

MERSEY TIDAL POWER

FEASIBILITY STUDY: STAGE 3

Financial Modelling Report

Date June 2011

Report prepared by:

URS



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Project Background

In the face of current and anticipated issues of security of supply and climate change, the need to find local sources of renewable energy has never been more urgent.

The Mersey Estuary has one of the largest tidal ranges in the UK, making it one of the best locations for a tidal power generation scheme. It has the potential to make a significant contribution to the Government's target to secure 15% of UK energy from renewable sources by 2020.

A large scheme could deliver enough renewable electricity to meet the needs of a significant proportion of the homes within the Liverpool City Region, as well as beyond. Any scheme put forward will need to take into account the ecological diversity of the Estuary, which supports internationally important bird habitats.

Phase 1 Pre-Feasibility Study - 'Power from the Mersey'

Peel, in partnership with the NWDA set out to explore the potential, the impacts and the implications of utilising the Mersey Estuary's renewable energy potential for the benefit of the Northwest region.

The Mersey Basin Campaign gave its full backing to the work and a consortium of consultants led by Buro Happold was commissioned in July 2006 to undertake a 'pre-feasibility' Phase 1 Study.

The primary objective of the Phase 1 Study was to undertake a full and open assessment of the options available for the generation of renewable energy and to undertake a preliminary assessment of viability.

A number of potentially viable schemes were identified. The continued development of marine power technology means that others may also need to be considered as the project moves into the next phase.

Meeting 2020 Renewable Energy Targets

An overall timetable was defined to ensure the project supports the policy objective of contributing to 2020 renewable energy targets. The key milestones of the project include submission of applications for planning or other statutory consents by 2012 and commissioning of the scheme by 2020.



Phase 2 Feasibility Study

Peel Energy and the Northwest Development Agency are progressing the project in line with the principles for sustainable development. A feasibility study has been commissioned to assess the options and identify a preferred scheme to take forward for submission of a planning application.

The feasibility study has been led by URS Scott Wilson, EDF and Drivers Jonas Deloitte, and supported by RSK, APEM, HR Wallingford, Regeneris, Turner and Townsend, University of Liverpool, Proudman and Global Maritime.

The feasibility study has been undertaken in three stages as follows:

- Stage 1: Definition of project strategies, data gathering and gap analysis, and selection of long list of suitable technologies
- Stage 2: Appraisal of the long list of technologies and formulation and appraisal of scheme options to identify a shortlist
- Stage 3: Further refinement and appraisal of the short list of scheme options and selection of the preferred scheme.

The project has been pursued in an open and transparent manner, building on the consultation and stakeholder engagement started in the Phase 1 study. An extensive programme of stakeholder engagement has taken place through project advisory groups, consultation with statutory and non-statutory consultees and public consultation targeted during appropriate stages of the project.

Mersey Tidal Power Scheme Objectives

The objectives of the Mersey Tidal Power scheme are:

- (a) To deliver the maximum amount of affordable energy (and maximum contribution to Carbon reduction targets) from the tidal resource in the Mersey Estuary with acceptable impacts on environment, shipping, business and the community either by limiting direct impact in the Mersey Estuary or providing acceptable mitigation and/or compensation;

and in doing so,

- (b) To maximise social, economic and environmental benefits from the development and operation of a renewable energy scheme, including where appropriate:
 - (i) the development of internationally significant facilities and skills to support the advancement of renewable energy technologies and their supply chains,
 - (ii) improvements to local utility and transport infrastructure,
 - (iii) improvements to green infrastructure and environmental assets,
 - (iv) the development of a leisure opportunity and tourist attraction.

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Note on Terminology

This technical report uses a different naming system to the Stage 3 Feasibility Report to refer to schemes variants, as follows:

- IBv2a = A1.02a;
- IBv2b = A1.02b;
- VLHBv2a = A2.01a; and
- VLHBv3a = A2.02a.

If a lower case letter is not used, this is because the operating regime (denoted by the lower case letter) is not relevant.

1 Introduction

- 1.1.1 This report sets out the results of the financial modelling of scheme variants undertaken to inform Stage 3 of the feasibility study.
- 1.1.2 In order to carry out the assessment, URS Scott Wilson has built a fully functioning financial model consistent with UK Generally Accepted Accounting Principles (UKGAAP). The integrity of the model has been stress-tested to ensure that it delivers consistent outputs across a variety of scenarios.
- 1.1.3 The model consists of a series of calculation sheets driven by assumptions contained within assumption sheets. For any given set of assumptions, the model will derive:
- a Project Internal Rate of Return (“project IRR”);
 - a blended Equity Rate of Return (“equity IRR”); and
 - a levelised cost of generation (calculated on the same basis as the costs in the UK Electricity Generation Costs Update report, commissioned by the Department of Energy and Climate Change and published in June 2010).
- 1.1.4 The model can also be used to determine the average real electricity sales price required in order to generate a specific return for any given scenario.
- 1.1.5 The model has been used to assess the commercial viability of the tidal power generating options under consideration in Stage 3 of the feasibility study by running a series of sensitivities.

2 Methodology

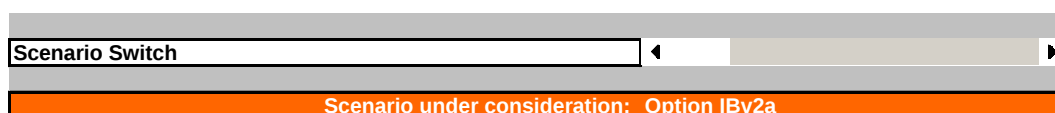
2.1 Model Structure

2.1.1 The model has been built with 10 assumption sheets that are populated with:

- data supplied by the other work-streams, including capital costs, operating costs and energy outputs, for each of the six scheme variants; and
- commercial assumptions such as interest rates, coupon rates, and gearing based on those attained by other large scale renewable energy and infrastructure projects.

2.1.2 Assumptions for each scheme variant are clearly identified in hard coded in cells shaded yellow.

2.1.3 The scheme variant under consideration is selected by moving a slider bar in the General Assumptions sheet.



2.1.4 This sets the scheme variant value, which is used by choose formulae to place the assumptions for that variant into the master assumption cells. The master assumptions are either unshaded (for cells that are a direct selection from the scheme variant under consideration) or are shaded blue (for cells that use the scheme variant data to perform a calculation). This is illustrated in the model extract below:

		Option A1 (Option A1.02a)
Timetable		
Model Start Date	01 April 2010	01 April 2010
Start of Development Phase	01 April 2012	01 April 2012
Development Phase Duration (months)	24	24
End of Development Phase	31 March 2014	
Construction Commencement	01 April 2014	01 April 2014
Construction Period (Months)	72	72
Commissioning Commencement	01 April 2019	
Commissioning Period (Months)	12	12
Operations Commencement	01 April 2020	
Life of Project	120.0 years	120.0 years
End of Life of Project	31 March 2140	
Project Life	120.0 years	
Model Length	130.0 years	
Final Period	130	

2.1.5 For example, when A1.02a is under consideration, the start of the development phase (assumed to be 01 April 2012 for the purposes of assessment) and the length of the development phase (assumed to be 24 months) for that scheme variant (in the third column) are placed into the master assumptions cells (in the second column). These are

then used to calculate, by means of Excel's "edate" function, the date of the end of the development phase (the fifth cell in the second column).

- 2.1.6 The master assumption cells are then used to drive the eleven calculation sheets, which include cash flow, balance sheet, profit and loss and tax. Within these sheets, the model calculates the cost of finance for the project, as well calculating the repayment of debt and subordinated debt if these are used.
- 2.1.7 Slider bars linked to choose formulae are also used in the model to select between nominal and real values, and to choose between using the Renewable Obligation and the Feed-in Tariff. This latter facility has been added into the model since the completion of Stage 2. This reflects the proposals contained in the Government's consultation document for Electricity Market Reform (EMR), which was issued on 16th December 2010. In it, the Government has articulated a preference to close the Renewable Obligation to new projects that come on stream after 31st March 2017. Instead, the Government proposes that schemes such as Mersey Tidal Power should be supported by a Feed-in Tariff.
- 2.1.8 The model makes extensive use of date references and date formulae. This enables the calculation of time dependent events by formulae rather than by hard-coded flags. In this way, scheme variants with dissimilar project timings can be modelled without the need for an individual model for each variant.
- 2.1.9 The project IRR and the equity IRR are calculated within the model using Excel's XIRR function.
- 2.1.10 The levelised cost of generation is calculated according to the formula below, which is derived from that used in the UK Electricity Generation Costs Update report issued by the Department of Energy and Climate Change (DECC) in June 2010:

$$\text{LCG} = \text{TOTC} / \text{NPVEG}$$

Where

LCG = **Levelised Cost of Generation in £ per MWh**

TOTC = Net Present Value (NPV) of the whole life real capital expenditure and real operating costs in £, calculated according to the formula:

$$\text{TOTC} = \sum_n^I (\text{TC}_n / (1 + r)^n)$$

where

TC_n = total capital and operating costs in £ in year "n"

r = the discount rate in %

I = the final year of generation

n = year number, with 2010 (the cost base year, which is the first year of the model) being 1 and 2139 (the final year of operation) being 130¹

NPVEG = whole life net electricity generation (MWh), discounted according to the formula

$$NPVEG = \sum_n^I (G_n / (1 + r)^n)$$

Where

G_n = The net generation in MWh in year “n”

2.2 Assumptions

2.2.1 The assumptions in the financial model are based on collated information from within the project team:

- revenue data has been supplied by EDF Energy;
- initial (construction) capital expenditure has been supplied by Turner & Townsend;
- operating and maintenance costs including capital expenditure for the replacement of major items of equipment (renewals) have been estimated by URS Scott Wilson and EDF; and
- all other assumptions have been provided by the project team and/or through discussions with Peel Energy.

2.2.2 All data is presented in 2010 prices.

Timetable

2.2.3 For all scheme variants:

- the Development Phase is assumed to commence in 2012 and last for 24 months (2 years);
- the Construction Phase is assumed to begin in 2014 and for last 72 months (6 years) including the commissioning period; and
- the operational phase of the project is assumed to be 120 years.

2.2.4 The programme is shown in Table 1.

¹ The DECC formula definition refers to “n” as being the operating year, however the supporting table in the report clearly shows that “n” is calculated from the model start date (cost base date).

Table 1: Project timetable for all scheme variants

Event	Timing
Start of development phase	1 st April 2012
End of development phase	31 st March 2014
Duration of development phase	24 months (2 years)
Start of construction period	1 st April 2014
End of construction period	1 st April 2019
Commissioning period	12 months
Duration of construction & commissioning	72 months (6 years)
Start of operations period	1 st April 2020
End of operations period	31 st March 2140
Duration of operations period	120 years

Generation Capacity

- 2.2.5 EDF supplied power generation capacity and output data for all scheme variants. In all cases, the output data takes into account reductions in generation attributable to ecological mitigation measures.
- 2.2.6 During the commissioning period, all scheme variants are assumed to generate 50% of the annual operational electricity output.
- 2.2.7 It has been assumed that parasitic load is very small compared to the output and has therefore been ignored; this is consistent with the approach adopted for the Severn Tidal Power commercial assessment.
- 2.2.8 The generation capacity and output assumptions for all scheme variants are shown in Table 2.

Table 2: Generation capacity and output for all scheme variants

	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Installed capacity (MW)	700	700	700	700	660	660
Annual output during operations (GW/h pa)	1,050	950	520	920	560	520
Output during commissioning period (GW/h pa)	524	474	259	459	279	259

Power Price and Revenue

- 2.2.9 In its EMR consultation document, the Government states that it wishes to migrate all renewable energy schemes coming on line after 31st March 2017 to a Feed-in Tariff support mechanism ("FiT"). The financial model has therefore been adjusted to model this, although it retains the functionality to model Renewable Obligation Certificates (ROCs) if required.
- 2.2.10 The exact details of the FiT will not be known until the late spring at the earliest. Given that the EMR consultation is designed to promote large-scale, low-carbon generation, with the greatest amount of electricity to come from nuclear power plant, we have assumed that the FiT will be designed to facilitate the financing of new nuclear power stations. We have therefore assumed that the FiT will run for a period of 50 years until the 31st of March 2070. We have also assumed that the FiT will be worth £160 per megawatt hour (MWh), which is comparable to the amount of money that an off-shore wind farm could currently expect to receive under the Renewable Obligation.
- 2.2.11 From 1st of April 2070, we have assumed that the electricity sales price achieved will be the wholesale market price of £56.25 per MWh. This is based on a 25% uplift, in real terms, of the 2010 price of £45 per MWh as advised by EDF. This assumption has been made to account for the expected market uplift in the price due to supply-side constraints by the time the project starts to generate revenue. It does not include any uplift in wholesale market prices attributable to the Government's proposal (in the EMR consultation) to set a floor price for carbon emissions.
- 2.2.12 The EMR consultation proposes that a floor be set under the price of carbon, through adjustments to the Climate Change Levy. The impact that this will have on wholesale electricity prices will depend on the way in which the floor price is set, and the amount of coal and gas fired generation within the generation mix in any future year, both of which are unknown at the time of writing. We have therefore conservatively assumed that Mersey Tidal Power, as a renewables generator, will benefit from Levy Exemption Certificates both during and after the FiT. The value ascribed is £4.50 per MWh as advised by EDF Energy.

2.2.13 The EMR consultation further proposes that capacity payments will be made to flexible generation. Mersey Tidal Power will have some flexibility of operation, in that it will be able to extend or shorten the period of generation at key times and therefore be able to respond to signals from the grid operator. Consequently, we have conservatively assumed that it will be able to earn up £111 per MW of net capacity per annum. This was derived from assuming that 1/9th of the capacity would be flexible and that flexible capacity is conservatively rewarded at the rate of £1,000 per MW per annum.

2.2.14 These assumptions generate annual revenues as shown in Table 3.

Table 3: Annual Revenue (£m real) from power generation for all scheme variants

£m (real)	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Commissioning period	86.1	77.9	42.7	75.5	45.9	42.7
Operational period from 1 st of April 2020 to 31 st of March 2070 (under a FiT)	172.8	156.4	85.6	151.4	92.2	85.6
Operational period from 1 st April 2070 to 31 st of March 2140 (once the FiT has expired)	63.9	57.8	31.7	56.0	34.1	31.7

Capital Expenditure During Construction and Commissioning

2.2.15 All upfront capital expenditure assumptions have been provided by Turner & Townsend and vary with each scheme. The assumptions which have been applied as an overlay on upfront capital expenditure for all schemes are shown in

Table 4. The total overlay for each scheme represents 33% of capex.

Table 4: Capital expenditure (£m real) and overlays for all scheme variants

£m (real)	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Upfront capital expenditure	2,150.8	2,150.8	2,150.8	2,150.8	2,841.3	2,790.8
Preliminaries & site overheads/profits	254.6	254.6	254.6	254.6	339.0	333.9
Design and supervision fees, legal fees, enquiry costs	285.2	285.2	285.2	285.2	379.7	374.0
Capital expenditure contingency	532.3	532.3	532.3	532.3	708.7	698.1
Total overlays	1,072.1	1,072.1	1,072.1	1,072.1	1,427.4	1,406.0
Total capex	3,222.9	3,222.9	3,222.9	3,222.9	4,268.7	4,196.8

- 2.2.16 Commissioning costs are assumed to be already included in the power generation technology cost supplied by Turner & Townsend for each scheme variant. There is an underlying assumption that this equates to 10% of the Power Generation Technology cost.

Capital Expenditure During Operations (Renewals)

- 2.2.17 Navigation structures included in the capital expenditure for all scheme are assumed to be renewed every 50 years. For all schemes, the renewal is assumed to take place within one year.
- 2.2.18 The power generation technology included in the capital expenditure is assumed to be refurbished every twenty-five years. For all schemes, the refurbishment is assumed to take place over five years.
- 2.2.19 The above assumptions have been estimated by URS Scott Wilson based on its industry experience of hydro projects.

Operational Expenditure: Routine Operations and Maintenance Costs

- 2.2.20 For all scheme variants, annual Operational Expenditure is assumed to be the sum of:
- overhead costs;
 - rents;
 - basin management costs; and
 - use of system charges.

2.2.21 The methodology used to calculate each component of the operations expenditure is described below:

- Overhead costs include all routine operating and maintenance costs as well as items such as rates. In aggregate, overhead costs are assumed to be 1% of the upfront capital expenditure in real terms.
- In the absence of any existing precedent for tidal energy, annual rents are conservatively assumed to be fixed and proportional (0.048%) to the upfront capital cost (i.e. excluding overlays) of each scheme variant. ..
- Basin management costs are assumed to be £2.5m per annum for all scheme variants. This is an estimate that takes into account costs associated with dredging, ecological management and navigation that can be reasonably expected to be attributed to Mersey Tidal Power. These costs will be dependent on which navigation option is adopted, the rate of sediment deposition, current water flow patterns and ecological impact mitigation measures, all of which are yet to be determined definitively.
- Use of system charges comprise of Transmission System Use of System (TSUOS) and Balancing System Use of System (BSUOS) charges levied by National Grid on transmission-connected generation. The annual TSUOS charge is assumed to be £3.59 per kW of power generation capacity for connections on the Wirral bank of the Mersey Estuary. This assumption has been provided by EDF Energy. The BSUOS charge is assumed to be £1.17 per MWh exported, based on the average charge for the period from 1st April 2010 to 6th February 2011. This methodology has been supplied by EDF Energy.

Operational expenditure is summarised in Table 5 below:

Table 5 Operational expenditure (£,000s real) for all scheme variants

£,000s (real)	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Overhead costs	27,934	27,934	27,934	27,934	37,669	37,164
Rents	1,340	1,340	1,340	1,340	1,808	1,783
Basin Management	2,500	2,500	2,500	2,500	2,500	2,500
Use of system charges	3,748	3,630	3,126	3,595	3,029	2,982
Total annual operating expenditure	35,522	35,404	34,900	35,369	45,006	44,429

Decommissioning Costs

- 2.2.22 Decommissioning of the barrage is assumed to occur after the project completion date of 31st March 2140; therefore decommissioning costs have not been included in the model. This is consistent with the DECC methodology for calculating levelised costs of generation. Notwithstanding this assumption, and the likelihood that the net cost of decommissioning (after disposal of saleable items) will be a fraction of the upfront capital cost, it is recognised that provision will have to be made for it during operation. There are a number of methodologies for achieving this, including the use of bonds or reserving mechanisms.

Indexation

- 2.2.23 General inflation used to calculate nominal costs and revenues is assumed to be 2.5%.
- 2.2.24 During the construction period the Building Cost Information Service (BCIS) index has been used for all capital costs except power generation equipment and the grid connection.
- 2.2.25 The indexation assumed for power generation equipment and the grid connection is 150% of the increase in the BCIS index.

Taxation

- 2.2.26 Corporation Tax has been assumed to be 24% as per Government policy.
- 2.2.27 Power generation equipment and utilities have been assumed to qualify for Capital Allowances at the 18% reducing balance rate, on the basis that the periodicity of replacement is 25 years. As the bulk of the rest of the capital expenditure is related to civil engineering and “landscaping” type work, it has been assumed to be non-qualifying. This is a conservative assumption, as in reality some of the other capital expenditure should also qualify for Capital Allowances.

Funding

- 2.2.28 It is assumed that pure equity will represent 1% of the funding requirement and will be injected up front.
- 2.2.29 It is assumed that subordinated debt will represent 29% of the funding requirement. It is assumed that this be injected pari pasu with senior debt during the construction period and will carry a 7.5% coupon rate with interest rolled up until the start of operations. Thereafter it will carry a coupon rate of 10%, with principal repayments not allowed to accelerate ahead of the senior debt repayment profile.
- 2.2.30 It is assumed that senior debt will represent 70% of the funding requirement, at an interest rate of 6.75% and with interest during construction rolled up. The assumed tenor of the debt is 35 years, with a profiled principal repayment schedule.

3 Lessons Learnt from Stage 2

- 3.1.1 The financial model has been refined to achieve greater functionality and robustness. We have further developed the financing assumptions, as well as introducing more flexibility into the model so that more variables can be sensitised. We have expanded the calculations for tax to more accurately model the effect of capital allowances on post-tax cash flow.
- 3.1.2 Stage 2 informed us that further public funding would significantly enhance the feasibility of the project. As a result of the EMR consultation, we have incorporated the ability to run FiTs of varying durations and values, and we have added the ability to model the effects of capital grants. However, the ability to model ROCs has been retained..

4 Stage 3 Scheme Assessment

4.1 Approach

- 4.1.1 The first output of our analysis is the levelised cost of generation for each scheme variant, which is the key measure used by DECC to compare different types of new-build generation. This can be used to compare Mersey Tidal Power with other tidal schemes such as those proposed in the Severn Tidal Power commercial assessment as well as other power generation technologies. The levelised cost of generation has been calculated for all scheme variants using a discount rate of 10% and 8% respectively.
- 4.1.2 The levelised cost of generation is calculated by taking the sum of the discounted whole life real capital and operational costs and dividing it by the sum of the discounted whole life forecast electricity output (in accordance with the formula described in paragraph 2.1.10 above). This is consistent with the approach adopted in Stage 2.
- 4.1.3 Sensitivities have been run by separately reducing capital expenditure and operating expenditure, first by 10% and then by 30%, to test how this impacts the levelised cost of generation.
- 4.1.4 The second output of our analysis is the average real unit prices of electricity (£ per MWh) required to produce a project IRR of 10%, 8% and 6% for the base case for each scheme variant. This average real price required (ARPR) is useful in that the costs of finance, tenor of debt and the effects of taxation are taken into account in its calculation. ARPR sensitivities can be run around any of the variables in the model, including financial variables.

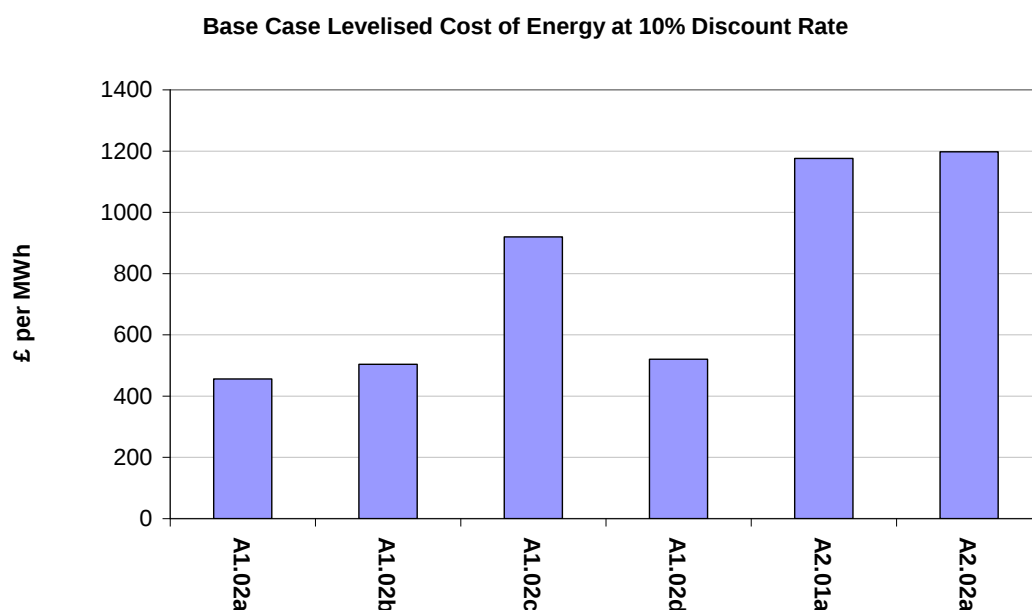
4.2 Results for all Scheme Variants

- 4.2.1 Overall results show that:
- The most attractive solution is A1.02a. This was anticipated as it has the highest power generation capacity combined with the lowest construction and operational costs of all the scheme variants.
 - The levelised cost is most sensitive to variation in capital expenditure. This is a consequence of the high levels of construction costs on the project (between £3.2bn to £4.2bn), which are less impacted by the effect of discounting over time.
 - All of the scheme variants have a negative project NPV in the base case (as described in 2.2 above and which assumes no uplift in wholesale electricity prices as a consequence of EMR other than a FiT of £160 per MWh).

- In order to be able to attract private investment, costs must be reduced and/or the average unit sales value of electricity must increase and/or a capital grant must be applied.

4.2.2 A1.02a has the lowest levelised cost of the schemes examined, at £456.06 per MWh (at a discount rate of 10%). This is illustrated in Figure 1 below.

Figure 1: Base case levelised cost of energy at 10% discount rate



4.2.3 This was anticipated, as it has the highest electricity output combined with the lowest capital and operational expenditure of all the scheme variants. This solution allows for ebb tide generation only with starting heads optimised for maximum energy output.

4.2.4 A2.01a and A2.02a have the highest levelised costs at £1,175.91 per MWh and £1,197.43 per MWh respectively.

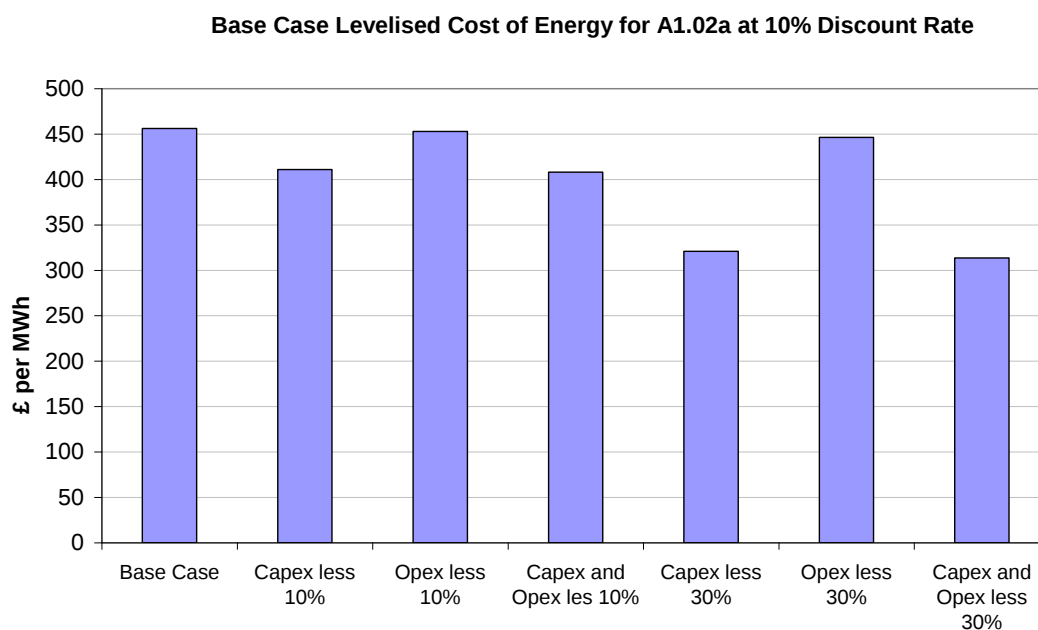
4.2.5 A1.02a generates a negative NPV of £1,171 m in the base case. In order to attract private investment, either its costs must fall or the power price must rise. For example, the ARPR that generates a 6% project IRR is £258.00 per MWh. This represents a 248% increase in the base case average real power price of £104.23.²

4.2.6 The results from all scheme variants consistently demonstrate that the levelised cost is more sensitive to variation in capital expenditure than operational costs. This was expected as the project construction costs are very high (between £3.2bn to £4.2bn) and are less

² £104.23 is calculated based in a Feed-in-Tariff of £160 from 1st April 2019 to 31st March 2070, followed by a power price of £56.25 from 1st April 2070 to 31st March 2140.

impacted by the effect of discounting over time. It is illustrated by Figure 2 below, which shows the effect of varying capital and operating expenditure on A1.02a.

Figure 2: Base case levelised cost of energy for A1.02a at 10% discount rate



4.2.7 A1.02a also produced the lowest levelised cost of £242.63 per MWh in the sensitivity study, by reducing both capital and operating expenditure by 30% from current levels, and using a discount rate of 8%.

4.2.8 The results for the base case for all scheme variants are shown in Table 6.

Table 6: Base case results for levelised cost of generation and project NPV for all scheme variants

Base Case	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£456.06	£503.95	£919.76	£520.35	£1,175.91	£1,197.43
Levelised cost of generation (at 8% discount rate)	£354.66	£391.88	£714.99	£404.62	£906.28	£932.00
Project NPV (m)	(£1,171)	(£1,249)	(£1,594)	(£1,273)	Not recorded ³	Not recorded
ARPR to achieve a project IRR of 10%	£491.00	£543.00	£993.00	£560.00	£1,270.00	£1,295.00
ARPR required to achieve a project IRR of 8%	£373.00	£412.00	£752.00	£424.00	£956.00	£986.00
ARPR to achieve a project IRR of 6%	£258.00.	£285.00	£516.00	£290.00	£662.00	£688.00

³ The financial model is designed to deal with a wide range of sensitivities, however when the Net Present Value of free cash flow is negative and the absolute value of this exceeds 50% of the capital expenditure, no value is recorded

4.2.9 The effect of reducing capital expenditure is shown in Tables 7 and 8 below

Table 7: Capital expenditure reduced by 10%

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£411.02	£454.17	£828.81	£468.95	£1,059.26	£1,078.69
Levelised cost of generation (at 8% discount rate)	£319.77	£353.31	£644.53	£364.79	£816.60	£839.81
Project NPV (m)	(£976)	(£1,053)	(£1,395)	(£1,076)	(£2,035)	(£1,942)
ARPR to achieve a project IRR of 10%	£441.00	£488.00	£894.00	£504.00	£1,140.00	£1,165.00
ARPR required to achieve a project IRR of 8%	£334.00	£369.50	£678.00	£381.00	£858.00	£884.00
ARPR to achieve a project IRR of 6%	£228.50	£253.00	£465.00	£261.00	£586.00	£609.00

Table 8: Capital expenditure reduced by 30%

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£320.95	£354.61	£646.92	£366.14	£825.96	£841.21
Levelised cost of generation (at 8% discount rate)	£249.98	£276.17	£503.62	£285.14	£637.25	£655.44
Project NPV (m)	(£605)	(£669)	(£998)	(£690)	(£1,487)	(£1,423)
ARPR to achieve a project IRR of 10%	£343.00	£380.00	£697.00	£392.50	£889.00	£907.00
ARPR required to achieve a project IRR of 8%	£260.00	£288.00	£528.00	£297.00	£668.00	£688.00
ARPR to achieve a project IRR of 6%	£178.00	£197.00	£363.00	£203.50	£457.00	£475.00

4.2.10 The effect of reducing operating expenditure is shown in Tables 9 and 10 below.

Table 9: Operating expenditure reduced by 10%

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£452.84	£500.40	£913.37	£516.69	£1,168.25	£1,189.29
Levelised cost of generation (at 8% discount rate)	£351.41	£388.29	£708.54	£400.92	£898.55	£923.78
Project NPV (m)	(£1,156)	(£1,233)	(£1,578)	(£1,257)	(£2,287)	(£2,181)
ARPR to achieve a project IRR of 10%	£487.00	£538.50	£987.00	£556.00	£1,260.00	£1,285.00
ARPR required to achieve a project IRR of 8%	£367.00	£406.00	£746.00	£420.00	£945.00	£973.00
ARPR to achieve a project IRR of 6%	£250.50	£277.00	£510.00	£286.50	£643.00	£667.00

Table 10: Operating expenditure reduced by 30%

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£446.40	£493.30	£900.58	£509.36	£1,152.94	£1,173.01
Levelised cost of energy (at 8% discount rate)	£344.90	£381.12	£695.63	£393.53	£883.10	£907.35
Project NPV (m)	(£1,124)	(£1,201)	(£1,545)	(£1,225)	(£2,245)	(£2,139)
ARPR to achieve a project IRR of 10%	£480.50	£531.50	£974.00	£549.00	£1,245.00	£1,269.00
ARPR required to achieve a project IRR of 8%	£361.00	£399.50	£733.00	£413.00	£930.00	£957.00
ARPR to achieve a project IRR of 6%	£244.00	£270.50	£497.00	£279.00	£628.00	£651.00

4.2.11 The combined effects of reducing capital and operating expenditure are shown in Tables 11 and 12 below.

Table 11: Capital and operating expenditure both reduced by 10%

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£408.07	£450.92	£822.96	£465.59	£1,052.27	£1,071.26
Levelised cost of energy (at 8% discount rate)	£316.78	£350.02	£638.62	£361.40	£809.55	£832.31
Project NPV (m)	(£962)	(£1,038)	(£1,380)	(£1,061)	(£2,015)	(£1,923)
ARPR to achieve a project IRR of 10%	£438.00	£485.00	£889.00	£500.00	£1,134.00	£1,157.00
ARPR required to achieve a project IRR of 8%	£331.00	£366.00	£672.00	£378.00	£850.00	£876.00
ARPR to achieve a project IRR of 6%	£225.50	£250.00	£459.00	£258.00	£579.00	£602.00

Table 12: Capital and operating expenditure both reduced by 30%

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£313.67	£346.60	£632.57	£357.88	£809.04	£823.22
Levelised cost of energy (at 8% discount rate)	£242.63	£268.09	£489.13	£276.81	£620.16	£637.27
Project NPV (m)	(£576)	(£639)	(£961)	(£658)	(£1,440)	(£1,377)
ARPR to achieve a project IRR of 10%	£336.00	£372.00	£683.00	£384.00	£872.00	£889.00
ARPR required to achieve a project IRR of 8%	£252.50	£279.50	£514.00	£289.00	£651.00	£670.50
ARPR to achieve a project IRR of 6%	£170.50	£189.00	£348.50	£195.50	£440.00	£457.00

- 4.2.12 The sensitivity of Mersey Tidal Power to electricity production is shown in Table 13; for each 1% that electricity production is increased; both the levelised cost and the ARPR inversely change by 0.91%.

Table 13: Electricity production increased by 10%

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Levelised cost of generation (at 10% discount rate)	£414.71	£458.24	£836.25	£473.15	£1,069.11	£1,197.43
Levelised cost of energy (at 8% discount rate)	£322.52	£356.35	£650.10	£367.94	£824.00	£932.00
Project NPV (m)	(£1,091)	(£1,176)	(£1,552)	(£1,201)	(£2,263)	(£2,202)
ARPR to achieve a project IRR of 10%	£445.00	£492.00	£902.00	£508.50	£1,152.00	£1,175.00
ARPR required to achieve a project IRR of 8%	£337.00	£372.50	£683.00	£385.00	£865.00	£892.00
ARPR to achieve a project IRR of 6%	£230.50	£255.00	£469.00	£263.50	£590.00	£614.00

- 4.2.13 The sensitivity of the project to changes in power prices has been examined in a number of ways, noting that it is complicated by the FiT creating a “step down” in prices when it ends. The sensitivity analysis shows that the single greatest influence on viability is the quantum of the FiT, which is illustrated in Table 14.

Table 14: Project NPV (m) for varying electricity wholesale electricity and FiT prices

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Base Case (Wholesale electricity price is £56.25 FiT is £160)	(£1,171)	(£1,249)	(£1,594)	(£1,273)	Not recorded ⁴	Not recorded
Electricity Price £56.25, FIT is £240	(£817)	(£911)	(£1,391)	(£940)	(£2,088)	(£1,999)
Electricity Price £56.25, FIT is £320	(£551)	(£649)	(£1,189)	(£676)	(£1,868)	(£1,796)
Electricity Price £95, FIT is £160	(£1,170)	(£1,249)	(£1,593)	(£1,272)	(£2,308)	(£2,201)
Electricity Price is £95 in 2020 and rises at RPI + 0.5%, FiT is 160	(£1,169)	(£1,248)	(£1,593)	(£1,271)	(£2,307)	(£2,201)

⁴ The financial model is designed to deal with a wide range of sensitivities, however when the Net Present Value of free cash flow is negative and the absolute value of this exceeds 50% of the capital expenditure, no value is recorded

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
Electricity Price £95, FIT is £240	(£816)	(£910)	(£1,390)	(£939)	(£2,087)	(£1,998)
Electricity Price £95, FIT is £320	(£550)	(£648)	(£1,188)	(£675)	(£1,867)	(£1,795)
Electricity Price is £160, FIT is £160	(£1,168)	(£1,247)	(£1,592)	(£1,271)	(£2,306)	(£2,200)
Electricity Price £160, FIT is £240	(£814)	(£908)	(£1,388)	(£937)	(£2,086)	(£1,997)
Electricity Price £160, FIT is £320	(£549)	(£646)	(£1,187)	(£674)	(£1,866)	(£1,793)

4.2.14 The sensitivity of the scheme variants to capital grants has also been examined. This has taken the form of calculating the amount of grant required to ensure that the project can achieve a positive return assuming an average electricity price of £160/MWh.

Table 15: Capital grant (m) required to generate a positive project return

Scenarios	A1.02a	A1.02b	A1.02c	A1.02d	A2.01a	A2.02a
At project IRR of 10%	£2,790	£2,920	£3,485	£2,960	£4,738	£4,749
At project IRR of 8%	£2,415	£2,590	£3,350	£2,648	£4,618	£4,657
At project IRR of 6%	£1,680	£1,950	£3,100	£2,030	£4,410	£4,527

5 Comparison of Schemes

- 5.1.1 All of the scheme variants have levelised costs of generation in the base case above £355 and therefore none can be considered to be economically viable under current market conditions without some form of support.
- 5.1.2 Of the six schemes under consideration, A1.02a, A1.02b and A1.02d clearly have a better economic performance than the other three.
- 5.1.3 Of these three, A1.02a has an economic performance that is 10.6% and 14.2% better than A1.02b and A1.02d respectively (measured against the ARPR to achieve a 10% project IRR)⁵.
- 5.1.4 A1.02c produces just 49.5% of the electricity output of A1.02a. Consequently the economic performance of A1.02a is 102.6% better than that of A1.02c
- 5.1.5 The construction costs of A2.01a and A2.02a are £4.268 billion and £4.196 billion respectively. These costs represent an uplift of 32.4% and 30.1% in construction costs compared to the other four schemes. As operating and refurbishment costs are calculated as a percentage of capital costs, these also have a similar uplift compared to the four A1.02 scheme variants. However, as the electricity output of these two scheme variants is lower, the consequence is that A1.02a has an economic performance that is 159% better than A2.01a and 164% better than A2.02a.

⁵ Measured against the levelised cost of generation, A1.02a has an economic performance that is 10.5% better than A1.02b and 14.1% better than A1.02d.

6 Recommendations for Final Scheme

- 6.1.1 Overall, further development is required to make any of the scheme variants commercially attractive to potential investors.
- 6.1.2 Of the six schemes under consideration, A1.02a is significantly better than the others. The financial modelling indicates that further study should be concentrated on this scheme.
- 6.1.3 Construction costs have the largest influence on the viability of the project and therefore should be refined further. Whilst refurbishment costs have less influence than construction costs, their effect is still significant, particularly on cash flow. Further refinement may show these to be lower and spread out more evenly than has been modelled in this study.
- 6.1.4 In this study we have assumed that operating expenditure (excluding renewals) is 1% of upfront capital costs. In reality, the operating expenditure will comprise:
- a proportion of “fixed” cost elements such as labour that are not related to the capital cost;
 - a proportion of “fixed” cost elements that such as insurance and National Non-Domestic Rates that are wholly or partly related to capital costs; and
 - a proportion of variable cost elements, which in many cases will be lower in the early years.
- 6.1.5 Refining operating costs may result in lower values, particular in the early years when maintenance requirements normally tend to be lower.
- 6.1.6 Whilst it is probable that the wholesale market price of electricity will rise to circa £95⁶ per MWh in real terms by 2020 (and are likely to continue to rise thereafter), this alone will not be enough to make any option economically viable. Mersey Tidal Power will therefore be dependent on a support mechanism and/or a capital grant if it is to proceed. The details of the FiT will not be known before June 2011, therefore it is not yet known what support (both price support and longevity of support) will be available. Consideration should be given to delaying further study until the FiT details are known.
- 6.1.7 The project is highly sensitive to the value of the FiT. Using the financial model, it is possible to calculate that, with a wholesale market price of £95 and a FiT of 50 years duration, a FiT strike price of £494.00 per MWh would be required to achieve a project IRR of 10% for A1.02a.
- 6.1.8 If capital costs are reduced by 30%, with a wholesale market price of £95 and a FiT of 50 years duration, the FiT strike price required to achieve a project IRR of 10% for A1.02a would reduce to £346.00 per MWh.

⁶ derived from Chapter 5 of the EMR consultation document

7 Assumptions and Limitations

7.1.1 The key assumptions used in this work-stream are given above in Section 2.2. The detailed assumptions used in the financial model are attached as an excel spreadsheet.

7.1.2 This assessment is limited by

- the unknown nature of the future renewable energy support mechanism that would apply to Mersey Tidal Power; and
- capital and operating costs that are not derived from a detailed design.

8 Summary

- 8.1.1 The financial modelling study has examined the economic viability of six schemes by means of a fully functioning financial model.
- 8.1.2 Using capital and operating cost assumptions and electricity output assumptions supplied by the project team, the levelised cost of generation has been calculated for the base case for each scheme variant. At a discount rate of 10%, these ranged from £456.06 for A1.02a to £1,197.43 for A2.02a. These levelised costs of generation are higher than the £211 achieved for the best scheme in the Severn Tidal Power commercial assessment.
- 8.1.3 By varying the construction costs and the operating costs, the sensitivity of the levelised costs of generation to changes in costs has been examined. This found that the factor with the greatest influence on the levelised cost of generation is construction costs.
- 8.1.4 By additionally using:
- assumptions about the wholesale price of electricity;
 - financial assumptions based on other large renewable and infrastructure projects; and
 - an assumption that the project will qualify for a Feed-in Tariff that will have a strike price of £160 for a period of 50 years,
- the project NPV for each scheme variant was calculated. At a 10% discount rate, these ranged from -£1,171 million for A1.02a to -£2,000+ million for A2.01a.
- 8.1.5 The model was also used to calculate the average real price (of electricity) required (ARPR) for each scheme variant to achieve a positive project IRR. For an IRR of 10%, the ARPR ranged from £491 per MWh for A1.02a to £1,295 per MWh for A2.02a. For an IRR of 6%, the ARPR ranged from £258 to £688.
- 8.1.6 The best scheme variant was A1.02a and the worst was A2.02a. The economic performance of A1.02a was better than that of other schemes by a factor that ranged from 10.7% to 164%.
- 8.1.7 As the future form of support for large renewable projects will not be known until June 2011 at the earliest, consideration should be given to delaying further study until then.
- 8.1.8 Any future studies should concentrate on A1.02a and be focussed on detailed capital and operating expenditure.

9 References

Department of Energy and Climate Change (2010) *UK Electricity Generation Costs Update*, London

Department of Energy and Climate Change (2010) *Electricity Market Reform Consultation Document*, London

Department of Energy and Climate Change (2010) *Severn Tidal Power Commercial Assessment Volume 1*, London

