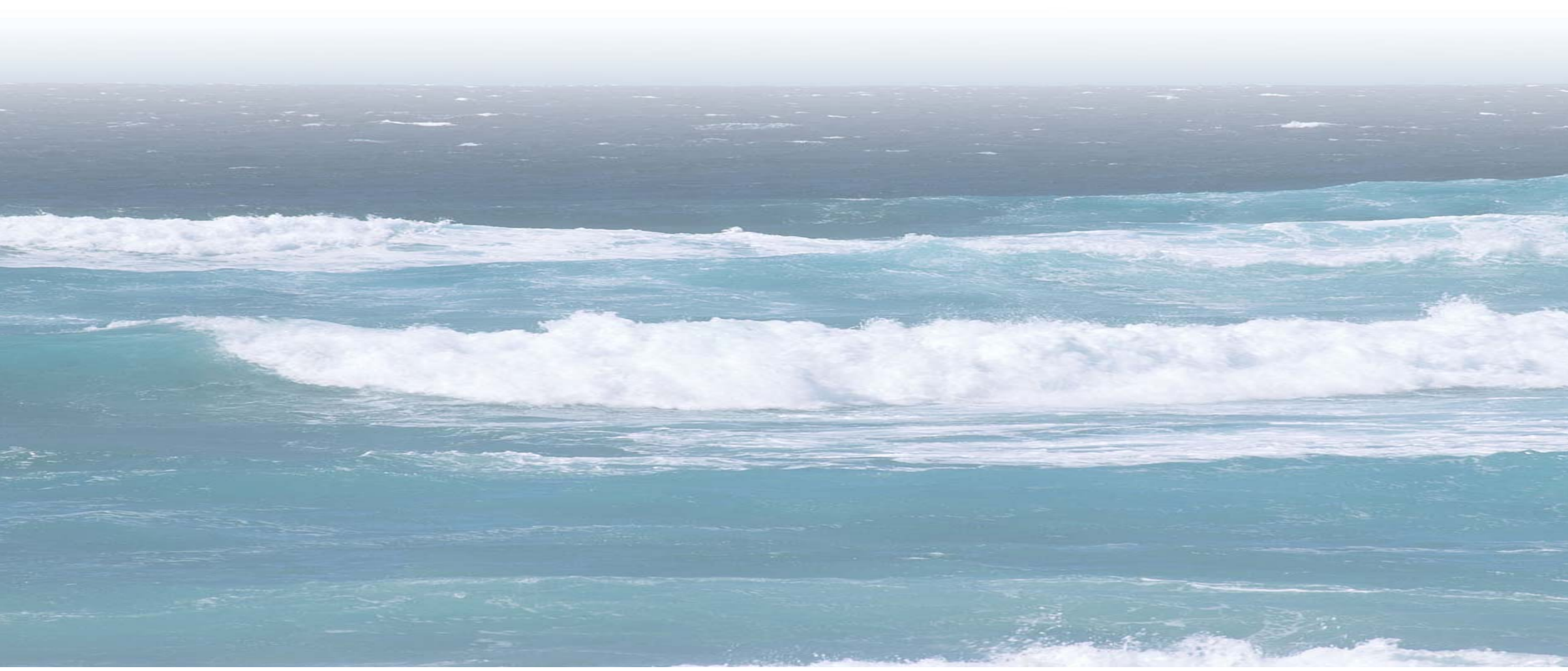
System Level Design, Performance and Costs – Maine State Offshore Wave Power Plant



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1. Introduction and Summary

This document describes the results of the system level design, performance and cost study for both a feasibility demonstration pilot plant and a commercial size offshore wave power plant installed off the coast of Maine. For purposes of this point design study, the Maine stakeholders selected the Ocean Power Delivery (OPD) Pelamis wave energy conversion (WEC) device and area for deployment in Cumberland County near Old Orchard Beach south of Portland. The study was carried out using the methodology and standards established in the Design Methodology Report (Reference 1), the Power Production Performance Methodology Report (Reference 2) and the Cost Estimate and Economic Assessment Methodology Report (Reference 3).

A pilot scale wave power plant using a single Pelamis Wave Energy Conversion device was evaluated. The yearly electrical energy produced and delivered to the grid interconnection is estimated to be 290 MWh/year at the selected deployment site and would cost $6.2 million to build ($5.6 million after 10% federal incentive tax credit). This cost only reflects the capital needed to purchase a single Pelamis unit, the construction costs to build it and the grid interconnection cost. Therefore, it represents the installed capital cost for a single Pelamis WEC system, but does not include the following elements:

- Detailed Design, Permitting and Construction Financing
- Yearly O&M Costs
- Test and Evaluation Cost

A commercial scale wave power plant was also evaluated to establish a base case from which cost comparisons to other renewable energy systems can be made. The yearly electrical energy produced and delivered to bus bar is estimated to be 488 MWh/year for each Pelamis WEC device. In order to meet the target output of 300,000 MWh/year a total of 615 Pelamis WEC devices are required. This is the equivalent output of a commercial 100MW wind farm. The elements of cost and economics (with cost in 2004$) are:

- Total Plant Investment = 735 million
- Annual O&M Cost = $33.4 million; 10-year Refit Cost = $74.2 million
- Utility Generator Levelized Cost of Electricity (COE)[1] = 32 cents/kWh (real rates) and 39 cents/kWh (nominal rates)
- Non Utility Generator Internal rate of Return (IRR) – No IRR

In order to compare offshore wave power to shore based wind economics, industry learning curves were applied. The results indicate that even with best-case assumptions in place,

[1] For the first 90 MW plant assuming a regulated utility generator owner, 20 year plant life and other assumptions documented in Reference 3

wave power cannot compete with commercially available wind technology at the chosen deployment site in Maine at any equivalent production volume.

Subsequent to completing the design study for the Old Orchard Beach site, new hindcast wave data for the Gulf of Maine became available from the U.S. Corps of Engineers (Reference 8). The Project Team evaluated this new data to see if there were other locations along the Maine coastline that would have a better wave energy climate and thus better economics. This analysis is documented in Appendix D and the results are summarized below.

This analysis indicated that relative to Old Orchard Beach, wave energy fluxes may be 70-100% higher in similar water depths off Great Wass and Head Harbor Islands in Washington County, and 50-80% higher off the entrances to Penobscot Bay in Knox County. Although "Down East" wave energy resources are somewhat better than those off Penobscott Bay, they are not associated with strong onshore grid connections or coastal rail access for transport of materials and equipment. By comparison, the western entrance to Penobscot Bay has a strong grid interconnection at the Rockland/Camden 115 kV substation (in Central Maine Power service territory), and this also is the northern limit for coastal rail access in Maine.

In unsheltered waters off Penobscot Bay, the output of a wave power plant might be 80% higher, which would translate to a 45% lower cost of energy compared with a similar plant off Old Orchard Beach. Thus at a national commercial wave power development level of 40,000 MW of installed capacity, the cost of offshore wave energy here might be in the range of 4.4 to 5.5 cents per kilowatt-hour (¢/kWh), rather than the 8-10 ¢/kWh projected for the Old Orchard Beach design (at a cumulative production learning level of 40,000 MWQ installed capacity). Although this is less than the average price of electricity to industrial customers in Maine (6.5 ¢/kWh), it is still more than the cost of onshore wind energy.

Given the limited number of Maine coastal sites where onshore wind turbines would be acceptable, however, the more appropriate comparison would be with offshore wind energy cost projections for similar water depths and distances offshore. In such a comparison, an offshore wave energy cost of 4.4 to 5.5 ¢/kWh may be comparable to projected offshore (>30 m depth) wind energy costs in the Class 6 wind regime that exists in this region south of Penobscot Bay. Reference 9 estimates that by the year 2015, offshore wind energy in such water depths and this wind climate would cost 4.5 to 5.8 ¢/kWh.

The Project Team recommends that Maine Electricity Stakeholders join with Massachusetts Electricity Stakeholders in the promotion and sponsorship of a project that will investigate local Gulf of Maine wave energy "hotspot" locations. The new WIS hindcast database assumes parallel bathymetric contours and as such does not account for the detailed, complex bathymetry found off the Maine coastline. Since the offshore wave climate in intermediate water depths off Maine and northern Massachusetts is "driven" by the same deep-water wave climate in the Gulf of Maine, there would be a relatively small incremental cost to add the Maine coastline to the Massachusetts detailed wave mapping study now being planned.

2. Site Selection

The Maine state stakeholders selected Orchard Beach, south of Portland as an area for locating an offshore wave power plant. A state-wide site identification and characterization study was carried out and the results are contained in reference 4. The land fall of the power cable would occur at Prouts Neck, a little bit north of Orchard Beach, where the single unit Pelamis device is connected to a local 12kV distribution line. For fabrication and assembly Portland was chosen because of its infrastructure. Operation and Maintenance can be carried out from Portland as well. No easement to land a power cable has been identified, although it is likely that easements such as sewer outfalls exist in this area. For a commercial size plant, grid interconnection will occur at the Orchard beach substation. Upgrades on 3-5km of transmission line will be required to interconnect the wave farm to the Orchard Beach substation. An additional substation at Old Orchard beach is in the planning phases, bringing in an additional 115kV line. The regional map (figure 1) shows the cable landing site (#1), the deployment site (#2) and the location of the wave measurement buoy (#3) used for this assessment (NDBC 44007).

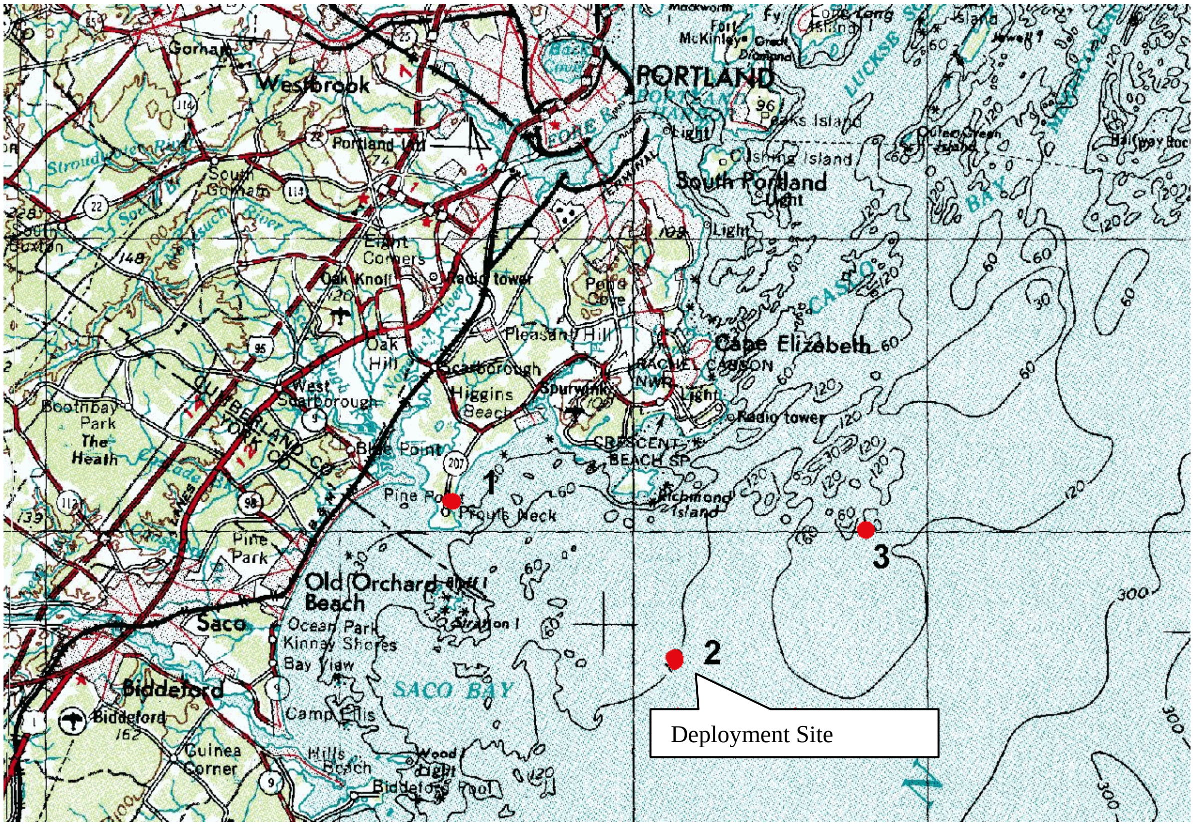

Figure 1: Regional map of deployment site (bathymetry depth contours in feet)

The bathymetry in the vicinity of Prouts neck is shown in more detail in Figure 2.

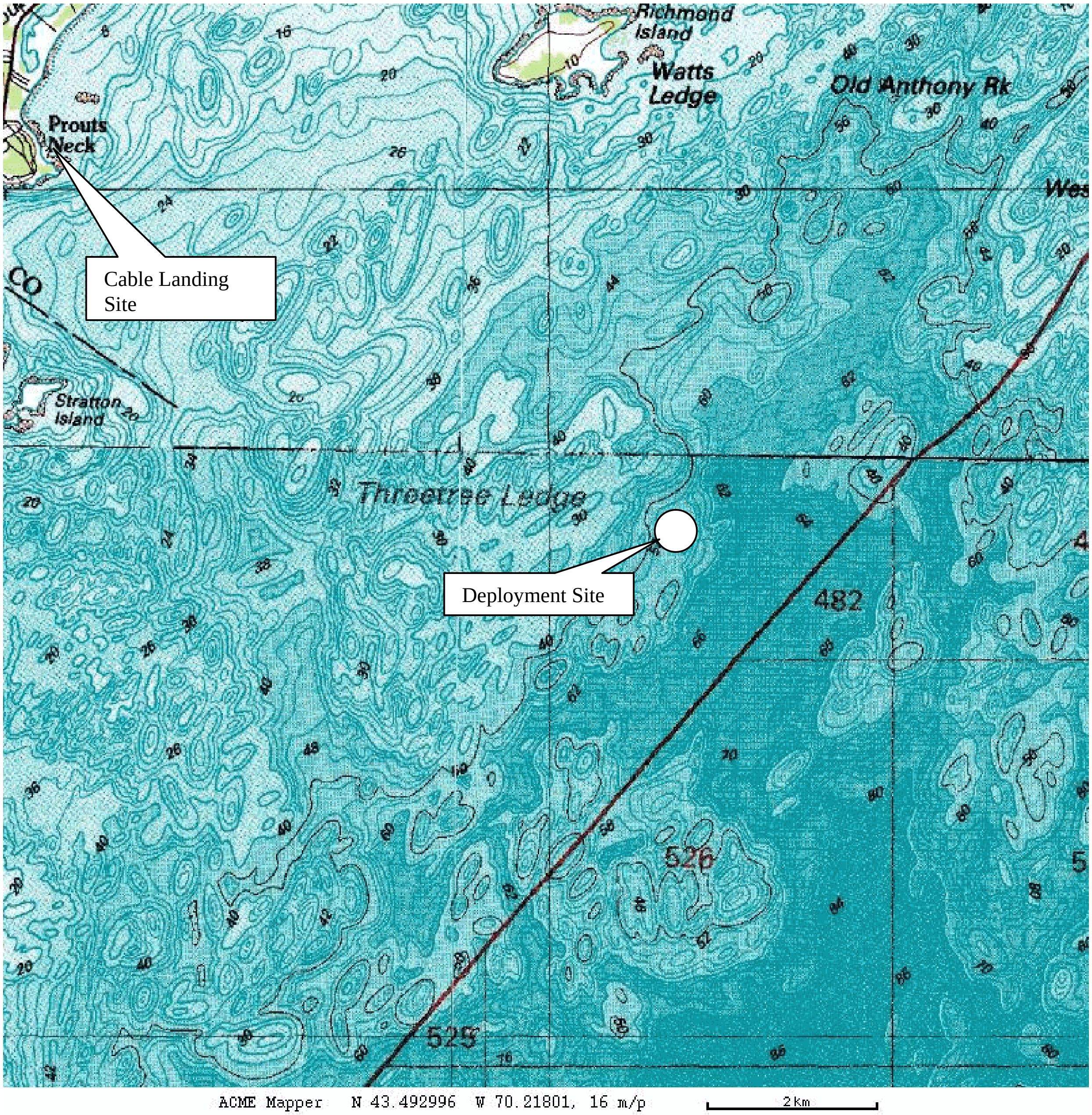

Figure 2: Bathymetry at deployment site (depth in meters)

The cable landing at Prouts neck is shown in Figure 3. As shown, the cable landing site is in close proximity to the 12kV distribution line.

Only two sediment sample sites were available in vicinity of the mooring site, one sand and one gravel, which suggests poorly sorted, coarse, non-cohesive sediments. Based on these sediments, it was assumed, that the sub-sea cable can be buried in soft sediments half of the cable route. The other half the cable will need to be laid on the ocean floor, using additional

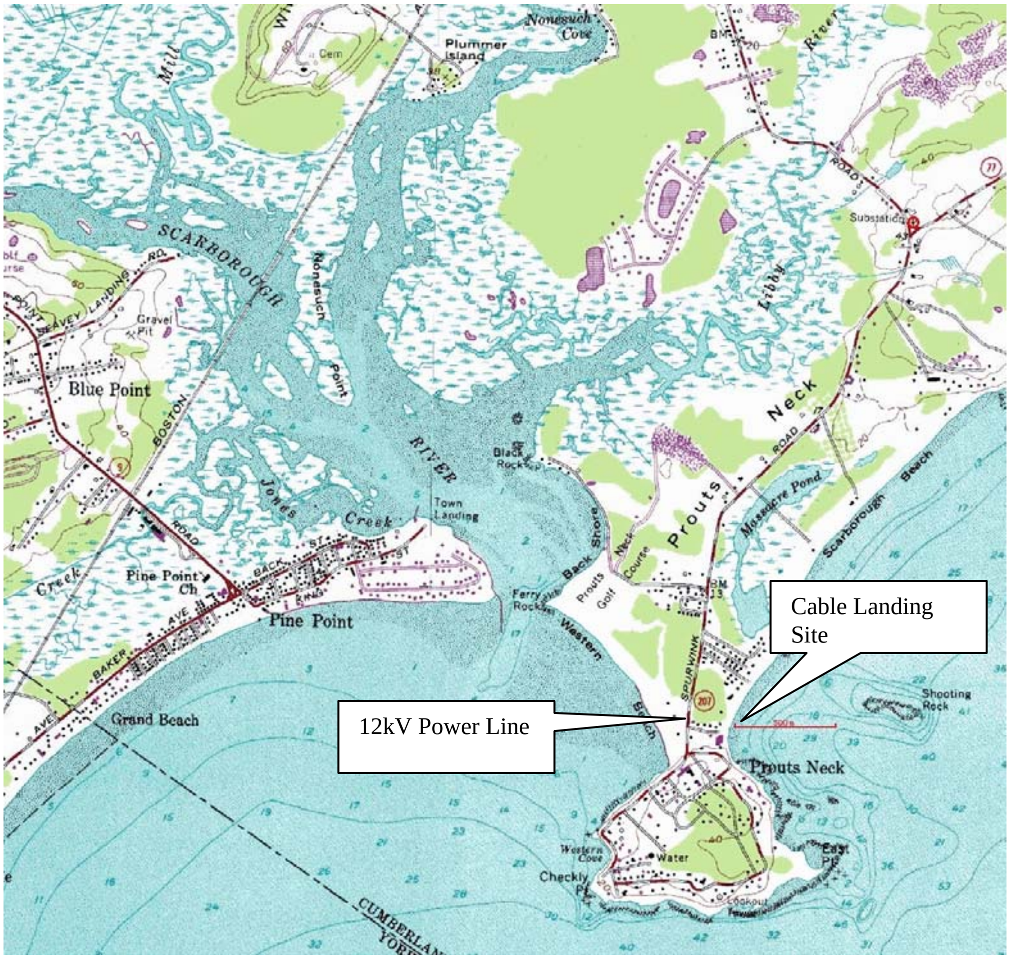

Figure 3: Cable landing site at Prouts Neck

protection. Detailed bathymetry and geotechnical assessments will need to be carried out in a detailed design and engineering phase. Special attention will need to be paid to identify potential obstacles such as large rock formations in the cable route and at the deployment location. This is accomplished by using a combination of side scan radar, sub-bottom profiler, local dives and sediment sampling.

The deployment features the following relevant parameters:

Water Depth at Deployment Site:	50-60 m
Distance from shore to 12kV line:	500 m
Distance to Shore:	9.2 km
Overland Transmission Substation-Cable landing Site:	5 km (estimated)
Ocean Floor Sediments:	Gravel / Rock / Sand
Transit Distance to Portland for O&M:	30 km

3. Wave Energy Resource Data

In order to characterize the wave resource at the proposed site, the NDBC 44007 wave measurement buoy was chosen to obtain the wave data. 20 years of measurement data is available from this measurement station. Below are some key results of the reference measurement station and characterization of the wave climate. The measurement buoy is in close proximity to the proposed deployment site. As a result, the measurements are very representative of the wave climate that the wave power units will experience. Figure 4 shows the average monthly wave energy power flux (in kW/m) Scatter tables for the wave energy resource were created for each month and used to estimate the power production of Pelamis as described in Section 6.

Measurement buoy:	NDBC 44007
Station Name:	Portland 12NM Southeast of Portland
Water depth	19 m (however, the buoy is located over a hill with the seafloor at about 40 m)
Coordinates:	43° 31’53’’ N 70° 08’39’’ W
Data availability:	19 year (1983-2002)
Maximum Significant Wave Height (Hs):	7.3m
Maximum Significant Wave Period (Tp)	11.1 s
Average Wave Power Density:	4.9 kW/m

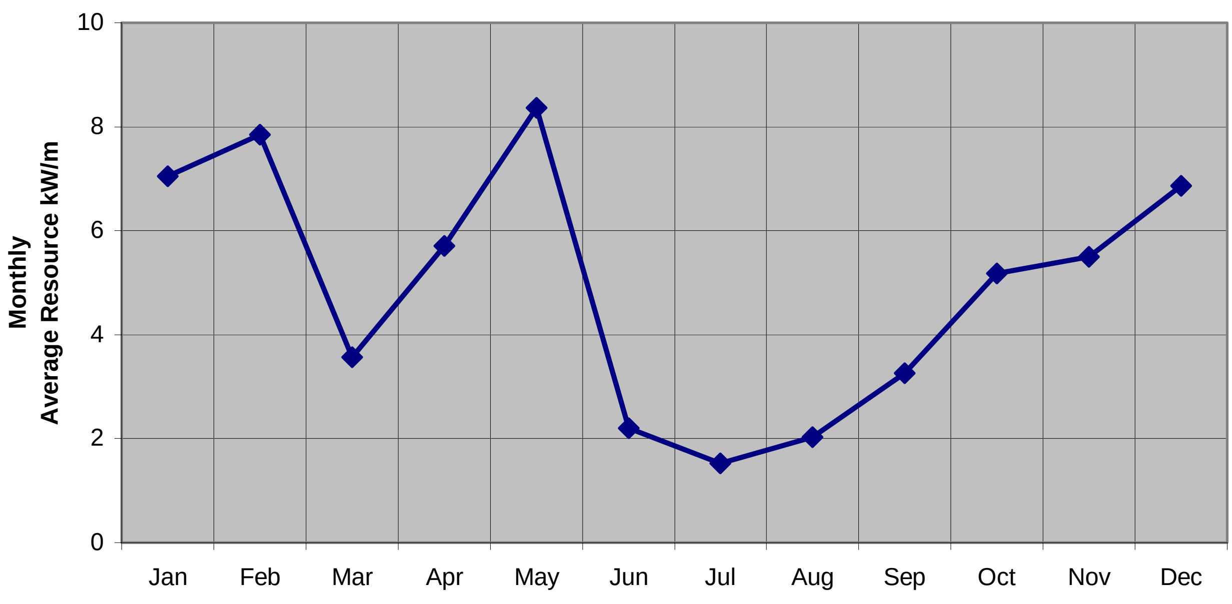

Figure 4: Monthly Average Wave Power Flux (kW/m)

4. The Technologies

The WEC device chosen for the Maine point design is the Pelamis from Ocean Power Delivery (OPD) based on an assessment of worldwide WEC device technology (reference 5). The device consists of a total of 4 cylindrical steel sections, which are connected together by 3 hydraulic power conversion modules (PCM). Total length of the device is 120m and device diameter is 4.6m. Figure 5 shows the device being tested off the Scottish coast. Individual units are arranged in wave farms to meet specific energy demands in a particular site as illustrated in Figure 6.

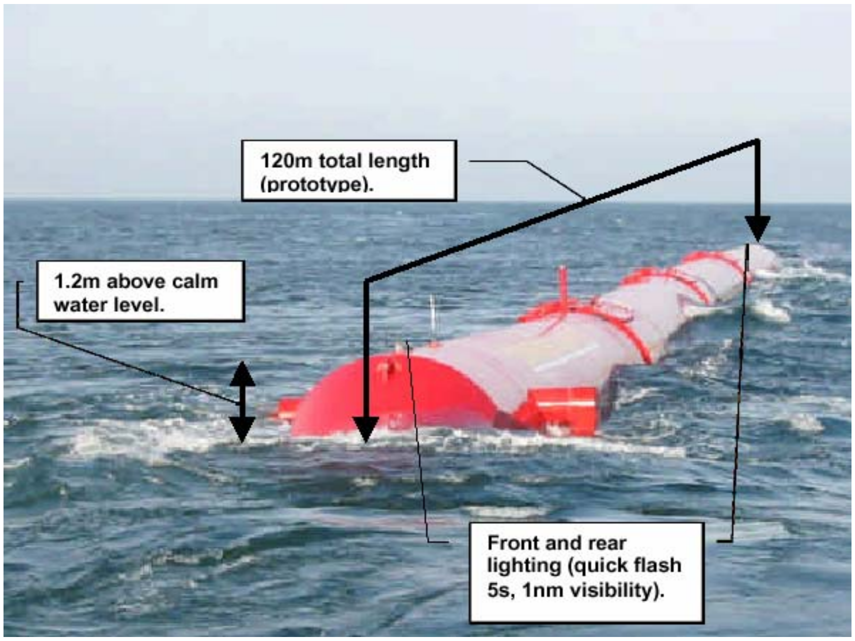

Figure 5: Pelamis pre-production prototype undergoing sea-trials

Figure 6: A typical Pelamis wave farm

The following sections provide a high level overview of the different subsystems that are device specific. Subsystems covered include the power conversion modules (PCM), the structural steel sections and the mooring system. The summary table below shows the key specifications of the Pelamis. The power conversion train is shown in Figure 6.

Table 1: Pelamis Device Specifications

Structure	
Overall Length	123 m
Diameter	4.6m
Displacement	700 tons
Nose	5m long conical drooped
Power Take Off	3 independent PCM's
Total Steel Weight	380 tons
Power Conversion Module (PCM)	
Power Take Off	4 x hydraulic rams (2 heave, 2 sway)
Ram Speed	0 – 0.1 m/s
Power Smoothing Storage	High pressure Accumulators
Working Pressure	100 – 350 bars
Power Conversion	2 x variable displacement motors
Generator size and speed	2 x 125kW / 1500 rpm
Power	
Rated Power	750kW
Generator Type	Asynchronous
System Voltage	3-phase, 415/690VAC 50/60Hz
Transformer	950kVA step up to required voltage
Site Mooring	
Water depth	> 50m
Current Speed	< 1 knot
Mooring Type	Compliant slack moored

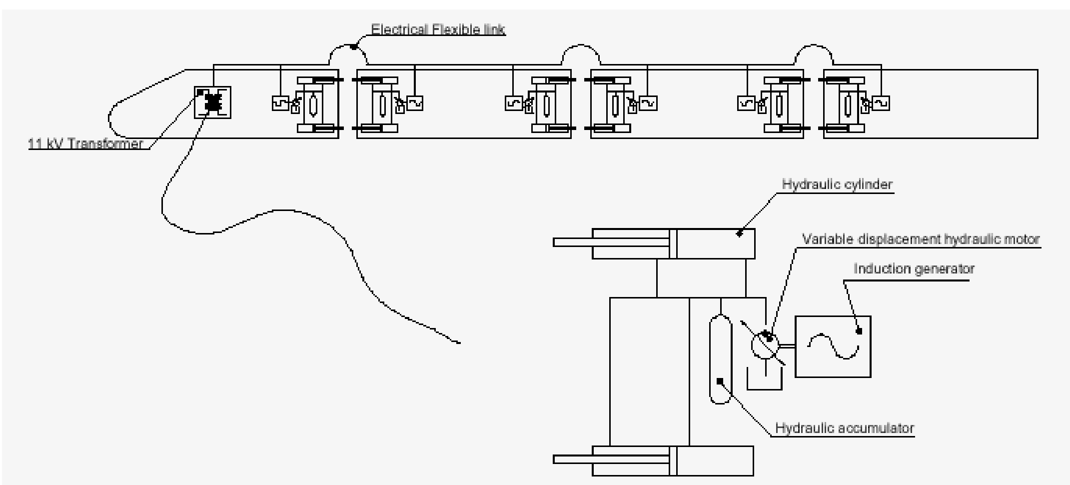

Figure 7: Pelamis Power Conversion Train

The Power Conversion Module (PCM)

As illustrated in Figure 7, a total of 3 power conversion modules (PCM's) connect the 4 individual steel tubes forming a Pelamis device. Each PCM illustrated in Figure 8 contains a heave and sway joint. The modular power-pack is housed in a second fully sealed compartment behind the ram bay so that in the event of seal failure only the hydraulic rams are immersed. Access to all system components is via a hatch in the top of the power conversion module. Maximum individual component weight is less than 3 tons to allow replacement using light lifting equipment.

The wave-induced motion of each joint is resisted by sets of hydraulic rams configured as pumps. These pump oil into smoothing accumulators which then drain at a constant rate through a hydraulic motor coupled to an electrical generator. The accumulators are sized to allow continuous, smooth output across wave groups. An oil-to-water heat exchanger is included to dump excess power in large seas and provide the necessary thermal load in the event of loss of the grid. Overall power conversion efficiency ranges from around 70% at low power levels to over 80% at full capacity. Each of the three generator sets are linked by a common 690V, 3 phase 'bus' running the length of the device. A single transformer is used to step-up the voltage to an appropriate level for transmission to shore. High Voltage power is fed to the sea bed by a single flexible umbilical cable, then to shore via a conventional sub-sea cable.

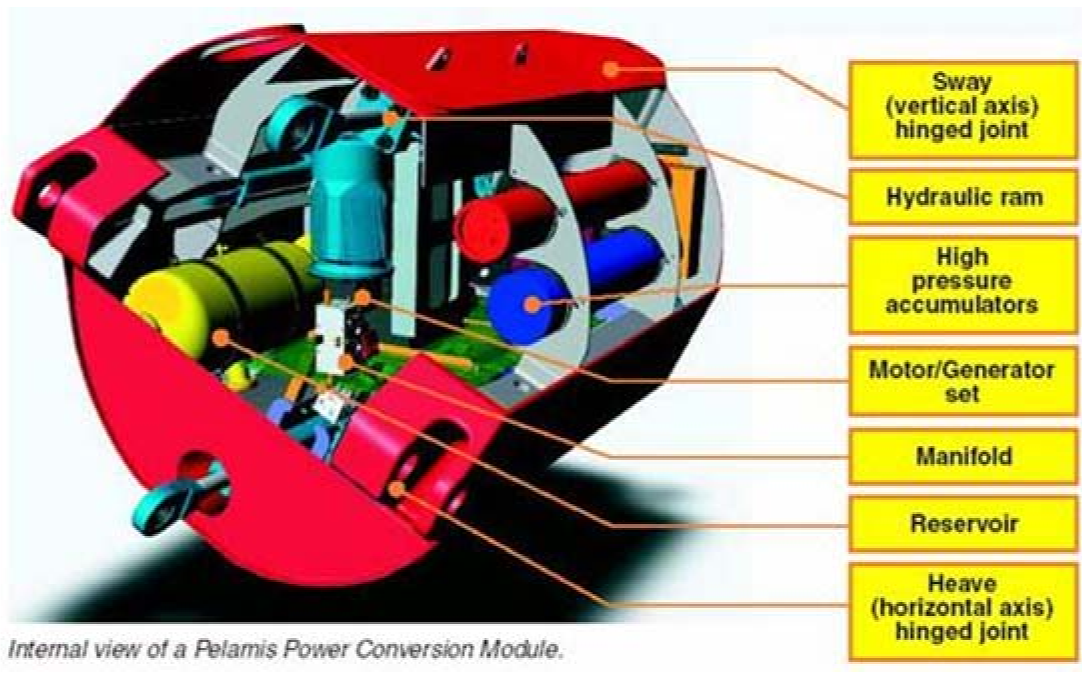

Figure 8: Internal View of the Pelamis PCM

Tubular Steel Sections

There are a total of 4 tubular steel sections, which are the main structural elements of the device. Each steel section is 25m long and weighs roughly 70tons. The main tube sections are manufactured in segments using steel plates that are rolled into shape as shown in Figure 9. Once formed, individual sections are welded together to form a segment. This manufacturing process is extensively used in the wind industry to manufacture wind turbine towers. The process can be automated and lends itself well to cost reduction.

Cast end caps on the steel tubes incorporate hinges, which then interconnect to the Power Conversion Modules. In order to properly ballast the device, sand is added.

Alternative construction materials were evaluated under a contract by the Department of Trade and Industry. Materials analyzed and compared to each other were steel, pre-tensioned concrete and GRP (filament wound composite). Out of the 3 options, concrete emerged as the preferred option (Reference 5).

Figure 9: Manufacturing Steel Tubular Sections

Mooring System

The mooring arrangement of Pelamis needs to be designed specifically for the site conditions. Similar to a wind turbine foundation, which needs to be type approved, the Pelamis mooring system needs to be designed by OPD and adapted to specific site conditions. Survival conditions, maximum current velocity, water depth, seafloor soil densities and other factors will need to be considered in a detailed design phase.

For the purpose of this project, the reference mooring system used for Ocean Power Delivery prototype testing was used to establish a costing base case as shown in Figure 10.

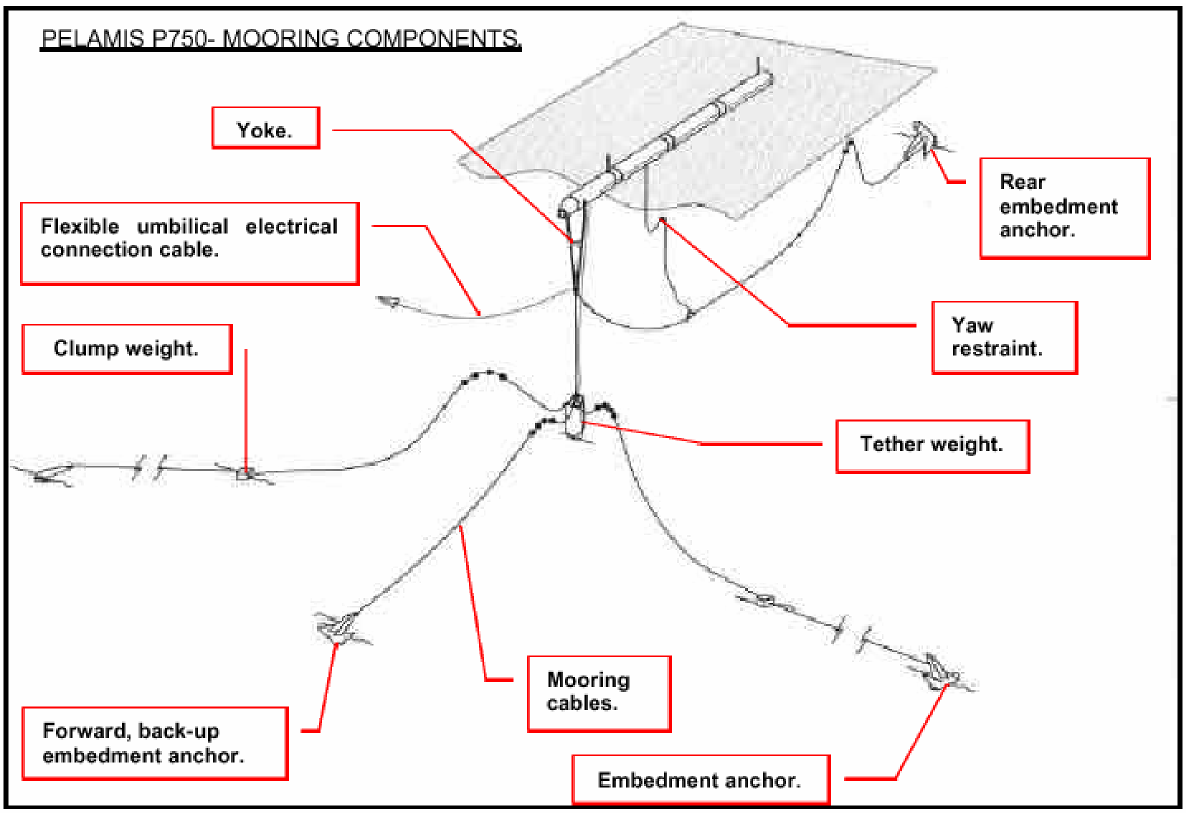

Figure 10: Mooring Arrangement of Pelamis

As shown in Figure 10, the Pelamis mooring system is a catenary type mooring using a combination of steel wire, chain, dead weights and embedment anchors.

Electrical Interconnection & Communication

Each Pelamis device houses a step-up transformer to increase the voltage from generator voltage to a suitable wave farm interconnection voltage. The choice of the voltage level is driven by the grid interconnection requirements and the wave farm electrical interconnection design. A flexible riser cable is connecting the Pelamis to a junction box, sitting on the ocean floor. If multiple devices are connected together, they are daisy-chained by a jumper cable which runs from one device to the next. Only at certain strong-points the electrical cable is then brought to the ocean floor. This approach reduces the number of riser cables required and makes the cabling more accessible for maintenance from the surface. Riser and jumper cables undergo a large number of cyclic loadings and it is likely that they will need to be replaced after 10 years of operation.

The cables used are 3-phase cables with a fiber core. This 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 Pelamis unit, reducing the physical intervention requirements on the device and optimizing operational activities. Operational activities offshore are expensive and minimizing such intervention is a critical component of any operational strategy in this harsh environment. A wireless link is used as a back-up in case primary communication fails.

Subsea Cabling

Umbilical cables to connect offshore wave farms (or wind farms) to shore are being used in the offshore oil & gas industry and for the inter-connection of different locations or entire islands. In order to make them 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 11 shows the cross-sections of armored XLPE insulated submersible cables.

Figure 11: 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 Pelamis 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. If there are ocean floor portions with a hard bottom, the cable will have to be protected by sections of protective steel pipe, which is secured by rock bolts.

An important part of bringing power back to shore is the cable landing. Existing easements should be used if they exist. 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.

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.

Procurement and Manufacturing

For the single-module Pelamis pilot plant, it was assumed that the 3 Power Conversion Modules are procured from Ocean Power Delivery (OPD) and shipped from the UK to Maine and that the structural steel sections are built locally in an appropriate shipyard. Figure 12 shows the Pelamis prototype under construction in Scotland. The picture on the left shows a hydraulic ram being mounted in one of the Power Conversion Modules. The picture on the right shows the large tubular steel sections of the Pelamis being completed.

Figure 12: Manufacturing the Pelamis

Mooring components such as wire, chain and the various anchor components will be purchased from local manufacturers and assembled in a local staging site before deployment. Sub-sea cables, circuit breakers etc. will also be purchased from US based manufacturers.

At the commercial scale envisioned, it will make economic sense to establish local manufacturing facilities for the Power Conversion Modules (PCMs). A number of capable manufacturing facilities exist in the Portland area, which would be able to build and test these modules. This will allow for a large amount of US content in the devices and bring benefits to the local economy.

Portland has also adequate infrastructure in place to carry out annual overhauls and 10-year refits, which will be required to replace major subsystems.

Installation Activities

Installation and operational offshore activities require special equipment such as anchor handler vessels, barges and heavy uplift cranes. In order to understand the offshore installation and removal activities and their impacts on cost, detailed process outlines were created to be able to estimate associated resource requirements. Results were verified with Ocean Power Delivery who deployed a prototype device this year, offshore operators and Sea Engineering Hawaii who managed the installation of Ocean Power Technologies Power Buoy in Hawaii. The major installation activities for both pilot demonstration plant and commercial wave farm are:

1. Landing cable on shore using directional drilling and grid interconnection
2. Installation of sub-sea cables
3. Installation of Mooring System
4. Commissioning and Deployment of Pelamis

Offshore handling requirements were established based on technical specifications supplied by Ocean Power Delivery. Figure 13 below shows the anchor handler vessel used for the installation of the prototype in the UK. It is a standard vessel used in the UK offshore Oil & Gas industry.

For the commercial plant, it proved to be cost effective to include an AHATS class vessel in the project cost and hire dedicated staff to carry out operational activities. Figure 14 shows the prototype Pelamis being towed to its first deployment site off the coast of Scotland.

Figure 13: AHATS class vessel used for prototype installation in UK

Operational stand-by time was included in form of a weather allowance. Weather allowances depend on many factors such as vessel capabilities, and deployment and recovery processes. Comparable numbers from the North Sea offshore oil & gas industry were adapted to local conditions, based on feedback from local offshore operators.

Figure 14: Towing the Pelamis P-750

Operational Activities

Pelamis was designed with a minimum amount of physical intervention in mind. Sophisticated remote monitoring capabilities allow the operator to monitor the device and, in case of a failure, isolate the fault to determine the exact problem and if required schedule physical intervention. In addition, the device features many levels of redundancies which will reduce the need to immediately respond to a failure.

The devices maintenance strategy is to completely detach the device from its moorings, tow the unit into a nearby harbor and carry out any repair activities along a dock-side. Initially it is envisioned, that the device is removed every year for maintenance activities. As the technology becomes more mature, these regular maintenance activities will become more infrequent. For the commercial reference plant, we assumed that removal for scheduled maintenance occurs every 2 years.

Every 10 years, the device will be recovered for a complete overhaul and refit. For that purpose, it will need to be de-ballasted and completely recovered to land. It is likely that only some touch-up painting will be required and the exchange of some of the power take off elements, such as hydraulic rams will take place at that point. The device will also need to be inspected at that time by the American Bureau of Shipping (ABS) or a related agency.

5. System Design – Pilot Plant

The outline below (Figure 15) shows the electrical setup of the demonstration pilot plant. A single Pelamis WEC device is floating on the surface and moored in a water depth of 50m – 60m. An umbilical riser cable is connecting the Pelamis to a junction box on the ocean floor. From this junction box, a double armored 3 phase cable is laid on the ocean floor, buried into the soft sediments on the ocean floor. The cable landing site will be at Prouts Neck. It is assumed, that a suitable 12kV distribution line is in close proximity to the cable landing site.

The cable is landed on shore using directional drilling. Directional drilling is well established to land cables to shore and is viewed as the method, which has the least impact on the environment.

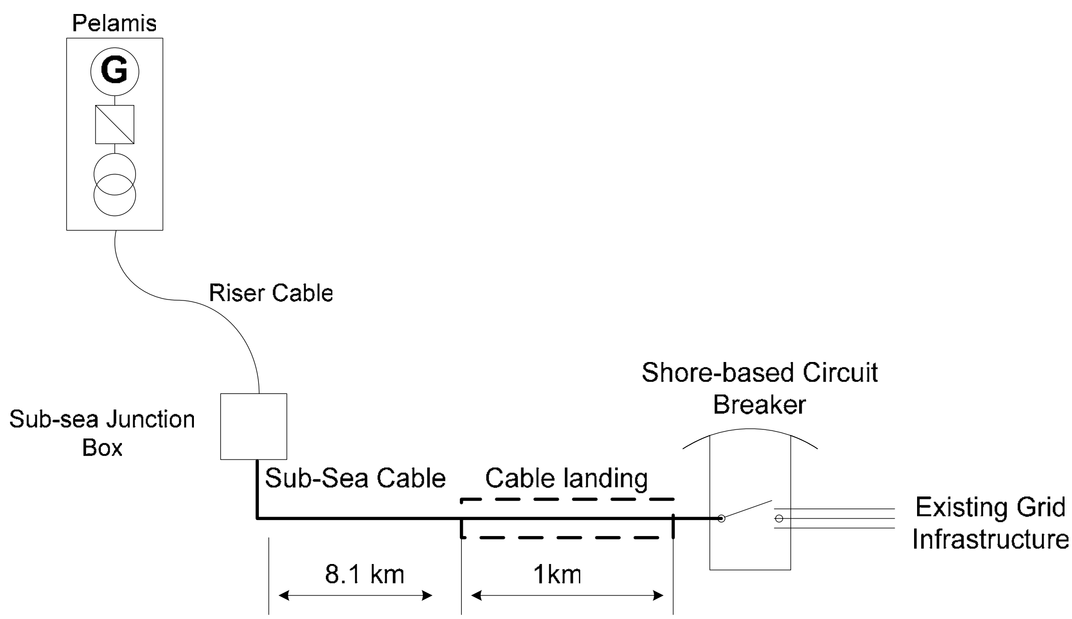

Figure 15: Electrical Interconnection of a single unit Pelamis Pilot Plant

6. System Design - Commercial Scale Wave Power Plant

The commercial scale wave farm design focused on establishing a solid costing base case, and assessing manufacturing and true operational costs for a large plant. The commercial scale cost numbers were used to compare energy costs to commercial wind farms to come to a conclusion on the cost competitiveness of wave power in this particular location.

The following subsections outline the electrical system setup, the physical layout and the operational and maintenance requirements of such a deployment. In order to meet the target output of 300,000 MWh/year, a total of 615 Pelamis units are required.

Electrical Interconnection and Physical Layout

As shown in figure 17, the commercial system uses a total of 4 clusters, each one containing 154 Pelamis units (except for 1 cluster containing 153), connected to sub-sea cables. Each cluster consists of 3 rows with 51 devices per row. The 4 sub-sea cables are connecting the 4 clusters to shore as shown in Figure 17. The electrical interconnection of the devices is accomplished with flexible jumper cables, connecting the units in mid-water. The introduction of 4 independent sub-sea cables and the interconnection on the surface will provide some redundancy in the wave farm arrangement.

The 4 clusters are each 7.69 km long and 1.8 km wide, covering an ocean stretch of roughly 31 km. The 4 arrays and their safety area occupy roughly 56 square kilometers. Further device stacking of up to 4 rows might be possible reducing the array length, but is not considered in this design, as subsequent rows of devices will likely see a diminished wave energy resource and therefore yield a lower output. Such effects and their impacts on performance are not well understood at present. It is not clear at present what the best interconnection voltage for this site would be. 26kV was assumed to be the system voltage.

Based on the above setup the following key site parameters emerged:

Array Length	31 km
Array Width	1.8 km
Device Spacing	150m
Number of Rows	3
System Voltage	26kV
Sub-sea cable specs	26kV / 40MVA / 3-phase with fiber optic core

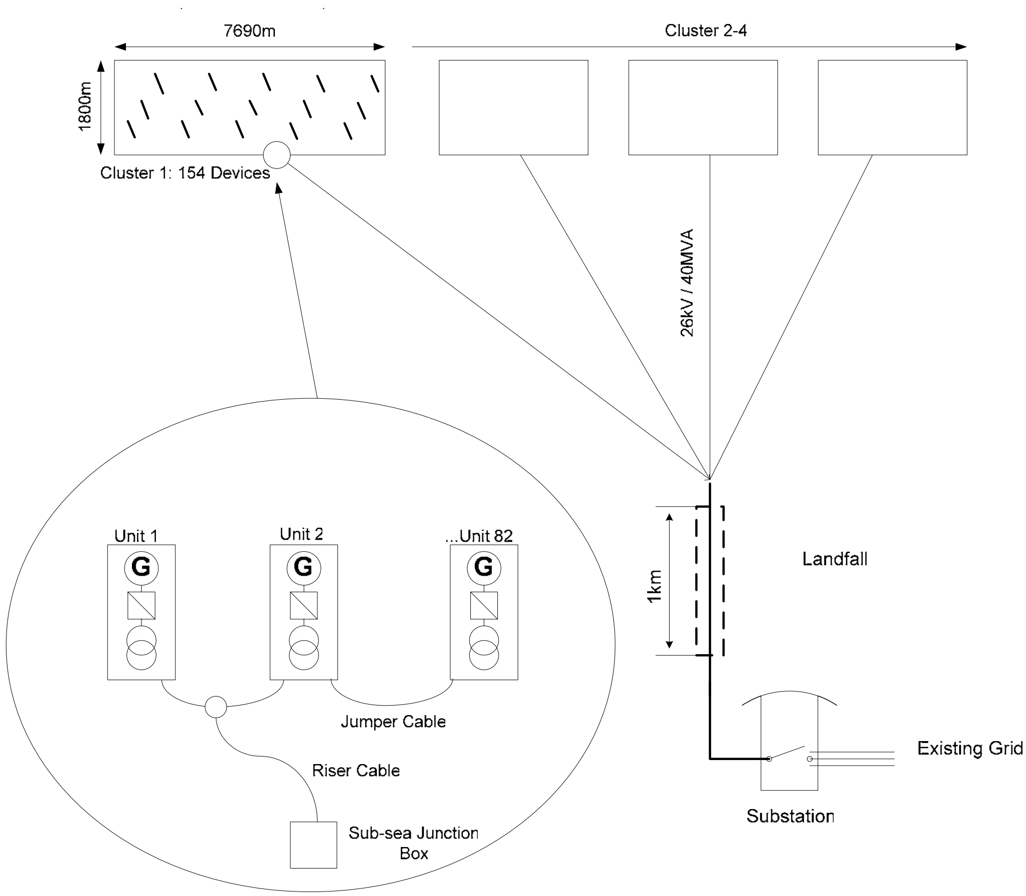

Figure 17: Overall System Layout and Electrical Connections

Operational and Maintenance Requirements

General operational activities are outlined in a previous section. It made economic sense for this wave farm to include an AHATS class vessel in the capital cost of the project. Based on the workload, the vessel will be almost at full capacity to operate the 615 device wave farm.

This type of vessel has sufficient deck space to accommodate the heavy mooring pieces and a large enough crane to handle the moorings. In addition the vessel has dynamic positioning capabilities and is equipped for a 24-hour operation. Based on the work loads involved with O&M and 10-year refit operation a total full-time crew of 20 is required. This includes onshore personnel to carry out annual maintenance activities and 10-year refits.

O&M activities can be carried out at a suitable pier side in Portland, with the device remaining in the water. For the 10-year refit, the device will need to be recovered to land. Budget allowance were given to accommodate improvement to streamline operational tasks.

7. Device Performance

The device performance was assessed based on data supplied by the manufacturer and the wave climate (outlined in previous section). The following summarizes the projected device performance as described in Section 2. In general the results for Maine demonstrate, that the targeted deployment site is not well suited for offshore wave power conversion. The wave climate offshore however could be an option as indicated by the device performance in Massachusetts. It would however require to locate the deployment site further offshore.

Transmission line losses for the sub-sea cable from the offshore farm to the grid interconnection point at the substation were ignored as they are not significant at the design voltage levels used and can only be estimated in a detailed design phase.

Scatter or joint probability diagrams for the wave energy resource were created for each month and used for power production calculations. Figure 18 shows the average power (kW) delivered to the grid by a single Pelamis WEC Device sited as described in Section 2.

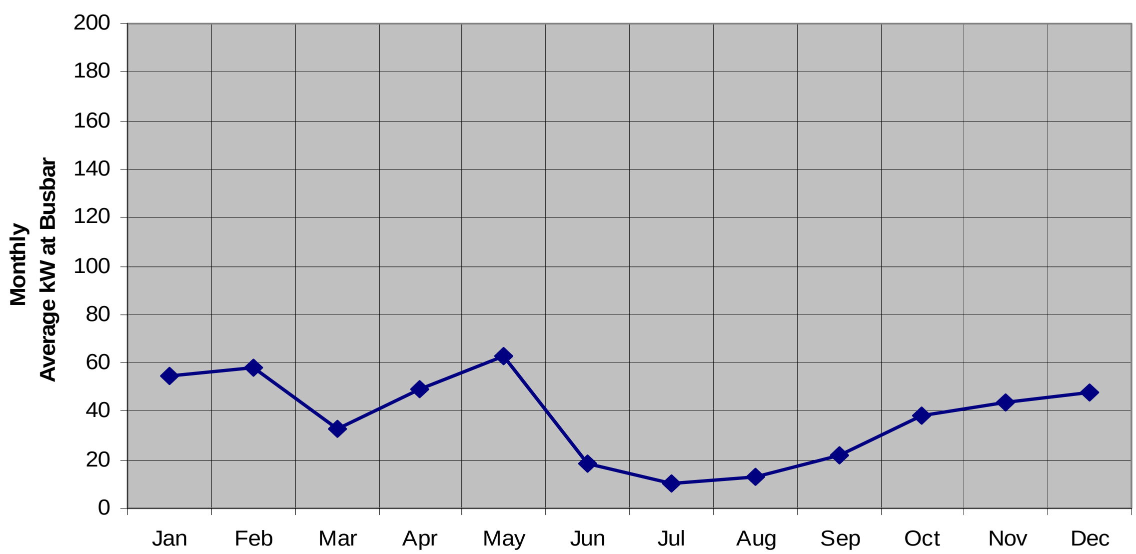

Figure 18: Monthly average power delivered to bus bar – Pilot Plant

A scatter diagram of the annual and monthly wave energy available at the deployment site was developed using long-term statistics from the NDBC wave measurement buoy. The scatter diagram for the annual energy is shown in Table 2.

Table 2: Maine Site Annual occurrence of hours per sea-state

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total annual hours
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.75	7.25	**7**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	*5*
5.75	6.25	**6**	0	0	0	0	0	0	0	1	2	1	0	0	0	0	0	0	0	*13*
5.25	5.75	**5.5**	0	0	0	0	0	0	0	2	3	1	0	0	0	0	0	0	0	*18*
4.75	5.25	**5**	0	0	0	0	0	0	1	4	3	3	0	1	0	0	0	0	0	*53*
4.25	4.75	**4.5**	0	0	0	0	0	1	3	6	5	3	0	1	0	0	0	0	0	*101*
3.75	4.25	**4**	0	0	0	0	0	3	6	7	7	4	0	1	0	0	0	0	0	*207*
3.25	3.75	**3.5**	0	0	0	0	0	10	9	10	7	7	0	2	0	0	0	0	0	*339*
2.75	3.25	**3**	0	0	0	0	6	21	16	15	14	12	0	3	0	0	1	0	0	*638*
2.25	2.75	**2.5**	0	0	0	6	30	39	26	24	29	21	0	5	0	0	2	0	0	*1,057*
1.75	2.25	**2**	0	1	4	56	75	74	38	48	61	40	0	9	0	0	4	0	0	*1,796*
1.25	1.75	**1.5**	0	21	86	207	130	132	91	118	125	69	0	15	0	0	4	0	0	*2,372*
0.75	1.25	**1**	31	292	357	364	220	374	282	291	244	125	0	28	0	0	7	0	0	*1,884*
0.25	0.75	**0.5**	323	449	257	279	428	869	523	430	309	168	0	75	0	0	18	0	1	*274*
0	0.25	**0.125**	22	9	5	14	23	49	33	27	17	16	0	10	0	0	1	0	0	*7*
		8,766	*1*	*10*	*91*	*369*	*772*	*1,014*	*1,383*	*1,241*	*996*	*1,057*	*934*	*367*	*216*	*166*	*92*	*48*	*9*	***8,766***

Table 3: Pelamis Wave Energy Conversion Absorption Performance (kW)

Hs (m) \ Tp (s)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20
10	750	750	750	750	750	750	750	750	750	750	750	750	711	750	750	738	734
9.5	750	750	750	750	750	750	750	750	750	750	750	750	691	750	710	694	662
9	750	750	750	750	750	750	750	750	750	750	750	750	670	746	668	650	592
8.5	750	750	750	750	750	750	750	750	750	750	750	750	650	699	626	606	551
8	750	750	750	750	750	750	750	750	750	750	750	750	630	653	584	562	509
7.5	750	750	750	750	750	750	750	750	750	750	750	748	610	607	542	518	467
7	750	750	750	750	750	750	750	750	750	750	750	692	566	560	500	474	425
6.5	750	750	750	750	750	750	750	750	750	750	723	592	617	513	458	430	384
6	597	630	663	684	750	750	750	750	750	750	616	633	525	476	396	386	329
5.5	428	497	566	612	750	750	750	750	750	635	642	532	482	400	399	341	322
5	259	364	469	539	750	750	750	750	644	641	531	482	399	394	330	308	274
4.5	94	233	371	467	735	744	738	634	626	520	473	390	382	319	299	250	208
4	105	216	326	394	632	616	583	585	494	454	374	361	339	283	236	197	153
3.5	0	86	211	326	484	577	568	502	421	394	330	312	260	216	196	164	140
3	0	91	180	246	402	424	417	369	343	331	275	229	208	173	144	120	93
2.5	0	7	93	171	279	342	351	320	274	230	210	174	145	120	100	84	65
2	0	0	66	109	199	219	225	205	195	162	135	112	93	77	64	54	41
1.5	0	0	26	62	112	141	143	129	110	91	76	63	52	43	36	30	23
1	0	0	11	27	50	62	64	57	49	41	34	28	23	0	0	0	0
0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

By multiplying each cell of the Pelamis performance scatter diagram (Table 3) with each corresponding cell in the hours of reoccurrence scatter diagram (Table 2) the total energy in each sea state was calculated. By summing up the two tables, the annual output (MWh/year) per Pelamis WEC device was derived. Pilot plant performance numbers are summarized in Table 4.

Table 4: Pilot Plant Pelamis Performance

Device Rated Capacity	750kW
Annual Energy Asborbed	426 MWh/year
Device Availability	85%
Power Conversion Efficiency	80%
Annual Generation at bus bar	290 MWh/year
Average Power Output at bus bar	33 kW

The commercial plant performance was assessed using the pilot plants performance data as its basis. In addition certain performance improvements were considered. Based on well established wave theory, the Pelamis device is only absorbing a small fraction of its theoretical limit. An increase in performance by a factor of 2-3 is possible without significant changes to the device geometry. For the purpose of this study, only performance improvements were considered which could be achieved in the near future, without any additional research. The following shows the changes incorporated in the commercial Pelamis performance numbers:

- Changing the mooring configuration will yield a performance improvement of 37%. This mooring configuration has been evaluated in wave tank tests and theoretical studies by Ocean Power Delivery and is well quantified.

- The current Power Conversion Modules use standard off the shelf components. Customizing some of these components could increase the power conversion efficiency by more then 10%. The technologies to improve the conversion efficiency exist and are therefore included in the performance for the commercial plant.

- The rated capacity was changed to 500kW, because the 750kW design is overrated for the Maine wave climate. As a matter of fact, it could be further decreased to 170kW at that particular site with an impact on annual performance of less then 5%.

Table 5 summarizes the performance values for a commercial Pelamis module incorporating improvements as outlined above.

Table 5: Commercial Plant Pelamis Performance

Device Rated Capacity	500kW

Annual Energy Asborbed	584 MWh/year
Device Availability	95%
Power Conversion Efficiency	88%
Annual Generation at bus bar	488 MWh/year
Average Electrical Power at bus bar	56 kW
# Pelamis required to meet target 300,000 MWh/yr	615

8. Cost Assessment – Pilot Plant

The cost assessment for the pilot was carried out using a rigorous assessment of each cost center. Installation activities were outlined in detail and hourly breakdowns of offshore operational activities created to properly understand the processes and associated cost implications. Wherever possible, manufacturing estimates were obtained from local manufacturers. An uncertainty range was associated to each costing element and a Monte Carlo Simulation was run to determine the uncertainty of capital cost. Operational cost was not assessed in detail for the Pilot plant. This is a task that is scheduled for subsequent project phases. Cost centers were validated by Ocean Power Delivery, based on their production experience of their first full scale prototype machine, which was deployed in 2004.

Based on the above assumptions the following results in constant year 2004$ are presented:

Table 6: Cost Summary Table rounded to the nearest $1000

Cost Element	Pilot Plant	Basis
Onshore Transmission & Grid Interconnection	$694,000	(1)
Subsea Cables	$1,695,000	(2)
Pelamis Power Conversion Modules	$1,565,000	(3)
Pelamis Manufactured Steel Sections	$851,000	(4)
Pelamis Mooring	$243,000	(5)
Installation	$633,000	(6)
Construction Mgmt and Commissioning (10% of cost)	$568,000	(7)
Total	**$6,249,000**	
Less federal incentive tax credit (10%)	$624,900	
Total after federal tax credit	**$5,624,000**	

1) Cost includes a breaker circuit and double armored power cable being laid through existing easement in place. Cable cost is based on quotes from Olex cables.

2) Subsea cable cost is based on quotes from Olex cables. It includes a sub-sea, pressure compensated junction box, to connect the riser cable.

3) Based on estimate by Ocean Power Delivery. Shipping cost is included from Edinburgh (UK) to Portland Maine based on quote by Menlo International.

4) Cost for 4 manufactured steel sections was estimated by using $2,850/per ton of manufactured steel. Each steel section of this unit weighs roughly 70 tons (excluding ballast). This is consistent with OPD experience with manufacturing their pre-production machine and input from local manufacturers. It includes cast elements and protective coatings. Range of cost from different sources was $2,500/ton - $3,500/ton.

5) Based on OPD's experience with their pre-production prototype. Cross checks were performed using local construction management feedback.

6) Installation cost was estimated by a rigorous assessment of vessel handling requirements, breakdown of installation tasks, quotes from local operators for vessel cost, fuel and crew, and allowance for weather downtime.

7) Based on E2I EPRI Project Team experience managing like custom construction projects and commissioning to owner acceptance.

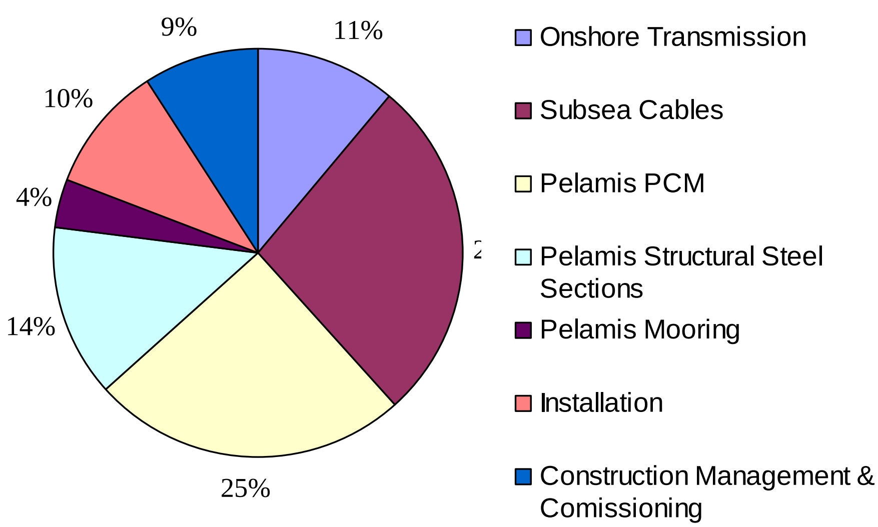

Figure 19: Pie Chart of cost centers for single unit installation

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation was used to determine the likely capital uncertainty of the project. Figure 20 below shows the cost as a function of cost certainty as an S-curve. A steep slope indicates a small amount of uncertainty, while a flat slope indicates a large amount of uncertainty. It shows that the cost accuracy is within -22% to +24%. This bottom-up approach to uncertainty estimation compares to an initially estimated accuracy of -25% to +30% for a pilot scale plant based on a preliminary cost estimate rating (from the top-down EPRI model described in Ref 3).

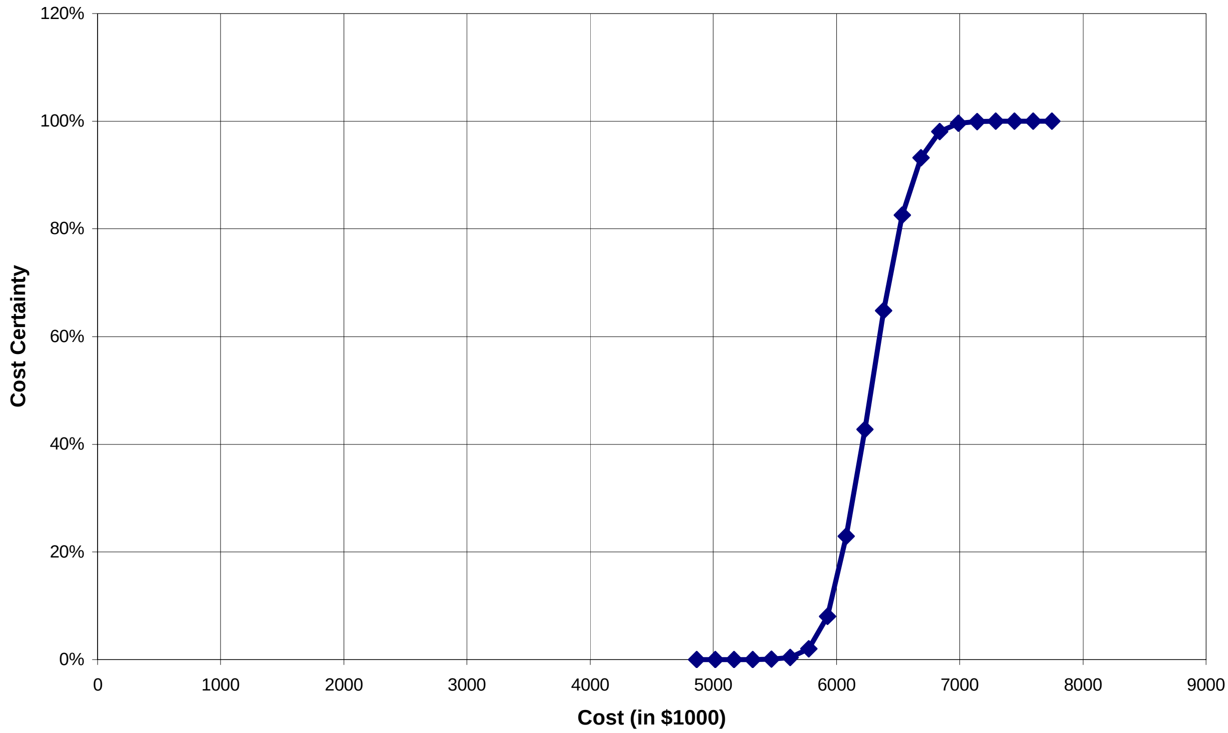

Figure 20: Capital cost uncertainty

9. Cost Assessment – Commercial Scale Plant

The cost assessment for the commercial wave power plant followed a rigorous assessment of each cost center. Instead of simply applying learning curves, a point design for the commercial plant using 615 devices was outlined and its cost estimated. For cost centers, which lend themselves well to cost reductions, outlines were created of how such cost reduction will be achieved. Installation activities were outline in detail and hourly breakdowns of offshore operational activity created to properly understand their impacts on cost and resources. Cost centers were validated by Ocean Power Delivery, based on their production experience of their first full scale prototype machine, which was deployed in 2004. Operational tasks and outlines were validated by local operators.

Table 7: Installed Cost Breakdown for Commercial Scale Plant

Cost Element	**206-Pelamis Device System**		**Basis**
Constant Dollar Year	2004	in %	
Installed Cost			
Onshore Transmission & Grid Interconnection	$4,160,000	2.4%	
Subsea Cables	$9,626,000	2.0%	
Mooring Spread	$71,125,000	9.7%	(1)
Power Conversion Modules	$383,735,000	51.5%	(2)
Concrete Structural Sections	$150,552,000	20.2%	(3)
Facilities	$12,000,000	4.8%	(4)
Installation	$8,618,000	4.9%	(5)
Construction Mgmt and Commissioning (5% of cost)	$31,560,000	4.5%	(6)
Total Plant Cost	**$671,376,000**	**100%**	
Construction Financing Cost	$63,753,000		
Total Plant Investment	**$735,129,000**		
Yearly O&M			
Labor	$6,517,000	21.0%	(7)
Parts (2%)	$13,428,000	39.5%	(8)
Insurance (2%)	$13,428,000	39.5%	(9)
Total	**$33,372,000**	**100%**	
10-year Refit			
Operation	$27,384,000	41.0%	(7)
Parts	$46,865,000	59.0%	(7)
Total	**$74,249,000**	**100%**	

(1) The mooring spread is an assembly of standard elements and equipment. A moderate cost reduction of 30% was assumed (as compared to the prototype). This cost reduction can easily be achieved by purchasing in larger quantities.

(2) Three (3) Power Conversion Modules (PCM) are required for a single Pelamis unit. Cost of a hydro-electric power take off will be significantly lower then initial production units. The performance assessment for our reference site also shows that the PCMs are overrated and reducing the rated power to 500kW per device would yield a relatively small decrease in annual output. This is mainly attributed to the fact that the Maine site has lower energy levels then UK sites for which the device was originally developed. Reference 7 shows that the cost for the three (3) PCM 500kW prototype unit in production volume is $289,00 for the power conversion train alone and another $234,000 for the manufactured steel enclosure, hinges and assembly for a total Pelamis unit cost (3 PCMs) of $523,000.

(3) The summary table in Reference 6 shows a production cost of $51,000 per tube or $204,000 per device excluding the end caps on the tubes. Including the end caps, the cost for the 4 concrete sections is $245,000 per Pelamis device. Concrete is widely used in the offshore industry and is considered the most reliable option among construction materials. However, it is important to understand that a design using concrete tubes will require design efforts up-front, to properly test the long-term fatigue characteristics of a particular design.

(4) Includes an AHATS class vessel, which is equipped to operate 24 hours per day and some provisions for dock modifications and heavy lift equipment.

(5) Installation cost was estimated by a rigorous assessment of vessel handling requirements, breakdown of installation tasks, quotes from local operators for vessel cost, fuel and crew and allowance for weather downtime.

(6) Construction management and commissioning cost was estimated at 5% of the plant cost based on discussions with experienced construction management organizations.

(7) The most cost effective approach to operate the wave power plant included an AHATS class vessel capable to operate effectively 24-hours per day. Based on a rigorous assessment of the tasks involved in operating the wave farm, it was concluded, that the vessel would be at less then 50% capacity. A major refit is required every 10-years for a commercial plant. In other words, assuming a 20-year life, one refit is required. Elements such as hydraulic rams are replaced during that period. In addition, some of the hull is repainted. Unlike the bi-annual maintenance activities, which can be carried out on a pier side, the 10-year refit requires de-ballasting the device and recovering it onto land. It will also need to be inspected at that point by ABS or a related agency.

(8) It is unclear at present what the failure rate of components and sub-systems are. Operational experience will be required with this specific technology to draw any conclusions. An allowance of 2% of Capital cost was included for a commercial project.

(9) 2% is a typical insurance rate for offshore projects using mature technology.

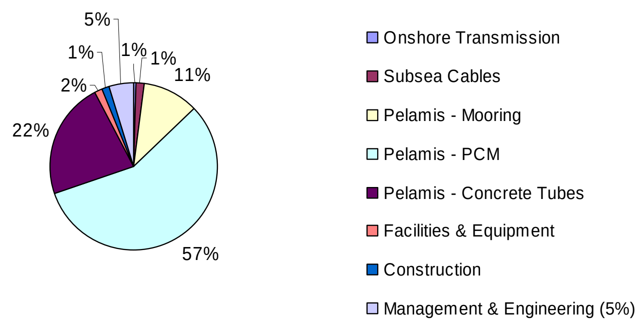

Figure 21: Installed Cost Breakdown for commercial scale plant

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation was run to determine the likely capital uncertainty of the project. Figure 22 below shows the cost as a function of cost certainty as an S-curve. A steep slope indicates little uncertainty, while a flat slope indicates a large amount of uncertainty. The uncertainty for a large-scale project is bigger at this stage because it is unclear at present how well cost reductions could be achieved. These cost uncertainties were estimated for each cost center analyzed.

It shows that the cost accuracy is -22% to + 31%. This bottoms-up approach to uncertainty estimation compares to an initially estimated accuracy of -25% to +30% (from the top-down EPRI model described in Reference 2). The reason, why the projections to a commercial plant have a higher uncertainty, then for a single unit demonstration plant is because certain cost centers include cost reduction measures, which have a higher uncertainty.

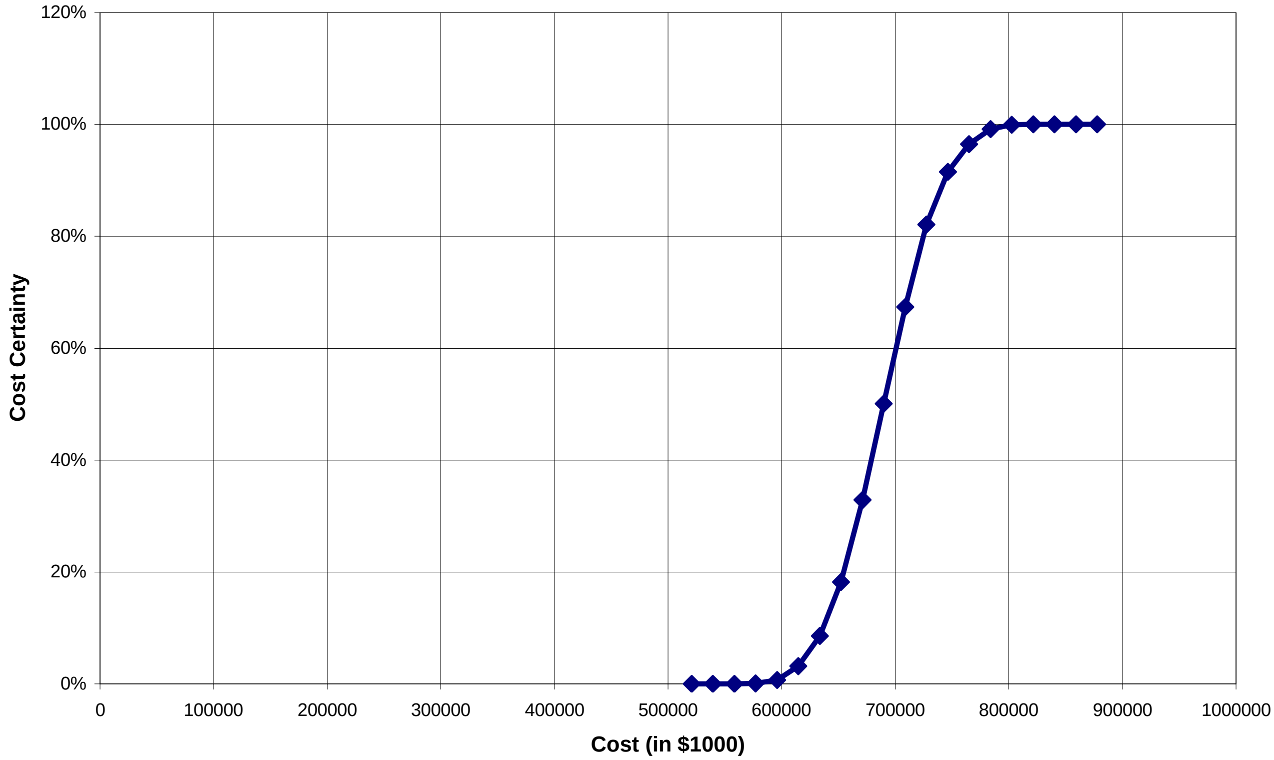

Figure 22: Installed Cost uncertainty S-curve

10. Cost of Electricity/Internal Rate of Return Assessment – Commercial Scale Plant

The Utility Generators (UG) cost of electricity (COE) and the Non-Utility Generator (NUG) internal rate of return (IRR) was assessed based on previously developed methodologies described in reference 3. In order to calculate the COE and IRR, underlying assumptions such as applicable tax rates, tax incentives, depreciation schedules and electricity price forecasts were identified based on the states applicable regulatory environment. Spreadsheet solutions were created for both Utility and Non-Utility Generators and results are outlined in this section.

Table 8: COE Assumptions for the State of Maine

	UG	NUG
Year Constant Dollar	2004	2004
Number of Devices	180	180
Annual Electrical Plant Output	300,000 MWh/yr	300,000 MWh/yr
Book Life	20 years	20 years
Taxation		
Federal Tax Rate	35%	35%
State Tax Rate (Oregon)	8.9%	8.9%
Composite Tax Rate	40.8%	40.8%
Financing		
Common Equity Financing Share	37.5%	32.5%
Preferred Equity Financing Share	10%	
Debt Financing Share	52.5%	67.5%
Nominal Common Equity Financing Rate	13%	14%
Nominal Preferred Equity Financing Rate	10.5%	
Nominal Debt Financing Rate	7.5%	9.3%
Real Common Equity Financing Rate	9.7%	11%
Real Preferred Equity Financing Rate	7.3%	
Real Debt Financing Rate	4.4%	6.3%
Real Construction Financing Rate	4.4%	6.3%
Inflation rate	N/A	3%
Renewable Credits & Incentives		
Federal Investment Tax Credit	10% of TPI	10% of TPI
Federal Production Tax Credit	1.8 cents/kWh (first 10 years)	1.8 cents/kWh (first 10 years)

State Investment Tax Credit	N/A	N/A
Renewable Energy Certificates (RECs)	N/A	REC (2.5 cents/kWh)[2]
Depreciation	MACR Accelerated 5 years	MACR Accelerated 5 years
Industrial Electricity Price (2002$) and	N/A	4.7 cents/kWh
Industrial Electricity Price Forecast (2002$) – The closest we could get to the electricity price as sold by a merchant plant to the grid operator	N/A	8% decline from 2002 to 2008, stable through 2011 and then a constant escalation rate of 0.3%

The capital, O&M and 10-Year Refit cost and their uncertainty was previously estimated in section 8. Table 9 shows the translation of those numbers into a levelized cost of electricity (COE) using the methodology described in Reference 3. The details of this economic analysis are contained in Appendix B.

Table 9 Major Cost elements and their Impacts on Cost of Electricity for Utility Generators (2004 constant year $)

Cost Element	Low	Best	High
Total Plant Investment	$570,248,000	$735,129,000	$961,534,000
Annual O&M Cost	$22,698,000	$33,373,000	$58,500,000
10-year Refit Cost (1 time cost)	$50,103,000	$74,249,000	$93,375,000
Fixed Charge Rate (Nominal)	10.5	10.9	10.8
Cost of Electricity (c/kWh) (Nom)	**28.3**	**39.1**	**55.6**
Fixed Charge Rate (Real)	7.8	8.1	8.0
Cost of Electricity (c/kWh) (Real)	**27.2**	**32.2**	**47.0**

O&M costs have a significant effect on COE. It is a cost center with potential for significant improvements and is also the cost center with the most uncertainty at present because there is little experience with operating such wave farms which could be used to validate any of the numbers. Currently standard offshore oil & gas industry practices and rates were applied to derive appropriate operational costs. The offshore oil & gas industry is well known for it's high operational overhead and steep cost profiles. In order to reduce this cost center, the industry needs to learn by doing, by operating small wave farms. Cost reductions can be expected by improving the reliability of the deployed devices as well as improving the operational strategies.

Table 10 shows the translation of capital, O&M and 10-Year Refit cost and their uncertainty into an internal rate of return (IRR) using the methodology described in Reference 3.

[2] Renewable Energy Certificates are available from the NE-ISO were considered in this study for NUG only

In terms of definition, the Internal Rate of Return (IRR) is the discount rate that sets the present value of the net cash flows over the life of the plant to the equity investment at the commercial operating date. The net present value represents the present value of profit or returns using the time value of money. This calculation results from discounting the net cash flows at the 'discount rate." The economics analysis for this first commercial offshore wave power plant is described in detail in Appendix C

Table 10: Major Cost elements and their impacts on Cost of Electricity for Non Utility Generators (2008 initial operation – 20 year life – current year $)

Cost Element	Lowest Estimate	Best Estimate	High Estimate
Total Plant Investment (2004)	$574,000,000	$739,431,000	$966,000,000
Annual O&M Cost (2004$)	$22,698,000	$33,373,000	$58,500,000
10-year Refit Cost (2004$)	$50,103,000	$3,712,000	$93,375,000
Internal Rate of Return with REC	No IRR	No IRR	No IRR
Internal Rate of Return without REC	No IRR	No IRR	No IRR

Table 10 shows that the first commercial plant owned by a NUG does not have a positive internal rate of return. This is not surprising given the 32 cents/kWh COE and the electricity selling price for Maine of 6.5 cents/kWh (2002$) . Figure 23 shows the cumulative cash in current year dollars for the 20 year life of the project. For the best estimate case, the cumulative is still negative at the end of the period, meaning that a return on the investment has not been made.

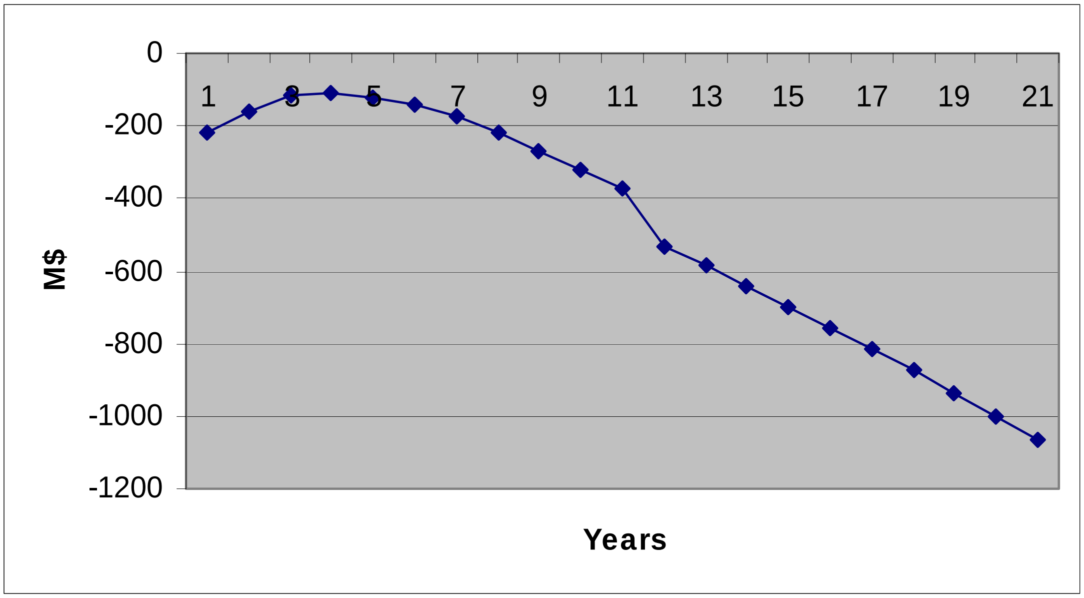

Figure 23: Cumulative Cash Flow Over 20 Year Project Life

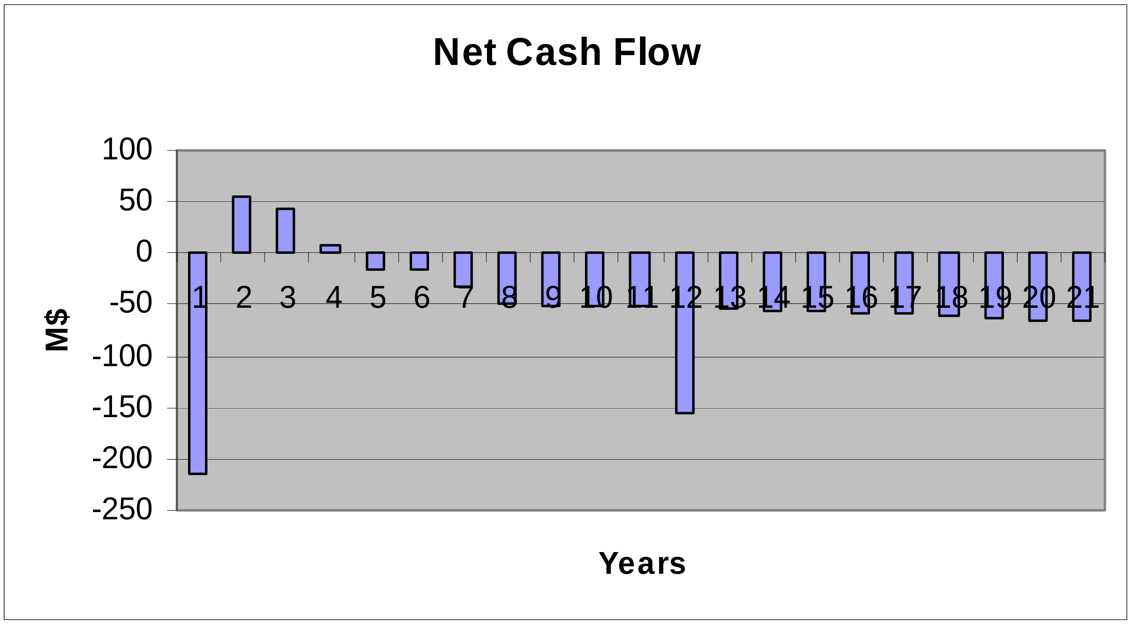

Figure 24: Cash Flow Over 20 Year Project Life

The next two sections describe learning curves and the reduction in cost associated with the learning experience

11. Learning Curves

Operating in competitive markets makes enterprises do better. This fact is at the core of the learning curve phenomenon. Learning through production experience reduces prices for energy technologies and these reductions influence the dynamic competition among technologies. In addition, learning curves are used by Government policymakers to design measures to stimulate the production of new technologies to where they become commercially competitive.

In order to make available environmentally effective technologies (or technologies that have characteristics that are deemed to be of societal benefit), which are price competitive, governments support these technologies through funding of RD&D and through price subsidies or other forms of deployment policy. Crucial questions concern how much support a technology needs to become competitive and how much of this support has to come from government budgets. Learning curves make it possible to answer such questions because they provide a simple, quantitative relationship between price and the cumulative production or use of a technology. There is overwhelming empirical support for such a price-experience relationship forms all fields of industrial activity, including the production of equipment that transfers or uses energy.

As explained in reference 3, cost reduction goes hand-in-hand with cumulative production experience and follows logarithmic relations such that for each doubling of the cumulative production volume, there is a corresponding percentage drop in cost. An 82% learning curve is the curve to use for wave technology based on experience in the wind, photovoltaic and offshore oil and gas platform industry.

How a learning curve is used to show the deployment investment necessary to make a technology, such as wave energy, competitive with an existing technology, such as wind energy is illustrated in Figure 24. It does not, however, forecast when the technologies will break-even. The time of break-even depends on the deployment rates, which the decision-maker can influence through policy.

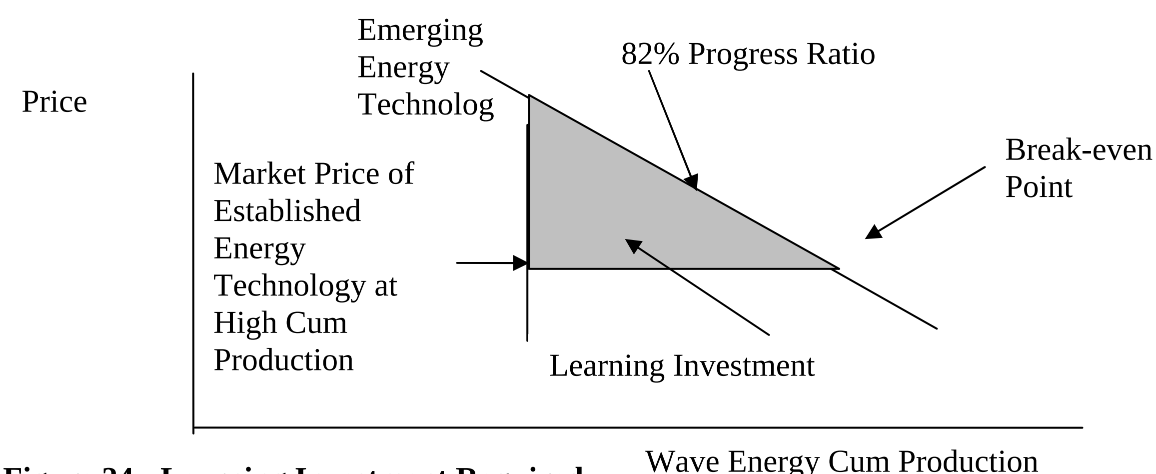

Figure 24: Learning Investment Required

12. Comparison with Commercial Scale Wind Power Plant

The costs (in 2004$) of a pilot offshore wave energy power are described in Section 7 using the production experience gained by OPD from the build of the first prototype machine. The costs (in 2004$) of a commercial scale offshore wave energy power plant are described in Section 8 and are an extension of the costs of the pilot plant with cost reductions estimated for each major component, i.e., on an individual basis and not using an overall learning curve effect.

In this section, we apply learning cost reductions discussed in the previous section to wave power systems using the cost of the 308 MW commercial plant as the entry point to the learning curve process. The purpose is to enable the comparison of the cost of an offshore commercial scale wave farm versus the cost of an equivalent wind farm assuming the same level of production experience for both technologies.

For wind power plants and as reported by the National Wind Coordinating Council (NWCC), the installed capital cost has decreased from more than $2,500/kW in the early eighties to the 1997 range of $900/kW to $1,200/kW in 1997$[3]. The actual cost for a given installation depends on the size of the installation, the difficulty of construction, and the sophistication of the equipment and supporting infrastructure. "Total installed cumulative production volume topped 39,000 MW in 2003 and was about 10,000 MW in 1997"[4]. Based on the above numbers, the wind industry shows a progress ratio of 82%.

It turns out that the comparison of installed cost per unit of maximum or rated power as a function of cumulative installed capacity is not a meaningful comparison because of the effect of overrated or derated energy conversion devices. The 615 device Pelamis 1st commercial plant system has a rating of 308 MW, however, it could be overrated or derated by the manufacturer without much of a change in the annual energy production. Therefore, the wave energy learning curve can be moved up or down in this chart at will and therefore has no useful meaning for the economic competitiveness to other renewable technologies. This is illustrated in Figure 25 which shows the learning curves for a 500kW and 750kW Pelamis device in comparison to wind.

[3] "Wind Energy Costs" NWCC Wind Energy Series, Jan 1997, No 11
[4] "Wind Energy Industry Grows at Steady Pace, Adds Over 8,000 MW in 2003" American Wind Energy Association

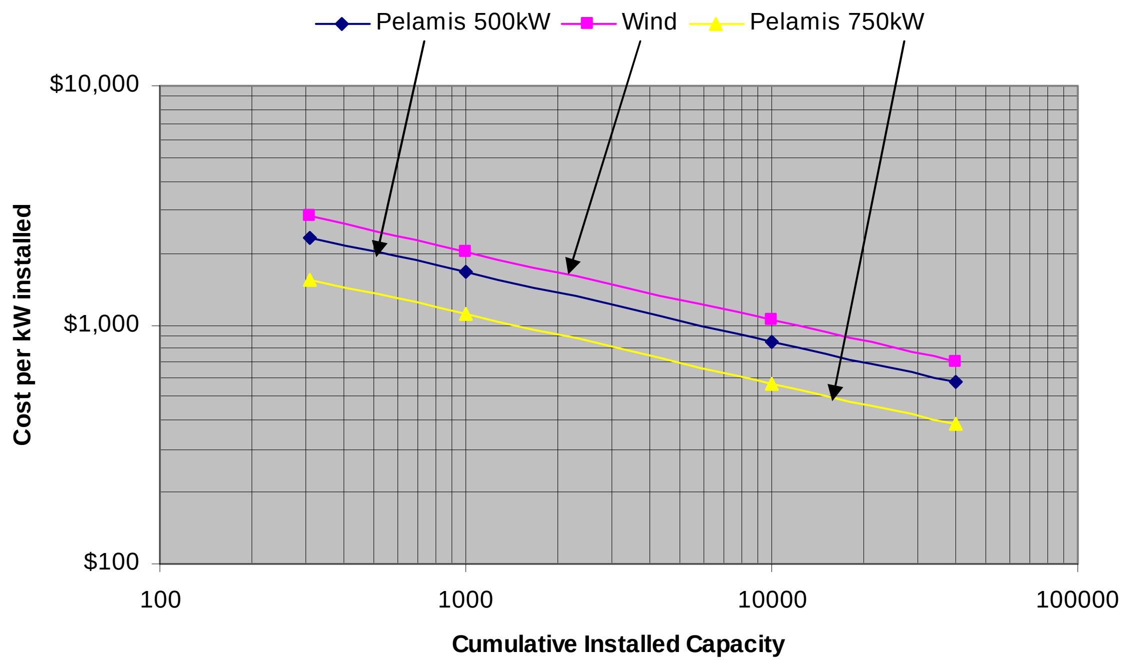

Figure 25: Installed Cost per kW installed as a Function of Installed Capacity

In order to make a meaningful comparison between wind and wave, a levelized comparison using COE numbers is required. In order to predict the cost of electricity for wave, a forecast of O&M cost is required. The following facts were considered in coming up with a conclusion:

- Offshore systems are more difficult to access then onshore systems and it is likely that it will always be more expensive to operate them then onshore systems
- Reliability will be similar to modern wind turbines Today (assuming the same cumulative production volume)
- Improvement in O&M costs can be made by paying greater attention to operational aspects in the design of the device

Based on numerous discussions, it was found a reasonable assumption for O&M cost for mature wave power technology to be 50% higher then shore based wind at a cumulative installed capacity of 40,000 MW. Using the O&M cost quoted by WCC of 1.29 cents/kWh, wave would have 1.9 cents/kWh at the equivalent cumulative installed capacity. Based on this assumption, COE costing curves are presented as a function of installed capacity and compared to wind. Optimistic and pessimistic scenarios are presented based on the uncertainty in opening Total Plant Investment and O&M costs of the commercial plant outlined in earlier sections of this report.

The NWCC also provides data on O&M costs (in 1997$) as follows:

Management, Insurance, Land use and Property Taxes	0.39 cents/kWh
Unscheduled Maintenance	0.68 cents/kWh
Preventative Maintenance	0.18 cents/kWh
Major Overhaul	0.04 cents/kWh
Total	**1.29 cents/kWh**

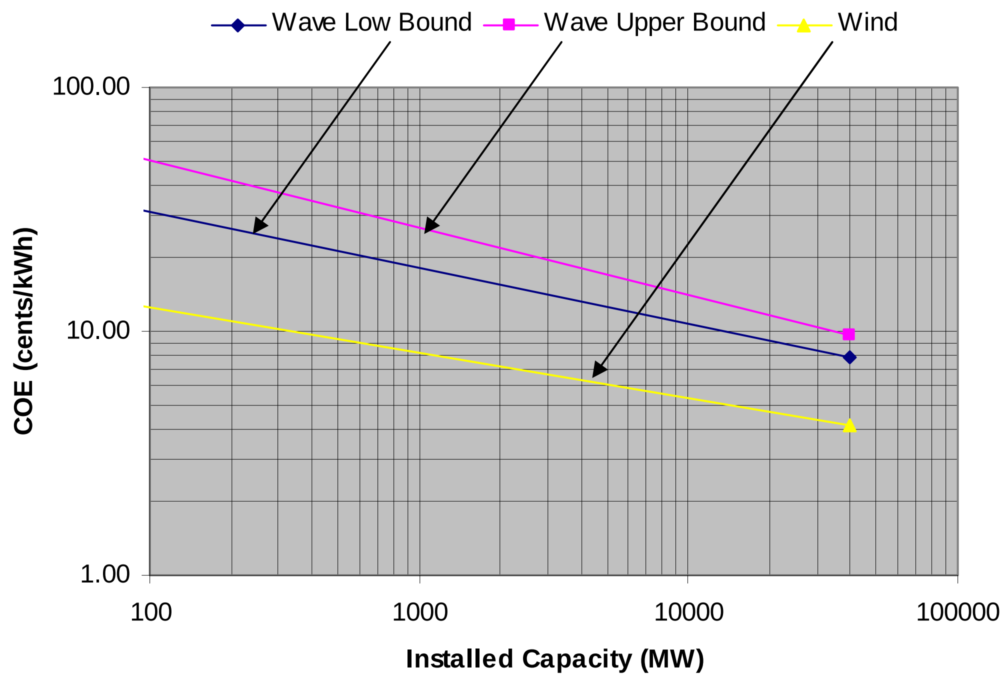

Figure 26: Levelized COE comparison to wind

Figure 26 shows that even under optimistic assumptions, wave energy will not become a viable option in the state of Maine until all the good wind regime shore-based wind sites are used. Wind is at present the most economic source of renewable energy. The situation with offshore wind is very unsettled at this time.

13. Conclusions

Pilot Offshore Wave Power Plant

Within state waters (< 3 nm), Cumberland County is not particularly a good area for locating an offshore wave power plant because of a poor wave regime. Although not studied, there is a possibility of going far offshore (100 nm or so) and seeking a better wave climate

The county has a growing coastal population and a robust grid interconnection to the coast. The Portland Harbor area contains the infrastructure needed to fabricate, assemble and deploy large wave conversion devices as well as operate and maintain them over their life. The Ocean Beach substation, with ists planned growth, represents a unique opportunity for evolving a pilot offshore wave energy technology plant into a commercial plant in Maine.

Commercial Scale Offshore Wave Power Plants

The Cumberland County Maine commercial scale power plant design, performance and cost results show that an offshore wave power plant will not provide favorable economics compared to wind technology in terms for Maine in terms of both COE for a UG and IRR for a NUG.

As a new and emerging technology, offshore wave 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. Private energy investors most probably will not select offshore wave technology when developing new generation because the cost, uncertainties and risk are too high compared to commercially available wind power technology. Even once wave technology reaches commercialization and uncertainties and risk are lowered, the economics in Maine is such that investor opportunities will be much greater in states with better wave regimes (Hawaii, Alaska, Washington, Oregon, California and Massachusetts – this project did not assess the wave energy climate south of Massachusetts on the Eastern seaboard).

Technology Issues

Offshore wave energy electricity generation is a new and emerging technology application. The first time electricity was provided to the electrical grid from an offshore wave power plant occurred in early August, 2004 by the full scale preproduction OPD Pelamis prototype in the UK. Many important questions about the application of offshore wave energy to electricity generation remain to be answered. Some of the key issues which remain to be addressed are:

- There is not a single wave power technology. Rather we are talking about a wide range of wave power technologies and power conversion machines which are currently under development. It is unclear at present what type of technology will yield optimal economics.

- It is also unclear at present at which size these technologies will yield optimal economics. Wave Power devices are typically tuned to prevailing wave conditions. As such optimization is largely driven by the wave climate at the deployment site. Very few existing designs have been optimized for the US wave climate. Wind turbines for example have grown in size from less then 100kW per unit to over 3MW in order to drive down cost.

- Given a certain device device type and rating, what capacity factor is optimal for a given site? Ocean waves have a vast range of power levels and optimal power ratings can be only determined using sophisticated techno-economic optimization procedures.

- Will the low intermittency (relative to solar and wind) and the better predictability of wave energy (relative to solar and wind) earn capacity payments for its ability to be dispatched for electricity generation?

- Will the installed cost of wave energy conversion devices realize their potential of being much less expensive per COE than solar or wind (because a wave machine is converting a much more concentrated form of energy than a solar or wind machine and is therefore smaller in size)?

- Will the O&M cost of wave 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)?

14. Recommendations

Pilot Offshore Wave Power Plant

The E2I EPRI Global Project Team recommends that Maine State Electricity Stakeholders join with Massachusetts State Electricity Stakeholders in the promotion and sponsorship of a project that will investigate local Gulf of Maine wave energy 'hotspots' locations.

Commercial Scale Offshore Wave Power Plants

None at this time.

Technology Issues

In order to stimulate the growth of ocean energy technology in the United States and to address and answer the techno-economic challenges listed in Section 13, we recommend the following take place:

- Federal recognition of ocean energy as a renewable resource, and public recognition by Congress that expansion of an ocean energy industry in the U.S. is a vital national priority.
- Creation of an ocean energy program within the Department of Energy's Energy Efficiency and Renewable Energy division.
- DOE works with the government of Canada on an integrated bi-lateral ocean energy strategy.
- The process for licensing, leasing, and permitting renewable energy facilities in U.S. waters must be streamlined
- Provision of production tax credits, renewable energy credits, and other incentives to spur private investment in Ocean Energy technologies and projects.
- Provision of adequate federal funding for ocean energy R&D and demonstration projects.
- Ensuring that the public receives a fair return from the use of ocean energy resources and that development rights are allocated through an open, transparent process that takes into account state, local, and public concerns
- Ensuring that the public receives a fair return from the use of ocean energy resources and that development rights are allocated through an open, transparent process that takes into account state, local, and public concerns.

15. References

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Appendix A – Monthly Wave Energy Resource Scatter Diagrams

Table A-1: Scatter diagram Maine January

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.75	7.25	**7**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
5.75	6.25	**6**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
5.25	5.75	**5.5**	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	*1*
4.75	5.25	**5**	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	*2*
4.25	4.75	**4.5**	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	*3*
3.75	4.25	**4**	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	*5*
3.25	3.75	**3.5**	0	0	0	0	0	2	1	2	1	1	0	0	0	0	0	0	0	*8*
2.75	3.25	**3**	0	0	0	0	1	3	2	2	2	3	0	0	0	0	0	0	0	*14*
2.25	2.75	**2.5**	0	0	0	1	5	5	3	3	4	4	0	1	0	0	0	0	0	*26*
1.75	2.25	**2**	0	0	1	9	12	12	5	5	6	6	0	1	0	0	0	0	0	*57*
1.25	1.75	**1.5**	0	5	14	25	14	14	9	14	18	12	0	1	0	0	0	0	0	*125*
0.75	1.25	**1**	3	43	36	27	12	12	16	26	34	14	0	0	0	0	0	0	0	*222*
0.25	0.75	**0.5**	42	45	17	11	6	24	30	36	31	11	0	4	0	0	0	0	0	*257*
0	0.25	**0.125**	5	2	1	1	1	4	3	4	2	1	0	0	0	0	0	0	0	*23*
		744	*50*	*95*	*68*	*74*	*51*	*76*	*72*	*95*	*102*	*53*	*0*	*9*	*0*	*0*	*0*	*0*	*0*	***744***

Table A-2: Scatter Diagram Maine February

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	0.0572	0	0	0	0	0	0	0	0	*0*
6.75	7.25	**7**	0	0	0	0	0	0	0	0	0.0572	0.0572	0	0	0	0	0	0	0	*0*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	0	0.1145	0.1145	0	0	0	0	0	0	0	*0*
5.75	6.25	**6**	0	0	0	0	0	0	0.0572	0.3435	0.458	0.3435	0	0	0	0	0	0	0	*1*
5.25	5.75	**5.5**	0	0	0	0	0	0	0.0572	0.1717	0.5725	0.1145	0	0	0	0	0	0	0	*1*
4.75	5.25	**5**	0	0	0	0	0	0	0.0572	0.4007	0.5152	0.687	0	0	0	0	0	0	0	*2*
4.25	4.75	**4.5**	0	0	0	0	0	0.3435	0.5152	1.0877	1.145	0.8587	0	0.0572	0	0	0	0	0	*4*
3.75	4.25	**4**	0	0	0	0	0	0.6297	0.9732	1.0305	1.7175	1.603	0	0.0572	0	0	0	0	0	*6*
3.25	3.75	**3.5**	0	0	0	0	0.0572	1.145	0.5152	0.9732	1.603	1.603	0	0.229	0	0	0	0	0	*6*
2.75	3.25	**3**	0	0	0	0.0572	0.8015	2.3472	2.1755	1.603	2.1755	1.603	0	0.3435	0	0	0	0	0	*11*
2.25	2.75	**2.5**	0	0	0.1145	0.916	3.9502	4.0074	4.8089	2.6335	4.6944	2.9769	0	0.7442	0	0	0	0	0	*25*
1.75	2.25	**2**	0	0.1145	0.6297	7.1561	11.393	9.3316	6.4119	6.0684	8.8163	6.3546	0	1.0877	0	0	0	0	0	*57*
1.25	1.75	**1.5**	0	1.4312	7.4996	21.697	19.007	12.538	8.0149	15.858	19.407	9.1026	0	1.4312	0	0	0	0	0	*116*
0.75	1.25	**1**	5.5532	32.804	20.61	27.938	14.083	12.938	13.339	24.388	29.712	11.106	0	1.0877	0	0	0	0	0	*194*
0.25	0.75	**0.5**	36.468	30.056	11.622	9.7323	8.6446	22.9	26.163	37.498	34.521	12.652	0	3.0914	0	0	0.1145	0	0	*233*
0	0.25	**0.125**	4.9807	1.8892	0.229	0.687	0.9732	4.0074	2.5762	3.4922	1.603	0.5152	0	0.3435	0	0	0.0572	0	0	*21*
		678	*47*	*66*	*41*	*68*	*59*	*70*	*66*	*96*	*107*	*50*	*0*	*8*	*0*	*0*	*0*	*0*	*0*	***678***

Table A-3: Scatter Diagram Maine March

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.75	7.25	**7**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
5.75	6.25	**6**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
5.25	5.75	**5.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
4.75	5.25	**5**	0	0	0	0	0	0	0	0.0534	0	0	0	0	0	0	0	0	0	*0*
4.25	4.75	**4.5**	0	0	0	0	0	0	0.0534	0.1601	0	0	0	0	0	0	0	0	0	*0*
3.75	4.25	**4**	0	0	0	0	0	0.1067	0	0.0534	0	0	0	0	0	0	0	0	0	*0*
3.25	3.75	**3.5**	0	0	0	0	0	0.2135	0.2135	0.1601	0.1601	0.3202	0	0.0534	0	0	0	0	0	*1*
2.75	3.25	**3**	0	0	0	0	0.1601	0.6938	0.4269	1.014	0.8005	0.5337	0	0.0534	0	0	0	0	0	*4*
2.25	2.75	**2.5**	0	0	0	0.4803	0.8005	1.5477	1.1741	1.4943	1.5477	1.5477	0	0	0	0	0	0	0	*9*
1.75	2.25	**2**	0	0	0.2668	3.8958	5.1767	7.8451	2.5083	3.8958	4.0026	1.6544	0	0.0534	0	0	0	0	0	*29*
1.25	1.75	**1.5**	0	1.2275	7.258	15.423	10.567	16.864	12.275	12.328	7.4181	1.8679	0	0	0	0	0	0	0	*85*
0.75	1.25	**1**	1.7611	19.906	26.577	29.032	28.658	76.476	44.562	30.313	12.755	3.7357	0	0.0534	0	0	0.1067	0	0	*274*
0.25	0.75	**0.5**	13.769	28.392	20.226	28.232	42.587	92.059	52.14	30.847	16.971	5.8705	0	2.4549	0	0	1.3876	0	0	*335*
0	0.25	**0.125**	0.2135	0.1601	0.0534	0.1067	0.5337	2.2948	1.7611	0.8005	0.4803	0.1601	0	0.2135	0	0	0	0	0	*7*
		744	*16*	*50*	*54*	*77*	*88*	*198*	*115*	*81*	*44*	*16*	*0*	*3*	*0*	*0*	*1*	*0*	*0*	***744***

Table A-4: Scatter Diagram Maine April

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
4.25	4.75	4.5	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
3.75	4.25	4	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	3
3.25	3.75	3.5	0	0	0	0	0	1	1	2	1	1	0	0	0	0	0	0	0	6
2.75	3.25	3	0	0	0	0	1	2	3	2	2	2	0	0	0	0	0	0	0	12
2.25	2.75	2.5	0	0	0	0	3	4	3	4	4	2	0	0	0	0	0	0	0	20
1.75	2.25	2	0	0	0	5	7	8	6	9	9	3	0	0	0	0	0	0	0	47
1.25	1.75	1.5	0	2	8	17	13	18	13	16	10	3	0	0	0	0	0	0	0	102
0.75	1.25	1	4	19	21	30	24	36	33	37	23	8	0	1	0	0	0	0	0	237
0.25	0.75	0.5	24	25	14	14	19	58	49	41	20	8	0	4	0	0	0	0	0	276
0	0.25	0.125	1	0	0	1	1	4	3	2	1	1	0	1	0	0	0	0	0	15
		720	29	47	43	68	68	131	111	117	71	29	0	6	0	0	0	0	0	720

Table A-5: Scatter Diagram Maine May

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
5.25	5.75	5.5	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	2
4.75	5.25	5	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	3
4.25	4.75	4.5	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	4
3.75	4.25	4	0	0	0	0	0	0	1	1	1	1	0	1	0	0	0	0	0	5
3.25	3.75	3.5	0	0	0	0	0	2	2	2	1	1	0	0	0	0	0	0	0	9
2.75	3.25	3	0	0	0	0	1	3	3	4	2	2	0	1	0	0	0	0	0	16
2.25	2.75	2.5	0	0	0	1	3	7	4	4	4	3	0	0	0	0	0	0	0	26
1.75	2.25	2	0	0	1	7	10	11	6	8	13	7	0	1	0	0	0	0	0	63
1.25	1.75	1.5	0	3	9	23	17	14	9	16	23	14	0	1	0	0	0	0	0	129
0.75	1.25	1	3	26	23	26	16	23	26	37	37	20	0	1	0	0	0	0	0	239
0.25	0.75	0.5	27	26	8	8	10	25	30	41	31	16	0	4	0	0	0	0	0	229
0	0.25	0.125	2	0	1	1	1	2	3	3	2	2	0	1	0	0	0	0	0	18
		744	33	56	41	66	60	87	86	118	117	68	0	11	0	0	1	0	0	744

Table A-6: Scatter Diagram Maine June

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.75	3.25	3	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	2
2.25	2.75	2.5	0	0	0	0	0	2	0	1	0	0	0	0	0	0	0	0	0	4
1.75	2.25	2	0	0	0	1	2	2	1	1	1	0	0	0	0	0	0	0	0	8
1.25	1.75	1.5	0	0	4	11	7	10	7	4	2	0	0	0	0	0	0	0	0	45
0.75	1.25	1	1	12	31	32	23	52	32	15	3	0	0	1	0	0	1	0	0	204
0.25	0.75	0.5	11	39	31	39	76	136	54	28	13	8	0	5	0	0	3	0	0	444
0	0.25	0.125	0	0	0	2	3	3	2	1	0	1	0	1	0	0	0	0	0	13
		720	13	52	66	85	113	206	96	51	19	9	0	7	0	0	4	0	0	720

Table A-7: Scatter Diagram Maine July

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.75	3.25	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.25	2.75	2.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
1.75	2.25	2	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	4
1.25	1.75	1.5	0	0	2	6	4	4	2	2	1	0	0	0	0	0	0	0	0	21
0.75	1.25	1	0	10	32	35	22	46	18	10	4	1	0	0	0	0	0	0	0	178
0.25	0.75	0.5	7	39	35	56	111	171	56	24	9	8	0	8	0	0	2	0	0	525
0	0.25	0.125	0	0	0	1	2	5	3	1	0	1	0	2	0	0	0	0	0	16
		744	8	50	69	99	141	227	79	36	13	11	0	10	0	0	2	0	0	744

Table A-8: Scatter Diagram Maine August

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.75	3.25	3	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
2.25	2.75	2.5	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	3
1.75	2.25	2	0	0	0	1	1	1	1	0	1	1	0	1	0	0	1	0	0	7
1.25	1.75	1.5	0	0	2	6	5	5	3	2	4	4	0	3	0	0	1	0	0	34
0.75	1.25	1	1	9	27	24	21	34	16	13	9	8	0	6	0	0	2	0	0	170
0.25	0.75	0.5	11	39	33	42	84	144	58	36	28	23	0	11	0	0	4	0	0	512
0	0.25	0.125	0	0	0	2	4	5	2	1	1	1	0	1	0	0	0	0	0	17
		744	12	49	62	75	116	190	81	53	42	36	0	21	0	0	7	0	0	744

Table A-9: Scatter Diagram Maine September

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
2.75	3.25	3	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	3
2.25	2.75	2.5	0	0	0	0	1	1	1	0	1	0	0	0	0	0	2	0	0	7
1.75	2.25	2	0	0	0	2	3	3	1	1	2	1	0	1	0	0	2	0	0	16
1.25	1.75	1.5	0	0	4	12	9	8	5	6	5	5	0	5	0	0	3	0	0	62
0.75	1.25	1	1	18	37	30	15	25	20	22	27	20	0	10	0	0	3	0	0	229
0.25	0.75	0.5	24	38	24	24	29	79	52	42	28	22	0	12	0	0	3	0	0	376
0	0.25	0.125	1	1	1	2	4	5	2	2	3	3	0	1	0	0	1	0	0	26
		720	27	57	66	71	61	122	81	73	66	52	0	30	0	0	14	0	1	720

Table A-10: Scatter Diagram Maine October

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
4.75	5.25	5	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
3.75	4.25	4	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	2
3.25	3.75	3.5	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	2
2.75	3.25	3	0	0	0	0	0	2	1	1	1	1	0	0	0	0	0	0	0	7
2.25	2.75	2.5	0	0	0	1	3	4	2	2	3	2	0	1	0	0	0	0	0	18
1.75	2.25	2	0	0	0	5	7	7	3	5	5	3	0	2	0	0	0	0	0	38
1.25	1.75	1.5	0	2	8	20	12	12	10	11	11	6	0	2	0	0	0	0	0	93
0.75	1.25	1	4	30	35	33	16	26	29	32	20	11	0	2	0	0	0	0	0	237
0.25	0.75	0.5	36	44	24	18	14	44	40	39	36	16	0	9	0	0	1	0	0	322
0	0.25	0.125	3	1	0	1	1	4	2	3	2	2	0	2	0	0	0	0	0	21
		744	43	77	68	78	54	100	89	95	79	40	0	17	0	0	3	0	1	744

Table A-11: Scatter Diagram Maine November

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
4.25	4.75	4.5	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2
3.75	4.25	4	0	0	0	0	0	1	1	0	1	0	0	0	0	0	0	0	0	3
3.25	3.75	3.5	0	0	0	0	0	2	1	1	1	0	0	0	0	0	0	0	0	5
2.75	3.25	3	0	0	0	0	1	2	1	1	1	0	0	0	0	0	0	0	0	7
2.25	2.75	2.5	0	0	0	0	4	4	4	3	3	2	0	0	0	0	0	0	0	20
1.75	2.25	2	0	0	0	7	8	6	5	4	8	4	0	1	0	0	0	0	0	42
1.25	1.75	1.5	0	2	11	29	11	10	8	11	15	8	0	1	0	0	0	0	0	106
0.75	1.25	1	3	32	33	43	15	17	19	25	26	13	0	2	0	0	1	0	0	228
0.25	0.75	0.5	40	43	18	16	10	35	41	33	30	14	0	4	0	0	1	0	0	284
0	0.25	0.125	2	1	1	1	2	4	4	3	1	1	0	1	0	0	0	0	0	21
		720	45	78	63	95	52	81	85	82	88	43	0	8	0	0	1	0	0	720

Table A-12: Scatter Diagram Maine December

		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
4.75	5.25	5	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	2
4.25	4.75	4.5	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	3
3.75	4.25	4	0	0	0	0	0	0	1	2	1	1	0	0	0	0	0	0	0	5
3.25	3.75	3.5	0	0	0	0	0	1	2	2	1	1	0	1	0	0	0	0	0	8
2.75	3.25	3	0	0	0	0	1	3	2	2	3	2	0	1	0	0	0	0	0	14
2.25	2.75	2.5	0	0	0	1	4	5	3	4	5	4	0	1	0	0	0	0	0	28
1.75	2.25	2	0	0	1	8	8	8	3	5	7	6	0	1	0	0	0	0	0	48
1.25	1.75	1.5	0	4	12	23	11	9	5	8	12	8	0	1	0	0	0	0	0	92
0.75	1.25	1	4	44	36	27	12	11	15	22	22	14	0	4	0	0	0	0	0	209
0.25	0.75	0.5	54	53	18	11	8	24	31	41	33	23	0	7	0	0	1	0	0	304
0	0.25	0.125	3	2	0	1	2	6	5	4	2	3	0	1	0	0	0	0	0	29
		744	60	102	67	71	45	67	67	91	88	64	0	18	0	0	1	0	0	744

Appendix B - Commercial Plant Economics Worksheet – Regulated Utility

INSTRUCTIONS

Indicates Input Cell (either input or use default values)

Indicates a Calculated Cell (do not input any values)

Sheet 1. TPC/TPI (Total Plant Cost/Total Plant Investment)

a) Enter Component Unit Cost and No. of Units per System
b) Worksheet sums component costs to get TPC
c) Adds the value of the construction loan payments to get TPI

Sheet 2. AO&M (Annual operation and Maintenance Cost)

a) Enter Labor Hrs and Cost by O&M Type)
b) Enter Parts and Supplies Cost by O&M Type)
c) Worksheet Calculates 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 + Levelized Overhaul and Replacement Cost Divided by the Annual Electric Energy Consumption

TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	
Procurement				
Onshore Trans & Grid I/C	1	$4,160,000	$4,160,000	
Subsea Cables	1	$9,626,000	$9,626,000	
Mooring	206	$345,267	$71,125,002	
Power Conversion Modules (set of 3) at $	206	$1,862,791	$383,734,946	
Concrete Structure Sections	206	$730,690	$150,522,140	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$8,618,000	$8,618,000	
Construction Management	1	$31,560,000	$31,560,000	
TOTAL			$671,346,088	

TOTAL PLANT INVESTMENT (TPI) - 2004 $

End of Year	Total Cash Expended TPC (2004$)	Before Tax Construction Loan Cost at Debt Financing Rate	2004 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT 2004$
2006	$335,673,044	$25,175,478	$22,731,809	$358,404,853
2007	$335,673,044	$50,350,957	$41,050,671	$376,723,715
Total	$671,346,088	$75,526,435	$63,782,479	$735,128,567

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount	
LABOR	$6,517,000	$6,517,000	
PARTS AND SUPPLIES (2%)	$13,428,000	$13,428,000	
INSURANCE (2%)	$13,428,000	$13,428,000	
Total		$33,373,000	

OVERHAUL AND REPLACEMENT COST (OAR) - 2004$

O&R Costs	Year of Cost	Cost in 2004$	
10 Year Retrofit			
Operation	10	$27,384,000	
Parts	10	$46,865,000	
Total		$74,249,000	

FINANCIAL ASSUMPTIONS

(default assumptions in pink background - without line numbers are calculated values)

1	Rated Plant Capacity ©	103	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	33.23	%
3	Year Constant Dollars	2004	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	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 years
18	State Investment Tax Credit	0	% of TPI up to $2.5M
19	State Investment Tax Credit Limit	$0	Credit - 1st year only for ≥ $10M plant
20	State Production Tax Credit	0	$/kWh for 1st 10 years

NET PRESENT VALUE (NPV) - 2004 $

TPI = $735,128,567

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
2007	**735,128,567**					**735,128,567**
2008	735,128,567	36,756,428	36,756,428	0.2000	44,994,830	653,377,309
2009	735,128,567	36,756,428	73,512,857	0.3200	80,990,695	535,630,185
2010	735,128,567	36,756,428	110,269,285	0.1920	42,595,106	456,278,651
2011	735,128,567	36,756,428	147,025,713	0.1152	19,557,753	399,964,470
2012	735,128,567	36,756,428	183,782,142	0.1152	19,557,753	343,650,288
2013	735,128,567	36,756,428	220,538,570	0.0576	2,279,738	304,614,122
2014	735,128,567	36,756,428	257,294,999	0.0000	-14,998,277	282,855,970
2015	735,128,567	36,756,428	294,051,427	0.0000	-14,998,277	261,097,819
2016	735,128,567	36,756,428	330,807,855	0.0000	-14,998,277	239,339,667
2017	735,128,567	36,756,428	367,564,284	0.0000	-14,998,277	217,581,516
2018	735,128,567	36,756,428	404,320,712	0.0000	-14,998,277	195,823,364
2019	735,128,567	36,756,428	441,077,140	0.0000	-14,998,277	174,065,212
2020	735,128,567	36,756,428	477,833,569	0.0000	-14,998,277	152,307,061
2021	735,128,567	36,756,428	514,589,997	0.0000	-14,998,277	130,548,909
2022	735,128,567	36,756,428	551,346,426	0.0000	-14,998,277	108,790,758
2023	735,128,567	36,756,428	588,102,854	0.0000	-14,998,277	87,032,606
2024	735,128,567	36,756,428	624,859,282	0.0000	-14,998,277	65,274,455
2025	735,128,567	36,756,428	661,615,711	0.0000	-14,998,277	43,516,303
2026	735,128,567	36,756,428	698,372,139	0.0000	-14,998,277	21,758,152
2027	735,128,567	36,756,428	735,128,567	0.0000	-14,998,277	0

CAPITAL REVENUE REQUIREMENTS

TPI = $735,128,567

End of Year	Net Book	Returns to Equity Common	Returns to Equity Pref	Interest on Debt	Book Dep	Income Tax on Equity Return	ITC and PTC	Capital Revenue Req'ts
	A	B	C	D	E	F	H	I
2008	653,377,309	44,168,306	8,918,600	17,151,154	36,756,428	55,786,875	78,912,857	83,868,507
2009	535,630,185	36,208,601	7,311,352	14,060,292	36,756,428	76,135,374	5,400,000	165,072,047
2010	456,278,651	30,844,437	6,228,204	11,977,315	36,756,428	46,660,206	5,400,000	127,066,589
2011	399,964,470	27,037,598	5,459,515	10,499,067	36,756,428	28,645,143	5,400,000	102,997,752
2012	343,650,288	23,230,759	4,690,826	9,020,820	36,756,428	26,510,134	5,400,000	94,808,968
2013	304,614,122	20,591,915	4,157,983	7,996,121	36,756,428	13,120,137	5,400,000	77,222,583
2014	282,855,970	19,121,064	3,860,984	7,424,969	36,756,428	385,192	5,400,000	62,148,637
2015	261,097,819	17,650,213	3,563,985	6,853,818	36,756,428	-439,713	5,400,000	58,984,730
2016	239,339,667	16,179,361	3,266,986	6,282,666	36,756,428	-1,264,619	5,400,000	55,820,824
2017	217,581,516	14,708,510	2,969,988	5,711,515	36,756,428	-2,089,524	5,400,000	52,656,917
2018	195,823,364	13,237,659	2,672,989	5,140,363	36,756,428	-2,914,429		54,893,011
2019	174,065,212	11,766,808	2,375,990	4,569,212	36,756,428	-3,739,334		51,729,104
2020	152,307,061	10,295,957	2,078,991	3,998,060	36,756,428	-4,564,240		48,565,198
2021	130,548,909	8,825,106	1,781,993	3,426,909	36,756,428	-5,389,145		45,401,291
2022	108,790,758	7,354,255	1,484,994	2,855,757	36,756,428	-6,214,050		42,237,385
2023	87,032,606	5,883,404	1,187,995	2,284,606	36,756,428	-7,038,955		39,073,478
2024	65,274,455	4,412,553	890,996	1,713,454	36,756,428	-7,863,861		35,909,572
2025	43,516,303	2,941,702	593,998	1,142,303	36,756,428	-8,688,766		32,745,665
2026	21,758,152	1,470,851	296,999	571,151	36,756,428	-9,513,671		29,581,759
2027	0	0	0	0	36,756,428	-10,338,576		26,417,852
Sum of Annual Capital Revenue Requirements								1,287,201,871

FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED

TPI = $735,128,567

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
2008	83,868,507	0.9118	76,467,325	76,751,565	0.9391	72,077,788
2009	165,072,047	0.8313	137,223,189	146,664,376	0.8819	129,346,017
2010	127,066,589	0.7579	96,307,992	109,608,756	0.8282	90,779,520
2011	102,997,752	0.6910	71,176,346	86,258,996	0.7778	67,090,533
2012	94,808,968	0.6301	59,735,754	77,088,367	0.7304	56,306,677
2013	77,222,583	0.5745	44,361,502	60,960,220	0.6859	41,814,970
2014	62,148,637	0.5238	32,551,463	47,631,755	0.6442	30,682,875
2015	58,984,730	0.4775	28,167,966	43,890,179	0.6049	26,551,009
2016	55,820,824	0.4354	24,304,636	40,326,151	0.5681	22,909,450
2017	52,656,917	0.3970	20,903,802	36,932,502	0.5335	19,703,838
2018	54,893,011	0.3619	19,868,446	37,379,469	0.5010	18,727,916
2019	51,729,104	0.3300	17,070,993	34,199,032	0.4705	16,091,048
2020	48,565,198	0.3009	14,612,549	31,172,152	0.4419	13,773,729
2021	45,401,291	0.2743	12,455,065	28,292,584	0.4150	11,740,093
2022	42,237,385	0.2501	10,564,569	25,554,312	0.3897	9,958,120
2023	39,073,478	0.2281	8,910,741	22,951,550	0.3660	8,399,228
2024	35,909,572	0.2079	7,466,533	20,478,727	0.3437	7,037,923
2025	32,745,665	0.1896	6,207,826	18,130,481	0.3227	5,851,472
2026	29,581,759	0.1728	5,113,129	15,901,653	0.3031	4,819,614
2027	26,417,852	0.1576	4,163,295	13,787,279	0.2846	3,924,305
	1,287,201,871		697,633,121	973,960,108		657,586,126

	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	697,633,121		657,586,126
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.68%		6.48%
4. Capital recovery factor value = $i(1+i)^n/(1+i)^n-1$ where book life = n and discount rate = i	0.114895692		0.090643616
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	80,155,040		59,605,984
6. Booked Cost	735,128,567		735,128,567
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.1090**		**0.0811**

LEVELIZED COST OF ELECTRICITY CALCULATION - UTILITY GENERATOR

COE = ((TPI * FCR) + AO&M + LO&R) / AEP
In other words…
The Cost of Electricity =

The Sum of the Levelized Plant Investment + Annual O&M Cost + Levelized Overhaul and Replacement Cost
Divided by the Annual Electric Energy Consumption

NOMINAL RATES

	Value	Units	From
TPI	$735,128,567	$	From TPI
FCR	10.90%	%	From FCR
AO&M	$33,373,000	$	From AO&M
LO&R = O&R/Life	$3,712,450	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	26.72	cents/kWh	
COE - AO&M	11.12	cents/kWh	
COE - LO&R	1.24	cents/kWh	
COE	$0.3908	$/kWh	Calculated
COE	**39.08**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$735,128,567	$	From TPI
FCR	8.11%	%	From FCR
AO&M	$33,373,000	$	From AO&M
LO&R = O&R/Life	$3,712,450	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	19.87	cents/kWh	
COE - AO&M	11.12	cents/kWh	
COE - LO&R	1.24	cents/kWh	
COE	$0.3223	$/kWh	Calculated
COE	**32.23**	cents/kWh	Calculated

Appendix C - Com'l Plant Economics Worksheet – NUG – With REC

INSTRUCTIONS

Fill in first four worksheets (or use default values) - the last two worksheets are automatically calculated. Refer to E2I EPRI Economic Methodology Report 004 Rev 2

Indicates Input Cell (either input or use default values)

Indicates a Calculated Cell (do not input any values)

Sheet 1. Total Plant Cost/Total Plant Investment (TPC/TPI) - 2004$

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) - 2004$

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) - 2004$

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 Energy payments(2002-2008) = AEP X 2002 wholesale price X 92% (to adjust price from 2002 to 2008 (an 8% decline) X Inflation from 2002 to 2008
2009-2011 Energy payments = 2008 Energy Payment X Inflation
2012-2027 Energy payments = 2011 Energy Price X 0.3% Price escalation X Inflation
2 Calculates State Investment and Producint 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) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	Notes and Assumptions
Procurement				
Onshore Trans & Grid I/C	1	$4,160,000	$4,160,000	
Subsea Cables	1	$9,626,000	$9,626,000	
Mooring	206	$345,267	$71,125,002	
Power Conversion Modules (set of 3)	206	$1,862,791	$383,734,946	
Concrete Structure Sections	206	$730,690	$150,522,140	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$8,618,000	$8,618,000	
Construction Management	1	$31,560,000	$31,560,000	
TOTAL			$671,346,088	

TOTAL PLANT INVESTMENT (TPI) - 2004 $

End of Year	Total Cash Expended TPC ($2004)	Before Tax Construction Loan Cost at Debt Financing Rate	2004 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT (TPC + Loan Value) ($2004)
2006	$335,673,044	$26,853,844	$24,258,215	$359,931,259
2007	$335,673,044	$53,707,687	$43,826,946	$379,499,990
Total	$671,346,088	$80,561,531	$68,085,160	$739,431,248

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) -

Costs	Yrly Cost	Amount
LABOR	$6,517,000	$6,517,000
PARTS AND SUPPLIES	$13,428,000	$13,428,000
INSURANCE	$13,428,000	$13,428,000
Total		$33,373,000

OVERHAUL AND REPLACEMENT COST (LOAR) -

O&R Costs	Year of Cost	Cost in 2004$	Cost Inflated to 2018$
10 Year Retrofit			
Operation	10	$27,384,000	$41,420,757
Parts	10	$46,865,000	$70,887,517
Total		$74,249,000	$112,308,274

FINANCIAL ASSUMPTIONS

(default assumptions in pink background - without line numbers are calculated values)

1	Rated Plant Capacity ©	90	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	38.03	%
3	Year Constant Dollars	2004	Year
4	Federal Tax Rate	35	%
5	State	Maine	
6	State Tax Rate	6.6	%
	Composite Tax Rate (t)	0.3929	%
	t/(1-t)	0.6472	
7	Book Life	20	Years
8	Construction Financing Rate	8	
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	8.50	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 yrs
18	State Investment Tax Credit	0	% 1st year only % of TPI up to $2.5M
19	State Production Tax Credit	0.025	REC
20	Wholesale electricity price - 2002$	0.065	$/kWh
21	Decline in wholesale elec. price from 2002 to 2008	8	%
22	Yearly Unscheduled O&M	5	% of Sch O&M cost
23	MACRS Year 1	0.2000	
24	MACRS Year 2	0.3200	
25	MACRS Year 3	0.1920	
26	MACRS Year 4	0.1152	
27	MACRS Year 5	0.1152	
28	MACRS Year 6	0.0576	

INCOME STATEMENT ($) **CURRENT DOLLARS**

Description/Year	2008	2009	2010	2011	2012	2013	2014	2015
REVENUES								
Energy Payments	21,421,298	22,063,937	22,725,855	23,407,631	24,182,189	24,982,378	25,809,045	26,663,066
State ITC and PTC	7,500,000	7,725,000	7,956,750	8,195,453	8,441,316	8,694,556	8,955,392	9,224,054
Federal ITC and PTC	79,343,125	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000
TOTAL REVENUES	108,264,423	35,188,937	36,082,605	37,003,083	38,023,505	39,076,934	40,164,437	41,287,120
AVG $/KWH	0.361	0.117	0.120	0.123	0.127	0.130	0.134	0.138
OPERATING COSTS								
Scheduled and Unscheduled O&M	37,561,606	38,688,454	39,849,107	41,044,581	42,275,918	43,544,195	44,850,521	46,196,037
Scheduled O&R	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0
TOTAL	37,561,606	38,688,454	39,849,107	41,044,581	42,275,918	43,544,195	44,850,521	46,196,037
EBITDA	70,702,818	-3,499,517	-3,766,502	-4,041,497	-4,252,412	-4,467,262	-4,686,084	-4,908,917
Tax Depreciation	147,886,250	236,618,000	141,970,800	85,182,480	85,182,480	42,591,240	0	0
Interest Pald	41,408,150	40,503,290	39,526,042	38,470,614	37,330,751	36,099,700	34,770,165	33,334,266
TAXABLE EARNINGS	-118,591,582	-280,620,806	-185,263,344	-127,694,591	-126,765,644	-83,158,202	-39,456,249	-38,243,183
State Tax	-7,827,044	-18,520,973	-12,227,381	-8,427,843	-8,366,532	-5,488,441	-2,604,112	-2,524,050
Federal Tax	-38,767,588	-91,734,942	-60,562,587	-41,743,362	-41,439,689	-27,184,416	-12,898,248	-12,501,696
TOTAL TAX OBLIGATIONS	-46,594,633	-110,255,915	-72,789,968	-50,171,205	-49,806,221	-32,672,857	-15,502,360	-15,025,747

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
27,545,347	28,456,823	29,398,459	30,371,254	31,376,239	32,414,478	33,487,074	34,595,161	35,739,915	36,922,548	36,922,548	38,144,316
9,500,776	9,785,799	10,079,373	10,381,754	10,693,207	11,014,003	11,344,423	11,684,756	12,035,298	12,396,357	12,768,248	13,151,295
5,400,000	5,400,000										
42,446,123	43,642,622	39,477,832	40,753,008	42,069,445	43,428,481	44,831,496	46,279,916	47,775,213	49,318,906	49,690,796	51,295,611
0.141	0.145	0.132	0.136	0.140	0.145	0.149	0.154	0.159	0.164	0.166	0.171
47,581,918	49,009,376	50,479,657	51,994,047	53,553,868	55,160,484	56,815,299	58,519,758	60,275,350	62,083,611	63,946,119	65,864,503
0	0	169,876,342	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
47,581,918	49,009,376	220,355,999	51,994,047	53,553,868	55,160,484	56,815,299	58,519,758	60,275,350	62,083,611	63,946,119	65,864,503
-5,135,795	-5,366,754	-180,878,167	-11,241,039	-11,484,423	-11,732,003	-11,983,802	-12,239,841	-12,500,137	-12,764,705	-14,255,323	-14,568,892
0	0	0	0	0	0	0	0	0	0	0	0
31,783,496	30,108,664	28,299,846	26,346,322	24,236,516	21,957,926	19,497,048	16,839,301	13,968,933	10,868,936	7,520,940	3,905,103
-36,919,291	-35,475,418	-209,178,013	-37,587,360	-35,720,939	-33,689,928	-31,480,850	-29,079,142	-26,469,070	-23,633,641	-21,776,262	-18,473,995
-2,436,673	-2,341,378	-13,805,749	-2,480,766	-2,357,582	-2,223,535	-2,077,736	-1,919,223	-1,746,959	-1,559,820	-1,437,233	-1,219,284
-12,068,916	-11,596,914	-68,380,292	-12,287,308	-11,677,175	-11,013,238	-10,291,090	-9,505,971	-8,652,739	-7,725,837	-7,118,660	-6,039,149
-14,505,590	-13,938,292	-82,186,041	-14,768,074	-14,034,757	-13,236,773	-12,368,826	-11,425,195	-10,399,698	-9,285,658	-8,555,893	-7,258,433

CASH FLOW STATEMENT

Description/Year	2006	2007	2008	2009	2010	2011
EBITDA			70,702,818	-3,499,517	-3,766,502	-4,041,497
Taxes Paid			-46,594,633	-110,255,915	-72,789,968	-50,171,205
CASH FLOW FROM OPS			117,297,450	106,756,398	69,023,466	46,129,708
Debt Service			-52,718,894	-52,718,894	-52,718,894	-52,718,894
NET CASH FLOW AFTER TAX		-221,829,375	64,578,556	54,037,504	16,304,572	-6,589,187
CUM NET CASH FLOW		-221,829,375	-157,250,819	-103,213,314	-86,908,743	-93,497,929

IRR ON NET CASH FLOW AFTER TAX

Description/Year	2012	2013	2014	2015	2016	2017	2018	2019
EBITDA	-4,252,412	-4,467,262	-4,686,084	-4,908,917	-5,135,795	-5,366,754	-180,878,167	-11,241,039
Taxes Paid	-49,806,221	-32,672,857	-15,502,360	-15,025,747	-14,505,590	-13,938,292	-82,186,041	-14,768,074
CASH FLOW FROM OPS	45,553,809	28,205,596	10,816,276	10,116,830	9,369,794	8,571,538	-98,692,126	3,527,035
Debt Service	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894
NET CASH FLOW AFTER TAX	-7,165,085	-24,513,298	-41,902,618	-42,602,064	-43,349,100	-44,147,356	-151,411,020	-49,191,859
CUM NET CASH FLOW	-100,663,014	-125,176,313	-167,078,931	-209,680,995	-253,030,095	-297,177,452	-448,588,472	-497,780,331

Description/Year	2020	2021	2022	2023	2024	2025	2026	2027
EBITDA	-11,484,423	-11,732,003	-11,983,802	-12,239,841	-12,500,137	-12,764,705	-14,255,323	-14,568,892
Taxes Paid	-14,034,757	-13,236,773	-12,368,826	-11,425,195	-10,399,698	-9,285,658	-8,555,893	-7,258,433
CASH FLOW FROM OPS	2,550,334	1,504,770	385,024	-814,646	-2,100,439	-3,479,047	-5,699,429	-7,310,459
Debt Service	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894	-52,718,894
NET CASH FLOW AFTER TAX	-50,168,560	-51,214,124	-52,333,870	-53,533,540	-54,819,334	-56,197,942	-58,418,323	-60,029,353
CUM NET CASH FLOW	-547,948,891	-599,163,015	-651,496,885	-705,030,425	-759,849,759	-816,047,700	-874,466,024	-934,495,377
IRR ON NET CASH FLOW AFTER TAX								#DIV/0!

Appendix D - Evaluation of New Wave Hindcast Data in the Gulf of Maine

Subsequent to completing the design, performance and cost study for the Old Orchard Beach site, new hindcast wave data for the Gulf of Maine became available from the U.S. Army Corps of Engineers (Reference D-1). The Project Team evaluated these new data to see if there were other locations along the Maine coastline that would have a better wave energy climate and thus better performance and economics than the Old Orchard Beach.

The NDBC 44007 measurement buoy used for characterizing the wave energy resource at the Old Orchard Beach site is:

Station Name:	Portland 12NM Southeast of Portland
Water depth	19 m (note, however that this buoy is moored on a localized high spot; the surrounding water depth is 35-40 m)
Coordinates:	43° 31’53’’ N 70° 08’39’’ W
Data availability:	19 year (1983-2002)
Maximum Significant Wave Height (Hs):	7.3m
Maximum Significant Wave Period (Tp)	11.1 s
Average Wave Power Density:	4.9 kW/m

New WIS Hindcast Data

Several Wave Information Studies (WIS) have been produced by the Waterways Experiment Station of the U.S. Army Corps of Engineers. WIS information is generated by numerical simulation of past wind and wave conditions, a process called hindcasting. The Corps of Engineers requires knowledge of the wave climate for design and maintenance of the nation's coastal navigation and shore protection projects.

By the end of 1998, hindcasts for all U.S. coasts had been completed; the Atlantic Ocean for two different periods, 1956-1975 and 1976-1995 and the Pacific Ocean for 1956-1975.

Recently the Corps began a reanalysis project, covering the period 1980-1999, to improve the quality of the WIS hindcasts using an advanced version of the wave hindcast model WISWAVE, more accurate and more highly resolved input winds, and better representation of shallow water topographic effects and sheltering by land forms through use of more highly resolved model domains. Advancements in weather modeling, increased availability of measured wind data (from buoys and satellites), and improved methods for integrating measured data with model-generated wind fields have all contributed to significant improvements in the quality of wind input that is available for use in hindcasting.

The wave hindcast grid for the older hindcasts (including the one used in the site selection surveys for this project) had a spacing of 0.25 degrees, while the new hindcast uses a spacing of 1/12 degree. The finer spacing in the new hindcast allows better resolution of bathymetry and more output-save locations, as shown by comparing the older hindcast grid point map (Figure D-1) with the newer hindcast grid point map (Figure D-2). More information about the WIS reanalysis project is available at the Web sites listed under Reference D-1.

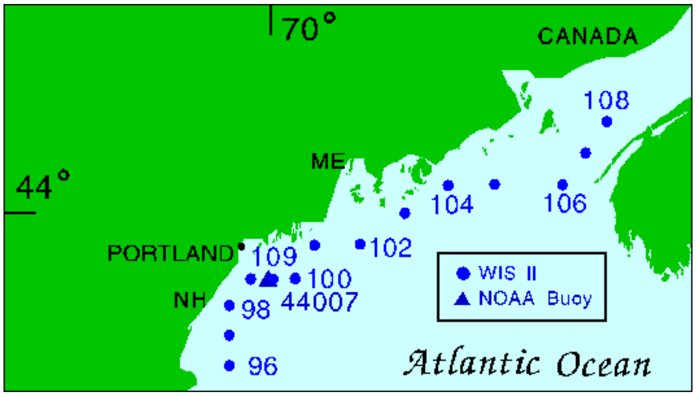
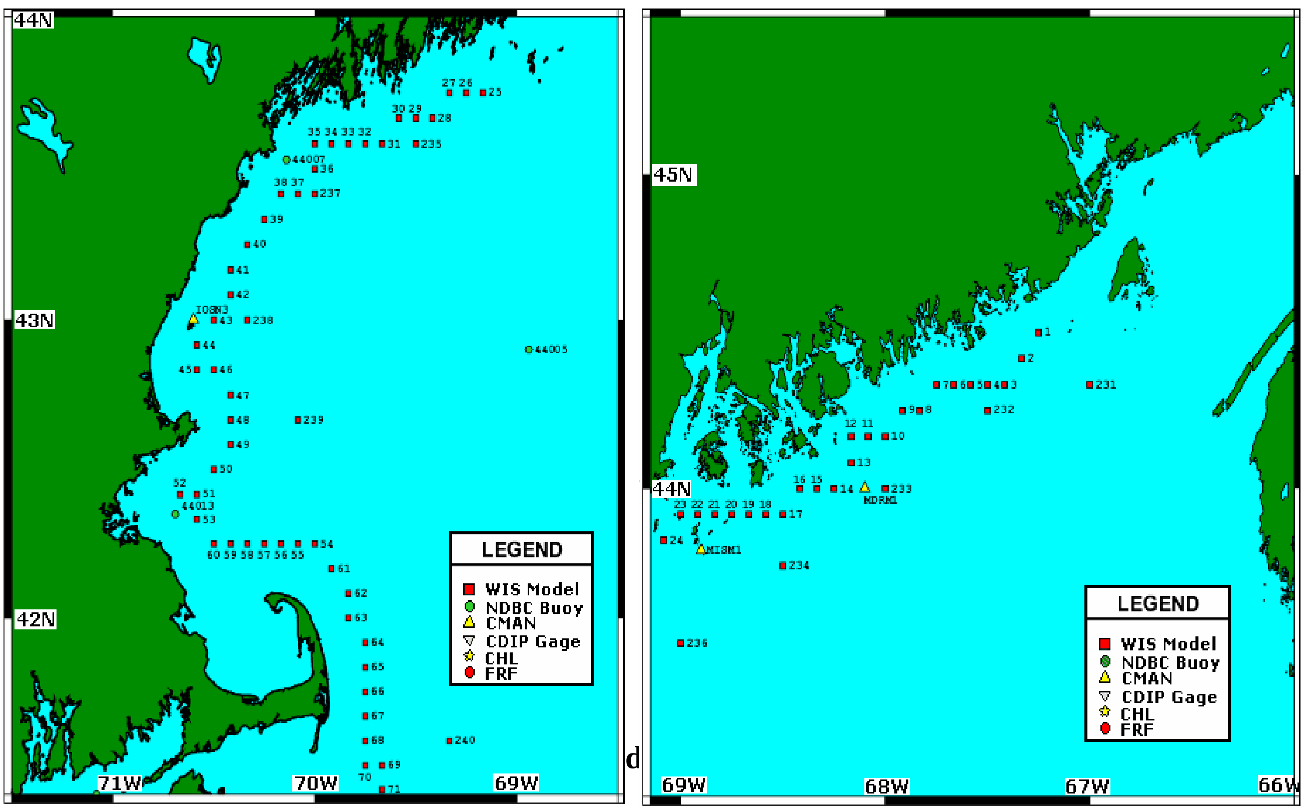


Figure D-1: Fourteen Maine WIS grid points for 1976-1995 hindcast.



d

Comparison of new WIS hindcast with Old Orchard Beach measurement site

The first year (1980) of the new hindcast data was downloaded for the WIS grid points off the entrance to Penobscot Bay and Down East, where wind energy maps suggested that wave energy resources immediately offshore might be greater than immediately offshore Old Orchard Beach. Since it is not valid to directly compare the 1980 year of hindcast data with the 1983-2002 years of measured data, we normalized the new WIS hindcast wave energy flux from these grid points with that year's hindcast wave energy flux from the WIS grid point that is closest to the Old Orchard Beach measurements site, and these normalized results are plotted in Figure D-3 for just those grid points falling within the inclusive depth range of 45 m to 75 m.

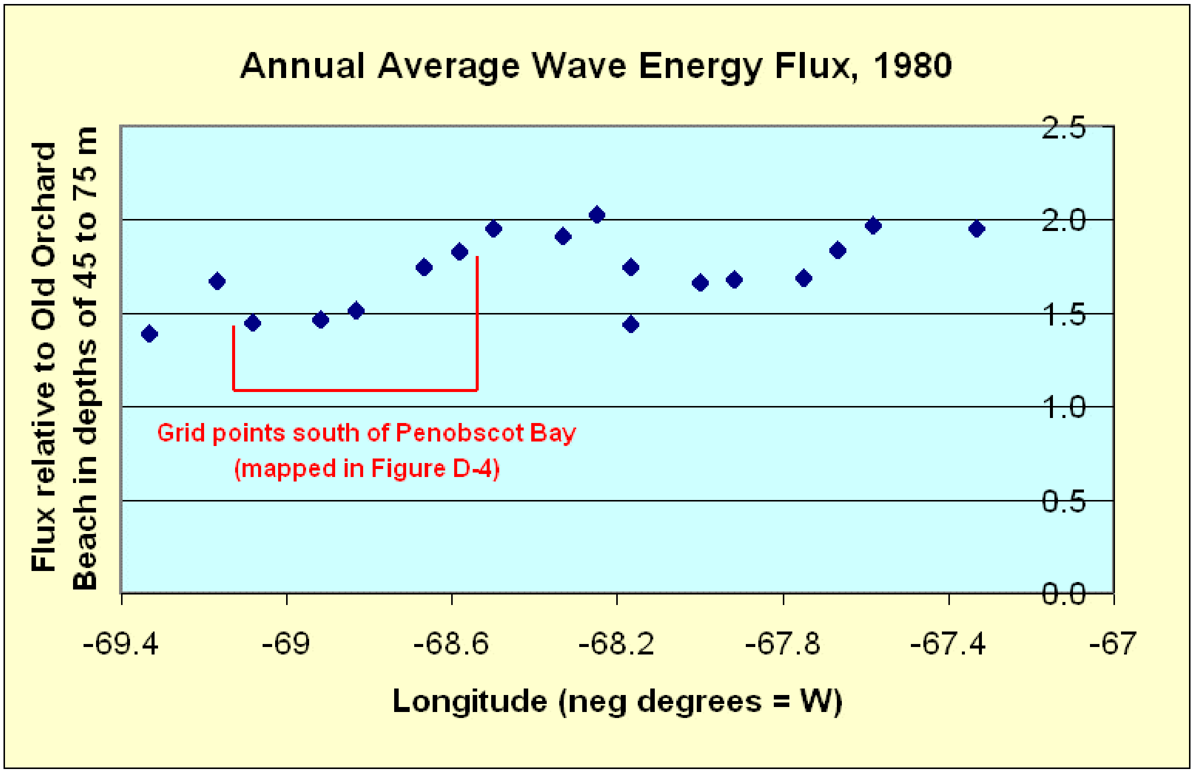


Figure D-3: Wave Energy Flux Distribution Normalized to Old Orchard Beach for 1980 in the New WIS Hindcast

This brief analysis suggests that wave energy fluxes may be 70-100% higher in comparable water depths off Great Wass and Head Harbor Islands in Washington County, and 50-80% higher off the entrances to Penobscot Bay in Knox County. Note the pronounced sheltering effect of Matinicus Island, Seal Island, and associated rocks for two of the grid points off the entrances to Penobscot Bay, which are mapped in Figure D-4.

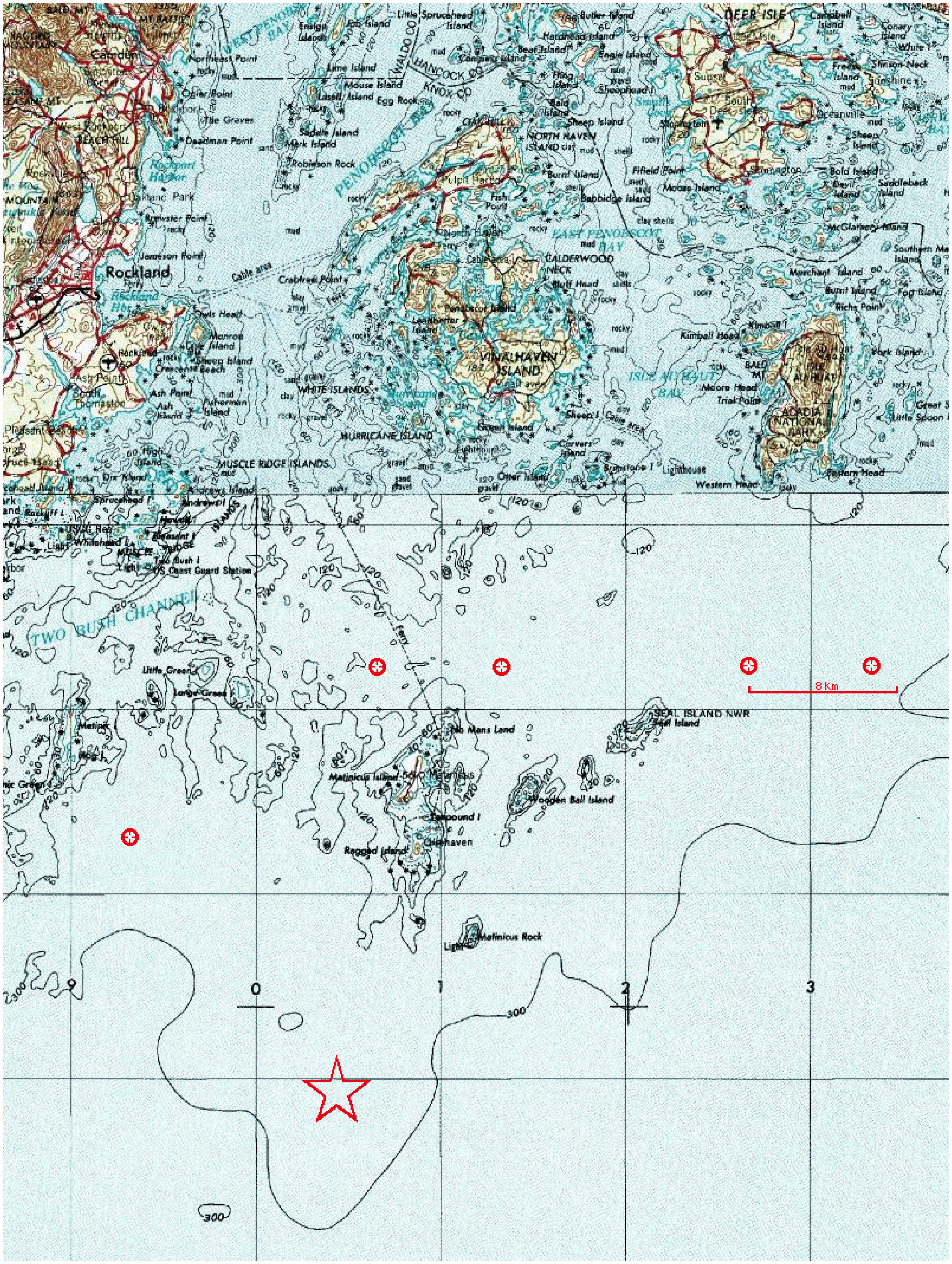


Figure D-4: New WIS Hindcast Grid Points off Penobscot Bay.

The five grid points mapped in Figure D-4 lie within a relatively narrow depth range, the shallowest being at 57 m, and the deepest being at 65 m, and yet the wave energy flux varies significantly among them. This is due not only to the sheltering effect of islands and rocks, but also to the refraction effects of bathymetric contours. For example, the western-most grid point in Figure D-4 is not sheltered by any island or rock, yet has a wave energy flux as low as the sheltered grid points to the east. This is because the concave embayment of the 300-ft depth contour immediately to the south causes wave rays to diverge, such that this particular grid point is in a "cool spot." The promontory of the 300-ft. depth contour, which lies to the east (and is marked by a star in Figure D-4), is quite likely to be a "hot spot" of wave ray convergence, and lies seaward of the sheltering islands and rocks to the north. This illustrates the importance of conducting a detailed wave energy mapping study that accounts for such bathymetric details.

Thus the exposed offshore region south of Penobscot Bay might offer a more economical site than the Old Orchard Beach location for any commercial wave power plant located off the coast of Maine. This would need to be substantiated by a more in-depth analysis of the full twenty-years of new WIS hindcast data.

The best interconnection point for an offshore wave power plant in this region would be Rockland/Camden 115 kV substation (in Central Maine Power service territory). Note that this is the northern limit for coastal rail access in Maine, and so is likely to have lower fabrication and maintenance costs than sites farther "Down East," even though the wave resource generally improves as one moves into Hancock and Washington counties, as shown in Figure D-3.

Conclusions

In unsheltered waters off Penobscot Bay, the output of a wave power plant might be 80% higher, which would translate to a 45% lower cost of energy compared with a similar plant off Old Orchard Beach. Thus at a national commercial wave power development level of 40,000 MW of installed capacity, the cost of offshore wave energy here might be in the range of 4.4 to 5.5 cents per kilowatt-hour (¢/kWh), rather than the 8-10 ¢/kWh projected for the Old Orchard Beach design. Although this is less than the average price of electricity for industrial customers in Maine, it is still more than the cost of onshore wind energy at its current level of commercial maturity. For example, in a Class 3 wind regime, which is characteristic of the best coastal wind sites in Maine, Reference D-2 estimates the cost of wind energy to be 3 to 4 ¢/kWh.

Given the limited number of Maine coastal sites where onshore wind turbines would be acceptable, however, the more appropriate comparison would be with offshore wind energy cost projections for similar water depths and distances offshore. In such a comparison, an offshore wave energy cost of 4.4 to 5.5 ¢/kWh may be comparable to projected offshore (>30 m depth) wind energy costs in the Class 6 wind regime that exists in this region south of Penobscot Bay. Reference D-3 estimates that by the year 2015, offshore wind energy in such water depths and this wind climate would cost 4.5 to 5.8 ¢/kWh.

Recommendations

Although these results are more encouraging than our earlier findings, it is clear that offshore wave energy in Maine is a long-term prospect at best, becoming economically viable only after 40,000 MW or more of wave generating capacity has been installed nationwide. Because it may be competitive with offshore wind energy in Maine coastal waters in the longer term,, the Project Team recommends that Maine State Electricity Stakeholders continue to monitor the progress of offshore wave power development.

The Project Team further recommends that Maine State Electricity Stakeholders join with Massachusetts State Electricity Stakeholders in the promotion and sponsorship of a project that will investigate local Gulf of Maine wave energy “hotspot” locations in both states. Although the WIS hindcast is driven by wind, the shoreward wave propagation from beyond the shelf edge includes seafloor interactions, such as refraction, shoaling, and bottom friction. For this purpose, the WIS hindcast assumes "best-fit" parallel bottom contours, however, and so only gives a crude indication of "hot spot" convergence or "cool spot" divergence based on a horizontal resolution on the order of 10 km. Many bottom features off the coast of Maine have significant depth changes over a scale smaller than this, and a spatial resolution for accurate modeling of bathymetric effects must be on the order of 1 km. Since the offshore wave climate in intermediate water depths (40 to 200 m) off Maine and northern Massachusetts is “driven” by the same deep-water wave climate in the Gulf of Maine, there would be a relatively small incremental cost to adding the Maine continental shelf to the Massachusetts detailed wave mapping study that is now being planned by the Massachusetts Technology Corporation.

References

D-1. U.S. Army Corps of Engineers, 2004. Wave Information Studies (WIS) Web Sites: http://frf.usace.army.mil/wis/ and http://chl.wes.army.mil/research/wave/wavesprg/numeric/wgeneration/wisdata.htp

D-2. Jacobson, Mark Z., and Gilbert M. Masters, 2001. Exploiting wind versus coal. *Science*, Vol. 293, p. 1438.

D-3. Musial, Walt, and Sandy Butterfield, 2004. *Future for Offshore Wind Energy in the United States*, preprint prepared for “EnergyOcean 2004.” NREL/CP-500-36313 (available at www.nrel.gov/docs/fy04osti/36313.pdf).