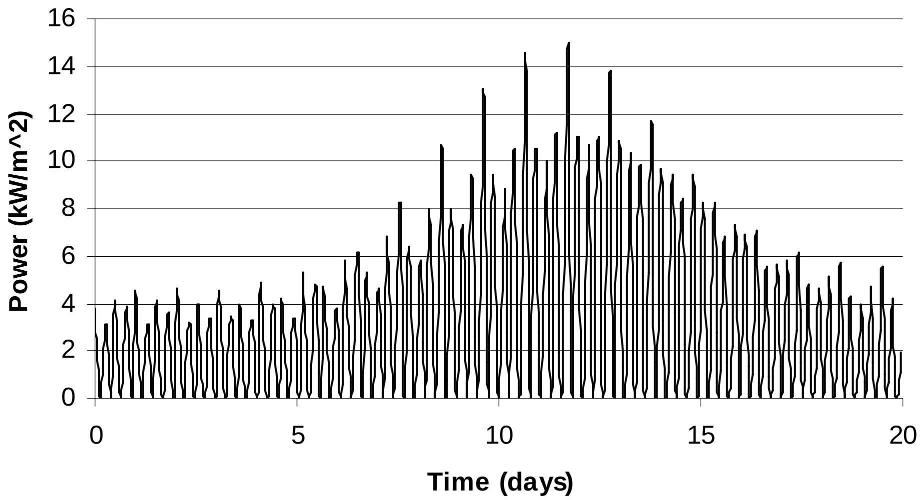


Figure 10 - Power variation of a 20-day period

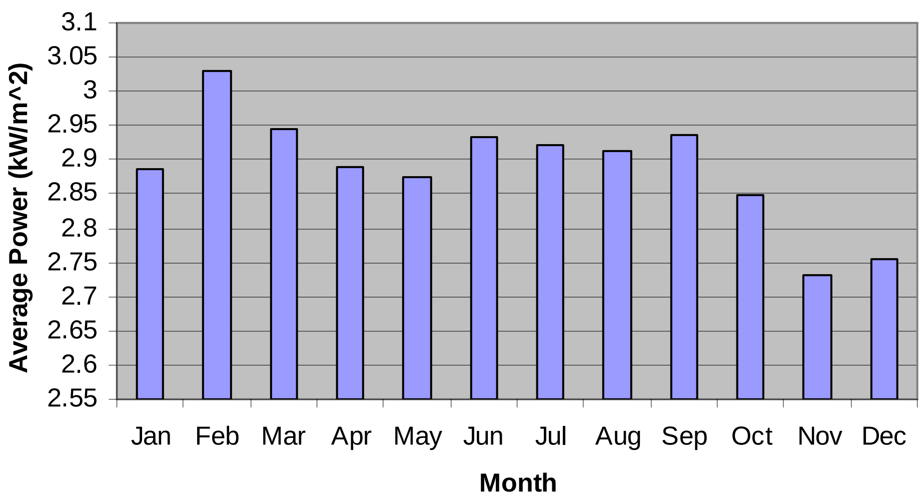


Figure 11 - Annual monthly relative power variation

Grid Interconnection options

The U.S. onshore interconnection point for a tidal energy project in Western Passage would be to the Bangor Hydro-Electric Company utility grid. A 34.5 kV transmission line runs adjacent to state Route 190, and 12.5 kV distribution lines run throughout the island, which minimizes the overland distance for grid interconnection to either a 500 kW demonstration or a 10 MW commercial scale TISEC project. Due to the rocky nature of the Eastport shoreline in the vicinity of Dog Island and the residential zoning there, a submarine power cable from a project in Western Passage probably would be landed into the rural residential area north of Harris Cove, where it is about 0.5 miles to both 34.5kV and 12.5 kV distribution lines.

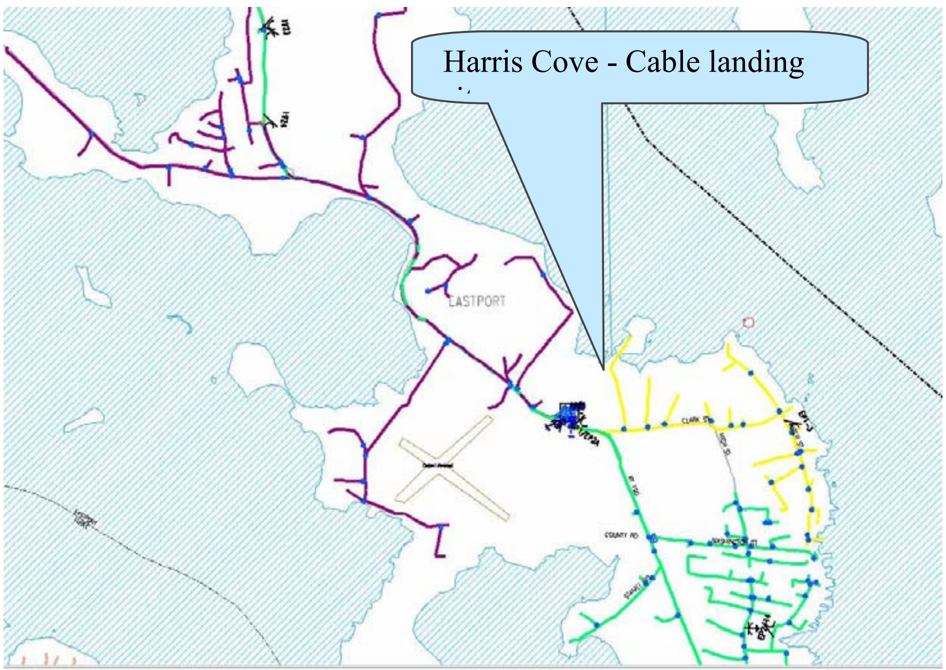


Figure 12 - Transmission and Distribution Network in Eastport

While BHE chose not to estimate grid infrastructure upgrade costs, limits of the existing infrastructure were explored to identify potential feed-in limitations. The following provides a summary overview of them:

- Up to 1.5MW peak, such as a demonstration the interconnection could be accomplished on the 4.6kV distribution network. Only minor upgrades to enable relaying at the substation would need to be carried out.

- Up to 19 MW peak, the interconnection could be accomplished by tying directly into the existing 34.5 kV level at the existing substation. About 1 mile of overland transmission and work on the substation would be required.
- Up to 30MW (19-30MW) peak, the interconnection would require additional work at the substation and reconductoring of about 6 miles of overland transmission lines.

Anything above the 30MW level would require substation upgrades to the existing transmission infrastructure.

Nearby Port facilities

Eastport is the nearest coastal town for basing inspection, maintenance and repair activities. Eastport, a city situated on the hilly east side of Moose Island, is the easternmost deepwater port in the United States. The docks of the port are along the waterfront on the east shore of the island. The principal industries are forest products, lobstering, herring fishing, scallop harvesting, farming and harvesting salmon, and tourism.

A dredged small-craft harbor for commercial and pleasure craft is off the customhouse in Eastport. The harbor is protected on its north and east sides by a steel piling, solid fill, L-shaped breakwater–wharf onto which fishing vessels can unload their catch into trucks. In April 1984, depths of 13 feet and 9 feet were available in the southern part and northern part of the harbor, respectively. A town float with 10 feet alongside is on the inner side of the breakwater at the north end of the harbor. Boats usually moor along the inner face of the breakwater. In fair weather, berthing is also possible along the east and north (seaward) faces of the breakwater in depths of 36 feet and 6½ to 10 feet, respectively. Forest products are loaded along the east face. Electricity is available at all the berths, and diesel fuel can be delivered by truck on short notice. The breakwater is floodlighted at night.

The only active cannery along the waterfront, 100 yards north of the breakwater, has a wharf with 65-foot face and 1 to 5 feet alongside. Fresh water is available on the wharf. The Port of Eastport offers general cargo dockage at the Breakwater Pier. The 420-foot facility can accommodate vessels with a draft up to 36 feet.

A machine shop in the port handles repairs to small-craft gasoline or diesel engines. Electrical repairs can be made. Small vessels are usually grounded out at high water for hull repairs after the tide falls. There is a private facility for hauling out craft up to 40 feet in length and a boatbuilder who makes hull repairs.

Pilotage is compulsory for all foreign vessels, and for U.S. vessels registered in foreign trade with a draft of 9 feet or more. Pilotage is optional for fishing vessels and vessels powered predominately by sail. Two tugs up to 2,400 hp are available at Eastport.

There is no railroad service to Eastport, but a good highway parallels the St. Croix River to Calais. There is a municipal airport at Eastport.

Bathymetry

The bathymetry (the ocean equivalent to land topography) is an important determinant in the siting of tidal turbines. In shallow water, there may be insufficient surface and seabed clearance for the turbine rotor. This drives site selection towards deeper water sites. However, installation and maintenance costs increase with water depth. These two competing desires result in a range of depth for each site suitable for deployment of tidal turbines.

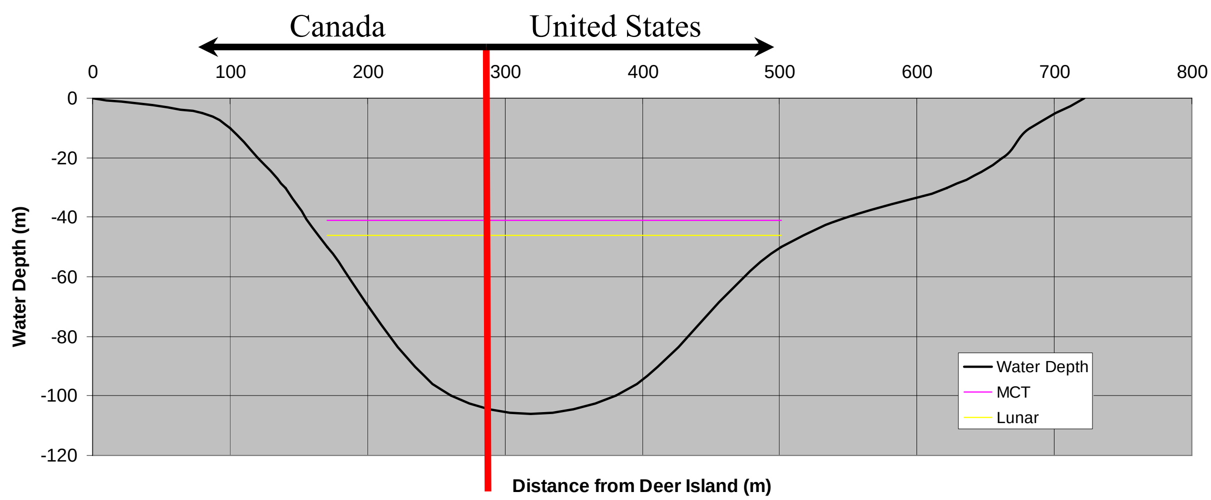


Figure 13 - Cross Sectional Area at Dog Island transect

Figure 13 shows the cross of the transect between Dog island and Deer island. Deer island is on the left, while Dog island on the right hand side. Also indicated in red is the border between the US and Canada and the yellow and pink line shows the minimum installation depth for MCT's second generation technology and Lunar Energy's RTT2000 provided that a shipping clearance of 15m below LAT is respected. For the purpose of this design study it was decided to stay on the US side of the border.

Seabed Composition

Sedimentation at a tidal energy deployment site is an important consideration for foundation design and has an impact on the type of foundation used, installation methods and scour protection methods (if required).

A geological map characterizing the surface properties of the seafloor in the northern part of Lubec Narrows and Friar Roads is given below.

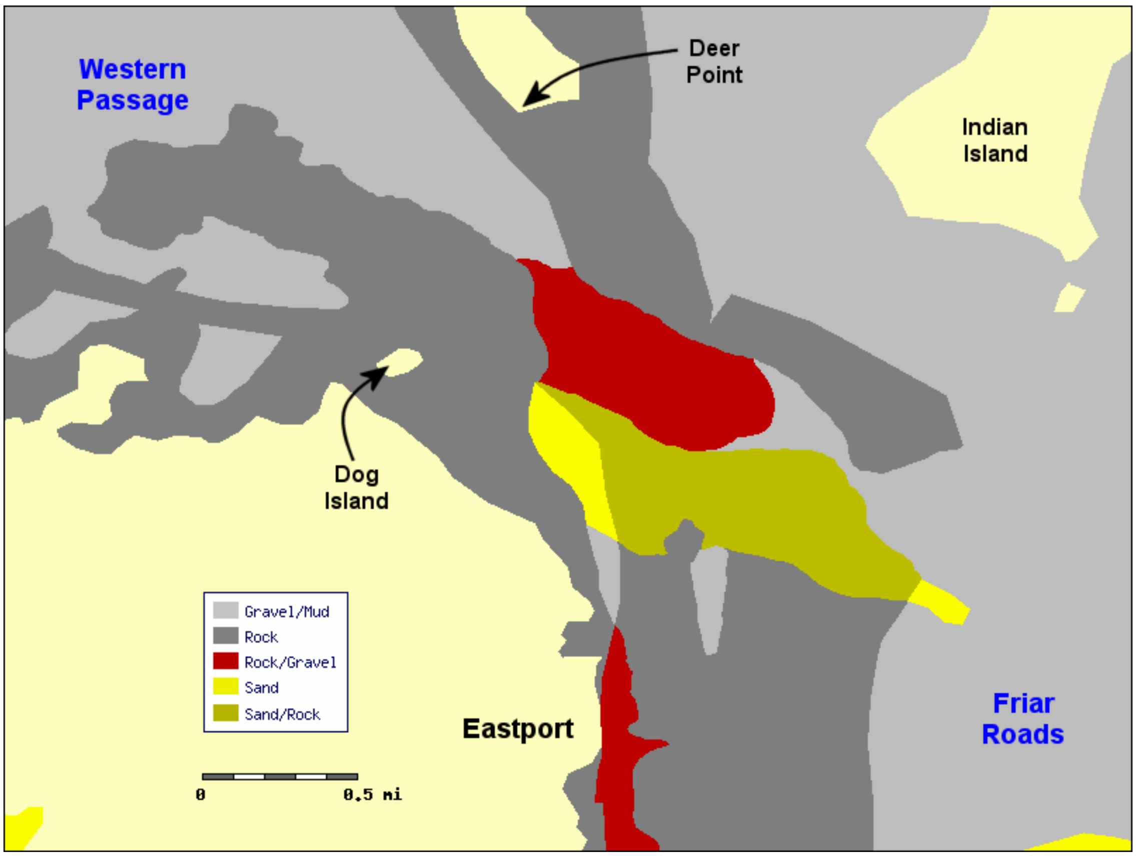


Figure 6: Surficial geology of Western Passage

Navigational Clearances

The principal navigation entrance to Passamaquoddy Bay is around the northern end of Campobello Island through Head Harbour Passage. This passage is deep and generally clear of dangers. South of Deer and Indian Islands, incoming vessels enter Friar Roads before turning north to approach the entrance to Western Passage. The safest route for navigation is toward the U.S. side of the entrance, which is free of turbulence. This also is the best location for a tidal in-stream energy project, but as previously mentioned, the depth here is 180 feet, which allows ample clearance for navigation, even by deep-draft commercial shipping. Maximum draft reached by deep-draft vessels passing through the area is 15m below LAT.

Other Site Considerations

Washington County is a relatively remote area in eastern Maine that is served electrically from a radial 115kv line that is 60 miles long. Although the load growth in the area has not historically been great, the cost of serving this load is high due to the distance from the generating sources. Given Maine's deregulated electric utility industry and its rigorous environmental regulations, adding generating sources at load centers is difficult. At the site of EPRI's proposed tidal project in Western Passage at Eastport, Maine, the area load is approximately 3MW. The total load served from the nearest 115KV step down point, which is almost fifty miles away, is approximately 15MW.

The most important potential competing uses of sea space in Western Passage is interference with navigation, commercial fishing and salmon farming. Western Passage is naturally quite deep, and these issues can be largely avoided by placing TISEC devices at sufficient depths within the passage.

Salmon Farming: Salmon farms are found along the shores of Western, and a potential conflict would arise if excessive amounts of tidal current energy were withdrawn from this flow, reducing the natural flushing action through salmon-rearing pens. Limiting tidal in-stream energy projects to withdrawing no more than 10 to 15% of the cross-sectional base resource should avoid this potential negative impact.

Also to be explored is BHE's projected rate of load growth in Eastport, which is at the end of a 34.5 kV transmission line, and whether the installation of local distributed generation might defer the need for upgrade of this line.

Relevant Site Data

For the purpose of establishing point designs for both a demonstration and commercial system, the following data points are relevant. One of the critical limitations to the amount of tidal power developed at the Dog island site is the amount of space that is available for the deployment of turbines. Given the limitations imposed by having to avoid turbulence on the Deer island side of the channel maximum ship draft and the US/Canadian border that cuts through the middle of the channel, it leaves an area of about 250m wide and a length of about 500m.

Table 3 - Relevant Site Design Parameters

Site	
Channel Width	770 m
Average Depth (from MLLW)	47 m
Deepest Point	105 m
Seabed Type	Bedrock
Suitable Deployment Area	250m wide and 500m long
Tidal Energy Statistics	
Depth Averaged Power Density	2.9 kW/m^2
Average Power Available	104 MW
Average Power Extractable (15%)	15.6 MW
# Homes equivalent (1.3 kW/home)	12,000
Peak Velocity at Site	3.1 m/s
Grid Interconnection Demo	
Subsea Cable Length	500m
Cable Landing	Directionally drilled to deployment site
Overland Interconnection Upgrade cost	Estimated at $200k
Infrastructure Upgrade Cost	None assumed
Grid Interconnection Commercial	
Subsea Cable Length	500m
Cable Landing	Directional drilling
Overland Interconnection Upgrade cost	Contingency of $500k included
Infrastructure Upgrade Cost	None Assumed[2]

[2] Bangor Hydro chose not to estimate grid infrastructure upgrade cost at this time.

3. Lunar Energy Device

Device Description

The Lunar Energy technology, known as the Rotech Tidal Turbine (RTT) and illustrated in Figure 14, is a horizontal axis turbine located in a symmetrical duct. Unique features of the RTT are the use of a fixed duct, a patent pending blade design and the use of a hydraulic speed increaser. The full-scale prototype is designed to produce 1 MW of electricity while the initial commercial unit, the RTT 2000, is designed to produce 2 MW from a 7.2 knot (surface current) tidal stream. While no detailed cost analysis was carried out for this device, EPRI used the geometry of the RTT2000 to establish parameters for this project to address critical engineering issues. Ballast and structural reinforcements were scaled to meet load conditions at the site based on the maximum tidal current speed. Where required scour protection and other measures were assessed which are likely to impact the design at a particular site. The gravity foundation is provided by a concrete base, which can be provided with additional ballast to meet the required stability in high currents. The duct consists of steel plates which are supported by a steel tubular frame.

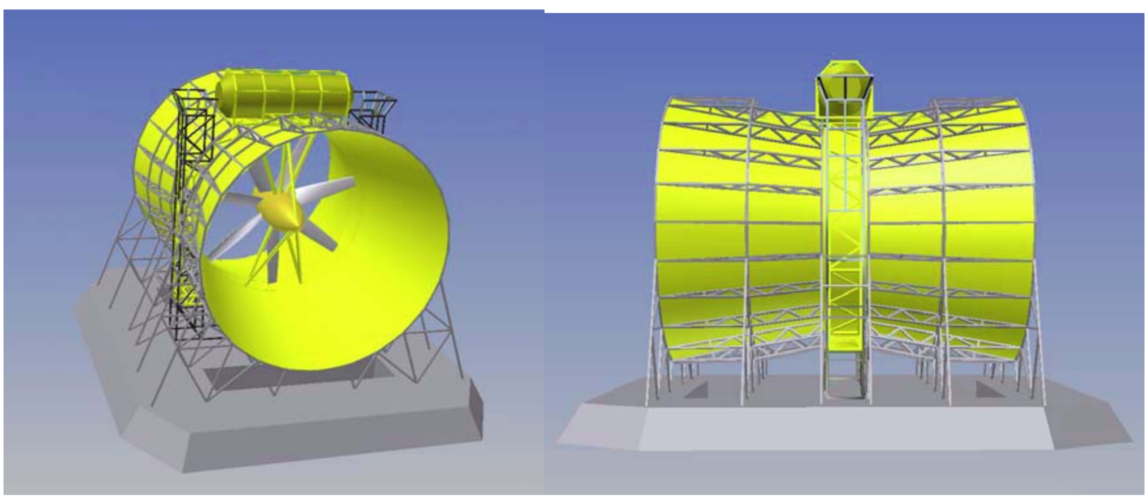


Figure 14 - Lunar Energy Mark I Prototype design

A cassette with the complete power take off, including rotor, hydraulic power conversion, electrical generation and grid synchronization is inserted as a module into the duct. This arrangement allows for relatively simple removal and replacement of the power conversion system and simplifies O&M procedures.

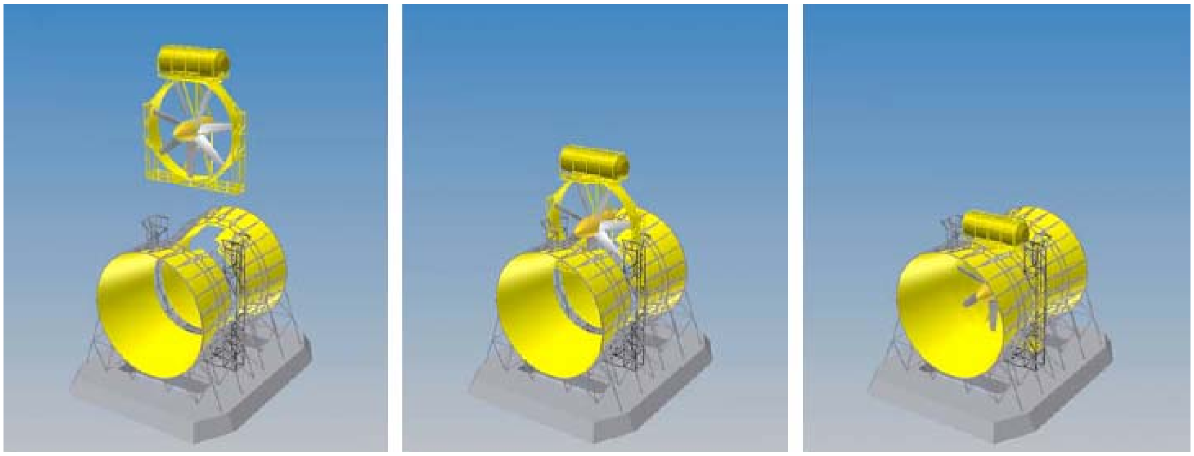


Figure 15 - Insertion and removal of cassette

Based on the site design velocity (maximum occurring velocity) the basic design's weight breakdown was scaled to ensure structural integrity and device stability. The following table contains the key properties for this site-design.

Table 2 - RTT2000 Mark II Specifications optimized for Western Passage Site conditions

Generic Device Specs	
Power Conversion	Hydraulic
Electrical Output	Synchronized with Grid
Foundation	Gravity Base
Dimensions	
Duct Inlet Diameter	21m
Duct Length	27m
Duct Clearance to Seafloor	10m
Duct Inlet Area	346m^2
Hub Height above Seafloor	20.5m
Average Deployment Depth at site	85m
Weight Breakdown	
Structural Steel	566 tons
Ballast	678 tons
Total installed dry-weight	1,244 tons
Power	
Cut-in speed	0.7 m/s
Rated speed	1.6 m/s
Rated Power	838 kW
Capacity Factor	32%
Availability	95%
Transmission losses	2%
Net annual generation at bus bar at site	2,353MWh

Device Performance

Given a velocity distribution for a site, the calculation of extracted and electrical power is discussed in [1]. Site surface velocity distributions have been adjusted to hub height velocity assuming a 1/10th power law.

The overall efficiency of the Lunar Energy RTT2000 is the product of rotor efficiency, gearbox efficiency and generator efficiency. The following chart shows the efficiency of the various elements as a function of rated speed as provided by Lunar Energy. In order to get to obtain the relative efficiency of the device, the numbers below should be multiplied by the Betz limit which is 0.593.

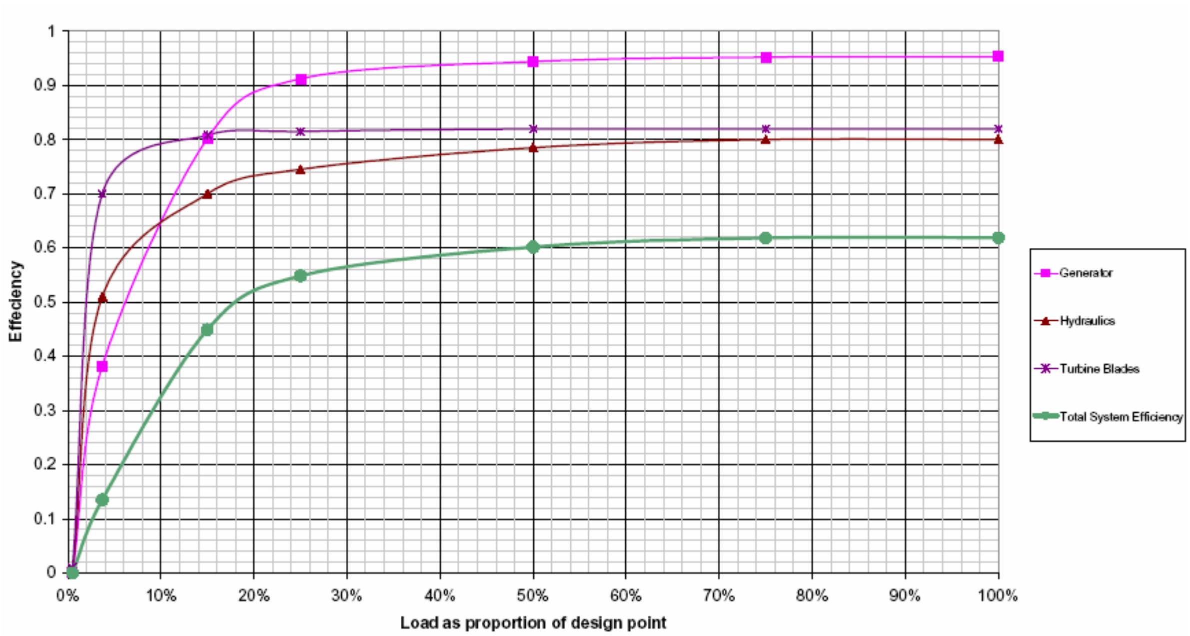


Figure 16 - Efficiency curves of Power Conversion System

Based on this efficiency chain and the exposed duct inlet area the device performance in a given site can be obtained. The following table shows the energy calculations at the Golden Gate site. The following definitions may help the reader understand:

- Flow velocities are depth adjusted using a 1/10 power law and represent the bin midpoint of the fluid speed at hub-height of the TISEC device.
- % Cases represents the percentage of time the flow at the site is at the flow velocity
- % Load represents the electrical output as a percentage of rated output of the device
- Power flux shows the incident power per square meter at the referenced velocity

- Flow power is the power passing through the cross sectional area of the device
- Extracted Power shows the amount of absorbed power

Average values can be found in the last column of the table.

Table 3 – Device Performance at deployment site (depth adjusted)

Fluid Speed m/s	% of Cases	% Load	Pfluid kW/m^2	Pfluid kW	Rotor Eff %	PCS Eff. %	Pelectric kW
0.09	4.24%	0.0%	0.00	0	33%	0%	0
0.26	4.51%	0.1%	0.01	3	33%	1%	0
0.43	4.51%	0.6%	0.04	14	35%	3%	0
0.61	4.55%	1.7%	0.11	40	37%	8%	0
0.78	5.11%	3.7%	0.24	84	41%	18%	6
0.95	5.50%	6.8%	0.44	154	44%	32%	22
1.13	5.71%	11.2%	0.73	254	47%	47%	56
1.30	7.03%	17.1%	1.13	391	48%	60%	111
1.47	8.94%	25.0%	1.64	569	48%	68%	186
1.65	10.04%	34.8%	2.29	794	48%	72%	275
1.82	11.48%	47.1%	3.09	1072	48%	74%	381
2.00	10.70%	61.8%	4.07	1408	48%	75%	507
2.17	7.99%	79.4%	5.22	1809	48%	75%	660
2.34	4.87%	100.0%	6.58	2278	48%	76%	838
2.52	2.77%	100.0%	8.15	2823	48%	76%	838
2.69	1.55%	100.0%	9.96	3448	48%	76%	838
2.86	0.46%	100.0%	12.01	4159	48%	76%	838
3.04	0.02%	100.0%	14.33	4963	48%	76%	838
3.21	0.00%	100.0%	16.93	5863	48%	76%	838
3.38	0.00%	100.0%	19.82	6866	48%	76%	838
3.56	0.00%	100.0%	23.03	7977	48%	76%	838
3.73	0.00%	100.0%	26.57	9202	48%	76%	838
3.90	0.00%	100.0%	30.45	10547	48%	76%	838
4.08	0.00%	100.0%	34.69	12017	48%	76%	838
4.42	0.00%	100.0%	44.33	15354	48%	76%	838
4.60	0.00%						
Avg.			2.51	869			288

Comparison of flow power to electric power generated is shown in Figure 17. Note particularly the cut-in speed (below which no power is generated) and rated speed (above which the power generated is constant).

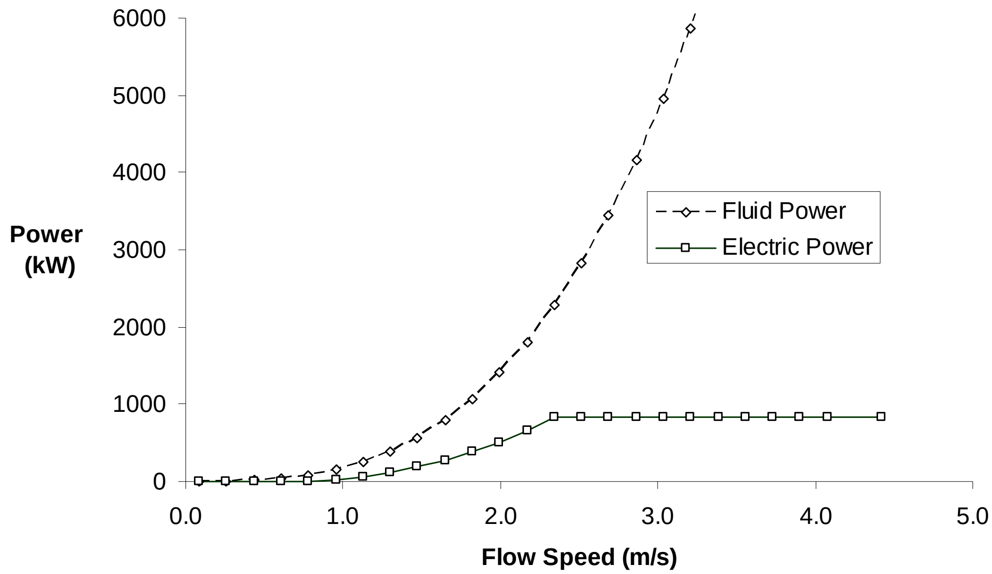


Figure 17 – Comparison of water current speed and electrical power output

The electrical output of the turbine compared to the fluid power crossing the swept area of the rotor is given in Figure 18, for a representative day and in Figure 19 for a Lunar cycle. The truncating effect of the machines rated power is clearly visible.

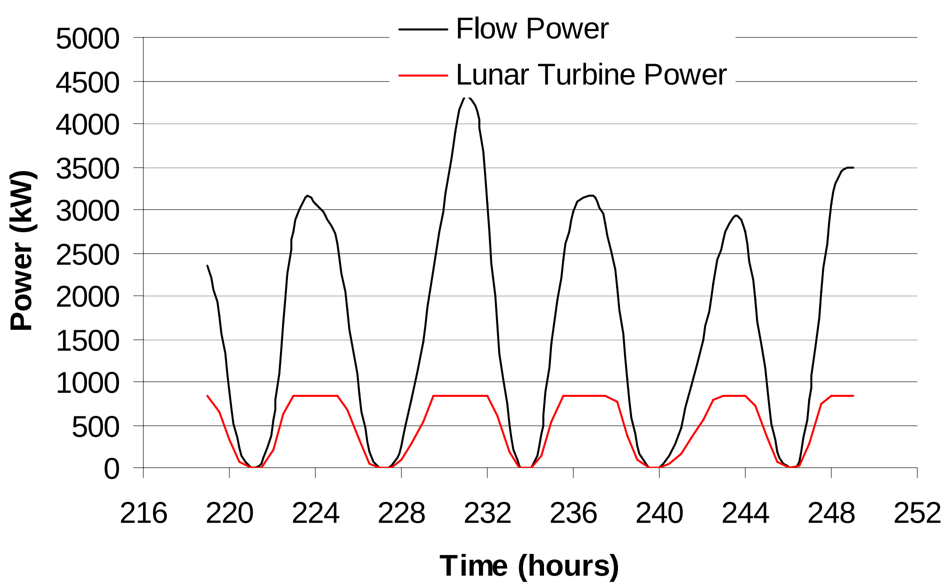


Figure 18 – Variation of flow power and electrical power output at the site

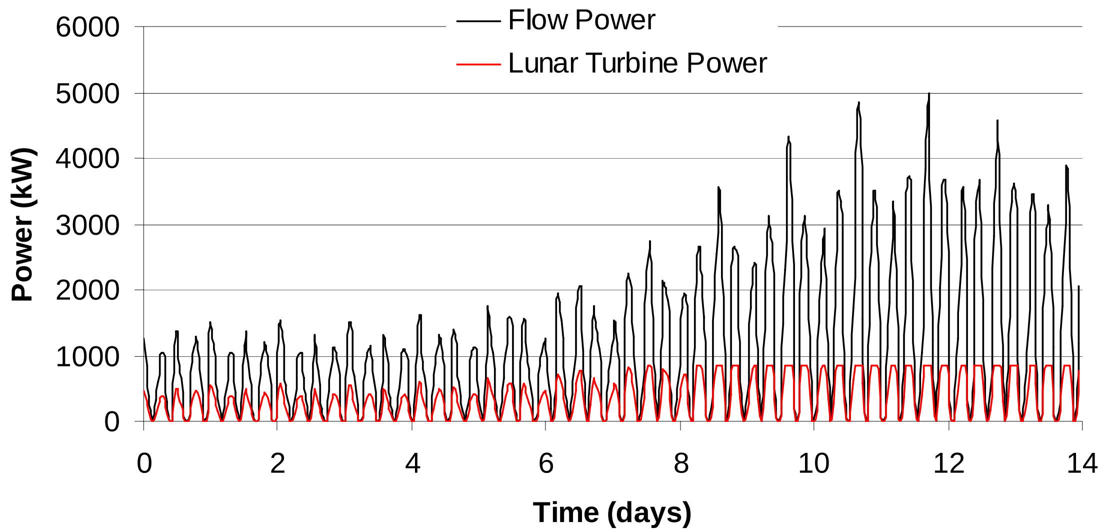


Figure 19 - Variation of flow power and electrical output at the site over a 14 day period

Lunar Device Evolution

Current design efforts carried out by Lunar Energy is focused on value engineering. Whereas the prototype design is in its final phase, the commercial units are expected to benefit from several potential areas of improvements, including:

1. Device Streamlining: Improving the overall design envelope to yield less drag, will reduce the stresses on the structure and result in savings on structural elements, foundation cost and weight.

2. Use of different materials: Replacing steel with concrete and composites could significantly reduce overall capital cost of the device.

3. Improving power train reliability: Improving the reliability of the power conversion system will result in less maintenance and could prove to provide significant savings. In particular replacing existing hydraulic elements with a direct induction generator could cut the number of interventions required over the devices design life by more then 50%.

4. Improving power train efficiency: The currently used hydraulic power conversion system shows an efficiency of about 76% at rated capacity. This is low as compared to other power train alternatives having efficiencies of up to 95%.

It is important to understand that none of the above measures would require novel technology and most of the measures could be implemented by means of simple value-engineering. Discussions with Lunar Energy showed that many of these improvements are already under consideration.

In March 2006, Lunar Energy provided EPRI with information on their redesigned prototype the RTT 2000 Mark II. The systems overall structural design was simplified by replacing the concrete base with 3 ‘steel-can’ legs. These steel pipes can be filled with ballast to provide stability against sliding in heavy currents. The duct-steelwork was also streamlined by making the duct a load-carrying element and eliminating the structural frame. While the overall redesign increased the steel-weight slightly, it reduced manufacturing complexities and associated cost.

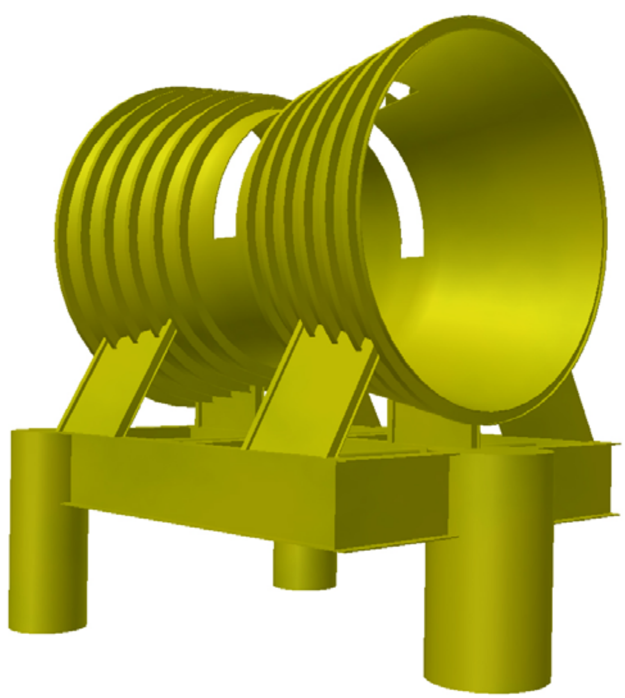


Figure 20 - RTT 2000 Mark II structural design

Installation of Lunar Module

The largest crane barges on the US west coast have capacities of up to 600 tons. With over 2000 tons, Lunar Energy's RTT2000 total system weight is well beyond of what any available crane-barge could handle and one of the big questions that needed to be answered was how this system was to be deployed, recovered and maintained. As a result, a detailed outline was developed of how the deployment and recovery of the device could be accomplished at reasonable cost. For the purpose of this outline we assumed that the device is deployed in two pieces, the concrete base and the duct. The text below outlines the deployment procedure.

The concrete base is constructed on a casting barge in calm, protected waters. The casting barge is then outfitted with four vertical pontoons (3m long), which are attached to each corner of the barge deck to provide stability during barge submersion. After the base is complete, the barge is ballasted until the deck is about 1.5m below the water level. This will allow the completed base shell to float free with a draft of about 1.2m. Once the base is floated off the barge it is sunk to the bottom in a water depth of at least 8m. Riser pipes are used to control the decent. A transport barge is floated over the base and preinstalled strand jacks are used to lift the base from the seabed until it is directly underneath the barge. The base is then filled with ballast and made ready for deployment. Finally, the barge is towed to it's deployment location and the same strand jacks are used to lower the base to it's prepared seabed.

Both the duct as well as the cassette unit are guided into final position using pre-installed guide wires extending vertically from the base structure to beams extending out in front of a derrick barge. The derrick barge places the duct onto a frame attached to the front of the barge. The duct is then attached to the guide wires and the guide wires are tensioned. Finally the duct is lowered onto the base using strand-jacks and guide wires. After set down, a ROV will disconnect strand jacks and guide wires from the base and duct.

The same procedure can be used to deploy and recover the cassette. The only difference is that the cassette weighs less and as a result a smaller (and less costly) derrick barge can be used.

Scour protection (if required) can be provided by either using concrete infill below the base or by placing articulated concrete mats onto the seabed. Both of these approaches have been successfully used in a number of North American projects.

Most installation and maintenance activities can be carried out from a derrick barge. These barges are in operation all over North and Central America and are used for a large variety of construction projects. Figure 21 shows Manson Construction's 600 ton derrick barge WOTAN doing construction work on an offshore drilling rig. Two tug boats are used for positioning the derrick barge and set moorings if required.

Figure 21 - Manson Construction 600 ton Derrick Barge WOTAN operating offshore

In heavy currents these barges use a mooring spread that allows them to keep on station and accurately reposition themselves continuously using hydraulic winches controlled by the operator.

A second piece of equipment that becomes really important for subsea installations is the remote operated vehicle (ROV). These systems increasingly replace divers and are used to monitor the subsea operation, visual inspections and carrying out various manipulation tasks such as connecting and disconnecting of guide wires, unplugging electrical cables etc. Technological advances have made these submersibles increasingly capable, in many instances eliminating the need to send down divers. This in turn reduces cost while increasing safety. A typical dual manipulator arm ROV making an underwater electrical connection is shown in Figure 21.

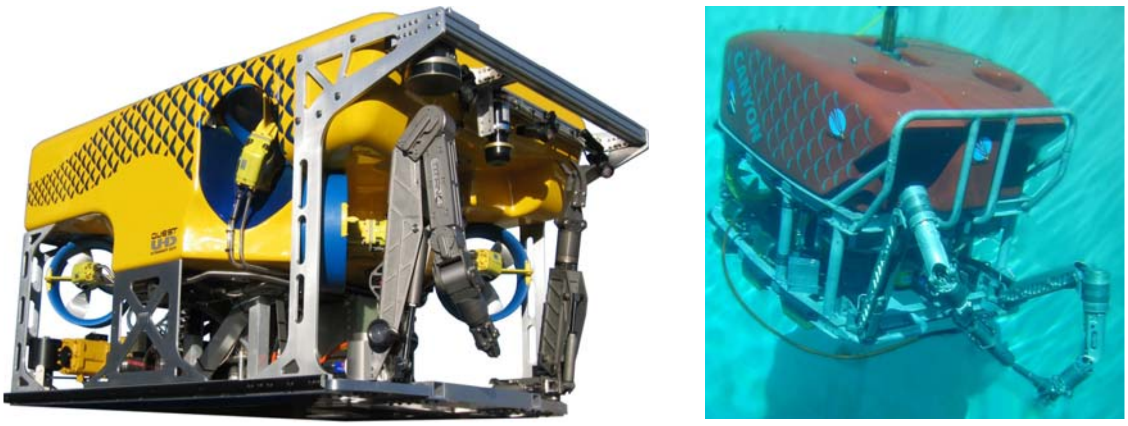


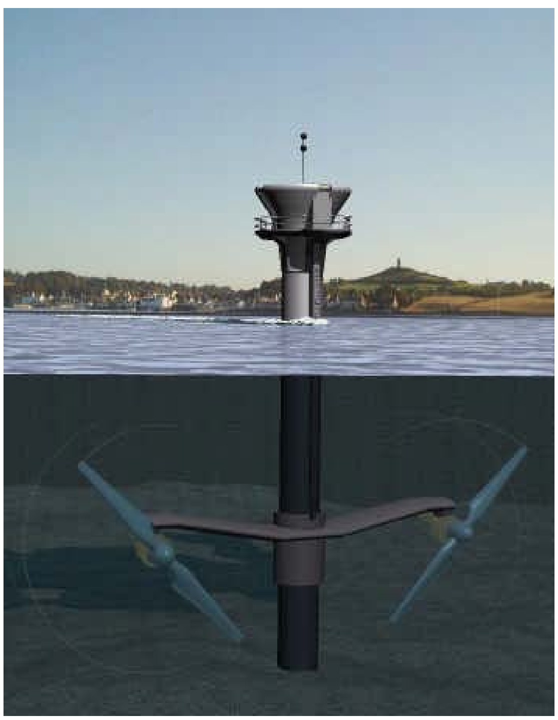
Figure 22 – Remotely Operated Vehicle (ROV) – ROV making electrical connection (courtesy of Schilling Robotics - www.ssaalliance.com)

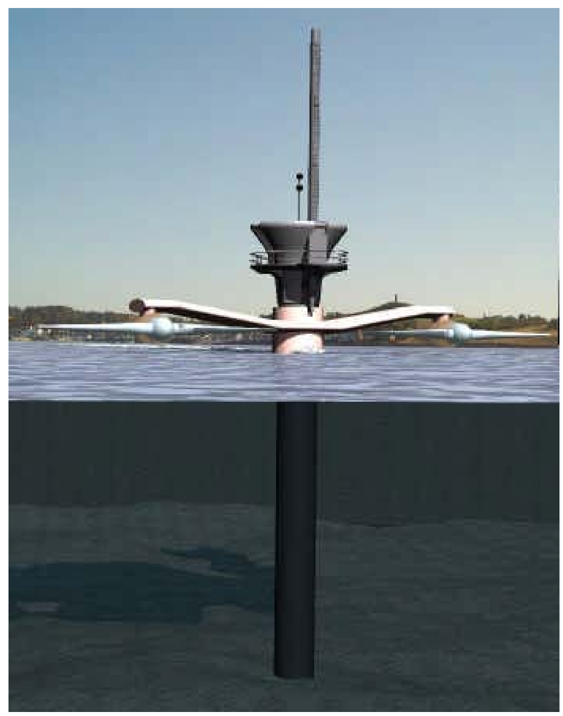
Operational Activities Lunar Energy

The O&M philosophy of Lunar Energy's RTT 2000 is to provide a reliable design that would require a minimal amount of intervention over its lifetime. In order to accomplish this Lunar Energy decided early on to use highly reliable and proven components even if that meant lower power conversion efficiency and performance as a result. All of the power conversion equipment of the RTT 2000 is mounted on a cassette, which can be removed from the duct and brought into a port to carry out operation and maintenance activities. The fact that the device is completely submersed makes its operation very dependent on attaining claimed reliability as each repair requires the recovery of the duct which requires specialized equipment. Lunar Energy has addressed this issue by optimizing its operation and maintenance strategy for minimal intervention. It is expected that the cassette is swapped out every 4 years and undergoes a complete overhaul after which it is ready to operate for another 4 years. The critical components prone to failure in the power conversion system are the hydraulic power conversion system. Given the high cost for maintenance intervention, reliability of the system becomes a critical attribute of the system, which will need to be proven on a prototype system. The L90 life of a component specifies after how much time 10% of components will fail (i.e. 90% of the components are still in good order therefore the term L90). The most critical hydraulic component of the RTT2000 has a L90 life of 5 years (meaning that after 5 years 90% of all devices are still operating without any issues). Given a typical Weibull failure distribution it was deemed that a 4-year service interval as proposed by the company is a sensitive approach.

4. Marine Current Turbines

The Marine Current Turbine (MCT) SeaGen free flow water power conversion device has twin open axial flow rotors (propeller type) mounted on "wings" either side of a monopile support structure which is installed in the seabed. Rotors have full span pitch control and drive induction generators at variable speed through three stage gearboxes. Gearboxes and generators are submersible devices the casings of which are exposed directly to the passing sea water for efficient cooling. A patented and important feature of the technology is that the entire wing together with the rotors can be raised up the pile above the water surface for maintenance. Blade pitch is rotated 180^{o} at slack water to accommodate bi-directional tides without requiring a separate yaw control mechanism. This device is illustrated in Figure 23.





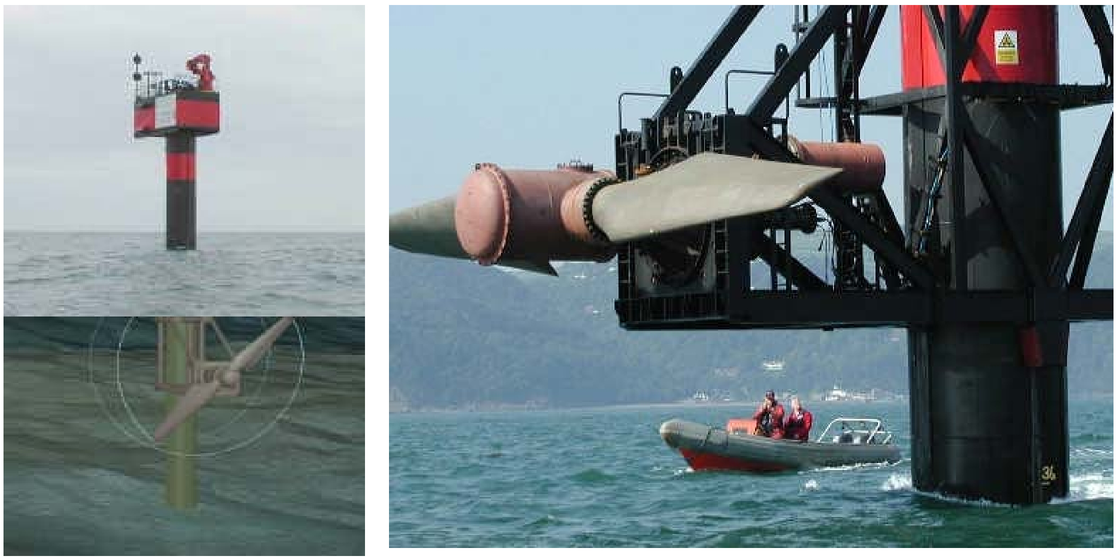
Operation Maintenance

Figure 23 – MCT SeaGen (courtesy of MCT)

(When printed photos are upside down courtesy of Microsoft or our lack of MW Word skills)

A 1.2 MW prototype SeaGen is presently being built and is scheduled for UK deployment in the fall of 2006. SeaGen is intended as a commercial prototype (not proof of concept) –

and incorporates important learnings from SeaFlow, a 300kW single rotor test rig (Figure 24), which has been in operation for about 3 years. SeaFlow tested many of the features of SeaGen and has informed the design process by providing large amounts of data. The photo shows the rotor raised out of the water for maintenance – the submersible gearbox and generator are clearly visible. The rotor diameter is 11m and the pile diameter is 2.1m.



Operation Maintenance

Figure 24 – MCT SeaFlow Test Unit (courtesy of MCT)
(When printed photos are upside down courtesy of Microsoft or our lack of MW Word skills)

Device Performance

Given a velocity distribution for a site, the calculation of extracted and electrical power is discussed in [1]. Site surface velocity distributions have been adjusted to hub height velocity assuming a 1/10th power law.

The overall efficiency of the MCT SeaGen is the product of:

- Rotor: constant efficiency = 45%
- Gearbox: efficiency at rated power = 96%
- Generator: maximum efficiency = 98%

The efficiency of the gearbox and generator is expressed as a function of the load on the turbine (% load). Power Conversion System efficiency (PCS) is assumed to follow the same form as for a conventional wind turbine drive train – which can be approximated by the following function:

$$\eta_{BOS} = 0.8337e^{0.1467(\%\,\text{Load})} - 0.7426e^{-33.89(\%\,\text{Load})}$$

The performance of a single turbine deployed at the site is shown in

Table 4. Average values can be found in the last row of the table.

Table 4 – Device Performance

Fluid Speed m/s	% of Cases	% Load	Pfluid kW/m^2	Pfluid kW	Pextracted kW	PCS %	Pelectric kW
0.09	4.24%	0.0%	0.00	0	0	9.32%	0
0.26	4.51%	0.2%	0.01	4	0	14.52%	0
0.43	4.51%	1.0%	0.04	20	0	31.07%	0
0.60	4.55%	2.8%	0.11	55	0	55.15%	0
0.77	5.11%	6.0%	0.23	117	53	74.36%	39
0.94	5.50%	10.9%	0.42	214	96	82.90%	80
1.11	5.71%	18.1%	0.69	353	159	85.44%	136
1.28	7.03%	27.7%	1.07	543	244	86.83%	212
1.45	8.94%	40.4%	1.55	790	355	88.46%	314
1.62	10.04%	56.4%	2.17	1103	496	90.56%	449
1.79	11.48%	76.1%	2.93	1489	670	93.22%	625
1.96	10.70%	100.0%	3.84	1956	880	94.08%	828
2.13	7.99%	100.0%	4.94	2512	880	94.08%	828
2.30	4.87%	100.0%	6.22	3165	880	94.08%	828
2.47	2.77%	100.0%	7.71	3921	880	94.08%	828
2.64	1.55%	100.0%	9.41	4790	880	94.08%	828
2.81	0.46%	100.0%	11.35	5778	880	94.08%	828
2.98	0.02%	100.0%	13.55	6894	880	94.08%	828
3.15	0.00%	100.0%	16.00	8144	880	94.08%	828
3.32	0.00%	100.0%	18.74	9538	880	94.08%	828
3.49	0.00%	100.0%	21.77	11081	880	94.08%	828
3.66	0.00%	100.0%	25.12	12783	880	94.08%	828
3.83	0.00%	100.0%	28.79	14651	880	94.08%	828
4.00	0.00%	100.0%	32.80	16693	880	94.08%	828
4.17	0.00%	100.0%	37.17	18916	880	94.08%	828
4.34	0.00%	100.0%	41.91	21328	880	94.08%	828
4.51	0.00%	100.0%	47.03	23937	880	94.08%	828
Average			**2.37**	**1207**	**443**		**409**

comparison of flow power to electric power generated is shown in Figure 25. Note particularly the cut-in speed (below which no power is generated) and rated speed (above which the power generated is constant).

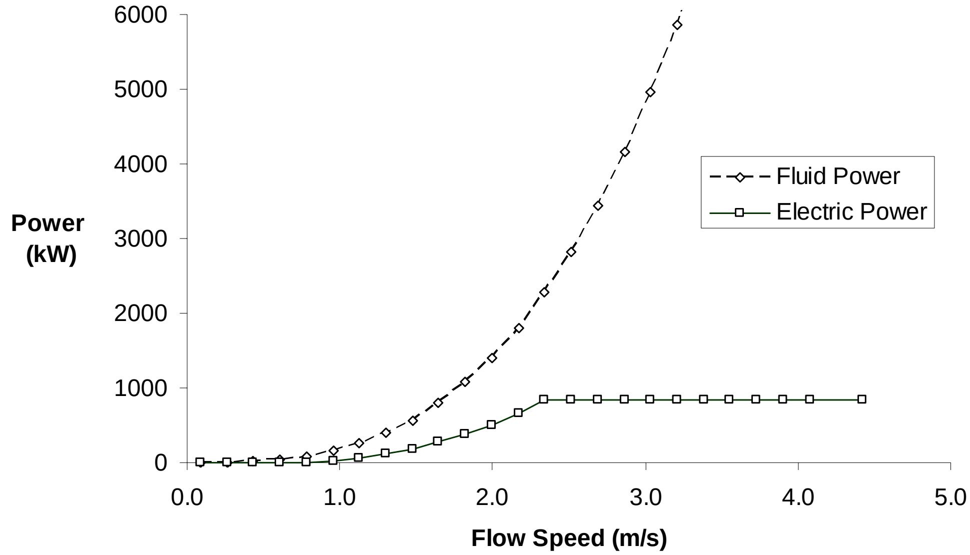


Figure 25 – Comparison of water current speed and electrical power output

The electrical output of the turbine compared to the fluid power crossing the swept area of the rotor is given in Figure 26, for a representative day and in Figure 27 over a 14 day period. The effect of truncating turbine output at rated conditions is obvious.

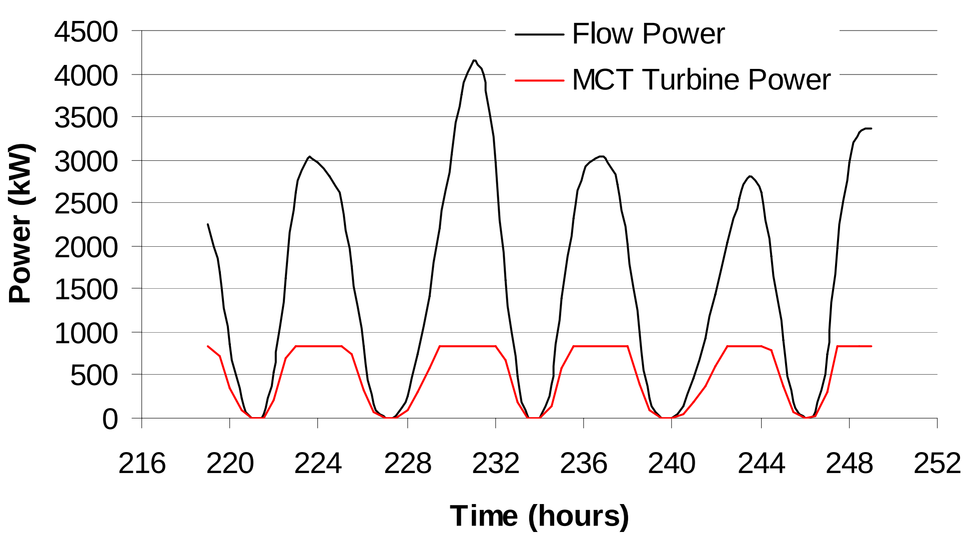


Figure 26 – Variation of flow power and electrical power output at the site

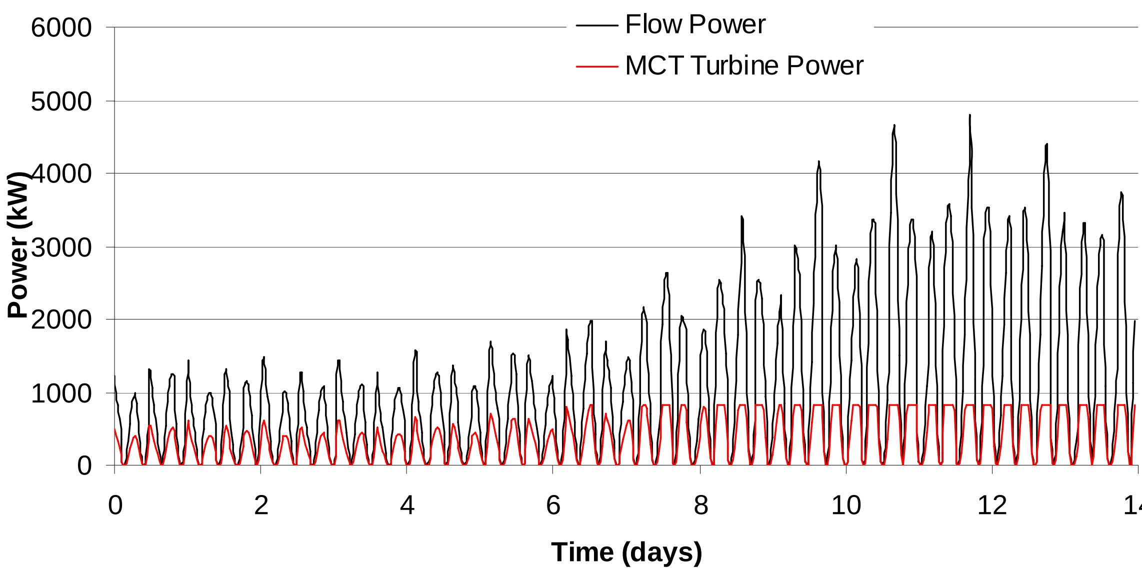


Figure 27 - Variation of flow power and electrical power output at the site over a lunar cycle

Device Specification

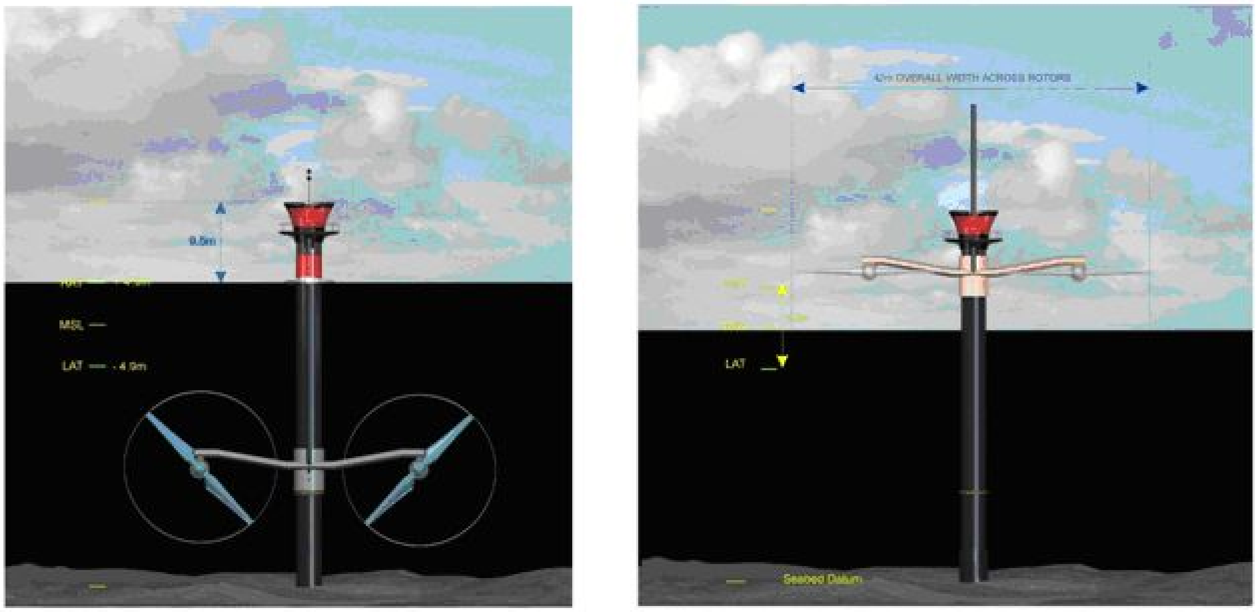
While in principle SeaGen is scalable and adaptable to different site conditions in various ways, EPRI used the 18m dual rotor version and optimized the system to local site conditions to estimate device cost parameters. The following provides specifications which are later used to estimate device cost. Since MCT's second generation completely submersed concept is not yet designed for manufacturing, EPRI was not able to do an independent cost analysis or it. Therefore the costing model represents an installation depth of 30m (which is representative of MCTs SeaGen technology). Based on discussions with MCT it is reasonable to expect that subsequent generation devices will have similar capital cost.

Table 5 – SeaGen Device Specification optimized for the Dog island transect site

Generic Device Specs	
Speed Increaser	Planetary gear box
Electrical Output	Synchronized to grid
Foundation	Monopile drilled and grouted into bedrock
Average Deployment Water Depth	85m
Dimensions	
Pile Length	58m
Pile Diameter	3.5m
Rotor Diameter	18m
# Rotors per SeaGen	2
Rotor Tip to Tip spacing	46m
Hub Height above Seafloor	17m
Weight Breakdown	
Monopile	116 tons
Cross Arm	68 tons
Total steel weight	184 tons
Performance	
Cut-in speed	0.7 m/s
Rated speed (optimized to site)	1.96 m/s
Rated Electric Power	828 kW
Capacity Factor	46%
Availability	95%
Transmission efficiency	98%
Net annual generation at bus bar	3,335 MWh/year

MCT Device Evolution

MCTs first commercial unit, the SeaGen has been designed for a target water depth of less then 50m using a surface piercing monopile, which will allow low cost access to the devices critical components such as the rotor, power conversion system, gearbox etc. This configuration is shown in Figure 28.



Operation Maintenance

Figure 28 – MCT SeaGen (courtesy of MCT)

This configuration is not necessarily suitable for all sites for two reasons. First, deployment in deep water would be difficult and expensive. Second, surface piercing turbines are incompatible in some channels due to interference with shipping traffic. Since a number of sites prospective sites in North American are located in deeper water or in shipping channels, MCT has revealed a conceptual design for a deep-water, non-surface piercing turbine. It is based on MCTs existing turbine technology with an arrangement to raise the whole system to the surface where it can be accessed easily for operation and maintenance purposes. A preliminary review suggests that capital and operational costs are likely going to be in a similar range then for the SeaGen unit for which detailed cost models were built to evaluate the technology’s economics in selected sites in North America.

Since a number of prospective sites in North American are located in deeper water or in shipping channels, MCT is considering a number of conceptual designs for deep-water, non-surface piercing installations. These next-generation devices would use the same power train as the SeaGen, but attached to a different support structure. Figure 29 shows a conceptual illustration of such a design.

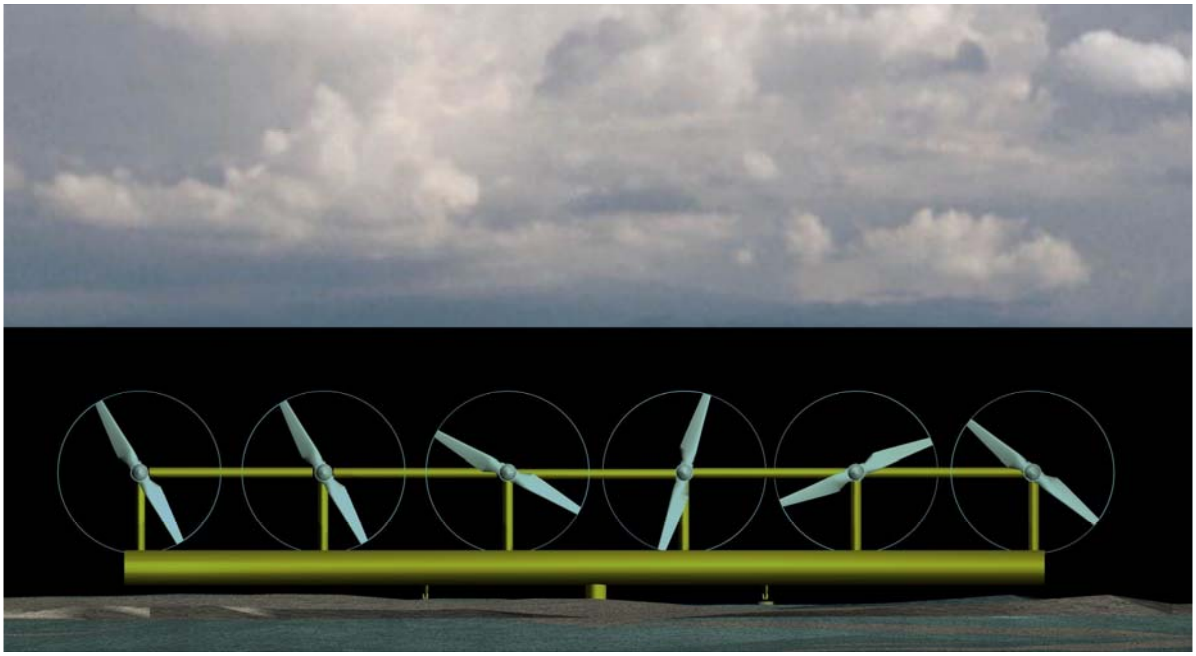


Figure 29 - MCT next generation conceptual illustration

A lifting mechanism (type to be determined) to surface the array for maintenance and repair without the use of specialized craft remains an integral part of MCT's design philosophy and would be present in any next-generation design. MCT is also investigating the use of gravity foundations instead of monopiles for certain sites.

MCT anticipates that maintenance of a completely submerged turbine will be more complicated than for a surface piercing structure. As a result, deployment of completely submerged turbines is contingent upon proving the reliability of the SeaGen power train.

Monopile Foundations

The MCT SeaGen is secured to the seabed using monopile foundation. Figure 30 shows a representative simulation of seabed/pile interaction. Near the surface the seabed yields due to stresses on the pile, but deforms elastically below a certain depth.

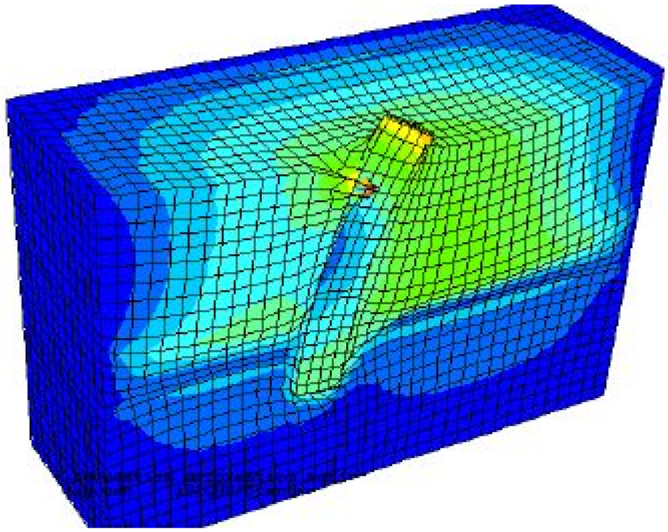


Figure 30 - Simulation of pile-soil interaction subject to lateral load (Source: Danish Geotechnical Institute)

Simulations such as the one shown above require detailed knowledge of the local soil conditions. Because this study did not perform any detailed geophysical assessment, three different types of soil conditions were chosen to model the pile thickness based on a simplified mechanical model:

- Bedrock
- Bedrock with 10m of sediment overburden
- Soft sediments

The design criterion was to limit maximum stresses to 120N/mm^2 and account for corrosion over the pile life. For Western Passage, the seabed is modeled as bedrock.

Figure 31 shows the range of pile weights as a function of design velocity (the maximum occurring fluid velocity at the site). These curves were then directly used to estimate capital costs of the piles depending on local site conditions. While the model is well suited for a first order estimate, it is important to understand that the detailed design phase may show deviation from EPRI's base model.

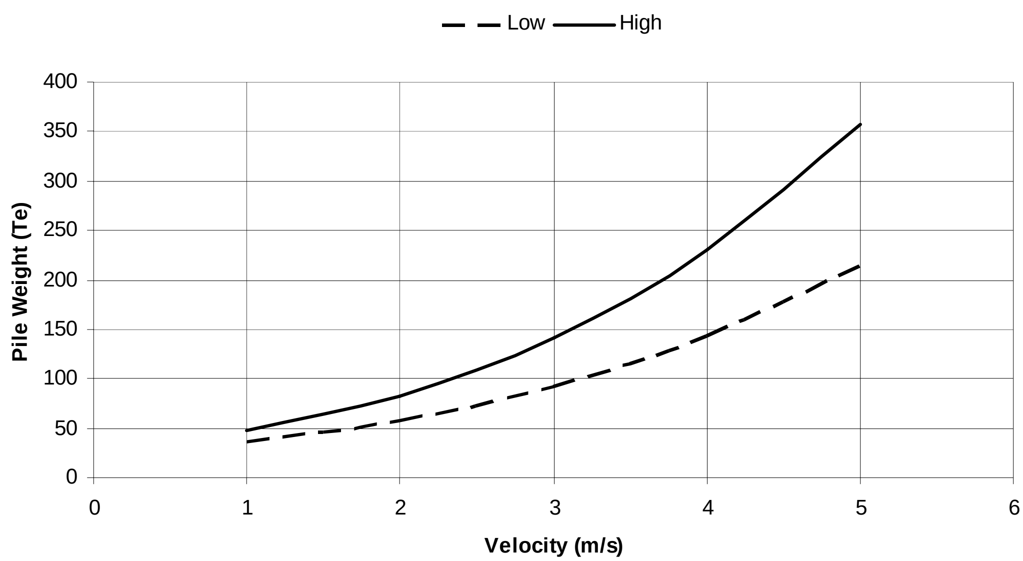


Figure 31 - Pile Weight as a function of design velocity for different sediment types

Pile Installation

MCT proposes to install their large diameter monopiles (3.5m - 4m outer diameter) using a jack-up barge. This is consistent with other European offshore wind projects that have used such barges to deploy offshore wind turbine foundations. While a few operators were found on the east-coast that use jack-up barges, most of them are used in the Gulf of Mexico and no suitable jack-up barge was found on the US west coast. Given the expense of mobilizing marine construction equipment from the Gulf of Mexico, EPRI decided to investigate lower-cost alternatives. The following outline shows the installation of a pile in bedrock from a jack-up barge.

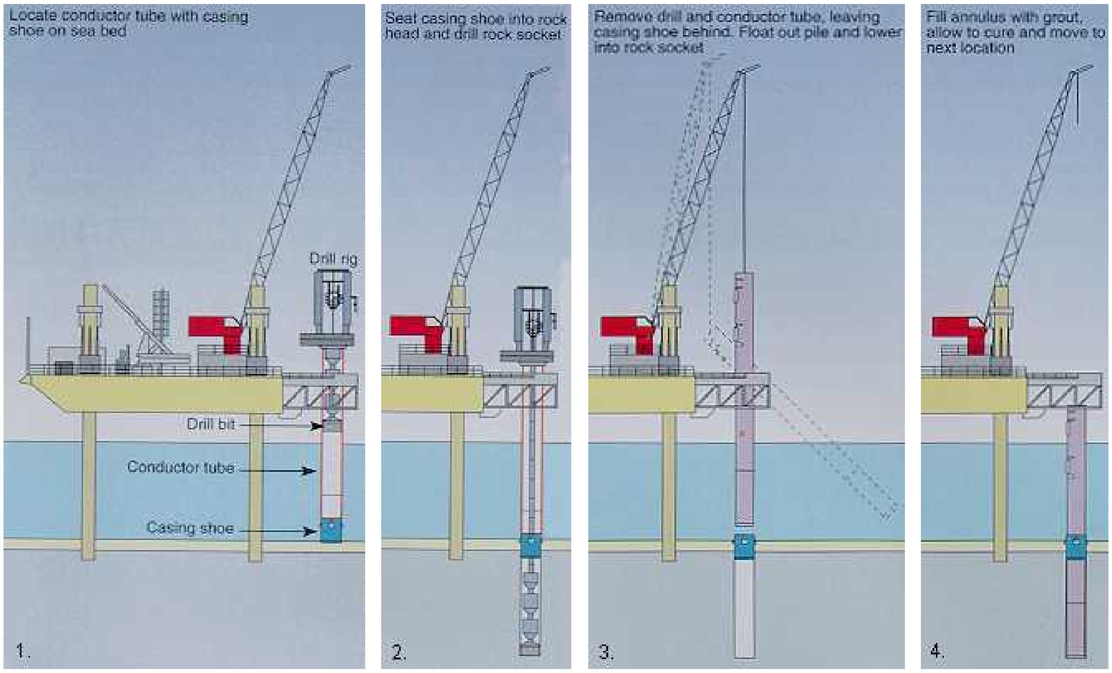


Figure 32 – Pile Installed in Bedrock (Seacore)

While jack-up barges are not commonly available in US waters, there are a significant number of crane barges available from which the installation of theses piles could be carried out. These derrick barges operate on the US west and east coast and are extensively used for construction projects in heavy currents such as rivers. Typical construction projects include the construction of bridges, cofferdams and pile installations. Crane capacities vary with some of the largest derrick barges being able to lift up to 600 tons. To carry out the installation of these relatively large 3.5m diameter piles, it was determined that a crane capacity of about 400 tons or more would be adequate to handle the piles, drilling bits and other installation equipment. Figure 27 shows Manson Construction's 600 ton derrick barge WOTAN doing construction work on an offshore drilling rig. Two tug boats are used for positioning the derrick barge and set moorings if required.

Figure 33 - 600 ton Derrick Barge WOTAN operating offshore (Manson Construction)

In heavy currents these barges use a mooring spread that allows them to keep on station and accurately reposition themselves continuously using hydraulic winches controlled by the operator.

Working from a barge, rather then from a jack-up platform does not set hard limits on the water depth in which piles can be installed. Some preliminary studies suggest that type of pile required for the MCT SeaGen device could be installed in water depths of as much as 90m. However such a configuration may not be cost effective due to high cost. In the offshore industry, piles are oftentimes used as mooring points for offshore structures. Installation of driven piles in water depths of more then 300m is not uncommon. It is, however, clear that pile installation in deeper waters becomes more costly and presents a limiting factor to their viability. Several options exist for installing piles, but it is important to stress that few marine construction companies in the US have experience with the installation of large piles in high current waters. Potential construction methods include:

- Driving piles using a hydraulic hammer

- Combination of water jetting and vibratory hammer
- Drill and socket a sleeve, then grout pile in place

Each of these methods has advantages and disadvantages. A drilled pile installation would involve drilling into the consolidated sediments and stabilizing the walls of the drill hole with a metal sleeve (follower). Once the hole has been drilled to a suitable depth, the pile is inserted and grouted into place. This method of installation is preferred by MCT to limit excessive pile fatigue during the installation process and drilling is required in most locations because of bedrock that would need to be penetrated.

Operational and Maintenance Activities

The guiding philosophy behind the MCT design is to provide low cost access to critical turbine systems. Since an integrated lifting mechanism on the pile (or level arm for the next generation design) can lift the rotor and all subsystems out of the water, general maintenance activities do not require specialized ships or personnel (e.g. divers). The overall design philosophy appears to be that the risks associated with long-term underwater operation are best offset by simplifying scheduled and unscheduled maintenance tasks. The only activity that could require use of divers or ROVs would be repairs to the lifting mechanism or inspection of the monopile, none of which are likely to be required over the project life.

Annual inspection and maintenance activities are carried out using a small crew of 2-3 technicians on the device itself. Tasks involved in this annual maintenance cycle include activities such as; replacement of gearbox oil, applying bearing grease and changing oil filters. In addition, all electrical equipment can be checked during this inspection cycle and repairs carried out if required. Access to the main structure can be carried out safely using a small craft such as a RIB (Rigid Inflatable Boat) in most sea conditions.

Figure 34: Typical Rigid Inflatable Boat (RIB)

For repairs on larger subsystems such as the gearbox, the individual components can be hoisted out with a crane or winch and placed onto a motorized barge. The barge can then convey the systems ashore for overhaul, repair or replacement. For the purpose of estimating the likely O&M cost, the mean time to failure was estimated for each component to determine the resulting annual operational and replacement cost. Based on wind-turbine data, the most critical component is the gearbox which shows an average mean time to failure of 10.8 years.

For the next generation design for a completely submerged turbine (assumed for commercial plant) major intervention could require the use of a crane barge to dismount the power train from the support structure. Since the lifting mechanism would also be subsurface, a failsafe retrieval method (e.g. retrieval hook) would be required in the case of a failure of the lifting mechanism. MCT does not anticipate the added complexity of full submergence to greatly increase maintenance costs, because deployment of a fully submerged device is contingent on proving that the chosen power train requires limited maintenance intervention.

5. Electrical Interconnection

Each TISEC device houses a step-up transformer to increase the voltage from generator voltage to a suitable array interconnection voltage. The choice of the voltage level of this energy collector system is driven by the grid interconnection requirements and the array electrical interconnection design but is typically between 12kV and 40kV. For the pilot scale, 12kV systems are anticipated – depending on local interconnection voltages. This will allow the device interconnection on the distribution level. For commercial scale arrays, voltage levels of 33kV are used. This allows the interconnection of an array with a rated capacity of up to about 40MW on a single cable.

A fiber core is used to establish reliable communication between the devices and a shore-based supervisory system. Remote diagnostic and device management features are important from an O&M stand-point as it allows to pin-point specific issues or failures on each unit, reducing the physical intervention requirements on the device and optimizing operational activities. Operational activities offshore are expensive and minimizing such interventions is a critical component of any operational strategy in this harsh environment.

The Surface piercing MCT SeaGen device has all it's electrical components located inside the monopile, where it is well protected and easily accessible for operation and maintenance activities. In other words, sub sea connectors or junction boxes are not required to interconnect the device to the electrical grid.

The completely submersed Lunar Energy Device houses all the generation equipment and step-up transformer in cylindrical watertight container mounted on the cassette, which needs to be recovered to the surface for servicing. Interconnection is envisioned to be accomplished using a pressure compensated junction box that allows a single device to be connected to a device cluster. The cassette can be interconnected by either using sub sea wet-mate cable connectors or using a flexible cable that is attached to the cassette so that it can be connected and disconnected on the surface.

Subsea Cabling

Umbilical cables to connect turbines to shore are being used in the offshore oil & gas industry and for the inter-connection of different locations or entire islands. With other words, it is well established technology with a long track-record. In order to make these cables suitable for in-ocean use, they are equipped with water-tight insulation and additional armor, which protects the cables from the harsh ocean environment and the high stress levels experienced during the cable laying operation. Submersible power cables are vulnerable to damage and need to be buried into soft sediments on the ocean floor. While traditionally, sub-sea cables have been oil-insulated, recent offshore wind projects in Europe, showed that the environmental risks prohibit the use of such cables in the sensitive coastal environment. XLPE insulations have proven to be an excellent alternative, having no such potential hazards associated with its operation. Figure 35 shows the cross-sections of armored XLPE insulated submersible cables.

Figure 35 – Armored submarine cables

For this project, 3 phase cables with double armor and a fiber core are being used. The fiber core allows data transmission between the units and an operator station on shore. In order to protect the cable properly from damage such as an anchor of a fishing boat, the cable is buried into soft sediments along a predetermined route. There are different technologies available to bury the cable along the cable route. All of them require the creation of a trench in which the cable can be laid. In order to protect the cable, this channel is then back-filled with rocks. Various trenching technologies exist such as the use of a plough in soft sediments, use of a subsea rock-saw in rock (if going through hard-rock) or the use of water jets. All of these cable laying operations can be carried out from a derrick barge that is properly outfitted for the particular job. The choice of technology best suited for getting the job done depends largely on the outcome of detailed geophysical assessments along the cable route. For this study, the EPRI team assessed both the use of a trenching rock saw as well as a plough.

An important part of bringing power back to shore is the cable landing. Existing easements should be used wherever possible to drive down costs and avoid permitting issues. If they do not exist, directional drilling is the method with the least impact on the environment. Directional drilling is a well established method to land such cables from the shoreline into the ocean and has been used quite extensively to land fiber optic cables on shore. Given some of the deployment location proximity to shore, detailed engineering might even reveal that directional drilling directly to the deployment site is possible. This would reduce environmental construction impacts at the site, while reducing overall cost.

Onshore Cabling and Grid Interconnection

Traditional overland transmission is used to transmit power from the shoreline to a suitable grid interconnection point. Grid interconnection requirements are driven by local utility requirements. At the very least, breaker circuits need to be installed to protect the grid infrastructure from system faults. VAR compensation voltage step-up and other measures might be introduced based on particular local requirements.

6. System Design – Pilot Plant

The purpose of a pilot plant is first, and foremost, to demonstrate the viability of a particular technology. Pilot plants are, in general, not expected to produce cost competitive electricity and often incorporate instrumentation absent from a commercial device.

For the pilot TISEC plant, the following should be successfully demonstrated prior to installation of a commercial array:

- Turbine output meets predictions for site
- Installation according to design plan with no significant problems
- Turbine operates reliably, without excessive maintenance intervention
- No significant environmental impacts for both installation as well as operational aspects.

For the pilot plant at the Dog Island transect, the following issues deserve particular attention and should be an integral part of the pilot testing plan:

- Large marine mammal and fish interaction with turbine. This will require instrumentation for fish monitoring.
- Bio-accumulation on turbine and support structure over course of demonstration.

The following illustration shows how a single TISEC device is connected to the electric grid.

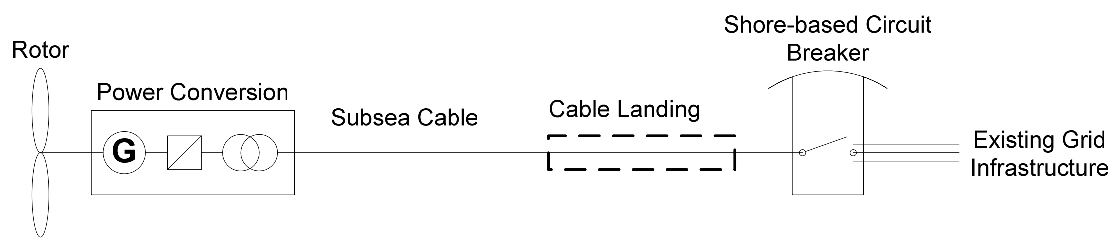


Figure 36 - Conceptual Electrical Design for a single TISEC Unit

Pilot power collection and grid interconnection details are summarized in Table 6 – Pilot Grid Interconnection. The cost for overland interconnection is for routing the power take-off cable from the beach to distribution line. Infrastructure upgrade costs are expected to be minor since power is being fed into an existing distribution line.

Table 6 – Pilot Grid Interconnection

Grid Interconnection Demo	
Grid Interconnection Point	4.6 kV distribution line close to cable landing
Subsea Cable Length	500m
Subsea Trench Length	500m
Sediment type along cable route	Bedrock and Gravel
Cable Landing	Directional Drilling
Overland Interconnection Cost	Estimated at $200,000
Infrastructure Upgrade Cost	None assumed

The deployment location for a single unit is described in the site selection section and turbine performance is outlined in the performance section. A demonstration unit is likely to be deployed in the narrowest cross section below the shipping channel close to Dog island.

The footprint of the pilot plant is quite small and should have little impact on recreation or shipping activities. It is likely that a pilot unit could be deployed in close proximity to Dog island in which case much of the underwater trenching operation could be eliminated or replaced by directional drilling. This could potentially reduce a pilot project by more then $1million.

7. System Design - Commercial TISEC Power Plant

The purpose of a commercial tidal plant is to generate cost competitive electricity for the grid without causing unacceptable environmental impacts. The single largest impact on the cost of electricity for a TISEC farm is the current velocity profile. The reason is that structural loads (and corresponding structural cost) increase to the second power of velocity, while the power generated increase to the 3rd power of the velocity. In a channel the fluid velocity will increase in narrow passages. So the channel transect with the lowest cross-sectional area will generally prove to be the most economic one.

Other factors considered in the design of this commercial tidal power plant are:

- Install turbines only in waters sufficiently deep to meet shipping clearance requirements
- Turbines are not to extract more then 15% of the total estimated resource
- Locate the plant in close proximity to a grid interconnection point to reduce costs

For purposes of establishing a conceptual design point, we assumed that either MCT's next generation multi-rotor machine or Lunar Energy's RTT2000 would be installed at the site. Both of these designs are completely submersed and do not directly interfere with any shipping activities when in operation. Only installation and O&M activities will interfere directly with surface based activities. It is reasonable that such activities can be coordinated so as not to conflict with other uses of the sea space. For design and cost estimate purposes we assumed that the commercial MCT design use the same rotor diameter and clearance requirements as the surface piercing SeaGen device.

Electrical Interconnection

In order to interconnect a large number of turbines to the electric grid, a power collection network needs to be set up. In order to maximize availability and stay within reasonable limits on the amount of electrical power fed back to shore per single cable devices are arranged in clusters. Each cluster connects back to shore using a single cable. This allows a cluster of devices to be isolated if required.

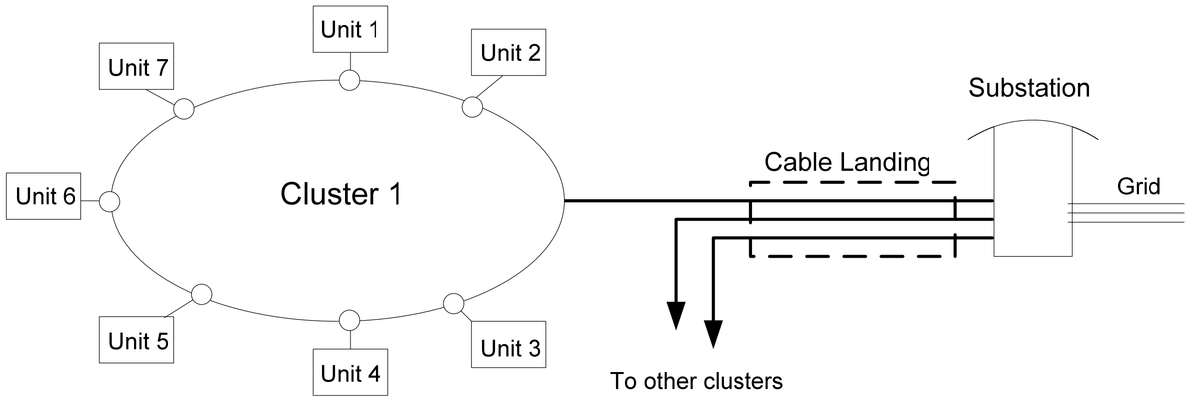


Figure 37 - Electrical Power Collection and Grid Interconnection for commercial plant

Physical Layout

In order to extract 15% of the resource at the site, a significant portion of the cross-sectional area needs to be intersected. With existing prototype device rotor diameters and non stackable structures, this can only be achieved by arranging the turbines in rows across the channel width in areas with sufficient depth. In addition, it might require the rows of turbines to be installed at different depths behind each other with sufficient spacing in order to avoid the wake of the previous row of turbines to affect subsequent rows. The narrowest transect where we can expect high velocities is short. The rectangular area in Figure 38 shows the length and width of interest for turbine deployment. Detailed modeling of the resource could reveal hot-spots and provide more information as to where such turbines should be located. However in absence of such models, the outline shown below shows reasonable boundaries within which devices could be deployed.

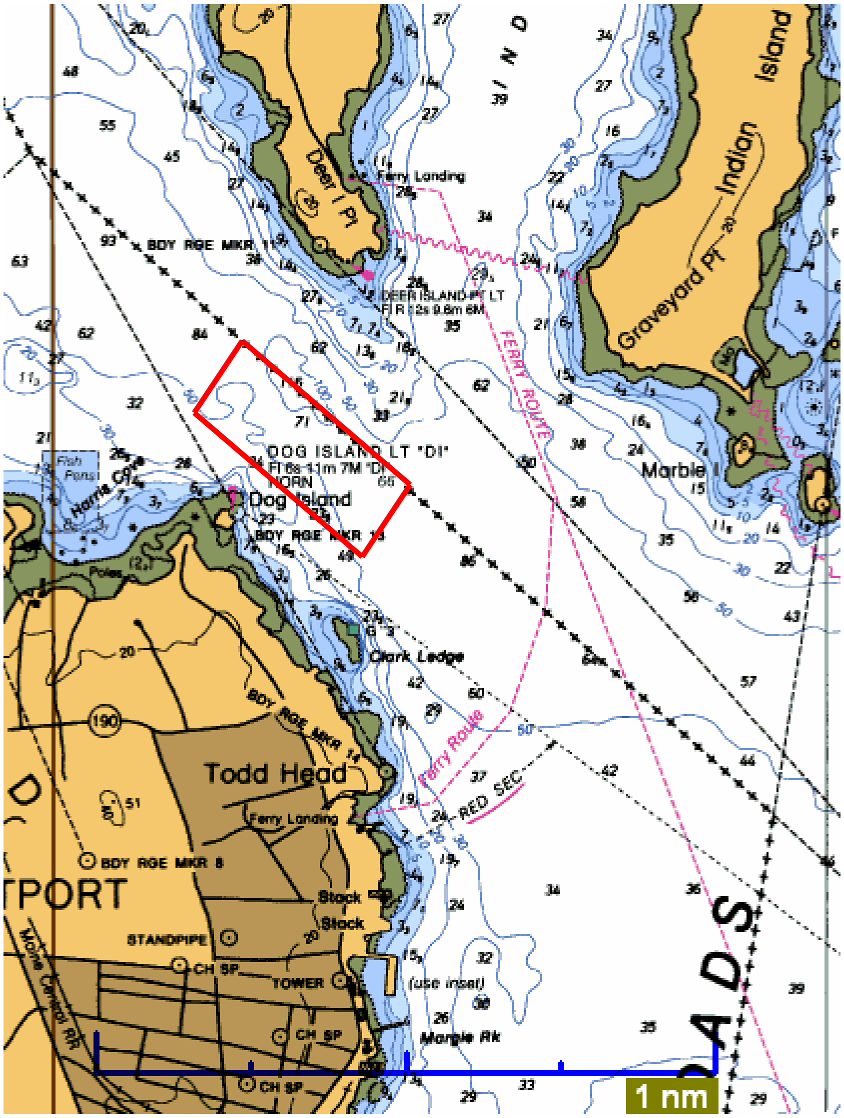


Figure 38 - ME Deployment Site. Water depth shown in fathoms with blue contours in meters

Since the deployment site is directly in below a navigation channel used by large ships, a navigation clearance of 15m (below LAT) is required. The following illustration shows the cross section of the channel and the turbine height for MCT's machine with a rotor diameter of 18m and a total height from seafloor of 26m and Lunar energy's turbine with a rotor diameter of 21m and a total height from the seafloor of 31m. Adding a 15m navigation clearance to these turbine heights, only water depths of more then 41m (for MCT), respectively 46m (for Lunar's RTT2000) are suitable. The following 2 figures show the turbine size and spacing assumptions for both turbines.

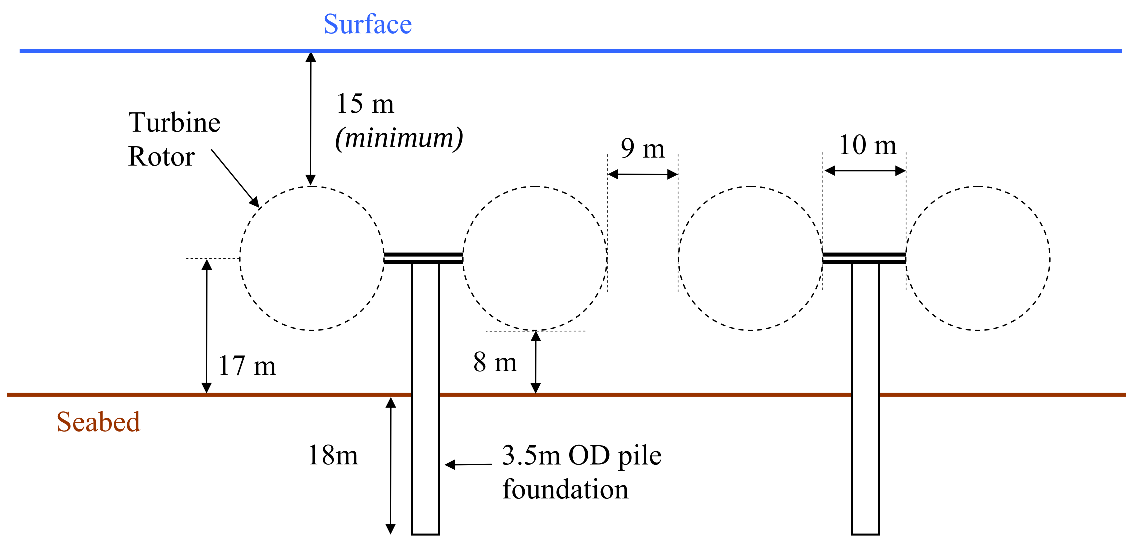


Figure 39 – MCT SeaGen Turbine Spacing Assumptions

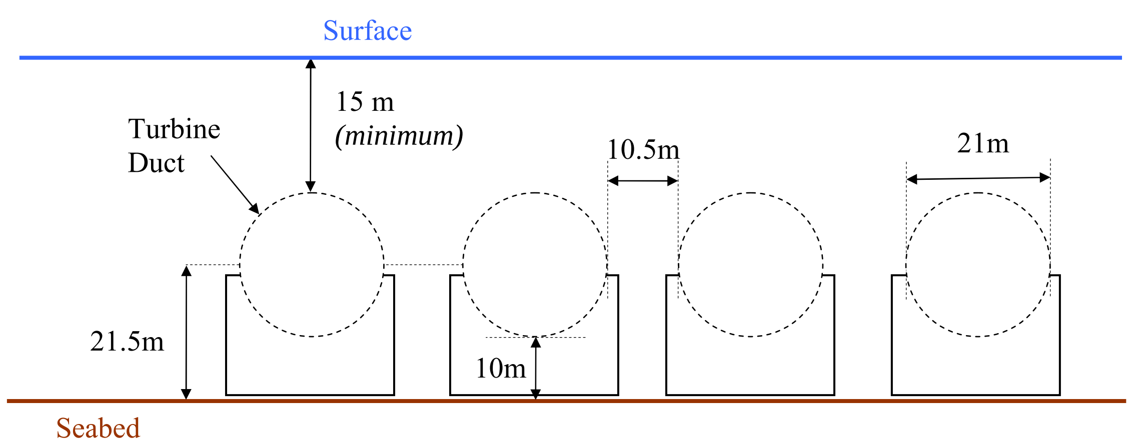


Figure 40 - Lunar RTT 2000 Spacing Assumptions

Figure 41 - Channel Cross section at Dog island transect

Based on this cross section, the useable channel width that accommodates sufficient water depth within US waters is 250m. The section length within which high fluid velocities are available is about 500m (See Figure 38). Based on this data the following table summarizes the critical assumptions leading to the likely number of turbines that could be deployed at the site.

Table 7 - Physical Layout Properties

	MCT	Lunar
Turbine Diameter	2 x 18m	21m
Device Width	46m	21m
Device Spacing	9m	10.5m
Channel width per device	55m	31.5m
Downstream Spacing	185m	235m
Useful Channel Length	500m	500m
Useful Channel Width	250m	250m
# of Turbines per Row	8	12
# of Rows	3	3
Total # of Turbines deployable	24	36
Average Power Extracted per Turbine	397kW	443kW
15% Extraction Limit	15.6MW	15.6MW
Technology Specific Extraction Limit	5.3MW	9.5MW

The above table shows that the extraction is technology limited. Both technologies looked at show similar extraction limits. The critical assumption taken is that the spacing between two rows of turbines needs to be 10x the device inlet cross-section. This spacing is required so the second row of turbines is placed outside of the wake of the first row. New research by the Carbon Trust however indicates that the spacing requirement could be as low as 3-4 times the turbine diameter. If this holds true, it would increase the extractable potential at the site by about a factor of 2.

8. Cost Assessment – Demonstration Plant

The cost assessment of the pilot demonstration plant was carried out by taking manufacturer specifications for MCT's SeaGen device, assessing principal loads on the structure and scaling the devices to the design velocity at the deployment site. While the MCT cost model was developed internally by EPRI, MCT provided data and support to calibrate the model, which was an important step to come up with a meaningful model. Installation and operational costs were evaluated by creating detailed cost build-ups for these aspects taking into considerations equipment availability and North American rates. A high-level capital cost breakdown relevant to the deployment site is shown in the table below.

Table 8 - Capital Cost breakdown of MCT Pilot plant

	$/kW	$/Turbine	in %
Power Conversion System	$1,428	$1,182,000	25.1%
Structural Steel Elements	$517	$428,000	9.1%
Subsea Cable Cost	$130	$108,000	2.3%
Turbine Installation	$1,741	$1,442,000	30.6%
Subsea Cable Installation	$1,636	$1,355,000	28.7%
Onshore Electric Grid Interconnection	$241	$200,000	4.2%
Total Installed Cost	$5,693	$4,715,000	100.0%

A single unit will cost significantly more then subsequent units installed at the site. This is apparent by an increase in capital and installation cost. Installation costs are dominated by mobilization charges and the fact that the first unit will always be more expensive then subsequent ones. Capital costs are higher as well for similar reasons. The assessment of operational and maintenance cost was not part of the scope of this study. It is important to understand that subsea cable installation cost could be potentially reduced by up to $1 million by careful siting of the prototype and use of directional drilling instead of trenching.

It is also important to understand that the purpose of the pilot plant is not to provide low cost electricity, but to reduce risks associated with a full-blown commercial scheme. Risks include technological risks such as device performance, operation & maintenance requirements and validation of structural integrity as well as environmental risks associated with the interaction between the natural habitat and the TISEC device.

9. Cost Assessment – Commercial Plant

Costs for the commercial plant are, as for most renewable energy generating technologies, heavily weighted towards up-front capital. In order to determine the major cost centers of the commercial plant, detailed cost build-ups were created in order to assess them properly in the context of the given site conditions. There are a few major influences impacting the relative economic cost at a particular site which are discussed below:

Design Current Speed: The design current speed is the maximum velocity of the water expected to occur at the site. Structural loads (and related structural cost) on a structure increase to the second power of the fluid velocity. Given the velocity distribution at the site, the design velocity can be well above the velocity at which it is economically useful to extract power. In other words, the design velocity can have a major influence on the cost of the structural elements. During normal operating conditions, the loads on the structure will peak near the rated turbine velocity and decrease thereafter as the turbine blades are pitched to maintain constant power output, decreasing the thrust coefficient on the rotor blades. For conservatism, the design velocity is set to the site peak, rather than device rating, in order to simulate the loads experienced during runaway operation in the event of pitch control failure.

Velocity Distribution: The velocity distribution at the site is outlined in chapter 2 of this report. It shows the tidal current velocities at which there is a useful number of reoccurrence to pay for the capital cost which is needed to tap into this velocity bin. Rather then trying to make assumptions on where the appropriate rated velocity of the TISEC device should be, an iterative approach was chosen to determine which rated speed of the machine will yield the lowest cost of electricity at the particular site. This in turn resulted in different machine capacity factors as rated speed of the machine was adjusted for lowest cost of electricity.

Seabed Composition: The seabed composition at the site has a major impact on the foundation design of the TISEC device. For a monopile foundation the seabed composition determines the installation procedure (i.e. drilling and grouting or pile driving). The soil-type will also impact the cost of the monopile. Typically soft soils yield higher monopile cost then rock foundations. For a bottom standing device there is a cost impact on the installation for seabed preparation, scour protection and assuring device stability in weak soils.

Number of installed units: The number of TISEC devices deployed has a major influence on the resulting cost of energy. In general a larger number of units will result in lower cost of electricity. There are several reasons for this which are outlined below:

- Infrastructure cost required to interconnect the devices to the electric grid can be shared and therefore their cost per unit of electricity produced is lower.

- Installation cost per turbine is lower because mobilization cost can be shared between multiple devices. It is also apparent that the installation of the first unit is more expensive then subsequent units as the installation contractor is able to increase their operational efficiency.

- Capital cost per turbine is lower because manufacturing of multiple devices will result in reduction of cost. The cost of manufactured steel as an example is very labor intensive. The cost of hot rolled steel plates as of July 2005 was $650 per ton. The final product can however cost as much as $4500 per manufactured ton of steel. With other words there is significant potential to reduce capital cost by introducing more efficient manufacturing processes and engineering a structure in such a way that it can be manufactured cost effectively. The capital cost for all other equipment and parts is very similar.

Device Reliability and O&M procedures: The device component reliability directly impacts the operation and maintenance cost of a device. It is important to understand that it is not only the component that needs to be replaced, but that the actual operation required to recover the component can dominate the cost. Additional cost of the failure is incurred by the downtime of the device and its inability to generate revenues by producing electricity. In order to determine these operational costs, the failure rate on a per component basis was estimated. Then operational procedures were outlined to replace these components and carry out routine maintenance such as changing the oil. The access arrangement plays a critical role in determining what kind of maintenance strategy is pursued and the resulting total operation cost.

Insurance cost: The insurance cost can vary greatly depending on what the project risks are. While this is an area of uncertainty, especially considering the novelty of the technologies used and the likely lack of specific standards, it was assumed that a commercial farm will incur insurance costs similar to mature an offshore project which is typically at about 1.5% of installed cost.

The following table shows a cost breakdown of a commercial TISEC farm at the deployment site. It was assumed that a total of 12 turbines are installed at the site each one with a rated capacity of 828 kW and a capacity factor of 46%, delivering a total of 40,024MWh per year to the electric grid.

Table 9 – MCT commercial plant capital cost breakdown

	$/kW	$/Turbine	$/Farm	in %	Ref
Power Conversion System	$894	$740,693	$8,888,000	37.6%	1
Structural Elements	$506	$419,149	$5,030,000	21.3%	2
Subsea Cable Cost	$20	$16,785	$201,000	1%	3
Turbine Installation	$593	$491,426	$5,897,000	25.0%	4
Subsea Cable Installation	$313	$259,436	$3,113,000	13.2%	5
Onshore Electric Grid Interconection	$50	$41,667	$500,000	2.1%	6
Total Installed Cost	**$2,378**	**$1,969,155**	**$23,630,000**	**100%**	
O&M Cost	$63	$52,540	$630,477	64%	7
Annual Insurance Cost	$36	$29,537	$354,488	36%	8
Total annual O&M cost	**$99**	**$82,077**	**$984,925**	**100%**	

1. Power conversion system cost includes all elements required to go from fluid power to electrical power suitable to interconnect to the TISEC farm electrical collector system. As such it includes rotor blades, speed increaser, generator, grid synchronization and step-up transformer. The cost is based on a drive-train cost study by NREL [12] with necessary adjustments made such as marinization,

gearing-ratio, rotational speed and turbine blade length. Manufacturing cost progress ratio's were used to scale to different production volumes.

2. Structural steel elements include all elements required to hold the turbine in place. In the case of MCT, it includes the monopile and the cross arm. For the Lunar turbine it includes all the structural members, the duct as well as ballast. In order to determine the amount of steel required, the manufacturer's data was scaled based on the estimated loads on the structure. Only principal loads based on the fluid velocity were considered and it was assumed that they are the driving factor. While this approach is well suited for a conceptual study, it needs to be stressed that other loading conditions such as wave loads or resonance conditions can potentially dominate and will need to be taken into consideration in a detailed design phase.

3. Sub sea cable cost includes the cable cost to collect the electricity from the turbines and bring the electricity to shore at a suitable location.

4. Turbine installation cost includes all cost components to install the turbines. Detailed models were developed to outline the deployment procedures using heavy offshore equipment such as crane barges, tugs, supply vessels drilling equipment, mobilization charges and crew cost. Discussions with experienced contractors and offshore engineers were used to solidify costs.

5. Subsea cable installation cost includes, trenching, cable laying and trench back-fill using a derrick barge. It also includes cable landing costs. If existing easements such as pipes or existing pier or bridge structures are in place, the cable can be landed on shore using these easements. If not, it was assumed that directional drilling is used to bring the cable to shore.

6. Onshore electrical grid interconnection includes all cost components required to bring the power to the selected substation. Cost components required to build-out the capabilities of the substation or upgrade the transmission capacity of the electric grid were excluded. Under FERC regulations, such cost is covered by 'wires'

charges and is not considered to be a part of the levelized busbar plant cost of electricity (COE).

10. Cost of Electricity Assessments

To evaluate the economics of tidal in-stream power plants, three standard economic assessment methodologies have been used:

a. Utility Generator (UG),
b. Municipal Generator (MG)
c. Non-Utility Generator (NUG) or Independent Power Producer (IPP).

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 or IPP 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 20-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 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.

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.

The methodology is described in detail in Reference [2].

The yearly electrical energy produced and delivered to bus bar is estimated to be 40,024 MWh/year for an array consisting of 12 dual-rotor MCT turbines. These turbines have a combined installed capacity of 9.9MW, and on average extract 5.3 MW of kinetic power from the tidal stream, which is roughly 5% of the total kinetic energy at the site. The elements of cost and economics (in 2005$) for MCT's SeaGen are:

- Utility Generator (UG) Total Plant Investment = $23.6 million
- Annual O&M Cost = $0.98 million

- UG Levelized Cost of Electricity (COE) = 5.6 (Real) – 6.5 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology
- Municipal Generator (MG) Levelized Cost of Electricity (COE) = 4.2 (Real) –4.8 (Nominal) cents/kWh with renewable financial incentives equal to that the government provides for renewable wind energy technology
- Nun Utility Generator (Independent Power Producer) Internal Rate of Return on net cash flows after tax is 34%

While being limited in size, this resource should be tapped strategically as it will contribute to a balanced energy supply system.

The detailed worksheets including financial assumptions used to calculate COE and IRR are contained in the Appendix.

TISEC technology is very similar to wind technology and has benefited from the learning curve of wind technology, both on shore and off shore. Therefore, the entry point for a TISEC plant is much less than that of wind technology back in the late 1970s and early 1980s (i.e., over 20 cents/kWh). Additional cost reductions will certainly be realized through value engineering and economies of scale.

Except for the Minas Passage in Nova Scotia which clearly has the size to be considered central power, all other sites studied in the U.S. and Canada fall in between the definition of distributed generation (DG) and central power generation.

We use the term distributed generation (DG) or distributed resources (DR) to describe an electric generation plant located in close proximity to the load that it is supplying and is either connected to the electric grid at distribution level voltages or connected directly to the load. Examples of DG/DR (DR when some form of storage is included) are rooftop photovoltaic systems, natural gas micro turbines and small wind turbines. Large wind projects and traditional fossil and nuclear plants are examples of central generation where the electricity delivers power into the grid at transmission voltage levels.

DG types of systems traditionally find applications in niche markets because of unique market drivers such as:

- Delay or defer an upgrade to T&D infrastructure that would otherwise have been necessary to bring power generated away from a load center to that load center
- Voltage stability support
- Displace diesel fuel in off grid applications
- Satisfy local citizens desires to have control of their own power source

A realistic comparison to equitably evaluate the cost of deferring T&D expenses with the cost of installing DG/DR is complex and requires considering depreciation and tax benefits, property tax and insurance for both options, maintenance and fuel costs of operating the DG/DR and employing discounted cash flow methods. This comparison must be made on a case-by-case basis.

EPRI, in collaboration with DOER, NJBPU and CEC, and funded by NASEO, is studying political and financial mechanisms for win-win DG/DR solutions for both the distribution utility and the end user.

Economic assessments of a commercial scale tidal power plant and other renewable and non renewable energy systems were made.

The current comparative costs of several different central power generation technologies are given in Table 10 - COE for Alternative Energy Technologies: 2010 for 2010. 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.

Table 10 - COE for Alternative Energy Technologies: 2010

	Capacity Factor (%)	Capital Cost[1] ($/kW)	COE (cents/kWh)	CO2 (lbs per MWh)
Tidal In Stream	46	$2,000	4 – 6.5	None
Wind	30-42	1,150	4.7-6.5	None
Solar Thermal Trough	33	3,300	18	None
Coal PC USC (2)	80	1,275	4.2	1760
NGCC[3] @ $7/MM BTU)	80	480	6.4	860
IGCC[2] with CO2 capture	80	1,850	6.1	344[4]

Notes:
1 Costs in 2005$;
2. 600 MW capacity; Pittsburgh#8 coal
3. Based on GE 7F machine or equivalent by other vendors
4. Based on 85% removal

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.

Table 13 - Assumptions forming the Basis for COE for Alternative Energy Technologies

	Book Life/ Tax life)	Fed Tax Rate	State Prov-ince 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
Tidal	20/20	35	8.93	CA Acc Dep	65/ 30 0	13/ 17/ 5	35/ 70/10 0	7.5/ 8/ 5	3
Wind	30/ 20	35	6.5	MAC RS	45/ 30/ 0	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2
Coal[(2)] PC First of a Kind USC	30/ 20	35	6.5	MAC RS	45/ 30/ 0	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	MAC RS	45/ 30/ 00	11.5/ 13/ N/A	55/ 70/ 100	6/5 8/ 4.5	2

11. Sensitivity Studies

The results reported thus far are for a single design case. Certain key parameters can have a significant impact on the cost of energy from a TISEC array. Among these are:

- Array size – economies of scale with larger arrays
- Plant system Availability – deployment of maturing technology
- Current velocities at site
- Financial assumptions – financing rates, renewable energy production credits

Cost of energy numbers presented are real costs for a UG generator with assumptions discussed in Chapter 9. All costs are in 2005 USD.

Array Size

This sensitivity has already been implicitly shown in the unit capital cost differences for pilot turbine versus commercial scale array. Figure 42 shows the sensitivity of cost of energy (COE) to the number of turbines installed.

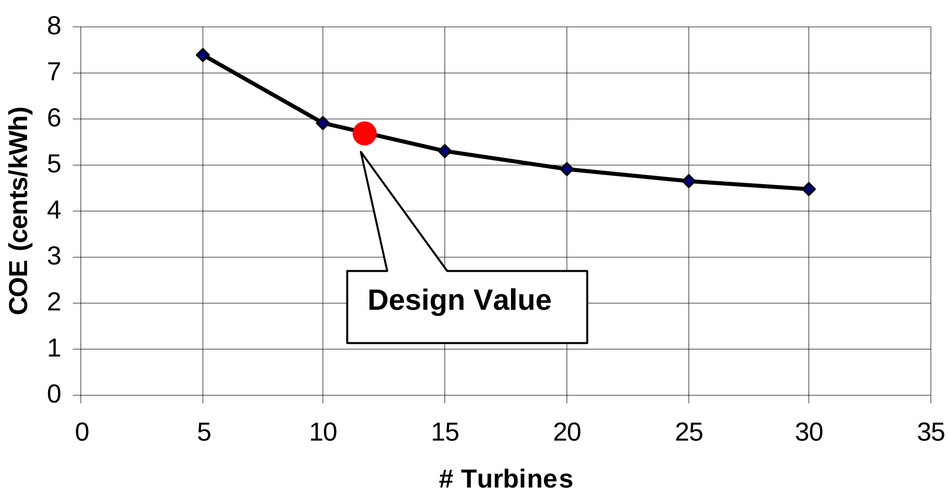


Figure 42 – Sensitivity of COE to number of turbines installed

Due to economies of scale (mobilization costs, increased manufacturing efficiency), the capital and operating costs for the array decrease with the number of installed turbines. The sensitivity of the different elements of capital cost to the number of turbines installed is given in Figure 43.

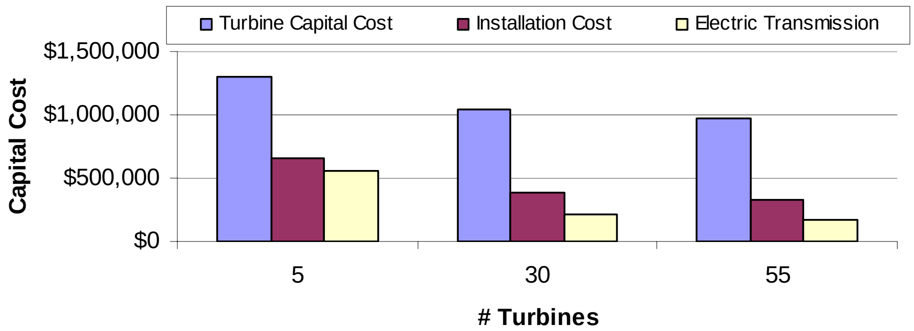


Figure 43 – Sensitivity of capital cost elements to number of installed turbines

Economies of scale due to decreasing capital cost occur in equipment, installation, and electrical interconnection. Installation and electrical transmission costs are near identical. Cost of energy decreases are not driven exclusively by scale in one particular area. Note that equipment costs dominate in all cases. Annual O&M costs also decrease due to economies of scale (e.g. maintenance mobilization costs spread out over more turbines). The sensitivity of annual O&M costs to number of installed turbines is given in Figure 44.

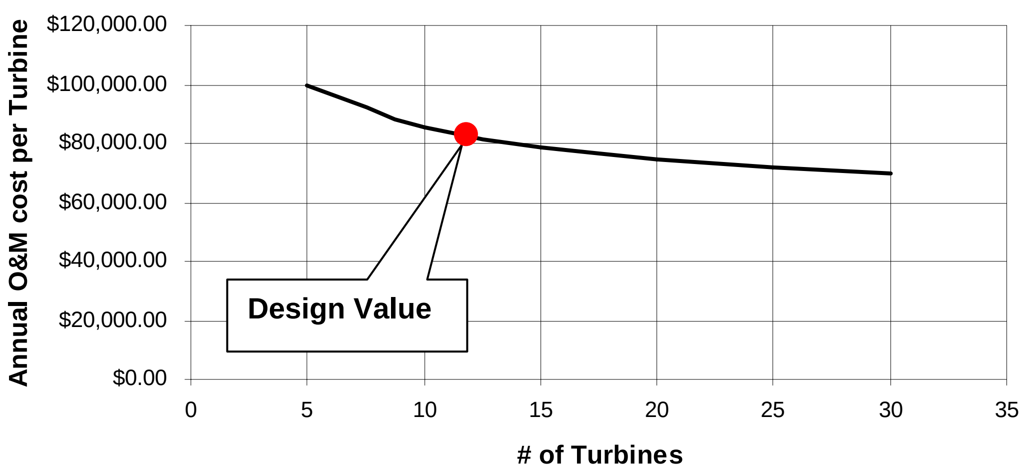


Figure 44 – Sensitivity of annual O&M cost to number of installed turbines

Power Plant System Availability

Given that tidal in-stream energy is an emerging industry and limited testing has been done to validate component reliability, the impact of the plant system availability on cost of energy is key. If the availability is lower than anticipated, array output will be lower, but costs will be the same. This is shown in Figure 45, where all parameters aside from availability are held constant for the commercial array design.

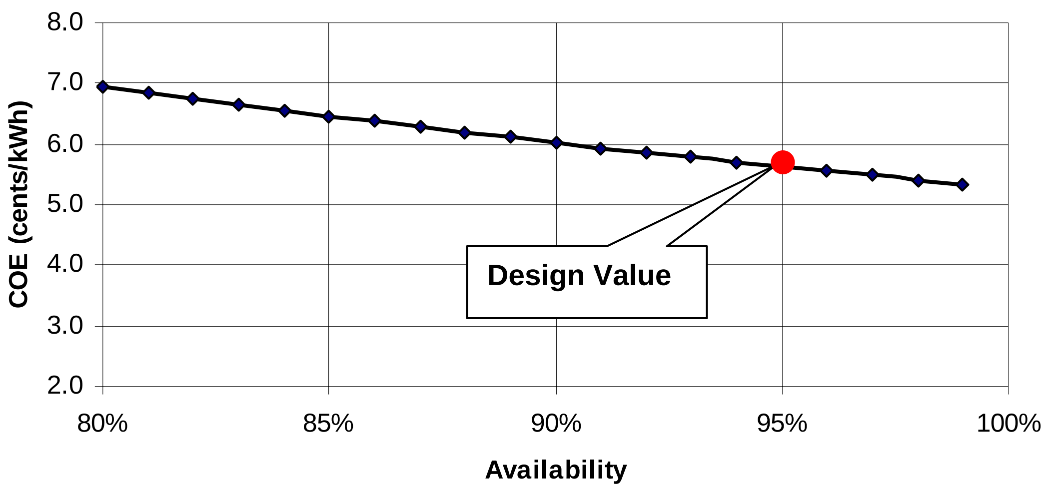


Figure 45 – Sensitivity of COE to array availability

If system availability is as low at 80%, the cost of energy with increase by a bit more than 1.5 cents/kWh (20% increase) compared to the assumed availability of 95%. This is a substantial increase and highlights the need of developers to verify expected component lifetimes and service schedules.

Current Velocity

One of the greatest unknowns in the array design is current velocity over the region of array deployment. The sensitivity of cost of energy to average current and power flux is shown in Figure 46 and Figure 47, where most other parameters are held constant for the commercial array design. Current velocity is modified by multiplying each velocity ‘bin’ by a constant value (e.g. 0.7). As a result, the shape of the velocity histogram is unchanged, only the mean value. As the velocity changes, the rated speed of the turbine is allowed to vary to maintain the lowest possible cost of energy. Note that average current velocity and power flux are not independent variables, the design point average current velocity corresponds to the design point average power flux.

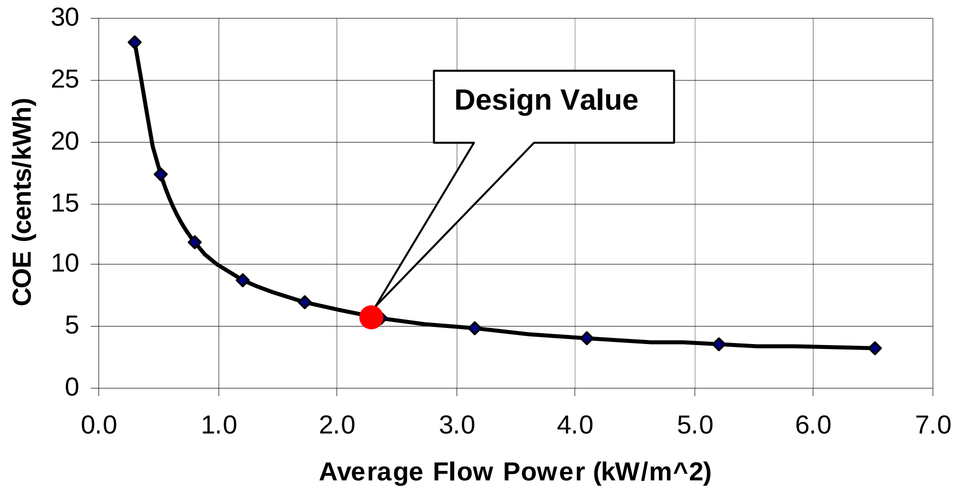


Figure 46 – Sensitivity of COE to average flow power in kW/m^2

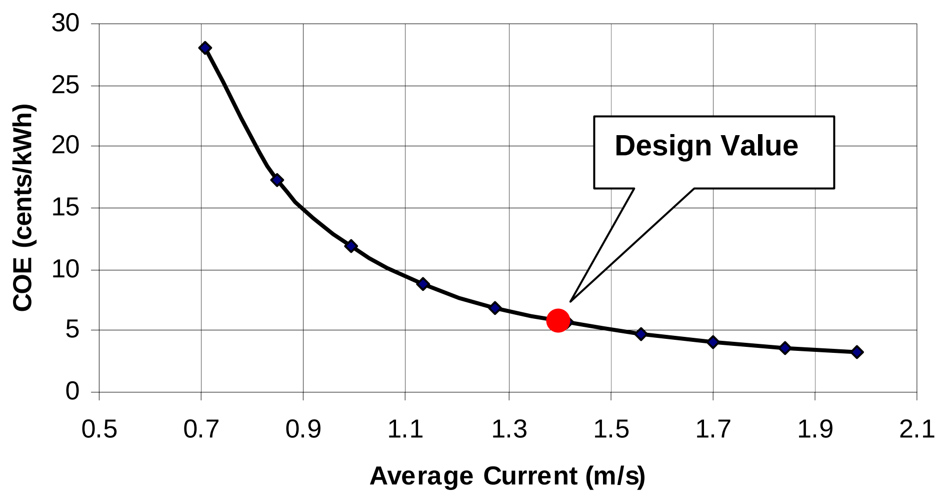


Figure 47 – Sensitivity of COE to average current speed (m/s)

Clearly, the average velocity at the site has a significant effect on cost of energy, particularly if average current speeds are lower than expected. Note that these results are dependent on the shape of the velocity distribution histogram and therefore, we can not broadly draw conclusions about the cost of energy at other sites from this analysis (though one would expect the general direction of the results to be comparable for all west coast sites).

Design Velocity

As discussed in Chapter 3, the design velocity for the turbine has been chosen to approximate “runaway” conditions – a pitch control failure in the maximum current existing at the site. However, since the most significant design load is the thrust on the rotors – which is maximized near rated conditions – this represents a potential system over design. If manufacturers are able to achieve sufficient operating experiences with their turbines to ensure that turbines will never operate in a “runaway” mode, then the design velocity could be set much closer to the rated velocity. Similar functionality is used in large wind-turbines to reduce loading conditions. Figure 48 shows the effect on the real cost of energy by lowering the design speed.

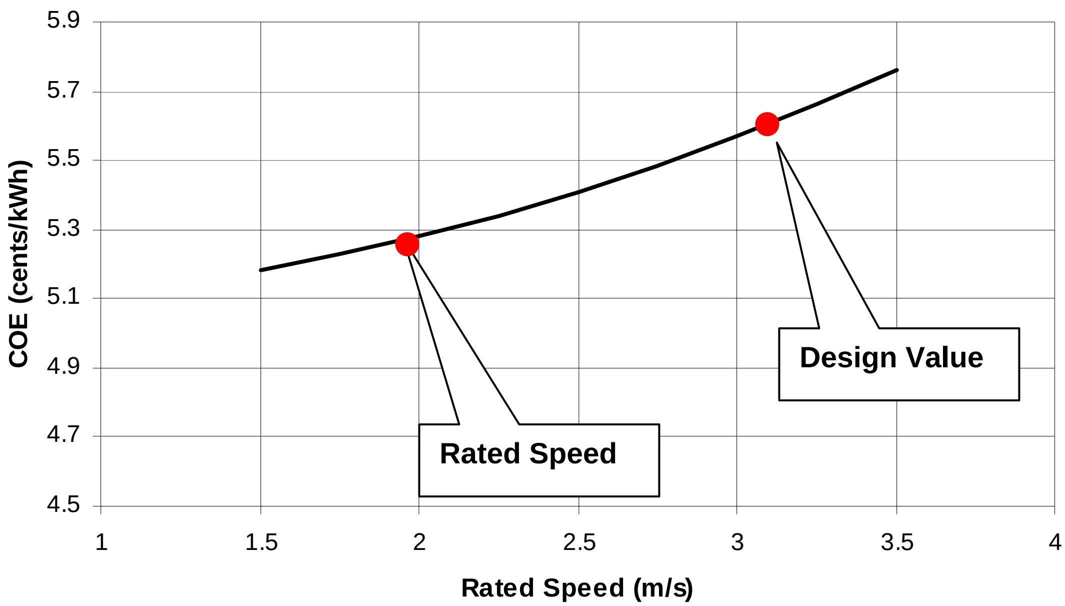


Figure 48 – Sensitivity of COE to design speed

Financial Assumptions

The effect of varying the cost of capital to finance the project is shown in the following figure. The fixed charge rate represents a single indicator of the cost of capital and is used here (see Reference 2 for a detailed explanation). It includes effects of interest rates, return of capital, taxation and production tax credits.

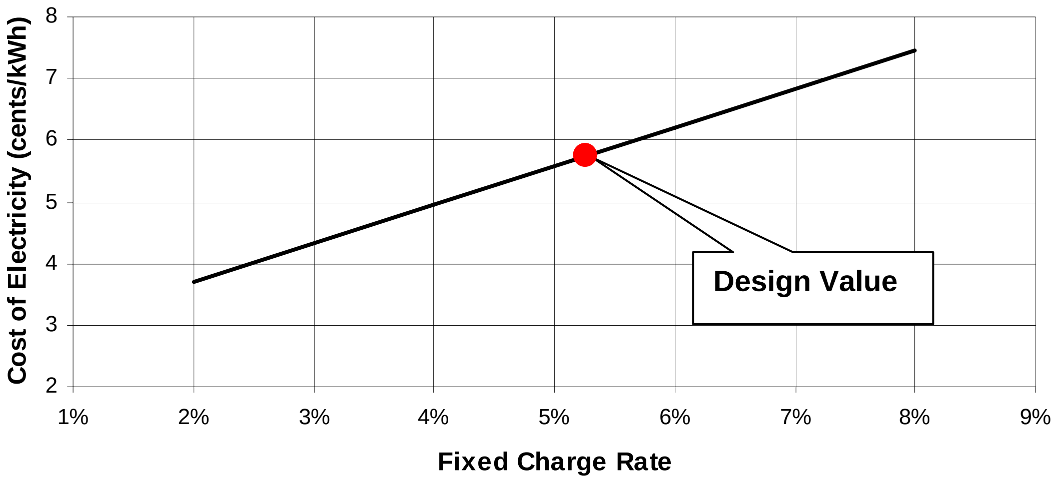
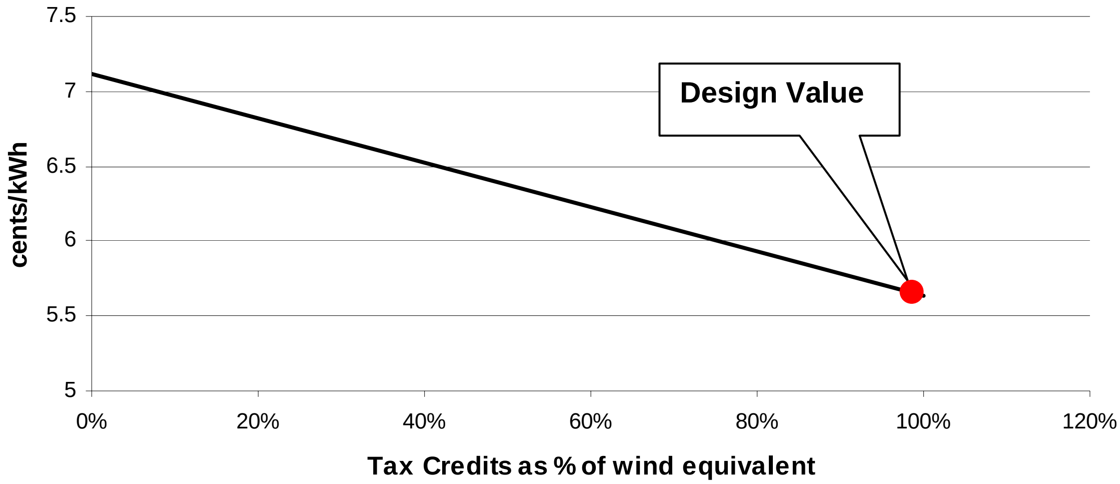


Figure 49 – Sensitivity of COE to Fixed Charge Rate

If a project is deemed ineligible for renewable production credits, or funds for such credits are not fully budgeted, COE increases substantially. Figure 50 shows the sensitivity of COE to production credits, with credits varied from 0% (no credits) to more credits than are currently assumed in the financial analysis, 100% being the design value used in our financing assumptions.

Figure 50 – Sensitivity of COE to production credits


Design Value
cents/kWh
7.5
7
6.5
6
5.5
5
0%
20%
40%
60%
80%
100%
120%
Tax Credits as % of wind equivalent

12. Conclusions

Pilot In-Stream Tidal Power Plant

For the single turbine pilot installation, the Dog Island transect in the Western Passage offers good potential sites. The predicted resource is strong, interconnection is easily managed, and the site is served by a major port facility in close proximity. All of the sites however are located below the shipping channel and therefore require fully submersible technology. Both manufacturers Lunar Energy and Marine Current Turbines have technology that could be deployed fully submersed. Also, the deployment location might have some turbulence which are not well understood at present. A pilot system is an important intermediary step before proceeding to a commercial installation and should use similar technology and units that are of similar scale as the full-scale devices. The purpose of the pilot is to demonstrate the potential for a commercial array, verify low environmental impact, and generally build towards regulatory acceptance of an array of similar devices. It is important to understand that many design requirements are unique to the site and the manufacturers will need to take local site conditions into consideration when adapting their technology to meet these requirements. The technology gap to be covered by both Lunar Energy and MCT in order to get to the point where a full-scale, fully-submersed TISEC pilot could be deployed is relatively small and it is reasonable to expect that such a deployment could occur within 2-years given a firm local commitment to move forward with this project.

Commercial In-Stream Tidal Power Plant

The Western passage is a good candidate site for the installation of a commercial tidal in-stream power plant. While this conceptual design study revealed that the amount of energy extracted at the site investigated is limited by the amount of space that is available, further study of the resource and detailed 3-dimensional flow simulation might reveal additional deployment locations in close proximity to Dog Island. Grid interconnection could be accomplished in Eastport to an existing 34.5 kV substation that could handle up to 19MW peak capacity, which could be increased to 30MW with some upgrades to transmission lines and substation. Given technology evaluated in this study, the resource extraction is technically limited to about 9% of the total kinetic energy at the site. However larger scale turbines, different turbine arrangements and a better understanding of the resource could fundamentally change these limitations.

Since the commercial array design incorporates features that are largely conceptual, there is significant economic and technical uncertainty in the deployment of a commercial array in the Western Passage. If, as MCT expects, the cost and performance of a fully submerged design is in-line with SeaGen, then the results of this study show that an in-stream tidal power plant may provide favorable economics. With other words, this is a renewable energy resource option worth pursuing.

As a new and emerging technology, in-stream tidal power has essentially no production experience and therefore its costs, uncertainties and risks are relatively high compared to existing commercially available technologies such as wind power with a cumulative production experience of about 40,000 MW installed. Given the technological uncertainty, it would make most sense that the technology companies carry technological and implementation risks and ideally are the owners of the generation assets. Local government can stimulate the implementation by addressing environmental and consenting issues, providing the manufacturers with a framework within which they can operate and if required provide financial incentives such as per kWh subsidies. Technological uncertainties also represent risks in that it is unclear at present which technology is best suited for the site and most manufacturers involved in TISEC are small companies that may or may not be around a few years from now. As such it is important that the resource is being developed as a strategic asset without locking into a single technology path or committing to a single company.

Techno-economic Challenges

The cost for the first tidal plant leverages the learning gained from wind energy. Therefore, the cost of future plants will not follow a learning curve based on the first plant. Rather than seeing a sharp reduction in unit cost for the next 10 MW or so plant, a substantial decrease might require another 40,000 MW of installed capacity (double the end of 2004 wind production volume). Device manufacturers are pursuing novel approaches to array-scale installations. The economic analysis presented in this report is based on first-generation device economics. The assumption contingent in this analysis is that while next-generation devices will enable turbine deployment at a wider range of sites (e.g. deep water) and with greater versatility (e.g. integrated lift without surface piercing pile) the cost of installing and operating next-generation turbines will be similar to first-generation devices. O&M costs are particularly uncertain since no tidal current turbine has been in service for extended periods of time. Assumptions regarding intervention frequencies, refit costs, and component lifetimes will not be completely borne out for at least a decade.

Sensitivities show that the cost of energy is highly dependent on the currents (and power flux) at the deployment site. Furthermore, sensitivity analysis indicates the manufacturers are best served by designing turbines which experience their design loads close to rated device speed.

Sensitivities also show that the cost of energy is sensitive to the number of turbines installed, since for larger arrays fixed mobilization costs are spread over a greater number of turbines. Therefore, a phased installation of the array (e.g. 10 turbines/year for 6 years) would substantially increase the cost of energy for the entire project. A regulatory approach that requires a long-term phased installation plan to study the impact of turbine deployment should be discouraged if the project will not be compensated for the increased cost.

General Conclusions

In-stream tidal current energy as a distributed renewable resource shows promise for Maine and represents a way to make sustainable use of a local renewable resource without the visual distractions that delay so many other energy projects. The installation of a TISEC array in Western Passage would provide valuable benefits to the local economy and further reduce its dependence on environmentally problematic fossil energy resources.

In-stream tidal energy electricity generation is a new and emerging technology. Many important questions about the application of in stream tidal energy to electricity generation remain to be answered, such as:

- There is not a single in-stream power technology. There is a wide range of in stream tidal power technologies and power conversion machines which are currently under development. It is unclear at present what type of technology will yield optimal economics. Not all devices are equally suitable for deployment in all depths and currents.
- It is also unclear at present at which size these technologies will yield optimal economics. Tidal power devices are typically optimized to prevailing conditions at the deployment site. Wind turbines for example have grown in size from less then 100kW per unit to over 3MW in order to drive down cost.
- Will the predictability of in stream energy earn capacity payments for its ability to be dispatched for electricity generation?
- How soon will developers be ready to offer large-scale, fully submerged, deep water devices?
- Will the installed cost of in-stream tidal energy conversion devices realize their potential of being much less expensive than solar or wind (because a tidal machine is converting a much more concentrated form of energy than a solar or wind machine)?
- Will the O&M cost of in-stream tidal energy conversion devices be as high as predicted in this study and remain much higher than the O&M cost of solar or wind (because of the more remote and harsher environment in which it operates and must be maintained)?
- Will the performance, reliability and cost projections be realized in practice once in stream tidal energy devices are deployed and tested?

And in particular for the Western Passage:

- Detailed velocity measurements and 3 dimensional flow simulations will be necessary prior to the deployment of even a pilot plant. Will the actual power flux experienced at the site meet the predictions made in this study? Sensitivity analysis clearly shows that the power flux has a substantial impact on the cost of electricity.

- Are assumptions related to turbine spacing (both laterally and downstream) reasonable? Could the array be packed even closer together (further reducing its footprint) without degrading individual turbine performance?
- Is extracting 15% of the kinetic energy resource a reasonable target? Could more of the resource be extracted without degrading the marine environment? If so, the cost of energy for the project could be further reduced by increasing the size of the array.
- The western passage is home to some of the most turbulent water flows in the world. How does this increased turbidity affect choice of technology and how do these factors affect site selection.

In-stream tidal energy is a potentially important energy source and should be evaluated for adding to Maine's energy supply portfolio. A balanced and diversified portfolio of energy supply options is the foundation of a reliable and robust electric grid. TISEC offers an opportunity for Maine to expand its supply portfolio with a resource that is:

- Local – providing long-term energy security and keeping development dollars in the region
- Sustainable and green-house gas emission free
- Cost competitive compared to other options for expanding and balancing the region's supply portfolio

Recommendations

EPRI makes the following recommendations to the Maine Electricity stakeholders:

General

Build collaboration with other states and the Federal Government with common goals. In order to accelerate the growth and development of an ocean energy industry in the United States and to address and answer the many techno-economic challenges, a technology roadmap is needed which can most effectively be accomplished through leadership at the national level. The development of ocean energy technology and the deployment of this clean renewable energy technology would be greatly accelerated if the Federal Government was financially committed to supporting the development.

Join a working group to be established by EPRI (to be called "OceanFleet") for existing and potential owners, buyers and developers of tidal in stream energy including the development of a permanent in stream tidal energy testing facility in the U.S. For this group EPRI will track and regularly report on:

- Potential funding sources
- In-stream tidal energy test and evaluation projects overseas (primarily in the UK) and in the U.S (Verdant RITE project, etc)
- Status and efforts of the permitting process for new in stream tidal projects
- Newly announced in-stream tidal energy devices

Encourage R&D at universities - potentially in partnership with pilot plant device developer.

Encourage State and Federal government support of RD&D

- Implement a national ocean tidal energy program at DOE
- Promote development of industry standards
- Continue membership in the IEA Ocean Energy Program
- Clarify and streamline federal permitting processes
- Study provisions for tax incentives and subsidies
- Ensure that the public receives a fair return from the use of ocean tidal energy resources
- Ensure that development rights in state waters are allocated through a fair and transparent process that takes into account state, local, and public concerns

Pilot Demonstration

In order to proceed with a pilot plant in the Western Passage, remaining technology, consenting and environmental issues will need to be resolved. This includes:

- Detailed velocity profiling survey and 3-dimensional flow simulations. Computational fluid dynamic (CFD) modeling of tidal flows could help focus this work on the most promising areas, as well as identifying turbulent eddies which could degrade turbine performance.
- High resolution bottom bathymetry survey
- Geotechnical seabed survey
- Detailed design using above data
- Environmental impact assessments
- Public outreach
- Implementation planning for Phase III – Construction
- Financing/incentive requirements study four Phase III and IV (Operation)

13. References

1 EPRI TP-001-NA Guidelines for Preliminary Estimation of Power Production

2 EPRI TP-002-NA Economic Assessment Methodology

3. EPRI-TP-003-ME Maine Tidal Site Survey and Characterization

4 EPRI TP-004-NA Survey and Characterization of TISEC Devices

5 EPRI TP-005-NA Methodology for Conceptual Level Design of TISEC Plant

6. Google Maps. http://maps.google.com/

7 NOAA Tidal Current Predictions 2005. http://www.tidesandcurrents.noaa.gov/

8 NOAA Tidal Range Predictions 2005. http://www.tidesandcurrents.noaa.gov/

9. Bywaters G, John V, Lynch J, Mattila P, Norton G, Stowell J, Salata M, Labath O, Chertok A, Hablanian D. Northern Power Systems WindPACT Drive Train Alternative Design Study Report. 2005. Available through: http://www.osti.gov/

10 Gerwick, B. Construction of Marine and Offshore Structures. CRC Press, Boca Raton, FL. 2000.

11 Dawson, T. Simplified Analysis of Offshore Piles Under Cyclic Lateral Loads. *Ocean Engineering* 7;553-562. 1980.

12 Myers L, Bahaj A. Simulated electrical power potential harnessed by marine current turbine arrays in the Alderney Race, *Renewable Energy* 30:11;1713-1731.

13 Poore R, Lettenmeier T, Wind Pact Advanced Drive Trains Design Study, NREL 2003

14 Dayton A. Griffin, Wind PACT Turbine Design Scaling Studies Technical Area 1 – Composite Blades for 80- to 120-Meter Rotor

15 API American Petroleum Institute. Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms Working Stress Design. API-RP2A-WSD, 21st edition, December 2000

16 Kellezi L, Hansen P, Static and dynamic analysis of an offshore mono-pile windmill foundation, Danish Geotechnical Institute, Lyngby, Denmark

17 Generic Design Framework Pile foundations (fixed steel structures), Offshore Technology Report 2000/99

14. Appendix

Irrelevance of Flow Decay Concerns

A concern established by some other researchers, particularly Bahaj and Myers [11] is that the power available in a tidal stream is reduced for each subsequent transect of turbines. Their results point to a substantial reduction in flow power, and degraded array performance, for arrays with more than a few transects.

This analysis is, however, in error as it violates mass conservation for tidal channels by assuming that the cross-sectional area of the channel is constant along the entire array. If the velocity of the flow is decreasing over each transect, then the area of the channel would have to increase to maintain conservation of mass.

However, the fuller picture is considerably more counter-intuitive. The total power in a tidal stream is the summation of the kinetic energy due to its velocity and the potential energy due to its height. For representative tidal channels, if the height of the water was to increase to satisfy mass conservation, the potential energy of the stream would also increase. In fact, this increase in potential energy would actually exceed the decrease of kinetic energy due to the presence of turbines and the total power in the channel would increase after each transect. Since this rationale violates conservation of energy it is also, clearly, incorrect. In order to satisfy both conservation of mass and energy, after each transect the height of the water decreases and velocity *increases*. The net effect is a decrease in channel power, but from a kinetic energy standpoint, the presence of upstream turbines actually should improve the performance of those downstream. This effect is described in detail for an ideal channel in Bryden and Couch.

However, without detailed information about cross-channel flow both upstream and downstream of the proposed turbine array it is not possible to model the potential performance enhancement. As a result, any such transect-to-transect enhancement is omitted from the model. However, it would appear that concerns related to flow degradation have little scientific basis.

Hub-height Velocity Approximation

In order to simplify calculations, it has been assumed that the power flux over the swept area of the turbine may be approximated by the power flux at the hub height. Assuming the velocity profile in the channel varies with a 1/10th power law, the average power flux over the area of the turbine is given by the following integral:

$$\overline{P} = \frac{\int_0^{2\pi}\int_0^{R} \frac{1}{2}\rho u_o^3 \left(\frac{r\sin\theta + z_{hub}}{z_o}\right)^{3/10} r\,dr\,d\theta}{\int_0^{2\pi}\int_0^{R} r\,dr\,d\theta}$$

where P is the average power flux, R is the radius of the turbine, u_o is the surface current velocity, z_o is the depth of the water, and z_{hub} is the hub height.

This integral is not readily evaluated by analytical methods, but may be approached numerically. This is done by approximating the rotor as a series of rectangles with height Δz and width Δx. The power flux for the rectangles is calculated, and an area-weighted average taken to find the average power flux over the rotor. A representation of this method is shown in Figure 51.

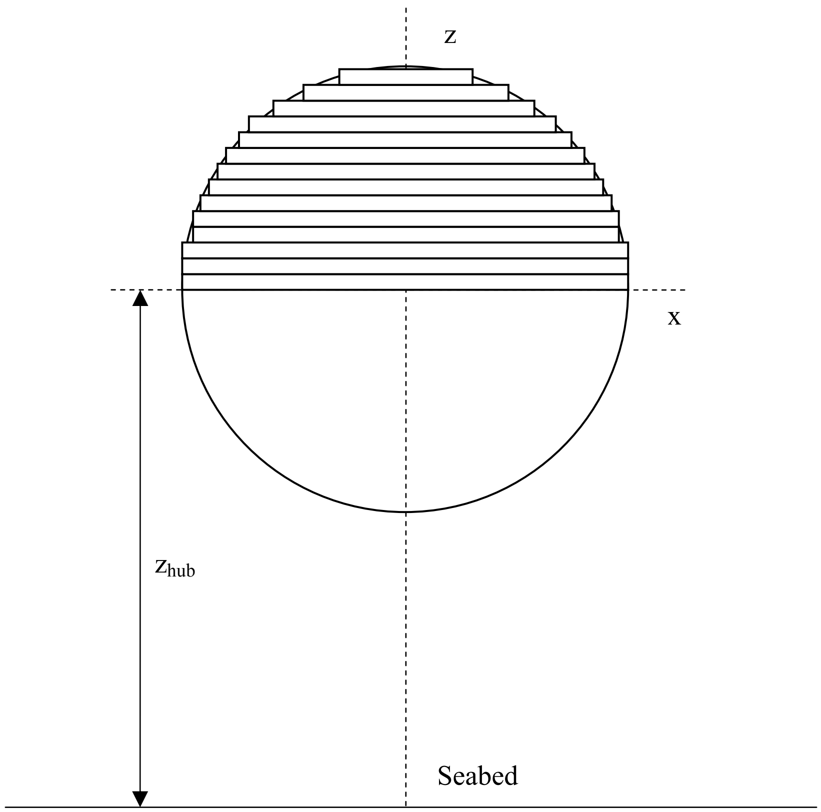


Figure 51 – Representative Numerical Integration

The result of this calculation is independent of water depth and velocity, but is dependent on hub height above the seabed. The variance from midpoint power flux (defined as $\Delta P/P_{hub\ height}$) is tabulated in Table 11.

Table 11 – Approximation Variance as Function of Hub Height

Hub Height (m)	Variance
10	-2.7%
15	-1.0%
20	-0.6%
30	-0.3%

A hub height of 17m (as assumed for the purposes of this feasibility study) introduces an error of -0.8% — that is, the actual power extracted by a turbine when approximating the power flux as the midpoint power flux is approximately 1% less than would be extracted by a turbine operating in water with a 1/10th power velocity profile. For the purposes of a feasibility study, this approximation is reasonable.

Utility Generator Cost of Electricity Worksheet

INSTRUCTIONS		
	(pink)	Indicates Input Cell (either input or use default values)
	(green)	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	12	$740,693	$8,888,316
Structural Elements	12	$419,149	$5,029,788
Subsea Cables	Lot	$200,000	$200,000
Turbine Installation	12	$491,426	$5,897,112
Subsea Cable Installation	Lot	$3,113,000	$3,113,000
Onshore Grid Interconnection	Lot	$500,000	$500,000
TOTAL			$23,628,216

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	$11,814,108	$886,058	$722,395	$12,536,503
2008	$11,814,108	$886,058	$652,275	$12,466,383
Total	$23,628,216	$1,772,116	$1,374,670	$25,002,886

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

Costs	Yrly Cost	Amount
Labor and Parts	$630,477	$630,477
Insurance (1.5% of TPC)	$354,423	$354,423
Total		$984,900

	FINANCIAL ASSUMPTIONS		
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	10	MW
2	Annual Electric Energy Production (AEP)	40,024	MWeh/yr
	Therefore, Capacity Factor	45.7	%
3	Year Constant Dollars	2005	Year
4	Federal Tax Rate	35	%
5	State	Maine	
6	State Tax Rate	8.93	%
	Composite Tax Rate (t)	0.408045	
	t/(1-t)	0.6893	
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	6.48	%
16	Federal Investment Tax Credit (1)	0	
17	Federal Production Tax Credit (2)	0.018	
18	State Investment Tax Credit	50,000	$
19	State Investment Tax Credit Limit	None	
20	Renewable Energy Certificate (3)	0.012	$/kWh

Notes

1. 1st year only - cannot take Fed ITC and PTC
2. $/kWh for 1st 10 years with escalation (assumed 3% per yr)
3. $/kWh for entire plant life with escalation (assumed 3% per yr)

NET PRESENT VALUE (NPV) - 2005 $						
TPI =	$25,002,886					
Year End	**Gross Book Value**	**Book Depreciation Annual**	**Accumulated**	**Renewable Resource MACRS Tax Depreciation Schedule**	**Deferred Taxes**	**Net Book Value**
	A	**B**	**C**	**D**	**E**	**F**
2008	**25,002,886**					**25,002,886**
2009	25,002,886	1,250,144	1,250,144	0.2000	1,530,345	22,222,397
2010	25,002,886	1,250,144	2,500,289	0.3200	2,754,622	18,217,631
2011	25,002,886	1,250,144	3,750,433	0.1920	1,448,727	15,518,759
2012	25,002,886	1,250,144	5,000,577	0.1152	665,190	13,603,425
2013	25,002,886	1,250,144	6,250,722	0.1152	665,190	11,688,090
2014	25,002,886	1,250,144	7,500,866	0.0576	77,538	10,360,409
2015	25,002,886	1,250,144	8,751,010	0.0000	-510,115	9,620,379
2016	25,002,886	1,250,144	10,001,155	0.0000	-510,115	8,880,350
2017	25,002,886	1,250,144	11,251,299	0.0000	-510,115	8,140,321
2018	25,002,886	1,250,144	12,501,443	0.0000	-510,115	7,400,292
2019	25,002,886	1,250,144	13,751,588	0.0000	-510,115	6,660,263
2020	25,002,886	1,250,144	15,001,732	0.0000	-510,115	5,920,233
2021	25,002,886	1,250,144	16,251,876	0.0000	-510,115	5,180,204
2022	25,002,886	1,250,144	17,502,020	0.0000	-510,115	4,440,175
2023	25,002,886	1,250,144	18,752,165	0.0000	-510,115	3,700,146
2024	25,002,886	1,250,144	20,002,309	0.0000	-510,115	2,960,117
2025	25,002,886	1,250,144	21,252,453	0.0000	-510,115	2,220,088
2036	25,002,886	1,250,144	22,502,598	0.0000	-510,115	1,480,058
2027	25,002,886	1,250,144	23,752,742	0.0000	-510,115	740,029
2028	25,002,886	1,250,144	25,002,886	0.0000	-510,115	0

CAPITAL REVENUE REQUIREMENTS 2005$

TPI : $25,002,886

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	22,222,397	1,502,234	303,336	583,338	1,250,144	1,897,400	1,250,720	4,285,732
2010	18,217,631	1,231,512	248,671	478,213	1,250,144	2,589,485	1,200,720	4,597,304
2011	15,518,759	1,049,068	211,831	407,367	1,250,144	1,586,987	1,200,720	3,304,678
2012	13,603,425	919,592	185,687	357,090	1,250,144	974,267	1,200,720	2,486,059
2013	11,688,090	790,115	159,542	306,812	1,250,144	901,652	1,200,720	2,207,546
2014	10,360,409	700,364	141,420	271,961	1,250,144	446,237	1,200,720	1,609,405
2015	9,620,379	650,338	131,318	252,535	1,250,144	13,101	1,200,720	1,096,716
2016	8,880,350	600,312	121,217	233,109	1,250,144	-14,955	1,200,720	989,107
2017	8,140,321	550,286	111,115	213,683	1,250,144	-43,012	1,200,720	881,497
2018	7,400,292	500,260	101,014	194,258	1,250,144	-71,068	1,200,720	773,888
2019	6,660,263	450,234	90,913	174,832	1,250,144	-99,124	480,288	1,386,710
2020	5,920,233	400,208	80,811	155,406	1,250,144	-127,181	480,288	1,279,101
2021	5,180,204	350,182	70,710	135,980	1,250,144	-155,237	480,288	1,171,491
2022	4,440,175	300,156	60,608	116,555	1,250,144	-183,293	480,288	1,063,882
2023	3,700,146	250,130	50,507	97,129	1,250,144	-211,350	480,288	956,272
2024	2,960,117	200,104	40,406	77,703	1,250,144	-239,406	480,288	848,663
2025	2,220,088	150,078	30,304	58,277	1,250,144	-267,462	480,288	741,053
2026	1,480,058	100,052	20,203	38,852	1,250,144	-295,519	480,288	633,444
2027	740,029	50,026	10,101	19,426	1,250,144	-323,575	480,288	525,834
2028	0	0	0	0	1,250,144	-351,631	480,288	418,225
Sum of Annual Capital Revenue Requirements								31,256,608

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

TPI = $25,002,886

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	4,285,732	0.6910	2,961,645	3,807,817	0.7778	2,961,645
2010	4,597,304	0.6301	2,896,598	3,965,675	0.7304	2,896,598
2011	3,304,678	0.5745	1,898,415	2,767,616	0.6859	1,898,415
2012	2,486,059	0.5238	1,302,118	2,021,394	0.6442	1,302,118
2013	2,207,546	0.4775	1,054,206	1,742,657	0.6049	1,054,206
2014	1,609,405	0.4354	700,742	1,233,475	0.5681	700,742
2015	1,096,716	0.3970	435,376	816,060	0.5335	435,376
2016	989,107	0.3619	358,006	714,552	0.5010	358,006
2017	881,497	0.3300	290,901	618,264	0.4705	290,901
2018	773,888	0.3009	232,851	526,980	0.4419	232,851
2019	1,386,710	0.2743	380,420	916,779	0.4150	380,420
2020	1,279,101	0.2501	319,933	821,006	0.3897	319,933
2021	1,171,491	0.2281	267,160	730,035	0.3660	267,160
2022	1,063,882	0.2079	221,209	643,666	0.3437	221,209
2023	956,272	0.1896	181,287	561,709	0.3227	181,287
2024	848,663	0.1728	146,689	483,981	0.3031	146,689
2025	741,053	0.1576	116,786	410,303	0.2846	116,786
2026	633,444	0.1437	91,017	340,507	0.2673	91,017
2027	525,834	0.1310	68,888	274,429	0.2510	68,888
2028	418,225	0.1194	49,955	211,911	0.2357	49,955
	31,256,608		13,974,201	23,608,815		13,974,201

	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	13,974,201		13,974,201
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.68%		6.48%
4. Capital recovery factor value = i(1+i)"/(1+i)"-1 where book life = n and discount rate = i	0.11489569		0.090643616
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	1,605,575		1,266,672
6. Booked Cost	25,002,886		25,002,886
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0642**		**0.0507**

LEVELIZED COST OF ELECTRICITY CALCULATION - UTILITY 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 including Levelized Overhaul and Replacement C

Divided by the Annual Electric Energy Consumption

NOMINAL RATES

	Value	Units	From
TPI	$25,002,886	$	From TPI
FCR	6.42%	%	From FCR
AO&M	$984,900	$	From AO&M
AEP =	40,024	MWeh/yr	From Assumptions
COE - TPI X FCR	4.01	cents/kWh	
COE - AO&M	2.46	cents/kWh	
COE	$0.0647	$/kWh	Calculated
COE	**6.47**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$25,002,886	$	From TPI
FCR	5.07%	%	From FCR
AO&M	$984,900	$	From AO&M
AEP =	40,024	MWeh/yr	From Assumptions
COE - TPI X FCR	3.16	cents/kWh	
COE - AO&M	2.46	cents/kWh	
COE	$0.0563	$/kWh	Calculated
COE	**5.63**	cents/kWh	Calculated

Non Utility Generator Internal Rate of Return Worksheet

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	12	$740,693	$8,888,316	
Structural Elements	12	$419,149	$5,029,788	
Subsea Cables	Lot	$200,000	$200,000	
Turbine Installation	12	$491,426	$5,897,112	
Subsea Cable Installation	Lot	$3,113,000	$3,113,000	
Onshore Grid Interconnection	Lot	$500,000	$500,000	
TOTAL			$23,628,216	

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	$11,814,108	$1,063,270	$867,657	$12,681,765
2007	$11,814,108	$1,063,270	$783,792	$12,597,900
Total	$23,628,216	$2,126,539	$1,651,449	$25,279,665

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

Costs	Yrly Cost	Amount	
Labor and Parts	$630,477	$630,477	
Insurance (1.5% of TPC)	$354,423	$354,423	
Total		$984,900	

	FINANCIAL ASSUMPTIONS		
	(default assumptions in pink background - without line numbers are calculated values)		
1	Rated Plant Capacity ©	10	MW
2	Annual Electric Energy Production (AEP)	40,024	MWeh/yr
	Therefore, Capacity Factor	45.66	%
3	Year Constant Dollars	2005	Year
4	Federal Tax Rate	35	%
5	State	Maine	
6	State Tax Rate	8.93	%
	Composite Tax Rate (t)	0.408045	%
	t/(1-t)	0.6893	
7	Book Life	20	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	8.41	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	0	Assumed take PTC
17	Federal Production Tax Credit inc 3% escalation	0.018	$/kWh for 1st 10 yrs
18	State Investment Tax Credit	50000	$
19	State Production Tax Credit		
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	0.0120	$/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**	**2017**
REVENUES									
Energy Payments	3,879,808	3,939,458	4,000,025	4,061,524	4,213,600	4,371,370	4,535,048	4,704,854	4,881,018
REC income	540,568	556,785	573,489	590,694	608,414	626,667	645,467	664,831	684,776
State ITC	50,000								
Federal ITC	0								
Fedaral PTC	810,853	835,178	860,233	886,040	912,622	940,000	968,200	997,246	1,027,164
TOTAL REVENUES	4,470,376	4,496,244	4,573,514	4,652,217	4,822,014	4,998,037	5,180,515	5,369,685	5,565,794
AVG $/KWH	0.112	0.112	0.114	0.116	0.120	0.125	0.129	0.134	0.139
OPERATING COSTS									
Scheduled and Unscheduled O&M	984,900	1,014,447	1,044,881	1,076,227	1,108,514	1,141,769	1,176,022	1,211,303	1,247,642
Other	0	0	0	0	0	0	0	0	0
TOTAL	984,900	1,014,447	1,044,881	1,076,227	1,108,514	1,141,769	1,176,022	1,211,303	1,247,642
EBITDA	3,485,476	3,481,796	3,528,634	3,575,990	3,713,500	3,856,268	4,004,492	4,158,382	4,318,152
Tax Depreciation	5,055,933	8,089,493	4,853,696	2,912,217	2,912,217	303,356	0	0	0
Interest Paid	1,415,661	1,384,726	1,351,316	1,315,233	1,276,263	1,234,176	1,188,722	1,139,631	1,086,614
TAXABLE EARNINGS	-2,986,118	-5,992,422	-2,676,378	-651,460	-474,980	2,318,736	2,815,770	3,018,750	3,231,538
State Tax	-266,660	-535,123	-239,001	-58,175	-42,416	207,063	251,448	269,574	288,576
Federal Tax	-951,810	-1,910,055	-853,082	-207,650	-151,398	739,085	897,513	962,212	1,030,037
TOTAL TAX OBLIGATIONS	-1,218,471	-2,445,178	-1,092,083	-265,825	-193,813	946,148	1,148,961	1,231,786	1,318,613

Description/Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
REVENUES											
Energy Payments	5,063,779	5,253,382	5,450,085	5,654,154	5,865,863	6,085,499	6,313,359	6,549,751	6,794,994	7,049,419	7,313,372
REC income	705,319	726,479	748,273	770,721	793,843	817,658	842,188	867,454	893,477	920,281	947,890
State ITC											
Federal ITC											
Fedaral PTC	1,057,979										
TOTAL REVENUES	5,769,098	5,979,861	6,198,359	6,424,875	6,659,706	6,903,157	7,155,547	7,417,204	7,688,471	7,969,701	8,261,261
AVG $/KWH	0.144	0.149	0.155	0.161	0.166	0.172	0.179	0.185	0.192	0.199	0.206
OPERATING COSTS											
Scheduled and Unscheduled O&M	1,285,071	1,323,624	1,363,332	1,404,232	1,446,359	1,489,750	1,534,442	1,580,476	1,627,890	1,676,727	1,727,029
Other	0	0	0	0	0	0	0	0	0	0	0
TOTAL	1,285,071	1,323,624	1,363,332	1,404,232	1,446,359	1,489,750	1,534,442	1,580,476	1,627,890	1,676,727	1,727,029
EBITDA	4,484,027	4,656,238	4,835,026	5,020,643	5,213,346	5,413,407	5,621,104	5,836,728	6,060,581	6,292,974	6,534,233
Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	1,029,355	967,515	900,728	828,598	750,697	666,565	575,702	477,570	371,587	257,126	133,508
TAXABLE EARNINGS	3,454,672	3,688,723	3,934,299	4,192,045	4,462,649	4,746,842	5,045,403	5,359,159	5,688,994	6,035,848	6,400,725
State Tax	308,502	329,403	351,333	374,350	398,515	423,893	450,554	478,573	508,027	539,001	571,585
Federal Tax	1,101,159	1,175,762	1,254,038	1,336,193	1,422,447	1,513,032	1,608,197	1,708,205	1,813,338	1,923,896	2,040,199
TOTAL TAX OBLIGATIONS	1,409,662	1,505,165	1,605,371	1,710,543	1,820,962	1,936,925	2,058,751	2,186,778	2,321,365	2,462,898	2,611,784

CASH FLOW STATEMENT							
Description/Year	2007	2008	2009	2010	2011	2012	2013
EBITDA			3,485,476	3,481,796	3,528,634	3,575,990	3,713,500
Taxes Paid			-1,218,471	-2,445,178	-1,092,083	-265,825	-193,813
CASH FLOW FROM OPS			4,703,947	5,926,974	4,620,716	3,841,815	3,907,314
Debt Service			-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353
NET CASH FLOW AFTER TAX		-7,583,899	2,901,594	4,124,621	2,818,363	2,039,462	2,104,961
CUM NET CASH FLOW		-7,583,899	-4,682,306	-557,684	2,260,679	4,300,142	6,405,103

2014	2015	2016	2017	2018	2019	2020	2021
3,856,268	4,004,492	4,158,382	4,318,152	4,484,027	4,656,238	4,835,026	5,020,643
946,148	1,148,961	1,231,786	1,318,613	1,409,662	1,505,165	1,605,371	1,710,543
2,910,119	2,855,531	2,926,596	2,999,539	3,074,365	3,151,073	3,229,655	3,310,100
-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353
1,107,766	1,053,178	1,124,243	1,197,186	1,272,012	1,348,720	1,427,303	1,507,747
7,512,869	8,566,047	9,690,290	10,887,476	12,159,489	13,508,209	14,935,511	16,443,258

2022	2023	2024	2025	2026	2027	2028
5,213,346	5,413,407	5,621,104	5,836,728	6,060,581	6,292,974	6,534,233
1,820,962	1,936,925	2,058,751	2,186,778	2,321,365	2,462,898	2,611,784
3,392,385	3,476,482	3,562,353	3,649,951	3,739,215	3,830,076	3,922,449
-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353	-1,802,353
1,590,032	1,674,129	1,760,000	1,847,598	1,936,863	2,027,724	2,120,096
18,033,290	19,707,419	21,467,419	23,315,017	25,251,879	27,279,603	29,399,699
			IRR ON NET CASH FLOW AFTER TAX			33.9%

Municipal Generator Cost of Electricity Worksheet

INSTRUCTIONS			
	(pink)	Indicates Input Cell (either input or use default values)	
	(green)	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	12	$740,693	$8,888,316	
Structural Elements	12	$419,149	$5,029,788	
Subsea Cables	Lot	$200,000	$200,000	
Turbine Installation	12	$491,426	$5,897,112	
Subsea Cable Installation	Lot	$3,113,000	$3,113,000	
Onshore Grid Interconnection	Lot	$500,000	$500,000	
TOTAL			$23,628,216	

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	$11,814,108	$590,705	$535,787	$12,349,895
2008	$11,814,108	$590,705	$510,274	$12,324,382
Total	$23,628,216	$1,181,411	$1,046,061	$24,674,277

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

Costs	Yrly Cost	Amount	
Labor and Parts	$630,477	$630,477	
Insurance (1.5% of TPC)	$354,423	$354,423	
Total		$984,900	

FINANCIAL ASSUMPTIONS				
	(default assumptions in pink background - without line numbers are calculated values)			
1	Rated Plant Capacity ©	10	MW	
2	Annual Electric Energy Production (AEP)	40,024	MWeh/yr	
	Therefore, Capacity Factor	45.7	%	
3	Year Constant Dollars	2005	Year	
4	Federal Tax Rate	0	%	
5	State	Maine		
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	5	%	
	Nominal Discount Rate Before-Tax	5.00	%	
	Nominal Discount Rate After-Tax	5.00	%	
15	Inflation Rate = 3%	3	%	
	Real Discount Rate Before-Tax	1.94	%	
	Real Discount Rate After-Tax	1.94	%	
16	Federal Investment Tax Credit	0		
17	Federal REPI (1)	0.015	$/kWh	
18	State Investment Tax Credit	0	% of TPI	
19	State Investment Production Tax Credit	$0	Credit - 1st y	
			$10M plant	
20	Renewable Energy Certificate (2)	0.012	$/kWh	
21	State Tax Depreciation	0	Installation Cos	
Notes				
	1	$/kWh for 1st 10 years with escalation (assumed 3% per yr)		
	2	$/kWh for entire plant life with escalation (assumed 3% per yr)		

PPI Change in inflation				
http://www.gpec.org/InfoCenter/Topics/Economy/USInflation.html				
			REPI incentive	
		1993	1.50	cents/kWh
1994	1.30%	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	1.10%	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 =	$24,674,277					
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	**24,674,277**					**24,674,277**
2009	24,674,277	1,233,714	1,233,714	0	0	23,440,563
2010	24,674,277	1,233,714	2,467,428	0	0	22,206,849
2011	24,674,277	1,233,714	3,701,142	0	0	20,973,135
2012	24,674,277	1,233,714	4,934,855	0	0	19,739,421
2013	24,674,277	1,233,714	6,168,569	0	0	18,505,708
2014	24,674,277	1,233,714	7,402,283	0	0	17,271,994
2015	24,674,277	1,233,714	8,635,997	0	0	16,038,280
2016	24,674,277	1,233,714	9,869,711	0	0	14,804,566
2017	24,674,277	1,233,714	11,103,425	0	0	13,570,852
2018	24,674,277	1,233,714	12,337,138	0	0	12,337,138
2019	24,674,277	1,233,714	13,570,852	0	0	11,103,425
2020	24,674,277	1,233,714	14,804,566	0	0	9,869,711
2021	24,674,277	1,233,714	16,038,280	0	0	8,635,997
2022	24,674,277	1,233,714	17,271,994	0	0	7,402,283
2023	24,674,277	1,233,714	18,505,708	0	0	6,168,569
2024	24,674,277	1,233,714	19,739,421	0	0	4,934,855
2025	24,674,277	1,233,714	20,973,135	0	0	3,701,142
2036	24,674,277	1,233,714	22,206,849	0	0	2,467,428
2027	24,674,277	1,233,714	23,440,563	0	0	1,233,714
2028	24,674,277	1,233,714	24,674,277	0	0	0

CAPITAL REVENUE REQUIREMENTS - 2005$

TPI : $24,674,277

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	23,440,563	0	0	1,172,028	1,233,714	0	1,080,648	1,325,094
2010	22,206,849	0	0	1,110,342	1,233,714	0	1,080,648	1,263,408
2011	20,973,135	0	0	1,048,657	1,233,714	0	1,080,648	1,201,723
2012	19,739,421	0	0	986,971	1,233,714	0	1,080,648	1,140,037
2013	18,505,708	0	0	925,285	1,233,714	0	1,080,648	1,078,351
2014	17,271,994	0	0	863,600	1,233,714	0	1,080,648	1,016,666
2015	16,038,280	0	0	801,914	1,233,714	0	1,080,648	954,980
2016	14,804,566	0	0	740,228	1,233,714	0	1,080,648	893,294
2017	13,570,852	0	0	678,543	1,233,714	0	1,080,648	831,608
2018	12,337,138	0	0	616,857	1,233,714	0	1,080,648	769,923
2019	11,103,425	0	0	555,171	1,233,714	0	480,288	1,308,597
2020	9,869,711	0	0	493,486	1,233,714	0	480,288	1,246,911
2021	8,635,997	0	0	431,800	1,233,714	0	480,288	1,185,226
2022	7,402,283	0	0	370,114	1,233,714	0	480,288	1,123,540
2023	6,168,569	0	0	308,428	1,233,714	0	480,288	1,061,854
2024	4,934,855	0	0	246,743	1,233,714	0	480,288	1,000,169
2025	3,701,142	0	0	185,057	1,233,714	0	480,288	938,483
2026	2,467,428	0	0	123,371	1,233,714	0	480,288	876,797
2027	1,233,714	0	0	61,686	1,233,714	0	480,288	815,112
2028	0	0	0	0	1,233,714	0	480,288	753,426
Sum of Annual Capital Revenue Requirements								20,785,198

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

TPI = $24,674,277

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	1,325,094	0.8227	1,090,158	1,177,329	0.9260	1,090,158
2010	1,263,408	0.7835	989,913	1,089,827	0.9083	989,913
2011	1,201,723	0.7462	896,744	1,006,424	0.8910	896,744
2012	1,140,037	0.7107	810,203	926,954	0.8740	810,203
2013	1,078,351	0.6768	729,871	851,260	0.8574	729,871
2014	1,016,666	0.6446	655,352	779,189	0.8411	655,352
2015	954,980	0.6139	586,275	710,595	0.8250	586,275
2016	893,294	0.5847	522,291	645,335	0.8093	522,291
2017	831,608	0.5568	463,071	583,273	0.7939	463,071
2018	769,923	0.5303	408,306	524,280	0.7788	408,306
2019	1,308,597	0.5051	660,930	865,137	0.7640	660,930
2020	1,246,911	0.4810	599,786	800,345	0.7494	599,786
2021	1,185,226	0.4581	542,966	738,593	0.7351	542,966
2022	1,123,540	0.4363	490,197	679,760	0.7211	490,197
2023	1,061,854	0.4155	441,222	623,727	0.7074	441,222
2024	1,000,169	0.3957	395,801	570,382	0.6939	395,801
2025	938,483	0.3769	353,704	519,615	0.6807	353,704
2026	876,797	0.3589	314,720	471,322	0.6677	314,720
2027	815,112	0.3418	278,646	425,401	0.6550	278,646
2028	753,426	0.3256	245,294	381,755	0.6425	245,294
	20,785,198		11,475,448	14,370,504		11,475,448

	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	11,475,448		11,475,448
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)	920,820		697,862
6. Booked Cost	24,674,277		24,674,277
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0373**		**0.0283**

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	$24,674,277	$	From TPI
FCR	3.73%	%	From FCR
AO&M	$984,900	$	From AO&M
AEP =	40,024	MWeh/yr	From Assumptions
COE - TPI X FCR	2.30	cents/kWh	
COE - AO&M	2.46	cents/kWh	
COE	$0.0476	$/kWh	Calculated
COE	**4.76**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$24,674,277	$	From TPI
FCR	2.83%	%	From FCR
AO&M	$984,900	$	From AO&M
AEP =	40,024	MWeh/yr	From Assumptions
COE - TPI X FCR	1.74	cents/kWh	
COE - AO&M	2.46	cents/kWh	
COE	$0.0420	$/kWh	Calculated
COE	**4.20**	cents/kWh	Calculated