APPENDIX C

3.1 The Role of DPSE in Electricity Generation in Malta

The demand for electrical power in Malta, for the time period used for the analysis, is based on an estimated demand of 2,135,000MWh in 2010, with a projected growth rate of 0.5% per annum thereafter. The relatively subdued rate of growth takes into account:

- the increase in the price of energy in recent years which is likely to be protracted in future, and which is leading to more efficient energy use;
- the reliance on alternative sources of energy, also in view of Malta's international commitments in this regard;
- the changing structure of Malta's productive base, which is tending to shift towards less energy intensive service activities.

It is thus assumed that energy to be serviced by Enemalta will amount to 2,157,000MWh in 2012, 2,241,000MWh in 2020 reaching 2,367,000MWh by 2031.

The way in which Enemalta expects to meet this demand is affected by the following considerations:

- the Marsa Power Plant will be decommissioned by end 2013;
- the DPSE, with a 144MW capacity, will commence service in May 2012;
- the interconnector to the European grid, with a 200MW capacity, will be brought on line in October 2013;
- the existing Delimara Power Station plant is assumed to remain in service for the purposes of this analysis.

For reasons of optimising operational efficiency and economic and financial costs, Enemalta will seek to supply energy output to meet demand by utilising facilities in the following order of preference:

First preference - the interconnector to the European grid, which is expected to optimise costs from both the financial and emissions perspective, and is also a flexible source which can rapidly be altered to meet demand fluctuations up to its maximum capacity of 200MW;

Second preference - the DPSE plant, which is relatively modern and has better operating efficiency parameters compared to the existing plant;

Third preference – the existing Delimara Power Station plant.

The extent to which each of these three facilities will be utilised depends heavily on the hourly variations in electricity demand. If, for example, the demand for electricity in 2031, at 2,367,000MWh, were to be perfectly evenly distributed across the 8760 hours in a year, this would imply a demand of 270MW in each and every hour. Of these, 200MW would be constantly supplied through the interconnector, and 70MW by the DPSE plant, requiring no further electricity generation facilities, and actually potentially pointing to the possibility of a smaller DPSE plant. In practice, however, there would be wide variations in demand during the year. On the basis of 2010 data, Chart 1 shows that on an hourly basis, electricity demand can vary substantially from the average. For 16.4% of the time, for instance, demand in 2010 was between 50% and 75% of the average, while for 11.3% of the time,

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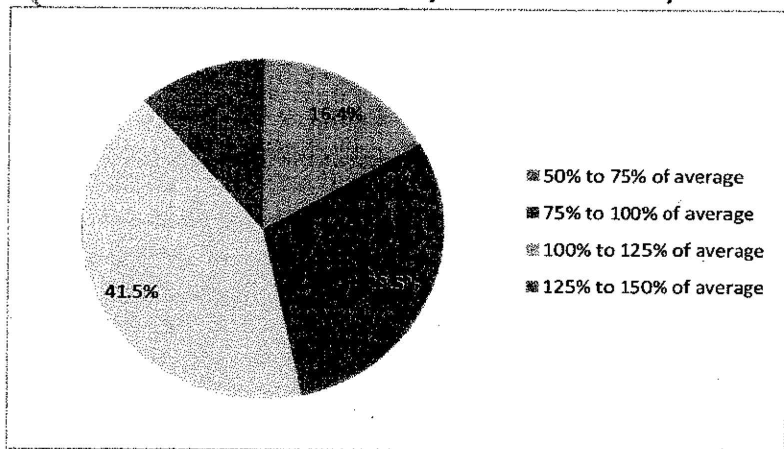
demand exceeded the average by at least 25%. Continuing on the example of the 270MW average hourly demand, should demand in a particular hour exceed the average by, say 40%, then demand would reach 378MW, requiring the input of the 200MW from the interconnector, the 144MW from DPSE, and the utilisation of other facilities as well. Clearly, in times when demand is 40% below the average, in this case at 162MW, the input from the interconnector would suffice. Therefore, the extent of demand variability will determine the amount of utilisation of the DPSE. Further complicating this decision is the fact that local power generating infrastructure is divided into units which, once switched on, must be kept operating for a minimum number of hours to ensure their efficient operation.

Chart 1: Distribution of Hourly Demand for Electricity



Source: Enemalta

The demand forecast, applied with the hourly variability patterns in 2010, and combined with the rules for preference and efficient operation of the facilities available, give a power generation plan as indicated in Chart 2. The Marsa plant will continue to play a role in power generation in 2012, accounting for around one-third of power generated by Enemalta, which role will diminish significantly in 2013 and will be completely absent in 2014. The DPSE will also account for around a third of power generation in 2012, and for an even large proportion, close to a half in 2013. With the full availability of the interconnector facility from 2014 onwards, the DPSE will be generating around one-fourth of the electrical energy sold by Enemalta. Thus, the interconnector facility will be responsible for close to three-fourths of electrical power supplied by the Corporation. The existing Delimara plant, which is expected to produce one-third of electrical power in 2012 and one-fourth in 2013, will be accounting for no more than 2% of all electrical power supplied by Enemalta from 2014 onwards. This information is provided in numerical form for selected years in Table 1.

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Chart 2: Expected Power Generation Plan

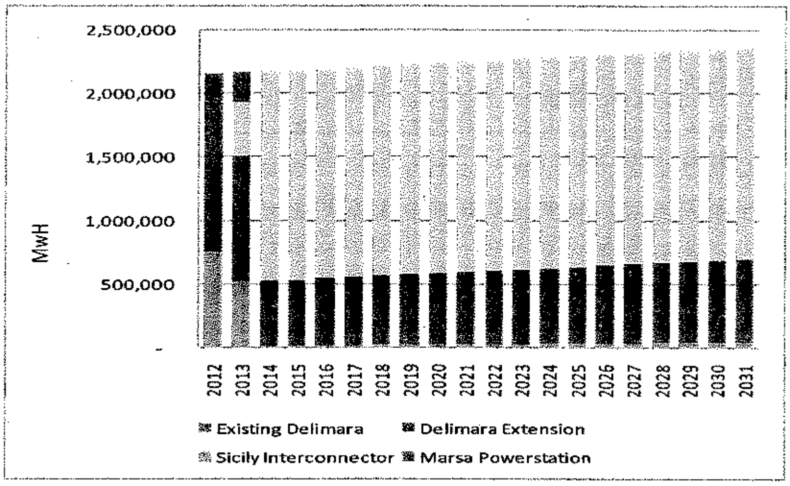

Table 1: Expected Power Generation Plan in Selected Years

MWh	2012	2013	2014	2031
Marsa Powerstation	750,706	233,876	-	-
Existing Delimara	756,576	520,020	16,862	48,830
Delimara Extension	649,728	988,721	512,605	652,827
Sicily Interconnector	-	425,177	1,645,056	1,665,282
Total	2,157,010	2,167,794	2,174,523	2,366,939

Underpinning these results is the calculation on the number of hours in each year for which the different power generation facilities will be utilised. Table 2 shows this information for selected years. From 2014 onwards, the inter-connector facility at 8,757 hours, would be in use practically all year round. Malta will be dependent on DPSE to fulfil its energy needs for between 6,900 and 7,437 hours between 2014 and 2031. The existing Delimara Power Station infrastructure will be in use for between 569 and 1,338 hours during the same period.

Table 2: Use of Electricity Generation Facilities

Hours in a year	Inter-connector	DPS Extension	DPS Existing
2014	8757	6900	569
2020	8757	7128	809
2031	8757	7437	1338

3.2 The Modelling of Operational Costs

In modelling operational costs under the three scenarios, costs are broadly divided into:

- the cost of fuel purchases, which is a major element in this regard;

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C3.1.1: Waste generation

Base load operation

Quantity generated per annum	Fuel type			
	HFO (1% S)	HFO (0.7% S)	Diesel (0.1% S)	Natural gas
Flue gas desulphurisation waste[7] (tonnes)	9,880 t (see 3.1.1)	6,916 t	Nil (see footnote 8)	nil
Spent catalyst[9]	see footnote 9	see footnote 9	see footnote 9	see footnote 9
Oil sludge (tonnes)	993	993	nil	nil
Boiler washdown sludge (m^3)	8	8	n/a (see footnote 10)	n/a (see footnote 10)
Catalyst wash water	nil	nil	nil	nil
Etc.	see table 12.2 in doc. C3.1.1	see table 12.2 in doc. C3.1.1		

Two-shift operation

Quantity generated per annum	Fuel type			
	HFO (1% S)	HFO (0.7% S)	Diesel (0.1% S)	Natural gas
Flue gas desulphurisation waste[7] (tonnes)	6,000	4,200	nil	nil
Spent catalyst[9]	see footnote 9	see footnote 9	see footnote 9	see footnote 9
Oil sludge (tonnes)	457	457	nil	nil
Boiler washdown sludge (m^3)	8	8	n/a (see footnote 10)	n/a (see footnote 10)
Catalyst wash water	nil	nil	nil	nil
Etc.	see table 12.2 in doc. C3.1.1	see table 12.2 in doc. C3.1.1		

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FOOTNOTE

7. The relative density of the flue gas DeSOx byproduct is between 0.7- 1.0, but is closer to 0.9.
8. There is no DeSOx requirement when operating on gasoil. However, the amount of waste generated by this fuel shall depend on whether the bag filters require a renewed coating of reagent when operating on this fuel. It is considered at this point that such coating may not be required.
9. Catalyst renewal is dependent on catalyst reaction depletion levels and follows a saw tooth curve. The first expected exchange of one catalyst layer, made of 484 elements is rated at 60,000 hours of operation.
10. The boiler washdown sludge when the plant is operating on gasoil or natural gas is not known, however, it is expected to be significantly lower than the case for HFO firing.
11 These values are based on the maximum levels of the fuel purchasing specficiations (Worst case). Actual values depend on consignment quality data.
12. Using BaP as a marker
13. Abatement plant, including DeSOx plant in operation
14. Abatement plant in operation excluding DeSOx plant since no DeSOx required on Gasoil
15 DeNOx plant only in operation.

Table 8: Estimates for Shadow Prices of Relevant Emissions

	Shadow Prices
Emission	**Price of emissions Euro/kg pollutant (EU27)**
CO2	0.0265
SO2	9.8
NOX	10.2
PM2.5	35.8
PM10	24.0
Dust	30.1
Nh3	18.6
Arsenic	771.8
Cadmium	121.9

Source: Handbook of Shadow Prices (2010) Table 16

* Prices used in the economic model have been adjusted based based on euro area inflation rate and a predicted inflation rate of 2%.

The price of emissions as reported in Table 8 and which are effectively taken for the purposes of this study pertain to EU27. The price of emissions could be refined to take into consideration Malta's relative income to the EU average by taking into consideration Malta's GDP per capita in PPS as 81%. This approach would however detract from the advantages of fuels with lower emission values. Therefore, the approach adopted here may be erring in favour of the relative advantages of low-emission fuels.

It is furthermore important to clarify at the outset that any methodology aimed at the estimation of shadow price effects is subject to considerable estimation variations and critical assumptions. The monetary values of damages per unit of the specific pollutants presented in the *Handbook* are no exception to this rule. The estimates presented in the *Handbook* use a variety of assumptions and models. There is thus a degree of uncertainty in the value of the estimates, particularly with regards to the valuation of health damages and the wide variation in published estimates of dose-effect relationships and monetary valuation of impacts.

It is to be added that there are no scientifically exact methods to measure shadow prices of emissions[7]. Values of shadow prices may furthermore change over time in the light of shifting political, social, and economic priorities. However, an estimate of such prices must be included in this type of analysis, and this assessment is being undertaken using the best available estimates at present. Nevertheless, in view of the inherent uncertainties, it will be important to undertake a sensitivity assessment with respect to different values of shadow prices to gauge implications on the baseline results.

[7] This is attested, for example, by outcome of the ExterneE Project http://www.externe.info/ financed by the EU Commission.

- the investment in gas infrastructure being cheaper by 26%;
- a 46% increase in the shadow price of emissions.

In the circumstances, a policy of flexibility in terms of the ability to use different types of fuel is advisable. This is especially in the light of the fact that the DPSE is projected to generate around 25% of Malta's energy requirements over the next twenty years, and will be required to supply energy for 85% of the time during a typical year. Its efficient operation will therefore be critical to the country's energy performance, from the financial and economic viewpoints.

It is furthermore to be considered that the operation and context of the energy market will be subject to important dynamics over the period, affecting conditions such as:

- prices of fuels, in absolute and relative terms;
- values placed on emissions, depending also upon political, economic and social priorities;
- the growth in the demand for electricity produced and/or supplied by Enemalta;
- costs of investments in Gas and other infrastructures;
- the availability and feasibility of the use of different energy production technologies in future.

All of these factors are bound to have a significant impact on the country's energy performance. This also implies that there can be no single unequivocal answer as to the cheapest cost solution regarding the type of fuel which the country should be utilising over the forthcoming 20-year period. It will therefore be essential for the country to be in a position to choose between different types of energy sources from time to time, and not necessarily to commit to any single source for a protracted period. At the same time, it will be essential for such technology to be operated in the most efficient manner possible, to optimise financial and economic performance and minimise any attendant risks.

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outside the objective of this report, in that the potential utilization of Gas, which can only start beyond 2015, would fall outside the purview of the current application for the IPPC. It is important however to note that the Gas option would not be devoid of risks, and these must be studied closely in any future application involving this type of fuel.

Potentially the most significant risks identified in the report:

- spillage during quayside oil offloading and transfer;
- catastrophic incident such as fire and loss of containment with application of substantial quantities of firewater, wherein the likelihood of such an incident is very small and current measures for control are considered to be generally appropriate to the risk;
- the handling and use of bulk chemicals and residues and the design and operation of the Effluent Treatment Plant.

Further details on these issues are provided in Annex 4.

It is to be noted that these risks already exist on the Existing Delimara Plant. However given that the footprint due to the extension is larger and given the fact that there will be additional plant and equipment the possibility of incidents with their associated risks may increase.

The report concludes that the risk assessment indicates that with the mitigation measures that the development has or proposes to have in place, the environmental risks are acceptable or tolerable. On this basis, this study finds no reason to consider such risks as being influential on the relative desirability of fuel options.

It may however be commented that from a wider economic perspective, it is important to ensure that emissions are kept within the expected limits. Therefore, an assessment of the risks associated with emissions is also warranted particularly in terms of the SCR emission abatement equipment.

7. Conclusions

On the basis of the analysis and discussion presented in this report, the following conclusions may be reached. In a baseline model which was founded on reasonable, but potentially varying, expectations about the future, the use of HFO to fuel the DPSE is found to be significantly more advantageous from a financial viewpoint and marginally more advantageous from an economic viewpoint. The next best option is Gas.

The financial advantage of HFO is robust to sensitivity assessments and actually improves significantly in the wake of energy efficiency in consumption, the utilisation of alternative energy sources and an increased reliance on inter-connection facilities. The economic advantage of HFO relative to Gas may be eroded by any one of the following conditions (everything else remaining the same):

- a 1% per annum increase in electricity demand;
- a 64% annual increase in crude oil prices;
- the relative price of gas to HFO declining from 110% to 95%;

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4.2 Emissions Values and Costs

The aim of this section is to derive the net present values of the cost of emissions over a 20-year period of operation under the three fuel scenarios. Towards this end, the value of shadow prices per unit of emissions must be combined with the values of the emissions expected under each scenario for fuel use. This requires, in the first place, the establishment of the amount of emissions per type of pollutant as would be applicable under each of the three types of fuel. Information in this respect is provided in Table 9.

The Table provides, for each fuel source, the expected amount of emissions in terms of grams per KWh of electricity produced or per metric tonne of fuel used. Information is relevant for the DPSE equipment and also for the existing Delimara plant, in that under the Gas scenario, the implications for emissions of the switch of fuel from Gasoil to Gas from 2015 onwards would have to be taken into account. As expected, Gas has the best performance in terms of emissions minimization, followed by Gasoil, with HFO having the worst performance. There is thus an immediately apparent trade-off to be made between the low financial costs of using HFO and the relatively high costs of emissions which this would entail.

The information presented in Table 9 was sourced from Enemalta, on the understanding that emissions values are subject to the specific characteristics and operating conditions of the power plant.

Table 9: Emissions Values

Emissions from Delimara Extension				
	Gas	HFO	Gasoil	Unit
CO2	415	576	551	g/KWh
SO2	nil*	0.73	0.365	g/kWh
NOX	0.49**	0.97	0.97	g/kWh
Dust***	0.09	0.33	0.198	g/kWh
Nh3		101		g/MT
Arsenic		0.0005555		g/kWh
Cadmium		0.0000257		g/kWh
* It is assumed that there is no sulfur content in the gas fuel.				
** There are conflicting figures regarding the emissions on NOX from gas fired diesel engine plant with Best Reference document quoting a range from 0.13g/kWh to 0.49g/kWh as translated to our plant. However, other sources in the same document also state a higher figure of 0.97g/kWh.				
*** The figures available between the three fuels are only for dust. Such figures do not discriminate between PM2.5 and PM10. The price of dust emissions has been taken as the relative Predicted Environmental Concentration of PM10 and PM2.5 noted in the EIA required for the planning extension of the Delimara Power Station.				
Emissions from Delimara Existing				
	Gas	HFO	Gasoil	Unit
CO2	498	N/A	658	g/KWh
SO2	nil*	N/A	0.134	g/kWh
NOX	0.102	N/A	1.41	g/kWh
Dust	0	N/A	0.0051	g/kWh
Nh3	0	N/A	0	g/MT
Arsenic	0	N/A	0	g/kWh
Cadmium	0	N/A	0	g/kWh

Source: Enemalta. Emissions values for DPSE were sourced from tender bidding documents and the application of IPCC and BREF2006 formulae to the extension plant. Emissions values for the existing plant were sourced from the application of IPCC formulae and LCP emission limits.