2.0 Technical and Environmental Constraints

2.1 Technical Constraints

Operational flexibility and high efficiency when operated on part load are the main technical constraints that need to be considered when selecting new generating plant.

The plant is required to have the capability to operate in load following, cycling and two-shifting modes apart from base load operation. This is due to the fact that the night time load can be as low as 160 to 170MW, with a corresponding day time load of about 260MW and an evening peak of about 280 to 290MW.

This large load change can be accommodated either by operating sufficient plant capacity for the daytime load and reducing the output at night or by starting and stopping plant daily. The cycling from full load to 50% or less load (overnight) can have seriously detrimental effects on the lifetime of the plant, particularly if these load changes are accompanied by changes in operating temperature, such as in the case of a steam and combustion plant.

During the period that the plant is operating at significantly reduced load the efficiency is expected to be reduced drastically. Similarly two-shift operation can result in both increased maintenance costs and the reduction of the lifetime of the cycled plant. Therefore it is essential that the plant acquired should be designed to be capable of this type of operation, so that the damaging effects both in terms of increased maintenance, reduced lifetime and reduced efficiency can be partially mitigated through use of superior materials and design.

2.2 Fuel considerations

2.2.1 Fuel Oil

At present all the electricity generated in Malta by Enemalta, is generated through the combustion of liquid fossil fuels, namely Heavy Fuel Oil (HFO) used in the production of steam for the steam turbine generators, and Light Distillate Oil also known as gas oil or diesel oil, which is the fuel used for the combustion gas turbine plant (both the open and the combined cycle plant). In the past Enemalta operated a number of boilers on coal, but these were converted to fuel oil firing during the 1990s mainly for environmental reasons.

Over the past two years there has been a significant increase in the demand for energy from the rapidly developing economies of China and India, which has placed severe strains on the supply of fuel, and which has resulted in significant increases in the cost of this fuel. Moreover most of the world's 'easy to extract' oil reserves are located in the Middle East, and with production from this area peaking, it may be expected to be less technically easy to extract therefore further pushing prices upwards.

Oil is also used as a raw material in the chemical industry for the production of chemicals, plastics, fertilisers, etc. As competition between the various industries for oil increases, the upward pressure on fuel costs can be expected continue and the quality of fuel available for the energy sector (combustion) will deteriorate as the more expensive and useful components are extracted for other purposes. This tendency which is already being felt and which may be expected to continue has an effect on emissions, which is contrary to the direction required by recent environmental legislation.

All member states are required under EU Directive 98/93/EC to maintain at all times within the territory of the EU, stocks of petroleum products corresponding to a level of at least 90 days average daily internal consumption. The expense of maintaining this stock has also to be considered when evaluating alternative fuels.

2.2.2 Coal

As stated above Malta has had experience with operating boilers on coal, and consideration of the use of this was given. However, a coal-fired plant has the highest emissions of CO_2 per unit of energy produced. Environmental legislation enacted since Malta's entry into the EU (NAP based on the Kyoto Protocol) would seem to preclude continuous operation with this fuel. Another major problem would be the disposal of the ash produced. However the EU has large reserves of this fuel, and a further advantage is that the price of coal is not expected to increase significantly in the short to medium term. Given that coal is cheaper when compared to fuel oil, for the same energy output, electricity derived from the combustion of coal has a significant economic advantage.

2.2.3 Natural Gas

Another attractive alternative to fuel oil is Natural Gas. This may be available either in the form of a pressurised gas supplied by pipeline or in liquid form (LNG) or in compressed form (CNG), both of which are supplied by tanker. Natural gas has the lowest emissions of CO_2 per energy produced when compared to the emissions when using fossil fuels. Added to the fact that natural gas is virtually free of any contaminants, this makes it the cleanest natural fossil fuel available. This fuel is available from many sources although the Middle East and North Africa appear to possess the largest reserves.

This fuel is largely supplied on long-term contracts, and the price is generally indexed to that of fuel oil. Preliminary indications are that as a consequence of these long term contracts, such fuel may not be available in the short term, although the relatively small amounts required by Malta may surmount this obstacle.

Enemalta has had no previous experience in the use of this fuel, however feasibility studies have been carried out to determine the viability of using either natural gas or LNG for power generation, whilst recently the possibility of using CNG was also mooted. The most recent was the feasibility study for a Sicily-Malta pipeline commissioned by the Government of Malta and carried out by ENI. The main conclusions of this study were:

- The Maltese market is small, with an approximate demand of 600million m^3 annually, assuming all power generation is converted to gas.

- The construction of a gas pipeline is technically feasible.

The projected cost of the pipeline at 2003 costs was approximately Lm40 million, but given the large increases in the costs of raw materials, particularly steel, this cost is today more likely to rise to Lm65 million.

Such a pipeline could be built and owned by a third party, with Enemalta purchasing the gas at an agreed terminal point. Natural gas could be sourced from either a European or a North African producer, in which case transmission fees would be payable to the gas network operator. Alternatively gas could be purchased from the Italian gas network operator directly. In this report, costs based on purchase of bulk supplies of gas from the Italian system have been assumed at the rate published by the Italian Energy Regulator for Jan-Mar 2006.

The other main option is the shipment to Malta of LNG, however although LNG is expected to be less expensive than natural gas, the quantities required by Malta counteract this benefit. Although on a small-scale, LNG terminals are being presently used in Norway and Japan. Such a small-scale system relies on frequent shipments, typically weekly, by a dedicated small LNG carrier. In such a case it would be feasible to convert the existing CCGT plant at Delimara. However in the event that more gas fired units would be available, both the size of the terminal would have to increase as would also the number of weekly shipments.

In such a case several dedicated LNG carriers will be required for redundancy and security of supply. It should also be noted that there are several major issues connected with the shipment of LNG, such as safety, terminal siting, environmental impact, tanker berthing, and security of supply. A detailed study is required should this or the CNG options need to be further considered.

Enemalta is aware that third parties in the private sector have for the past months been evaluating the possibility of an LNG terminal in Malta. Different private interests have also recently enquired about the possibility of delivering CNG by ship to Malta, and are pursuing their own studies. Enemalta is also informed that the Malta Resources Authority will shortly publish a Tender related to the energy generation and alternative fuels.

It should also be noted that given the possible disruptions to supply (bad weather for LNG shipments, supply interruptions or shortages on pipeline gas), a backup fuel would still be required. In the case of the gas turbine plant, this would be light distillate, although this would be expensive to store and would require periodic cycling to prevent deterioration in storage.

Assuming that this fuel would be available in Malta in the short to medium term, all plant can be converted to use this type of fuel. It is to be noted that such a move does not increase the efficiency of the present plant. It could effect plant output since the present steam plant may have to be slightly de-rated due to the different flame characteristics between oil and gas firing. Similar de-rating issues also affect other generating plant such as diesel engines. These derating values are not known. However, there would be a considerable improvement to the rate of emissions.

With the exception of NO_X, all significant pollutants would be reduced. As an added benefit, the boilers would then operate in a cleaner manner, improving their performance and radically reducing cleaning time during overhauls. The only remaining environmental problem with the present plant would be the CO_2 emissions due to possible requirements to comply with the Kyoto protocol emission reduction targets. As stated above, drastic CO_2 reduction would only be achievable by replacing the present plant with units of higher efficiency and or by reducing demand through demand management.

Natural gas may not be available before late 2012 at the earliest. Therefore, any plant, which, has to be installed before this date, has to be capable of dual fuel firing. Any plant after this date can be designed for gas firing with a standby arrangement for running on liquid fuel. The costs associated with this option are rather high and therefore it is usually uneconomical to switch back to other fuels should the gas supply contract go sour. This means that once this option is taken, the decision is practically irreversible.

2.2.4 Alternative fuels and Renewable sources of energy

The use of alternative fuels or renewable sources of energy is not expected to make a significant impact on the generation of electricity in the near future, since according to recent MRA studies, these are not expected to exceed 3% of demand by 2010. However Enemalta confirms its commitment to purchase and distribute all the electricity produced through the use of alternative fuels or renewable sources of energy by third parties locally.

Connection of decentralised generation sources could be beneficial to the network, if it can provide voltage support and reduce network power flows, thereby extending the life of the distribution system (in terms of capability to meet the required load flows). These benefits would be expected to increase the lower down in the distribution network that the decentralised generation is connected (Lower down in the distribution network means ‘at lower voltage’). Unfortunately, however, renewable generation suffers from three features which by contrast may require network reinforcement.

1. Intermittency

   Networks have to cater for intermittent generation, that may be present at times of low demand and not available at times of peak load.

2. Voltage Support

   Wind turbine generators typically use induction machines. These are not generally able to provide voltage support at the present state of technology although research is being undertaken on how to change this. Similarly photo-voltaics, which generate DC, which is then inverted to AC, will not generally be expected to provide voltage support.

3. Capacity factors

   Renewable generation based on the use of natural forces such as wind, sun, etc, typically have low capacity factors, and hence larger capacity must be installed than the equivalent conventional generation. This combined with the previously mentioned factors, may require substantial network reinforcement.

2.2.4.1 Refuse Derived Fuels (RDF)

Recent studies by WasteServ indicate that there is a potential of up to 16MW (thermal) available from the combustion of RDF produced by the San Antnin facility. In addition to this there is a potential of up to 10MW (thermal) from recovery at the Magħtab and Għallis landfills. Given an optimistic conversion efficiency of 40%, this would indicate a potential for electricity generation from waste derived fuels to be about 10.5MW, leading to a potential generation of about 88400MWhrs (3.3% of anticipated demand in 2010). A more practical use of this energy would be in the direct production of high quality distilled water, where efficiencies of 80% or higher are feasible.

2.2.4.2 Wind Energy

Several wind energy projects have been or are being considered. These vary from land based windfarms with generation capacities of the order of tens of MW, and capacity factors of typically 30%, to offshore windfarms with generation capacities of several tens of MW and capacity factors of about 50%. These projects suffer from relatively high capital costs and high levels of intermittency (lower for the offshore windfarms).

In addition to these large projects, the Malta Resources Authority is promoting the use of relatively low cost micro wind turbines, which can be installed over a wide area and would be effective in providing a decentralised source of supply infeed into the distribution system.

2.2.4.3 Photo-voltaic Systems

These are typically quite small systems, typically of the order of tens of KW or lower. The initial capital cost is high, giving a payback period in the order of 10 to 12 years but this is offset by the requirement for minimal maintenance and expected long lifetime (in excess of 25 years). They are mainly marketed to domestic and or commercial users, and if there is a sufficient take up, they could be expected to provide a small percentage of the required generation.

2.3 Environmental Constraints

2.3.1 Impact of Emissions Legislation

There are several EU environmental protection directives which effect the operation of the generating plant by imposing limits on emissions either on a per plant basis (the Large Combustion Plant directive, LCPD) or nationally under the National Emissions Ceilings Directive (NEC), the National Allocation Plan (NAP), the Integrated Pollution Prevention and Control Directive (IPPC) and the Gothenburg Protocol (not yet ratified by Malta).

The related European Union legislations and the transposed Maltese legal notices are as follows:

Table 2.1
Environmental Legislation

International legislation	Malta Legal Notice	Description
Directive 2001/80/EC	L.N. 329/2002	Large Combustion Plant Directive
Directive 2001/81/EC	L.N. 232/2004	National Emissions Ceiling Directive
Directive 2003/87/EC	L.N. 140/2005	Greenhouse Gas Emissions Trading Scheme
Convention on Long Range Transboundary Air Pollution	//	//
Directive 96/62/EC	Act XX of 2001 Environmental Protection Act	Ambient Air Quality Assessment and Management
Directive 74/464/EC	Act XX of 2001 Environmental Protection Act	Pollution Caused by Certain Dangerous Substances Discharged into the Aquatic Environment
Directive 99/31/EC	Act XX of 2001 Environmental Protection Act	The Landfill of Waste
Directive 97/265/EC	//	Eco-Management and Audit Scheme (EMAS) Directive
Directive 2002/49/EC	//	Assessment and Management of Environmental Noise
Directive 96/61/EC	L.N. 230/2004	Integrated Pollution Prevention and Control Directive.

2.3.1 Large Combustion Plant directive (LCPD)

2.3.1.1 Marsa Power Station

Malta (Enemalta) has declared in correspondence with the MEPA that should the existing plant (licensed before 1st July 1987) *"fail to comply with the National Emission Reduction Plan, then any plants which are non-compliant, shall not be operated for more than 20,000 hours starting from 1st January 2008 and shall end not later than 31st December 2015*". With the present mode of plant operation this 20,000-hour limited operation period is expected to be fully utilised by April 2010 for boilers 3-6 and August 2010 for boilers 7-8. The existing plant in question is all the steam plant at Marsa. This implies that if measures are not taken to reduce the emissions from these boilers a total of 210MW of installed capacity at Marsa will have to be replaced by 2010, failing which the Commission may be expected to initiate infringement procedures against Malta.

The total emission's of SO_2 depends on the quality of fuel used and as such, there is no problem with meeting the present SO_2 emission limit levels with the continued use of 1% sulphur fuel oil.

Dust emission levels are within LCPD emissions levels on Boilers 6, 7 and 8. However, NO_x from all plant and dust from chimneys 1 and 2 are above the limits.

The estimated cost for NO_x abatement for boilers 7 and 8 is approximately Lm 2,000,000 for primary measures. If secondary abatement is required, this is estimated at an additional capital cost of Lm 2,500,000 and an annual running cost of Lm1,200,000. This estimate depends on the technology adopted and the amount of electricity generated.

For the other units (Boilers 3 to 6), a study is required to identify the best approach for NO_x and dust abatement. However ball park estimates show that the capital cost of precipitators for boilers 3-5 and primary NO_x abatement measures for boilers 3-6 are approx Lm 3,500,000. An additional capital cost of Lm 3,500,000 and an annual running cost of Lm 800,000 would be necessary should primary NO_x abatement measures fail to satisfy the requirements. Such cost estimates again depend on the technology adopted and the amount of electricity generated.

It is to be noted however, that there are technical and space issues associated with the modification of the existing plant at MPS that may prevent the implementation of the above modifications or cause other more expensive solutions to be adopted. If no viable technical solutions can be found, then there is no option but to replace the steam plant at MPS with new generating units. It should also be considered that the plant in question is very inefficient (averaging less than 26% efficiency) and has been in service for over 40 years, therefore the benefit of such extensive and expensive modifications are likely to be short-term. It should also be noted that at this late stage, it would be very difficult to implement the required modifications by 1st January 2008.

2.3.1.2 Delimara Power Station

Malta obtained a 'transition period', which expired on the 1st of January 2006 from the provisions of the LCPD for the Delimara steam plant. This transition period was applicable to particulate emissions only and did not cover emissions of SO_2 and NO_x. The steam plant at Delimara is not compliant with the LCPD.

In order to achieve compliance with the SO_2 emission limit values, a lower sulphur fuel oil must be used or de-SO_x measures taken. It is not believed that there is space available for such de-SO_x plant, even if a permit to operate such a plant could be obtained from MEPA, given the problems associated with the disposal of by-products of the de-SO_x process. The most viable solution is considered to be the use of 0.7% S fuel oil at additional cost.

The reduction of NO_x will require extensive modifications to the boilers, and a tender for the engagement of consultants for this project has been issued. The reduction of particulates will require the installation of either electro-static precipitators or filters. Given the limitations on availability of the plant for extensive outage, it is not expected that this project can be completed in less than three years for both boilers.

The cost to meet the LCPD dust and NO_x limits vary from an estimated capital cost of Lm 5,000,000 for precipitators and primary NO_x abatement techniques. If secondary NO_x abatement is required, this is estimated to cost an additional Lm 2,500,000 with an annual running cost of Lm 1,200,000. This estimate depends upon the technology adopted and the amount of electricity generated. In the case of secondary NO_x abatement, there are a number of technical issues that need to be solved. Such solutions may require more additional expenditure.

2.3.1.3 Post 2003 Plant

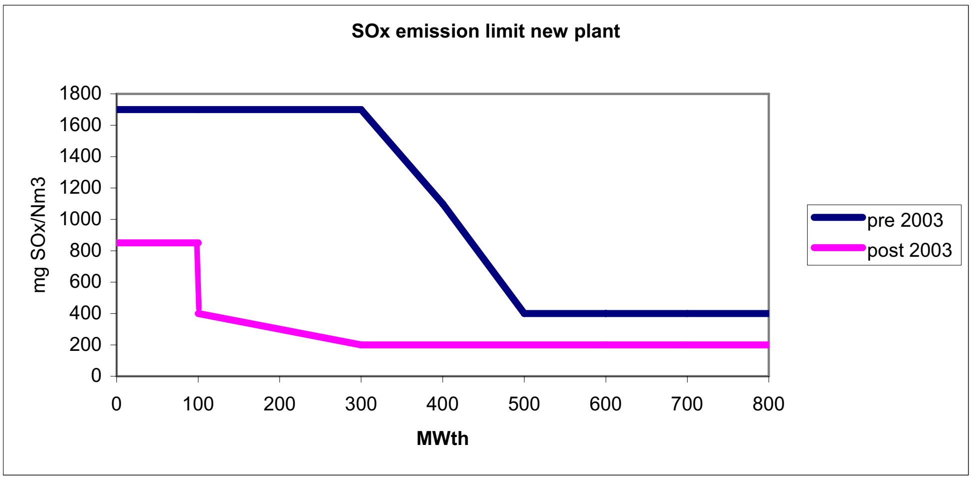
For the 'New Plant' licensed after 2003, i.e. all future plant, the emissions limits for SO_2 and NO_x would be considerably lower than those for all presently installed plant.

Gas turbines installed after 2003 will also be subject to NO_x limits (120mg/Nm3 for liquid fuel, 50mg/Nm3 for gas), whereas pre-2003 gas turbines are presently exempt from current emission limits.

As a result of the commissioning of the plant in 2003, NO_x emission limits have been lowered to 200 mg/Nm^3 for liquid fuel fired 60 MWe equivalent plant and the dust emission limits have also been lowered to 30mg/Nm^3 for liquid fuel fired 60 MWe equivalent plant.

The SO_2 emission limits for liquid fuel fired plant are shown below in Figure 2.1:

Figure 2.1
Sulphur Dioxide emission limits as per LCPD



These post-2003 SO_2 emissions limits implies that any new steam plant installed will have to be fuelled with an extremely low (<0.2 %) Sulphur fuel or the plant must have a secondary de-SO_x plant installed.

2.3.2 National Emissions Ceiling Directive (NEC)

The NEC provides for the national aggregate limits for emissions of SO_2, NO_x, Ammonia, VOC's and particulates after 2020. These limits include the emissions from other industries and users. The emission limits implied by the present and expected NEC limits are considerably more onerous to achieve than those required by the LCPD. These annual emission limits are mandatory from 2010. Table 2.2 below gives the national limits for 2010, the anticipated allocation for the energy sector and the anticipated 2020 limits from the present RAINS model which is expected to be adopted by the EU Commission as the basis for the 2020 NEC directive.

Table 2.2
National Emissions Limits - NEC directive

		2010		2020	
		National[1]	**Energy sector[3]**	**National[2]**	**Energy sector[2]**
SO_2	kt	9.00	7.50	2.202	2.105
NO_x	kt	8.00	4.00	3.503	2.004
PM_{10}	kt			0.629	0.248
$PM_{2.5}$	kt			0.361	0.177
Ammonia	kt	3.00	0	1.425	0.02
VOC	kt	12.00			

[1] From LN 232 / 2004
[2] From Present RAINS model
[3] Indicated from discussions with MEPA

Enemalta's (electricity generation) main concerns are the limits for SO_2, NO_x and ammonia, (since ammonia is used in post combustion secondary NO_x abatement applications). VOC's (volatile organic compounds) are of main concern to the petroleum sector, particularly volatile petroleum product storage facilities, since the contribution by the electricity generation section is limited.

2.3.2.1 SO_2 Emissions

The situation with the present generating plant, is that emissions of SO_2 by the power stations alone exceed the permitted limits, based on the use of 1%S HFO and 0.2%S gas oil. In order to reduce these emissions various options exist:

1. Change to fuels with an even lower Sulphur content.

2. Increase the conversion efficiency of the plant, i.e. burn less fuel for the same output. This would require the existing plant to be replaced by more efficient plant.

3. Reduce the total amount of electricity generated by the combustion of fossil fuels by the introduction of energy efficient appliances, local renewables, tariff structure, etc.

In order to meet the SO2 emissions limits for 2010, the emissions from MPS must be reduced by approximately 50%, either through the use of low sulphur fuel (0.5% S), or the installation of de-SOx plant, or by replacing part or all of the generating plant. If the replacement plant is to consist of a diesel engine plant operating on 1% S HFO, all the plant at MPS must either be shut down or lower sulphur fuel used, and only one 100MW plant may be installed, or a lower sulphur fuel used (or de-SOx plant installed) for the diesel engine. In order to meet the expected 2020 SO2 limits, the diesel engine plant would require use of 0.2%S HFO or have a de-SO_x plant installed

2.3.2.2 NO_x Emissions

The total NO_x emissions by Malta in 2000 are estimated to be about 11,000t of which about 50% is from transport, 41% from electricity generation and 9% from other sources (industry, etc). In order to reduce NO_x emissions to below the limit values indicated by MEPA for emissions from the power generation sector, simply meeting the LCPD limits may not be enough, and present power station emissions, estimated at 5000t annually will have to be reduced by more than 20% by 2010 and 60% by 2020. This assumes an allocation to the energy sector of 4000t/a in NEC2010 and 2000t/a in NEC 2020.

The National Emissions Ceiling directive is very difficult to meet and compliance will require either the extensive and expensive modification of the existing plant or its replacement by more efficient and environmentally friendly units or the replacement of part of the local generation by importation of electricity through a cable interconnection with the European electricity grid.

Table 2.3 shows the expected annual emissions of a typical plant generating 100MW operated at base load. As can be seen by comparison to the anticipated NEC 2020 limits, the diesel engine plant operating with maximum NO_x abatement at 90% efficiency cannot meet the specified limit values since one single 100MW block operating at base load under the specified abatement conditions will produce over 50% of the allowable emissions in the case of typical medium speed diesel plant and 75% in the case of typical slow speed diesel plant.

By 2020, the total load is expected to be around 650MW. The anticipated emissions are based on the present level of generating plant technology and the effectiveness of the available abatement techniques. If these abatement techniques improve as a result of technology improvements or if the plant is designed with lower emissions through developments in the combustion systems, then the situation would have to be reviewed.

Table 2.3
Comparison of Annual emissions (100MWe generating blocks operating at base load)

Plant type	**NO_x**	**SO_2**	**Particulates**	**Ammonia**	**CO_2**
	Tonnes	**Tonnes**	**Tonnes**	**Tonnes**	**Tonnes**
CCGT (diesel) [6]	521[1] 720[2]	257	85	0	448,000
CCGT (Gas)	<310	Negligible	Negligible	0	291,000
SSD (HFO)	1492[3]	2820[4]	106[5]	330[3]	493,000
MSD (HFO)	1024[3]	3000[4]	96[5]	662[3]	520,000

[1] With maximum water/steam injection for maximum abatement
[2] Abatement to LCPD limits
[3] $DeNo_x$ unit operating at 90% efficiency
[4] HFO with 1% S content assumed
[5] Precipitator installed (80% efficient)
[6] Diesel fuel with 0.1% S content assumed

New environmental standards require changes in policy regarding electricity generation which will continue to change in the future.

Malta's size determines the fact that electricity generation section is a major contributor to the level of pollutant emissions in Malta. The various regulations concerning the emissions into the environment are going to have an impact on the operations of the organisation.

It should also be noted that the use of a large generating plant leads to economies of scale and makes the use of lower quality fuels and subsequent use of secondary abatement techniques economically viable.

One of the main issues that must be faced is the continued operation of the present plant at Marsa Power Station. This plant is inefficient by modern standards and contributes both to a high fuel bill as well as to the environmental impact. Replacing the plant will make long term financial sense especially in the light of the high fuel costs as at present.

2.3.3 The 1999 Gothenburg Protocol

The 1999 Gothenburg Protocol, also known as the Convention on Long Range Transboundary Air Pollution, sets national emissions ceilings for Sulphur Dioxide, Nitrogen Oxides, Ammonia and VOC's, based on a progressive reduction of emissions from 1990 levels. Allocations for Malta have not yet been determined.

The Protocol also imposes limit values on emissions from the power generating plant, which are similar to those of the Large Combustion Plant Directive, with the following exceptions.

The provision (described in 2.1.1 above) for existing plant which is not compliant with the limit values given, to operate for 20,000 hrs as from 1st January 2008 is not allowed under the Protocol. The limit values for existing plant come into force as soon as the protocol is ratified.

The exclusion given to stationary diesel (compression ignition) engines from the provisions of the LCPD are not allowed in the case of NO_x emissions, where a limit value of 600mg/Nm^3 at 5% O_2 content is stipulated for new plant.

For a 100MWe diesel engine plant (SSD) with typical NO_x emissions of 7486mg/ Nm^3 at 5% O_2, NOx abatement to 92% efficiency is required. This will require the use of a large SCR plant and the consumption of approximately 15,000t of ammonia annually, with an estimated loss (ammonia slip) to exhaust of over 330t ammonia annually.

2.3.4 The National Allocation Plan

The National Allocation Plan (NAP) was prepared by MEPA for the three-year period from January 2005 to December 2007. It sets limits on the emissions of greenhouse gases (GHG), and is incorporated in an EU wide Emissions Trading Scheme (ETS). A second NAP is now to be prepared by MEPA to cover the five-year period from January 2008 to December 2012. At present there are only two installations in Malta which fall under the NAP, namely the two power stations operated by Enemalta.

The NAP takes into account the disproportionate effect that single developments can have on small systems and allocations covering these events have been provided considering the effect of these developments on electricity consumption both in terms of an increase in consumption and in terms of increased non-Enemalta generation. The NAP therefore takes into account both natural growth in consumption as well as the added consumption as a result of large developments which in small systems tend to be disproportionate and have an effect greater than in larger systems where the effect is averaged out.

The proposed allocation for CO2 emissions from the two Enemalta power stations for the five-year period 2008-2012 is 9.826 million tonnes, equivalent to an annual average of 1.965 million tonnes. It is expected that until the new generating plant is installed, i.e. in the period 2008-2010, the annual emissions of CO2 from Marsa and Delimara combined, will slightly exceed this annual average, therefore in order to avoid the necessity of purchasing emissions allocations under the EU Emissions Trading Scheme (ETS) the new plant should have lower emissions.

An allocation of 3.439 million tonnes over this five year period will be held in reserve for new entrants to power generation (or other sectors which may be covered).

It should be noted that the allocation under these two NAPs are more or less based on a ‘business as usual’ policy, since Malta, although a signatory to the Kyoto Protocol, is classed as a non-Annex 1 party which effectively implies that Malta has no GHG emission limitation commitments. However although Malta does not have any National reduction commitment, this is an exceptional situation within the EU (in fact it is a situation applying to Malta and Cyprus only). Should Malta at any time in the future be required or decide to meet the Kyoto Protocol 1990 emissions limits, this would be very difficult to achieve with a liquid fuel fired plant.

In this regard detailed consultations were held with MEPA in order to ensure that the future direction regarding a new generation plant ensures that Malta complies with the emission levels it is expected to assume on an EU and international basis. Since MEPA is the competent authority charged with this regulation, Enemalta has sought and obtained its guidance in a letter, dated .30th March 2006. It is clear from this letter, that in order to meet EU and international obligations on emissions levels, the new generation plant has to be gas fired. This is also apparent from the analyses carried out as part of this report.

3.0 Technical Options Available

There are several technical options available both for the replacement plan and for the generating units. These are summarised below together with consideration of the cases for a Sicily/Malta submarine cable and the continued operation of the present plant at Marsa Power Station, discussed at the end of this section.

3.1 Diesel Engines

These units are available as High, Medium and Low speed units and are primarily used for ship propulsion. High-speed diesels are normally rated up to 5MW and as such are not practical for use in Enemalta's power stations and will not be discussed further in this report. Medium speed units are most common with vessels below 30,000 tons dead weight. Low speed units are employed on practically all the larger commercial vessels.

3.1.1 Medium Speed Diesel Engines

Medium speed engines come in a variety of sizes up to about 18 MW. Delivery time and construction time for such units is 15 months or less for a green field site. One of the manufacturers claims that commercial operation of his machines can be done within 11 or 12 months from contract signing assuming a green field site.

These units are constructed on a production line basis and are therefore normally easily available. Such units are popular with island utilities and Independent Power Producers (IPP's). Electrical generation efficiency is in the region of 40 to 42%. One disadvantage of such a unit is the amount of maintenance required since engine interventions are required every 1500 hours. The actual achievable economic lifetime of such a generating plant operated as a two shifting, load following unit is also severely limited compared to base load or standby operation. This type of diesel engine was recommended for the previous 'Short Term generation Plan'.

Table 3.1.1.
Medium Speed Diesel Engine main data

Capital cost (incl. Auxiliary plant, buildings and abatement equipment)	euro/kW	600 - 750
Life expectancy	years	25
Economic lifetime	years	15
Availability rate	%	86
Overhead and Maintenance Cost	euro/MWh	10.7(HFO) 10.5(LD) 8.7(NG)
Efficiency at MCR	%	44
Fuel types used		Gas; light distillate; HFO
Output range	MW	Up to 18 MW
Lubricating oil consumption	g/kWh	1.0

Overhead and Maintenance figures for liquid fuel in the table are based on a report issued by the Institute of Diesel and Gas Turbine Engineers. Another source (EDF) quotes 68 euro/kW output/year +2.4 euro/MWh. This is broadly equivalent to 12.7 euro/MWh for HFO fired units based on a 15% forced outage rate and 10% scheduled maintenance rate.

3.1.2 Slow Speed Diesel Engines

Most of the comments for medium speed units apply for the low speed diesels. However, low speed diesels tend to be rather large and capital cost-intensive machines. Such units normally operate on HFO and due to their economics are usually operated as base load units. The efficiency of such units has now reached the high figure of 50%. The power output range of such units has now reached up to 100 MW. One characteristic of the slow speed diesels is the amount of harmonics that they emit on the network. A detailed study regarding the electrical matching between these machines and the ones we have already installed would probably have to be conducted.

Table 3.1.2.
Slow Speed Diesel Engine Main Data

Capital cost (incl. Auxiliary plant, buildings and abatement equipment)	euro/kW	965 – 1300
Life expectancy	years	30
Economic lifetime	years	20
Availability rate	%	87
Overhead and Maintenance Cost	Eur/Mwh	2.17 (HFO) 2.16 (LD and NG)
Efficiency at MCR	%	49
Fuel types used		Gas; light distillate; HFO
Output range	MW	Up to 100 MW
Lubricating oil consumption	g/kWh	1.2

The Overhead and Maintenance figures are based on a report issued by the Institute of Diesel and Gas Turbine Engineers for the liquid fuel figures. The natural gas figures have been kept equal to the LFO figures. EDF quotes 63.6 euro/kW output/year +2.14 euros/MWh. This is broadly equivalent to 10.6 euros/MWh for HFO fired units (based on 8% forced outage rate and 7% scheduled maintenance rate).

In general terms, all diesel engines have very high emissions and are noisy (70dBA at 100m away from the power house if no sound attenuation is employed). Due to the proximity of the power stations to inhabited areas, especially Marsa Power Station, noise and vibration attenuation would be a must.

One advantage of diesel units is the very low start up time. The ability to run on HFO is also an advantage for these units. However, the maintenance cost is higher in this case. Diesel engines also exhibit very high part load efficiency, which is typically the highest of any generating unit. Similar to gas turbines, start-ups have a number of equivalent running hours and therefore reduce the engine lifetime. Fuel for diesel engines must meet tight specifications especially for metal contaminants.

The capital cost range depends on the amount of units ordered as well as the non-standard items required by the operator to meet the demand profile and environmental regulations.

3.2 Gas Turbines

These units are among the cheapest capital cost per kW output. However, these units are rather inefficient and utilise either gas or light distillate or both as their main fuel. Start up time is around 20 minutes and the units are relatively compact. Such characteristics result in these units being operated as emergency and on peak lopping duties. There are two basic variations of these units. One is the heavy duty type which is the type operated by Enemalta Corporation at present and the other is the aero-derivative type which is basically an aircraft engine modified for electric generator drive.

3.2.1 Heavy Duty Gas Turbines

As the name implies, heavy-duty gas turbines are rather more robust than aero-derivative gas turbines, however, the second type is more efficient. Gas turbines do not tolerate fuel contaminants since they suffer significantly from high temperature corrosion processes. Aero-derivative gas turbines are even more delicate in this respect. Both the efficiency and the power output of these units depend on the ambient temperature.

Table 3.2.1.1
Heavy Duty Gas Turbine main data.

Capital cost	euro/kW	400 - 500
Life expectancy	years	20
Economic lifetime	years	15
Availability rate	%	90
Overhead and Maintenance Cost	euro/MWh	3.2 (LD) 2.1 (NG)
Efficiency at MCR	%	31
Fuel types used		Gas; light distillate
Output range	MW	10 - 250

The above table is based on the heavy-duty type. The maintenance cost is based on a recent LTSA agreement between GE and Enemalta Corporation.

3.2.2 Aero-Derivative Gas Turbines.

Aero-derivative gas turbines are based on the application of aircraft technology to power generation. The aero-derivative gas turbines tend to be more efficient but are less robust and require better quality fuels than the heavy duty gas turbines.

Table 3.2.2.1
Aero-derivative Gas Turbine main data.

Capital cost	euro/kW	500 – 600
Life expectancy	years	20
Economic lifetime	years	15
Availability rate	%	88
Overhead and Maintenance Cost	euro/MWh	4.8 (LD) 3.1(NG)
Efficiency at MCR	%	38
Fuel types used		Gas; light distillate
Output range	MW	Up to 58 MW

The output figure is the maximum available to-day and is achievable with water injection. Without water injection the maximum power available is 52 MW. The maintenance figure has been based on the GE/Enemalta Corporation Contractual Service Agreement (CSA) multiplied by the ratio as specified in the 1993 EDF report. EDF estimated in 1993 the maintenance figure at 20.7 euro/MWh based on full load operation for 1200 hours/year on light distillate.

3.3 Combined Cycle gas turbine units.

When natural gas is available, these units are the most popular generating plant used. Such plant can achieve conversion efficiency of between 45 to 50%. Complex systems have been employed in some plants abroad to push efficiencies close to 60%. These units can also operate on light distillate as an alternative fuel. However, if long-term operation is contemplated with light distillate, there are some newer designs of gas turbines that are not suitable. These newer units unfortunately tend to be the most efficient of the series.

There are no references of such plant operating on HFO by utilities as the long-term fuel. Operation on Light distillate also requires the use of water/steam for De-NO_x purposes in order to meet the latest EU emission requirements. Natural gas environmental figures in this case can be achieved in the dry mode. Enemalta Corporation already has one such unit in operation at Delimara Power Station since 1998. Under normal circumstances, maintenance is only required at specified hours, which are major events. This contrasts with the maintenance on diesel engines, which tends to be more frequent but on a lower technological level.

Table 3.3.1:
Combined Cycle Plant main data.

Capital cost	euro/kW	700 - 1000
Life expectancy	years	20
Economic lifetime	years	15
Availability rate	%	88
Overhead and Maintenance Cost	euro/MWh	6.3 (LD) 4.3 (NG)
Efficiency at MCR	%	45-50
Fuel types used		Gas; light distillate
Output range	MW	55 – 375 (per block)

The maintenance figures were derived from the prices stipulated in the recent GE/Enemalta Corporation LTSA agreement. Other sources (EDF) quote a price in the range of 16-29.8 euro/kW (5.52-10.2 euro/MWh). Please note that these figures are for light distillate firing. For natural gas, the maintenance figure typically is reduced by 33%. Efficiency figures are also higher for natural gas firing than on light distillate. Gas turbines and CCGT units pay a price during each start up due to the reduction in lifetime of the unit. Such a reduction is dependent both on the machine design and the fuel used. If operation on light distillate is considered, the additional costs are estimated to be 1.2 euro/MWh for de-NOx purposes.

3.4 Conventional steam Plant.

At present, these units form the bulk of the electric power generation equipment in Malta. Such units operate on any fuel type available ranging from coal through all liquid fuels to gas. These are the only units that can produce over 1000 MW as single units. Compared to other electric generation machines, steam units suffer from a lower efficiency (25-35%) with the highest efficiency achieved by those machines with the higher output and supercritical boiler operation.

In Europe, fuel oil fired steam units are only used in Italy, Malta and Cyprus. Otherwise all other countries prefer to operate such units on coal due to its lower price which offsets the lower efficiency. There are some steam units, which, for environmental reasons run on gas, but this type of operation has been described as temporary until it is replaced by other generation types. For more details about the environmental restrictions applied to new plant of such type, refer to Section 2.3 of this report.

Table 3.4.1
Steam Plant main data.

Capital cost	euro/kW	1000 – 1450
Life expectancy	years	30
Economic Lifetime	years	20
Availability rate	%	80
Overhead and Maintenance Cost	euro/MWh	1.68
Efficiency at MCR	%	28 – 35
Fuel types used		Coal, HFO, gas
Output range	MW	40-1200

The capital cost figures exclude expenses required to meet the new environmental limits if the steam unit is to run on HFO. Such extra expenses include both De-SO_x and De-NO_x equipment and are estimated at approx 120euro/kW and a running cost of approx 30 euro/Mwh. The maintenance figures have been derived from the Enemalta Corporation's internal management accounts between 1999 and 2002. Other sources (EDF) quote a price in the range of 29-44 euro/kW (3.62-5.5euro/MWh assuming the unit runs at base load for 8000 hours/year).

One of the characteristics of steam units is their relatively long construction time when compared with other plant types. While GT and diesel engine based units can start commercial operation within 30 months of contract date – if not less – steam units can take approximately up to 40 months for construction and commissioning.

3.5 Re-powering

This technique involves the conversion of conventional steam plant into a CCGT unit by substituting the steam boiler with a combination of gas turbines and Heat Recovery Steam Generators and feeding steam to the original steam unit possibly converting the steam unit to operate on sliding pressure.

This technique results in a generating unit that is possibly cheaper than procuring a CCGT unit. However, it is to be noted that capital cost and efficiency figures are very site-specific since they vary with the condition and the amount of modifications required to the original plant. Therefore the economic advantage of having this option has to be studied more deeply before embarking on such a project. Thus this technique is not discussed further in the report.

3.6 Electric Cable link

Although this is not strictly electric generation equipment, it is another option that ultimately produces the same result. The link proposed would connect Malta and Sicily, which is the shortest route such a cable can take for connection to the grid in continental Europe. There are several advantages and disadvantages associated with such a choice, which are summarised as follows:

<u>The advantages:</u>

1. Relatively invisible to the Maltese citizen since there are no large noise and visual signatures attached to such an infrastructure as well as no air pollution.

2. Can be used as back up in case of emergency and therefore, a reduction in the spare capacity would be possible.

3. There would be no need for additional fuel storage facilities if the natural gas scenario would not materialise.

4. Depending on the cable contract, the present plant operation regime can be tailored to optimise machine efficiency. This however would then penalise the cost of electricity passing through this link.

5. Malta can satisfy at least some of the obligations regarding renewable electricity generation through buying renewable energy generated overseas through this connection.

<u>The disadvantages:</u>

1. Since the Italian tariffs are high, the source of electricity has to be sourced from outside Italy with the nearest cheapest sources being Greece and France. Other countries e.g. Norway, UK, Czech Republic, etc., are further away and therefore network restrictions and increased network fees may apply in some cases.

2. The Italian power system has a demand profile which is similar to that of Malta. It also has revealed itself to be rather weak in electricity generation capabilities. Such weaknesses can

manifest themselves during concurrent high demand periods on the Maltese and Italian grids and therefore lead to problems during high peak demands.

3. As with the failure of any large unit, if the cable connection is lost when supplying a load greater than 60 MW, local grid instability may result, leading to partial shut down of the generation facilities running at the time, at least until the gas turbines can be started up and synchronised.

4. Any damage that can occur on the cable/s can take a long time to repair, which is estimated at one month on average. Since this repair has to be carried out by specialised foreign contractors, it can also be assumed that it would be rather expensive.

5. For reliability and security of supply a redundant cable link is necessary, so that maintenance work can be carried out without interruption to the supply.

The large interconnected European electricity grids are extremely stable when compared with island systems which may improve system reliability locally. However recent experience has shown that in times of localised energy shortages, each country puts its national interests above that of overseas contractual obligations which could impact on the reliability and security of supply, especially during periods of concurrent peak demand. It is also not good practice to rely on electric cables for supply without having backup generating plant available in case of interruption of supply due either to a fault (land cables, converter stations, sub-marine cables) or other reasons. Hence for security of supply reasons, a cable interconnection needs to be backed up by alternative sources of supply.

The installation of a submarine cable interconnection with the European grid will result in Malta's electricity distribution system losing the status of a 'Small Isolated System'. A report on the foreseeable consequences of this change in status has been prepared by the EU Affairs Office. The consequences are not considered to be a significant obstacle to the installation of such an electric cable interconnection.

It should also be noted that the anticipated outage duration for a submarine cable fault is in the order of 30 days and would require a specialised vessel and specialist personnel. If an electric cable interconnection is installed, the reserve capacity required to ensure security of supply, should include the cable rating and the largest generating unit, if the rating of one single cable is more than the rating of the largest generating unit, i.e. if one or more 100MW rated cables are installed, the reserve capacity required would be 160MW to 200MW.

Similar to the gas pipeline situation, since the Maltese internal market is very small, the economics of the cable connection are extremely marginal. Moreover, EU regulation states that any extra pollution that a country generates in order to supply another country with energy, is to be accounted for by the receiving country. This therefore does not exonerate Malta from its environmental obligations unless fossil fuel free energy is procured.

Three versions on this option are listed below, based on the report "Malta-Sicily Interconnection Pre-Feasibility Study" – EDF – October 1995

Table 3.6.1
100 MW peak demand consisting of one cable link and associated equipment. (Non-Redundant Link).

Capital cost	euro/kW	670 – 900
Life expectancy	years	30
Availability rate	%	95
Overhead and Maintenance Cost	euro/MWh	1.6
Efficiency at MCR	%	Not applicable. This will depend on external contractual factors.
Fuel types used		As above.
Output range	MW	100 MW for peak demand

Table 3.6.2
100 MW base load option consisting of two cable links and associated equipment.

Capital cost	euro/kW	830 – 1350
Life expectancy	years	30
Availability rate	%	95
Overhead and Maintenance Cost	euro/MWh	1.6
Efficiency at MCR	%	Not applicable. This will depend on external contractual factors.
Fuel types used		As above.
Output range	MW	100 MW for base load demand

Table 3.6.3
200 MW base load option consisting of two cable links and associated equipment.

Capital cost	euro/kW	650 – 847
Life expectancy	years	30
Availability rate	%	95
Overhead and Maintenance Cost	euro/MWh	1.38
Efficiency at MCR	%	Not applicable. This will depend on external contractual factors.
Fuel types used		As above.
Output range	MW	200 MW for base load demand

One of the major unknowns of this option is the electricity cost as this would be subject to a negotiated contract. As can be seen from the above tables, economics of scale are evident in the last version. However, this option will definitely result in a large disturbance on the Maltese electricity grid should one of the cables fail under full load condition.

Experience has shown that similar sized unit trips have resulted in total shut down. Further technical investigations on this matter and the short circuit capability of the networks involved would be required if this option is to be selected.

3.7 Plant Operational Duty

As stated previously, there are three basic types of generating plant:

- Base Load plant

  This type of plant is used for a long continuous period usually in the region of more than 8000 hours per year. Such plant usually operates on the cheapest fuel available and is traditionally composed of steam units running on the cheapest available fuel on site. The generation plant in Malta is mostly composed of this type of plant.

- Two Shifting Plant

  This plant is capable of being switched on and off every day. Although in theory, every type of generating plant is capable of operating in such manner, special design features have to be incorporated in the plant in order to relieve the mechanical and thermal stresses associated with such an operation mode. In Malta, the CCGT unit at Delimara Power Station operates in this mode.

- Peak Plant.

  This type of plant normally operates for less than 1000 hours per year in order to cover peak demand periods. Such plant is also used for emergencies when the other more economical plant is off line for repair. This plant may also be used for black start up purposes after a total shut down. It is normal that for this type of plant, the units with the cheapest capital cost are chosen. Since the operation of these units is rather limited, capital cost rather than fuel efficiency considerations is the limiting factor. These units are normally gas turbines. Diesel engines are also used in certain cases for this type of operation since both gas turbines and diesels offer short start up times.

The most versatile plant is the two shifting type. Another advantage of this type of plant is that it can also be used as base load plant although the economics would then vary due to the fuel cost.

For peaking duties, Enemalta Corporation has three gas turbines installed at the power stations. These offer a total of slightly over 100 MW available in this mode. Under the present conditions, this amount of power (one sixth of the installed) is considered sufficient. Therefore, it would not be practical to continue to purchase any more of these units. These three units are also used by Enemalta to provide the 'Black Start' capability that in the event of a total shut down is necessary to restart the main plant.

The new generation plant is also required to replace part of the older plant at Marsa Power Station, which is of the base load type, and is well below today's standard of efficiency. The present MPS plant has been designed for base load operation and experience shows that damage can result if the plant is operated in the long term in any other mode. During spring/autumn periods, there are difficulties in operating the station during nights since the minimum load is sometimes not sufficient to keep the station running and there have been cases where plant has had to be shut down for the night and started up during the early hours of the day. This has had major consequences on the plant reliability and availability with a large increase in the incidents of tube failures and general unavailability due to forced outage.

It would be advantageous to procure plant which would be designed to cope with the stresses associated with a two shifting operation and which is also economically suitable for operation under base load conditions if required.

3.8 Plant replacement plan

From the projected load growth and the constraints previously explained, it is clear that:

1. An additional capacity of approximately 300MW is required by 2010 to meet the expected demand and to retire the Marsa steam plant if it is not made compliant by 1st January 2008 (at this late stage, a highly improbable target);

2. That additional capacity should be available for summer 2008 in order to ensure security of supply;

3. Another 100MW of additional generating plant is required in 2011;

4. Another 50MW of generating plant is required in 2015 in order to maintain a reserve capacity of at approximately 120MW.

The following table (table 3.8.1) shows the impact of this planned new generating plant on the reserve capacity (as a measure of security of supply) however even this would not ensure that the required reserve capacity is available at all times particularly during the peaks.

Table 3.8.1
Impact of planned new generating plant on Reserve Capacity

	Available Generating Plant Capacity (MW)	**Low Growth rate (3%) (12MW/annum) + planned developments**		**Medium Growth rate (4%) (16MW/annum) + planned developments**	
		Expected Summer Peak Load (MW)	**Reserve Capacity (MW)**	**Expected Summer Peak Load (MW)**	**Reserve Capacity (MW)**
2005 (actual)	495	411	84	411	84
2006	495	423	72	427	68
2007	495	442	53	450	45
2008	495	462	33	474	21
2009	595 (add 100MW)	488	107	504	91
2010	585 (add 200MW and MPS retired)	511	74	531	54
2011	685 (add 100MW)	532	153	556	129
2012	685	553	132	581	104
2013	685	570	115	602	83
2014	685	587	98	623	62
2015	735 (add 50MW)	604	131	644	91

Over the past 18 months Enemalta has considered various types of new electricity generating plant to meet its requirements. These have included medium speed diesel engines (MSD), slow speed diesel engines (SSD) and gas turbine combined cycle plants (CCGT). Traditional steam plant was also investigated However, due to the relatively low efficiency (circa 34%) of these units for the electrical power output range considered (60MWe), with respect to the other plant types which offer efficiencies in excess of 42%, steam units were not considered further.

The various liquid and gas fuel options for the plant have also been investigated. Due to various problems, particularly those associated with the disposal of ash resulting from the combustion of solid fuel (coal), this type of fuel was not considered.

From these investigations it clearly emerged that the least expensive generation units using a liquid fossil fuel (at present day fuel costs) are slow speed diesel engines fired on HFO followed by medium speed diesel engines also fired by HFO.

Unfortunately both these plant types have very high NOx emissions and even with the maximum practical post combustion abatement technology, using present Best Available Technology (BAT), the emissions of NOx from these HFO fired diesel engines far exceed the permitted levels under the National Emissions Ceiling directive (NEC) should these engines be primarily installed.

In fact the only plant which is able to meet the anticipated 2020 emissions limit values, without post combustion NOx abatement, are Natural Gas fired gas turbine combined cycle plants (CCGT). The same plant fired on light distillate (gas oil) may marginally meet the anticipated limit values. This situation may change in the future as more effective abatement technologies are developed, in which case the generation plan would need to be revised.

It should be stated that this is a change from the original recommendation given by Enemalta in February 2005.

It was originally planned to install two medium speed diesel engines of about 18MW output each, as part of a short-term generation plan. The plan also provided for the eventual installation of either additional medium speed diesel generation plant or slow speed diesel generation plant.

However, following discussions with MEPA on the provisions of the various EU environmental directives, it has been recognised that although offering the least cost generation option, the operation of such plant would result in Malta breaching National Emissions directives, particularly the NEC and the Gothenburg Protocol, incurring the risk of penalties for infringements.

The generation plan was then re-evaluated based on achieving compliance with the environmental directive, at the least possible generation cost. On this basis we considered gas turbine combined cycle plants initially fired on gas oil but planned for eventual changeover to gas fuel and an electric cable interconnection to the European electricity network.

Table 3.8.2 is a comparison of the installation and fuel costs of the different generating plant, based on 100MWe blocks operating for 8000hours per annum at base load. Table 3.8.3 shows the different plant types and the cost of generation based on fuel costs and the capital cost at NPV calculated over 30 years with plant replacement where necessary. Table 3.8.4 shows the various plant types and whether they meet the present anticipated emissions limits (from the present RAINS model for 2020) should plant replacement continue with the same type and rating of plant operating on present (BAT) abatement technology limits.

Table 3.8.2
Comparison of installation and fuel costs

Plant Type	Capital Cost	Maintenance Cost p.a.	Fuel Consumption	Fuel Cost
	Lm million	**Lm million**	**tonnes**	**Lm million**
CCGT (diesel)	40	1.35	135,200	25.82
CCGT (Gas)	40	0.92	150,400[1]	17.60
SSD	48	1.00[2]	144,800	14.01
MSD	30	4.85[2]	152,800	14.91

[1] value in $1000m^3$
[2] from comparative listing in "Journal of Institution of Diesel and Gas Turbine Engineers (May 2004)"

Assumptions: HFO Lm121/mt
Gas oil Lm202/mt
Natural Gas Lm117/$1000m^3$

Table 3.8.3
Comparison of generation cost of plan t- Based on calculated NPV over 30 years[*]

Plant Type	Expected Lifetime (years)	NPV unit cost for base load (MTLc/kWhr)	NPV unit cost for 2-shift load [2] (MTLc/kWhr)	Cost per kWhr[6] (base/2-shift)
CCGT (diesel)	15	4.16	5.39	High/High
CCGT (Gas)	15	3.03 [1]	4.31 [1]	Low/High
SSD	20	2.97	3.74	Low/Low
MSD	15	3.39	3.88	Low/Low
Cable interconnection [5]	30	4.96 [3] 4.77 [4]	n/a	High

[*] Inclusive of NOx abatement costs and fixed costs of Lm0.5million annually per unit to cover insurance etc.

[1] Inclusive of the cost of gas pipeline (pro-rata) over 4 blocks
(Gas pipeline cost taken as Lm4.7million/annum based on a 30-year lifetime and Lm65million capital cost)
[2] Assuming 360,000MWhrs generated annually
[3] Assuming 100MW base load operation
[4] Assuming 100MW base load and 200MW peak load operation
[5] Electricity supply costs through cable taken from Italian bulk production tariff (euro7.92c) + transmission charges (euro 2.33c) – From Autorita Energia Italian Regulator web site (Valid Jan-Mar 2006)
[6]Base Load/ 2-shift operation

Table 3.8.4
Comparison of plant types and emissions limits compliance.

Plant Type	Cost per kWhr[1]	Emissions	
		NEC limits 2010	**NEC limits 2020[2]**
CCGT (liquid fuel fired)	High/High	Meets present limits	Marginally meets present anticipated limits
CCGT (Gas fired)	Low/High	Meets present limits	Meets present anticipated limits
Slow Speed Diesel (HFO fired)	Low/Low	Meets present limits with 90% NO_x abatement and precipitators	Does not meet present anticipated limits even with 90% NO_x abatement
Medium Speed Diesel (HFO fired)	Low/Low	Meets present limits with 90% NO_x abatement and precipitators	Does not meet present anticipated limits even with 90% NO_x abatement
Cable	High	Depends on source of electricity	Depends on source of electricity

[1]Base Load/ 2-shift operation
[2]Based on present RAINS model

Table 3.8.5
Comparison of emissions from the main plant replacement options (2010)

	Emissions			
	SO_2 tonnes	**NO_x tonnes**	**CO_2 tonnes**	**Remarks**
Reference Case 2005 Actual	11802	5753	1952490	NO_x above 2010 limit SO_2 above 2010 limit
No New Plant in 2010	11508	7802	2306273	No Reserve Capacity NO_x above 2010 limit SO_2 above 2010 limit CO_2 above annual limit
Add 100MW SSD, 200MW cable, Retire MPS	6243	4565	1617601	NO_x above 2010 limit
Add 120MW diesel CCGT, 200MW cable, Retire MPS	2911	4034	1598084	
Add 3 new 120MW diesel CCGT, Retire MPS	2710	3711	1782158	
Add 120MW gas CCGT, 200MW cable, Retire MPS	1829	2029	1198736	
Add 3 new 120MW gas CCGT, Retire MPS	1776	2060	1201889	
Add 200MW cable, retire MPS 3-6 only	7061	4387	1824081	NO_x above 2010 limit
Add 120MW diesel CCGT, retire MPS 3-6	6969	5599	2031615	No Reserve capacity NO_x above 2010 limit CO_2 above annual limit
Add 120 MW gas CCGT, retire MPS 3-6	5514	3077	1574238	No Reserve Capacity
Add 2 new 120MW diesel CCGT, retire MPS 3-6	4798	4275	1893811	NO_x above 2010 limit
Add 2 new gas 120MW CCGT, retire MPS 3-6	3012	2191	1307419	
Add 100MW SSD, retire MPS 3-6	9853	7013	2038977	No Reserve Capacity NO_x above 2010 limit SO_2 above 2010 limit CO_2 above annual limit
Add 100MW SSD and 120MW diesel CCGT, retire MPS 3-6	8105	5210	1912850	NO_x above 2010 limit SO_2 above 2010 limit
Add 100MW SSD and 120MW gas CCGT, retire MPS 3-6	4705	2766	1375141	

Another very important consideration is that the present site at Delimara can only accommodate three more 130MWe CCGT type plants, which would give Delimara a potential total capacity of circa 694MWe comprising 390MW new CCGT at nominal rating of 130MW each (and only 300MW at summer rating of 100MW each), 110MW existing CCGT, 74MW open cycle gas turbines and 120MW steam plant. This, together with the 37MW open cycle gas turbine expected to be still operating at Marsa would give an installed capacity of circa 730MW.

The Delimara steam plant is planned for decommissioning by 2020 (after almost 30 years of operation) or earlier (for reasons of low efficiency as compared to newer plant). A new site would then be required to construct the replacement plant and since this is unlikely to be found, the only solutions are either to build new plant at Marsa or replace part of the generation by means of an electric cable interconnection.

In the event that all the generating plant at Marsa is decommissioned, the present power station site represents a potential source of capital and operating revenue due to its waterfront location either for industrial or commercial development. The feasibility or otherwise of this is not however part of this analysis.

The replacement of 200MW of HFO fired steam capacity at Marsa by an equivalent capacity of diesel fired CCGT plant and the installation of an additional 100MW of diesel fired CCGT plant to meet the increase in load expected by 2009, will increase the average unit cost by approximately Lm0.007 based on current fuel costs. Diesel fired gas-turbines will require extensive steam or water injection in order to meet the limits for NO_x emissions in the LCPD. This solution would also be required for the present CCGT plant in order to lower its NO_x emissions. Otherwise, the emission limits 2010 NEC directive would not be met. This is expected to significantly increase the maintenance cost on this type of plant, which is already very expensive.

In order to reduce the costs of operation of the new (and existing) CCGT and open-cycle gas-turbine plant, and possibly also the existing HFO-fired boilers at Delimara, and in order to further reduce emissions in accordance with current trends and possible future regulatory requirements, conversion of the plant to gas firing is required. This requires the availability of a source of supply and a means of landing the gas at Delimara either using a pipeline or a gas carrier.

It is estimated that a submarine pipeline connection to Sicily would cost circa Lm65 million. Availability of gas locally would also allow consideration of the use of alternative plant such as gas engines. These are presently excluded from consideration in the short to medium term since operation on liquid fuel (HFO or diesel) results in unacceptably high NO_x emissions. Operation of the gas turbines on gas will result in the minimising of emissions and will also effectively lower the maintenance cost since the maintenance intervals can be expected to increase by 33% or more.

The Malta Resources Authority (MRA) is preparing a call for tenders for consultants to carry out a study on ‘interconnections to the European Electric and Gas distribution grids and sources of alternative fuels’. This study will include evaluation of supply of LNG and CNG as well as renewable sources such as offshore wind generation. This MRA study is not expected to be completed before early- to mid- 2007 and the publication of this report may be too late for the above replacement programme for Marsa.

As indicated above, the target for commissioning and commercial service of the 200MW electric cable interconnection is 2010. It is expected that a project of this type would require at least four years from initiation to completion. If the project is carried out as a private sector initiative, this time period could possibly be reduced, unless EU funding of some sort is to be involved which would then require lengthier procurement procedures.

The proposed new CCGT plant would be expensive to operate on diesel fuel and ideally a source of gas would be required by summer 2009, which may be unrealistic given the present state of the gas market and the difficulty to secure adequate long-term gas supplies. However, in the event that gas is made available locally, this would then be used for all the existing gas turbine plant although several months need to be allocated for conversion of the existing gas turbines.

4.0 Financial Analysis

4.1 Economic Considerations

The options for the new plant hinge tightly on the fuel to be used and the mode of operation of plant. Both two-shifting and base-load operation modes are being considered.

The costs of reducing emissions using primary methods and application of ‘Best Available Techniques’ together with the operational costs involved in such abatement measures have been included in the economic analysis. However the total environmental costs of non-compliance and the general cost to society of emissions have not been considered in the economic scenarios taken. Such costs are smaller in the natural gas scenario when compared with the fuel oil one.

The inflation rate has been taken at 0% and the Discount rate has been taken at 6% (reduced from the usual Enemalta Corporation rate of 8%) per year to cater for the 0% rate of inflation. Project lifetime has been established at 30 years.

A fixed cost has been added to the maintenance figures to reflect salaries, insurance, chemicals, stores, administration, etc. These costs are independent of the amount of energy that the machine generates. This fixed cost has been taken at 1,200,000 euro per year for all the new machines while for the MPS plant it has been established at 4,800,000 euro (always per 100 MW of plant).

In all the economic scenarios, only the costs have been considered. The revenue associated with this plant has not been accounted. This enables one to establish a cost/kWh for any of the plant listed. Each choice of plant has the following factors to be taken into consideration:

4.1.1 Factors effecting cost

4.1.1.1 Plant construction time

This is the time taken from the signing of a contract to the time the plant starts producing energy. This also accounts for the fact that for some types of plant (steam in particular), the production of electricity starts at a later date than others.

4.1.1.2 Economic Lifetime

This is taken as the lifetime of the equipment after which the maintenance figure would have to increase as the lifetime expectancy of the plant would be reached. These values in table 4.1.1 are based on the premise that during the last years of operational lifetime, the maintenance figure increases considerably and economic figures of the plant may thus be doubtful. The economic lifetime is therefore less than the physical lifetime of the plant listed above. This economic lifetime is taken as per table 4.1.1. It is to be noted that in the case of Marsa Power Station, the economic life has not been stated since the steam plant in this station is already past its economic lifetime.

Table 4.1.1
Expected lifetime of equipment

Type of plant	Economic lifetime (years)
Steam Plant	20
Combined Cycle Gas Turbines (CCGT)	15
Heavy Duty Gas Turbine (HD G/T)	15
Aeroderivative Gas Turbines (Aero G/T)	15
Medium Speed Diesel Engines	15
Slow Speed Diesel Engines	20
Cable Malta – Sicily	30
Present MPS steam plant	N/A

4.1.1.3 Capital cost

This outlay is based on 100 MW plant output at maximum continuous rating and has been kept as a fixed price . In all cases, due to the 30-year project lifetime considered, two plants are installed in tandem with the installation interval depending on the economic life of the type of unit involved.

4.1.1.4 Residual Value

The plant is assumed to have zero residual value at decommissioning.

4.1.1.5 Fuel Cost

The Fuel cost varies with the type of machine due to efficiency, type of fuel used and plant start up date due to the construction and commissioning time. Fuel prices have been taken at the present three month average (Jan-March 2006) prices without any price escalation following consultations with the Financial Section. The liquid fuel prices include transport while the natural gas value is the Italian regulator tariff for Jan-Mar 2006.

1% Low Sulphur Heavy fuel Oil:	Lm 121 per ton
1% Low Sulphur Heavy fuel Oil for diesel engines:	Lm 123 per ton
Light Distillate:	Lm 202 per ton
Natural Gas:	Lm 117 per $1000m^3$

A Lm2 premium was added to the HFO for diesels because of the superior quality of fuel required by the diesels with respect to the steam plant, primarily the lack of catfines.

The cases for base load and two shifting plant operation were considered. Base load operation has been calculated on full load operation for 8000 hours (91.3% availability) while the two shifting operation has been calculated for a 16 hour operation for a duty of 5 days a week, 45 weeks a year. The new plant is expected to operate normally on the two shifting regime. However, due to other plant outages, the new plant may also be occasionally required to run at near base load operation.

The efficiency figures for these two load cycles are different since the machine efficiency varies according to the power output. However due to multi-unit configuration in the case of gas turbines and medium speed diesel engines, this has a lower effect since such units are started up in sequence according to the load demand, thus having these units operating at near full output. For steam units, this type of plant exhibits a flat efficiency curve above 50% output.

It is to be noted that the present Delimara plant is not being considered for replacement in the time period covered in this report since it is still within its economical lifetime and the steam plant at Marsa Power Station is less efficient than the plant installed at Delimara Power Station.

4.2 Impact on the cost of generation

The impact of the proposed generation plan on the cost of electricity generation has been estimated in the following tables. This estimation is presented for comparison purposes only and is based on the present fuel and operational costs and does not take into account any major changes in the differentials between the various fuel types or inflation. It does not represent a prediction of the actual cost of electricity in the future.

Table 4.2.2 gives a summary of the anticipated effect of the various main generation plant and fuel options on the unit cost of electricity depending on growth in electricity consumption. The calculations are based on the following fuel and capital costs and present Enemalta Corporation overheads (no inflation). These cost assumptions are listed in table 4.2.1.

The following assumptions have been taken:

All steam plant is assumed to be operating to LCPD limits.

Fuel costs (HFO and gasoil) are taken as the average actual cost for the first quarter of 2006.

Generated unit tariff includes generation overheads, cost of environmental compliance with LCPD using primary abatement only for present plant, secondary abatement for diesel engines and water injection for liquid fuel fired CCGT plant. No costs for abatement for gas fired CCGT plant since these units do not normally require any such technology to meet the present emission limits. Direct generation operating costs have also been included.

HFO 0.7%S is required so that the present steam plant at Delimara would meet the LCPD SO_2 emissions limits.

SO_2 emissions from the liquid fuel fired gas turbines have been estimated using gas oil at 0.1%S. This type of fuel is legally required as from 1st January 2008.

Final tariff includes distribution overheads, direct costs and technical losses (7%).

The cost of electricity purchased in Italy is taken from the Autorità Energia Italian Regulator web site for Jan-Mar 2006 as euro cent7.92 / kWhr bulk production tariff + euro cent2.33 / kWhr transmission and metering charges. It is to be noted that both these tariffs may be subject to negotiation. The electricity purchased is assumed to be gas fired CCGT generated for the purposes of emissions compliance. The cable link is rated at 100MW base load capacity and 200MW peak load capacity and consists of two 100MW rated trains (cables and converter stations).

The cost of the gas pipeline is shared between the number of CCGT plants actually planned to be installed in each scenario.

The cost for natural gas is the price in Italy (Jan-Mar 2006) and includes the actual natural gas price, the transmission charges, storage charge and wholesale charges, and is taken from the Autorità Energia Italian regulator web-site.

The present operating scenario and a 2010 operating scenario based only on existing plant is given for reference and comparison. The energy consumption for 2010 is taken to be 2,693,145MWhrs in 2010. The actual energy generated in 2005 is taken as 2,263,145MWhrs.

Table 4.2.1
Assumed costs for Electricity cost calculations

HFO 1% S	Lm121 / tonne
HFO 0.7% S	Lm131 / tonne
HFO 1% S for diesel engines (No catfines for SSD/MSD)	Lm123 / tonne
Gas oil 0.1% S	Lm202 / tonne
Natural Gas	Lm117 / 1000m^3
Imported Electricity	LM43 / MWhr
120 MW CCGT Plant (capex)	Lm40 million
100 MW SSD Plant (capex)	Lm48 million
200 MW cable to Sicily	Lm55 million
Gas pipeline to Sicily	Lm65 million

The fuel and imported electricity costs quoted in the above table are based on information available for the period January – March 2006. The fuel costs (HFO and gasoil) are based on the average values quoted by Platts and the natural gas and electricity costs are based on tariffs quoted by the Italian Energy Regulator. In particular the cost of Natural gas and electricity, both of which are subject to market fluctuation and negotiation, are quoted as reference values for comparison purposes only and are not presented as either actual present-day or expected future tariffs.

Table 4.2.2
Electricity Costs comparison (main options) (2010)

	Fuel cost only **MTLc/kWh**	**Generation Cost** **MTLc/kWh**	**Total ElectricityCost** **MTLc/kWh**
Reference Case 2005 Actual	4.20	5.08	5.98
No New Plant in 2010	4.35	5.10	5.87
Add 100MW SSD, 200MW cable, Retire MPS	3.97	4.83	5.87
Add 120MW diesel CCGT, 200MW cable, Retire MPS	4.56	5.36	6.38
Add 3 new 120MW diesel CCGT, Retire MPS	4.51	5.59	6.68
Add 120MW gas CCGT, 200MW cable, Retire MPS	3.50	4.38	5.56
Add 3 new 120MW gas CCGT, Retire MPS	2.81	3.92	5.17
Add 200MW cable, retire MPS 3-6 only	4.42	5.16	6.08
Add 120MW diesel CCGT, retire MPS 3-6	4.40	5.24	6.12
Add 120 MW gas CCGT, retire MPS 3-6	3.21	4.12	5.17
Add 2 new 120MW diesel CCGT, retire MPS 3-6	4.40	5.43	6.41
Add 2 new gas 120MW CCGT, retire MPS 3-6	2.90	3.97	5.12
Add 100MW SSD, retire MPS 3-6	3.88	4.77	5.67
Add 100MW SSD and 120MW diesel CCGT, retire MPS 3-6	3.86	4.93	5.93
Add 100MW SSD and 120MW gas CCGT, retire MPS 3-6	2.84	3.98	5.15

5.0 Conclusions

From the analysis carried out and described in the previous sections the following conclusions have been reached:

1. NEC emission limits cannot be met using existing plant only.

2. Operation of Diesel engine generating plant (both SSD and MSD) does not meet the anticipated NEC emissions limits for 2020 based on the current RAINS model.

3. To achieve the NO_x limit values, which represent 90% abatement, Ammonia has to be injected and it can be estimated that between 330 and 650 tonnes of Ammonia per 100MWe generating plant (actual value depending on the specific type of plant) may be emitted (ammonia slip). At present there is no emission allowance for ammonia allocated to the energy sector in the 2010 NEC. Although in the short term a 100MW diesel engine plant would meet 2010 NEC limits, the limits anticipated by the RAINS model for 2020 are so much lower that not even one 100MW plant would be acceptable using current technology limits. Since 2020 is well within the economic lifetime of such plant (20 years), it is not feasible to invest in such plant at this stage, knowing that in 2020 (after only 10 years of operation) it may not be able to operate.

4. The least expensive cost of electricity is achieved through using gas fired CCGT units (at present fuel prices). This is also the only plant, which can safely meet the anticipated NEC 2020 emissions limits. However it is unlikely that natural gas would be available in Malta before 2012-2015.

5. All operating scenarios utilising an electric cable link are within or below the NEC limit values. However it is to be noted that this conclusion is based on the assumption that the source of the imported electricity is also a plant with negligible emissions (such as gas fired CCGT or nuclear).

6. Gas oil fired CCGT plant scenarios result in the highest cost of electricity. It is therefore an economical imperative that if this plant is opted for, natural gas must also be sourced in order to keep operational costs down. This plant (operated on diesel) may marginally meet the NEC 2020 emissions limits.

7. This report recommends the commissioning of a combined cycle gas turbine plant and an electric cable interconnection.

8. The present plan is to prepare a specification for a combined cycle plant with an overall capacity of 100MW, at summer rating, implying a nominal rating of approximately 130MW. This tender specification is targeted to be ready for publication later in 2006. The CCGT plant is expected to require 24 months for completion from award of contract, so it should be available by July 2009 at the very earliest. Any delays in this extremely tight program will make it almost impossible to achieve the target of operation by summer 2009. It may be necessary to plan for the possibility of operation of part of the new gas turbine plant in open cycle mode during summer 2008. This however may impact negatively on the overall programme of works apart from increasing costs.

9. In order to meet the target of decommissioning the steam plant at Marsa by 2010, an additional 200MW of generation capacity needs to be commissioned by the beginning of

2010. This can be a 200MW electric cable link to the European mainland or two additional combined cycle plants of 100MW each or a combination of the two options (assuming that the DPS steam plant would still be in operation and meeting LCPD limits). However whichever option is chosen, work needs to begin immediately. It is planned to site the new CCGT plant at Delimara.

10. An electric cable interconnection implemented through multiple units ideally needs to be landed in an area free from shipping activity, which excludes Marsa, and close to a 132kV Distribution Centre. Possible suitable areas are Delimara or Pembroke. The site at Pembroke is preferred since it distributes generation input to the network instead of concentrating all generation (and import) at Delimara, which could then be vulnerable to a common fault or incident. The electric cable interconnection would ideally be a dc link and apart from the submarine cables the project would require dc/ac converter stations and land lines at both ends to connect to a source of supply. Discussions need to start immediately with ENEL and GRTN the Italian TSO to agree on the physical connection points to the Italian network, and in parallel negotiations on the source of supply, conditions of supply and the relevant tariff need to commence.

11. In order to accommodate the increase in demand and the shift in generation from Marsa, the distribution network needs to be significantly reinforced. This implies completion of Mosta 132kV Distribution Centre (planned for April 2007), completion of Kappara 132kV Distribution Centre by end of 2009 and the completion of a new 132kV Distribution Centre at Marsa (power station), including new 132kV feeders, tunnels and additional reinforcement at 33kV and 11kV.

5.1 Resources required

At the moment both the distribution development section and the generation projects section are understaffed and need additional experienced and capable electrical and mechanical engineers in order to achieve completion of each of these associated projects, which need to be carried out in parallel, within the given very limited timeframe.

The planned projects require a heavy financial investment in a very short timeframe and are in addition to ongoing and envisaged projects to reinforce the distribution network, such as new 33kV Distribution Centre's at St. Andrews, Manoel Island and Ricasoli, and reinforcement of existing Distribution Centre's at Bugibba and the north of Malta (Mosta, Mellieha).

The expected expenditure levels for the above infrastructure projects are as follows:

- 130MW CCGT plant — Lm35-40 million
- 132kV DC's and cables — Lm20 million
- 200MW electric cable interconnection — Lm55 million
- 33kV Distribution Centre's and reinforcement — Lm10 million
- Malta Sicily gas pipeline (if adopted) — Lm65 million

If funds for these projects are not made available within the required timeframes, then the projects will be inevitably delayed, with the consequence of either not meeting the forecasted peak load demand or of not meeting the plant decommissioning targets and thus risking EU penalties.

This report was complied in good faith and based on documented information made known to Enemalta at the time of presenting this report. Every effort was made to ensure that the information collected was factual and accurate.

Attachment 2

Advert No. GN/DPS/T/3/2006: Supply and Installation of Automated Measuring Systems and Data Acquisition Recording System

ENEMALTA CORPORATION

TENDER FOR SUPPLY AND INSTALLATION OF AUTOMATED MEASURING SYSTEMS AND DATA ACQUISITION RECORDING SYSTEM FOR THE CONTINUOUS MEASURING OF GASEOUS AND PARTICULATE EMISSIONS AT ENEMALTA POWER STATIONS

FILE REF NO: GN/DPS/T/3/2006

Sealed tenders are to be submitted up to 10.00 a.m. on
Tuesday, 05th December 2006
at the Department Of Contracts, Notre Dame Ravelin, Floriana, Malta

This tender falls under the 3-Envelope Procedure.

<u>Issue Date of Tender:</u> 22nd September 2006

Fee for Tender Document	-	Lm 100 (€ 232,94)
Value of Bid-Bond	-	Lm 8,000 (€ 18.635,00) which is to be valid for 9 calender months from closing date

Enemalta Corporation
Central Administration Building
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Malta

Website: www.enemalta.com.mt

Procurement Section
Telephone: (00356) 2298 0738
(00356) 2298 0562
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Email: procurement@enemalta.com.mt

A. INSTRUCTIONS TO TENDERERS

PUBLICATION REF.: GN/DPS/T/3/2006

In submitting a tender, the tenderer accepts in full and without restriction the special and general conditions governing this contract as the sole basis of this tendering procedure, whatever his own conditions of sale may be, which he hereby waives. Tenderers are expected to examine carefully and comply with all instructions, forms, contract provisions and specifications contained in this tender dossier. Failure to submit a tender containing all the required information and documentation within the deadline specified will lead to the rejection of the tender. No account can be taken of any reservation in the tender as regards the tender dossier; any reservation will result in the immediate rejection of the tender without further evaluation.
A glossary of the terms used here is included in Part C of this tender dossier.

1 Supplies to be provided

1.1 The subject of the contract is the manufacture, delivery, installation, commissioning and maintenance by the Contractor of the following goods:

Automated Measuring Systems (AMS), also known as Continuous Emissions Monitoring Systems (CEMS), and data acquisition recording systems are required to monitor and log stack emissions from combustion plants at Enemalta Corporation's Marsa and Delimara power stations, as detailed in the tender technical specifications. These systems are needed so that the power stations will comply fully with EU Directive 2001/80/EC better known as the Large Combustion Plants Directive (LCPD). Apart from the supply, installation and commissioning of the AMS the supplier is to support the systems with a 5 year service maintenance agreement so that the systems will comply with EN ISO 14956 and MSA EN 14181:2004.

1.2 The supplies must comply fully with the technical specifications set out in the tender dossier (technical annex) and conform in all respects with the drawings, quantities, models, samples, measurements and other instructions.

1.3 Tenderers are not authorised to tender for a variant in addition to the present tender.

2 Timetable

	DATE	TIME*
Deadline for request for any clarifications from the Contracting Authority	17th November 2006	16.15 hours Malta time
Clarification meeting / site visit (if any)	27th October 2006	10.00 hours Malta time
Last date on which clarifications are issued by the Contracting Authority	28th November 2006	16.15 hours Malta time
Deadline for submission of tenders	05th December 2006	10.00 hours Malta time
Tender Validity Period	04th September 2007	

* **All times are in the time zone of the country of the Contracting Authority**

Attachment 3

PEP99 Emulsion Technology Preliminary Report

PEP99 EMULSION TECHNOLOGY
PRELIMINARY REPORT

Enemalta has on the 20 July 1995 started a pilot project on a test basis for six months on Boiler No 4 at Marsa Power Station. The Technology involved together with the monitoring of results are being conducted by ***Misan Chimica*** who supplied the Emulsification Unit and the chemical additive. The process is simply the injection of the additive **PEP99** together with water into the fuel oil, which is being burned.

1. Advantages of Emulsion Fuel Oil: -

Misan Chimica sustains that with Emulsion Fuel Oil the following will be accomplished: -

1.1 a) Less attention in draining water from Fuel Service Tanks.
b) Less cleaning of fuel strainers.
c) Less cleaning of fuel heaters.
1.2 Elimination of sludge in Fuel Service Tanks and corresponding cost of cleaning of Tanks.
1.3 Saving in operational cost due to efficient fuel heaters.
1.4 Saving in operational cost due to carbon burnout.
1.5 Saving due to less disposal costs of particulates.
1.6 Saving due to better combustion efficiency. Less excess air.
1.7 Saving due to lower stack temperature.
1.8 Saving due to reduction in Firemag dosing.
1.9 Saving due to better heat transfer. Clean tubes.
1.10 Saving due to less sootblower operations.
1.11 Saving due to less maintenance cost to clean boiler tubes during overhaul.
1.12 Better availability of Boiler. Constant load capacity.

2. Disadvantages of Emulsion Fuel Oil: -

2.1 Cost of additive PEP99.
2.2 Cost of water production.
2.3 Cost of water evaporation.
2.4 Cost of Electrical Power to run Emulsion Unit.
2.5 Cost of hiring of Emulsion Unit.

3. History.

Boiler No 4 was last Overhauled and cleaned in March 1995. It was warmed up and placed on range on the 6 April. In July the Emulsion plant was installed and readings of Boiler parameters taken on the 12 and 13 July before starting on emulsion oil firing. Emulsion firing started on 20 July 1995.

On the 21 September Boiler 4 developed a tube leak and later ID fan Fluid coupling bearing failure and had to be shut down. During this period an internal inspection of the boiler was carried out. Boiler was back on range on the 23 October. Readings of boiler parameters were again taken on the 1, 2 and 6 November.

On the 2 January 1996 boiler had to be forced shut down due to a bearing failure. An internal inspection was therefore made.

4. Observations So Far.

After four months burning 100% fuel oil and four months burning emulsion oil the following observations were made: -

4.1 Fuel heaters remained clean. The same heater has been in service since April 1995. Fuel temperature was kept to the required level without difficulties. The steam valve to heater is still not fully open.
Last September a consignment of fuel was received with a high percentage of ash which created grave problems on all other boilers since heaters were getting dirty in only a few days. However, on Boiler 4 no effects were felt.

4.2 When change over to burning emulsion oil was made in July the Boiler had already been burning 100% oil for four months. Consequently tubes were already getting dirty. After two months burning emulsion oil an internal inspection was made in October. The furnace wall tubes were found only covered with a thin layer of fragile deposit and the floor was covered with a considerable amount of ash. A more softer and finer deposit was found on the superheater tubes. In both cases this deposit fell off simply by touching with ones bare hand. In January 1996 another internal inspection was performed when boiler was forced shut down due to a bearing failure. The above was confirmed. Fragile deposits on furnace wall tubes and finer deposits on superheater tubes. The amount of ash on furnace floor had increased substantially. The colour of the samples of particulates from boiler has also changed from dark black to light brown.

4.3 Load capacity of Boiler remained constant for eight months at around 265×10^3 Lbs/Hr (≈ 26.5 MW). Boiler could take all six burners and the limitation of load was due to fuel pump capacity and not draught fans.
Past experience on this boiler show that after about four months running, boiler capacity starts dropping due to the deposits that starts accumulating on tubes. Consequently, draught fans run at their full capacity because of the pressure drop across boiler. Once this process starts the accumulation of deposits increase exponentially. Eventually, boiler will have to run at lower capacity. This also creates some difficulties to keep the flame as close to desired conditions as possible. Usually, by this time the boiler capacity drops to around 180×10^3 Lbs/Hr (~18MW) until it is shut down for cleaning or overhaul.

4.4 The following are the most relevant readings taken so far.

Date	13/7/95	2/11/95	6/11/95
Fuel	100% oil	Emulsion	Emulsion
CO	170 mg/Nm^3	48 mg/Nm^3	85 mg/Nm^3
SO_2	5439 mg/Nm^3	4823 mg/Nm^3	4830 mg/Nm^3
NO_x	531 mg/Nm^3	577 mg/Nm^3	535 mg/Nm^3
Particulates	2575 mg/Nm^3	353 mg/Nm^3	182 mg/Nm^3
Combustion Eff.	81.5%	86%	88%
Burners	6	6	6
Flue Gas Temp.	188 ^{o}C	193 ^{o}C	196 ^{o}C
Steam Flow x10^3	260 Lbs/Hr	270 Lbs/Hr	265 Lbs/Hr

From the above readings it can be seen that:-

4.4.1 Particulates reduction is considerable from 2575 mg/Nm^3 to 182 mg/Nm^3 which is equivalent to 92.9% reduction.

4.4.2 Combustion Efficiency has increased by 6.5%.

4.5 MgO (Firemag) dosing has been reduced by half, from 400 ppm to 200 ppm. PEP99 dosing at the rate of 700 ppm.

4.6 No difficulties were encountered during operation.

4.7 Boiler is not hermetically sealed, ingress of non-combustion air has been recorded. Consequently, gas analysis is not 100% correct.

5. Calculations.

5.1 Combustion Efficiency.

As stated in 4.7 above due to the ingress of non-combustion air the gas analysis does not give the true picture. Hence, the true combustion efficiency cannot be calculated. However, one may assume that the conditions before and after the burning of emulsion oil have remained the same. The increase in combustion efficiency is considerable since it has increased by 6.5 %. The true increase may be lower than this value, but the comparisons were made when the boiler was relatively clean. If readings were taken with the boiler running with dirty tubes this figure might be accomplished.

5.2 Particulates Reduction.

Ash content in fuel oil vary from one consignment to another. The average, however can be taken as 0.06 %. This represents the inorganic unburnable material.

$$0.06\ \% = \frac{0.06kg\ of\ ash}{100kg\ of\ fuel} = 600\text{mg/kg of fuel}$$

For good combustion one requires 12Nm^3 of flue gas per kg of fuel burned at 3% O_2. These figures are International Standard Values.

$$\therefore \text{ The ash content after burning 1 kg of fuel} = \frac{600mg}{kg\ of\ fuel} \times \frac{kg\ of\ fuel}{12Nm^3} = 50\ \text{mg/Nm}^3.$$

Another inorganic material is the Firemag which is added to the fuel. With Emulsion Oil the rate of Firemag is 200ppm. Therefore, the ash content due to Firemag is:-

$$200\text{ppm} = \frac{200kg}{100000kg\ of\ fuel} \times \frac{kg\ of\ fuel}{12Nm^3} = 17\ \text{mg/Nm}^3$$

$\therefore$ Total unburnable compounds after burning 1 kg of fuel = 50 + 17 = 67 mg/Nm^3.

The above implies that all other particulates registered is unburned compounds (mainly carbon) which is being lost to the stack. Under favorable conditions when burning 100 % fuel oil the percentage of unburned carbon in the particulates is over 80 %. After analyzing the particulates of boiler 4 the percentage of unburned carbon was found to be 27.6 %, at the measured particulates value of 196 mg/Nm^3.

$$\therefore \text{ The amount of unburned carbon} = \frac{196mg}{Nm^3} \times \frac{27.6}{100} = 54\ \text{mg/Nm}^3.$$

and the amount of unburnable compounds = 196 - 54 = 142 mg/Nm^3.
However, this value from calculation above should be 67 mg/Nm^3.
Therefore, the amount of deposits which by the cleaning characteristics of PEP99 is being removed from boiler tubes and carried over by the flue gases

$$= 142 - 67 = 75\ \text{mg/Nm}^3.$$

And the true percentage of unburned carbon in particulates = $\frac{54}{54+67}$ = 45 %.

Particulates reduction so far is from 2575mg/Nm^3 burning 100 % Oil, to 182 mg/Nm^3 burning Emulsion Oil = 2575 - 182 = 2393 mg/Nm^3.

Therefore, Particulates reduction = $\frac{2393}{2575}$ = 92.9 %

(The value of 182 mg/Nm^3 can be reduced further because it incorporates the deposits which are being cleaned away from boiler tubes. From calculations above this figure should, by time, go down to 54 + 67 = 121 mg/Nm^3.)

5.3 Carbon Burnout.

The unburnable substances are constant depending on the type of fuel oil burnt.
Therefore, all the particulates reduction is unburned carbon which is now being burnt. In fact the colour of the particulates has change from dark black to light brown.

This amounts to $\frac{2393mg}{Nm^3} \times \frac{12Nm^3}{kg\ of\ \ fuel}$ = 28716mg/kg of fuel = 28.72kg/ton of fuel.

= 28.72×10^{-3} ton of carbon/ton of fuel.

Fuel Oil contains on average 81.6 % carbon = 0.816 ton of carbon/ton of fuel.
Therefore increase in efficiency by burning Emulsion Oil = 28.72×10^{-3} × .816
= 0.02343 = 2.34 %.

Taking the price of Fuel Oil as 27.87 ML/ton of fuel.

Savings = $\frac{27.87\,ML}{ton\ of\ \ fuel}$ × 0.02343 = 0.653 ML/ton of fuel.

5.4 Firemag Dosing Reduction.

As stated in 4.5 above MgO dosing was reduced from 400ppm to 200ppm.
Percentage of MgO in Firemag is 60 %.
Cost of Firemag = 1920 ITL/kg.

$$= \frac{1920\,ITL}{kg} \times \frac{ML}{4494\,ITL} = 0.427 \text{ ML/kg.}$$

Cost of 200ppm MgO dosing = $\frac{200g}{1000000g\ of\ \ fuel} \times \frac{100}{60} \times \frac{0.427\,ML}{kg}$

Savings = 0.142 ML/ton of fuel.

5.5 Cost of PEP99.

Cost of PEP99 is at the rate of 5700 ITL/kg = $\frac{5700\,ITL}{kg} \times \frac{ML}{4494\,ITL}$

= 1.268 ML/kg.

Dosage of PEP99 is at the rate of 700ppm = $\dfrac{700g}{1000000g\ of\ \ fuel} \times \dfrac{1.268\,ML}{kg}$

Cost of PEP99 dosing = 0.888 ML/ton of fuel.

5.6 Cost of Water Injection.

Rate of water injected is 10 %.
Heat required to evaporate water is 520 kCal/kg of water.
Calorific value of fuel (average) is 10200 kCal/kg of fuel.
Cost of fuel Oil is 27.87 ML/ton.

Cost of heat to evaporate water injected = $\dfrac{10}{100} \times \dfrac{520kCal\,/\,kg}{10200kCal\,/\,kg} \times \dfrac{27.87\,ML}{ton\ of\ \ fuel}$

= 0.142 ML/ton of fuel.

5.7 Rental Cost of Unit.

Rental of Emulsion Unit for 6 months is 15,000,000 ITL.
If a discount of 20 % is offered this will amount to 12,000,000 ITL.
The average consumption of fuel on boiler 4 is 150 ton/day.

Rental Cost = $\dfrac{12000000ITL}{6mths} \times \dfrac{mth}{30.4days} \times \dfrac{ML}{4494ITL} \times \dfrac{day}{150ton\ of\ \ fuel}$

= 0.098 ML/ton of fuel.

Considering only 5.3, 5.4, 5.5, 5.6, 5.7 above the balance will be as follows:-

Savings		Extra Costs	
Carbon Burnout	0.653 ML	Cost of PEP99	0.888 ML
Firemag Dosing	0.142 ML	Water Injection	0.142 ML
		Rental Cost	0.098 ML
Total	0.795 ML	Total	1.128 ML

Hence, an extra cost of 0.333 ML/ton of fuel will be incurred. This extra cost is equivalent to an improvement in Combustion Efficiency of:-

$$\frac{0.333\,ML\,/\,ton\ of\ \ fuel}{27.87\,ML\,/\,ton\ of\ \ fuel} = 0.011 \quad \text{or} \quad 1.1\ \%$$

Therefore, if in section 5.1 above one can accomplish an improvement of 1.1 % instead of the 6.5 % registered the costs will even out. However, as stated in section 5.1 the improvement in Combustion Efficiency is expected to be more than 1.1 %.

6. **Added Benefits Not Considered in Section 5**.

In section 5 above only 1.4, 1.6 and 1.8 mention in section 1 were considered.

6.1 The cost of cleaning boiler heaters involves 4 men for 3days = 96 man-hours per heater.

= 96 x 1.62 = 155.52 ML per heater.

This not considering the availability of a heater. Moreover, while cleaning heaters the oil that is in the heater is placed into 45 gal. drums. These drums are then transported and the oil pumped back to the Fuel Storage Tanks. Therefore, added expenditure.

6.2 Fuel Storage Tanks have to be cleaned after some years of service. The period between cleaning depends on the quality of Oil procured. This also depends on the availability of storage tanks due to the limited storage capabilities. At present it has become more difficult since all boilers are at present burning 100 % fuel oil.
The last tank that was cleaned of its slug was No 2 Tank. Around 50cm of sludge was found and the cost involved was 12,000 ML.

6.3 As stated in section 4.1 the steam required to heat the fuel oil to the required working temperature has decreased. The savings involved cannot be calculated since no steam flow meters are available.

6.4 When cleaning boilers skips are used to dispose of the ashes. The average number of skips is approximately 10 skips. Cost per skip is 3.50 ML.

Cost of disposal of ash = 10 x 3.5 = 35 ML.

6.5 From readings in section 4.4 stack temperatures have remained approximately the same. Therefore, no improvement has been registered.

6.6 Sootblower operation is still being performed but less frequently.

6.7 As stated in section 4.2 the boiler is still relatively clean, hence boiler cleaning will reduce considerably. The last boiler cleaned was boiler 3 and it was performed by incentive. The cost amounted to 380 ML x 9 men = 3420 ML. The cleaning operation took 3 weeks.

6.8 Availability of boiler has increased drastically. Considering that the boiler can still be loaded to its full capacity after 8 months running. This has never been experienced before.

7. **Other Cost Not Considered**.

In section 5 above only 2.1, 2.3 and 2.5 mention in section 2 were considered.

7.1 The cost of water production to be added to the fuel is free for the following reason. At present the steam used to heat the fuel storage tanks is condensed and drain to the sea. This water can be collected and used as the added 10 % to the Fuel. The contamination of this water by the fuel will not jeopardize the Emulsion Unit since eventually it is going to be mixed with the Fuel oil.

7.2 Electrical Power required for running booster pump of PEP99 Unit is negligible. 3000 kWh per 6 months and can process around 300 ton of fuel per day.

$$\text{Cost} = \frac{3000kwh}{6mths} \times \frac{mth}{30.4days} \times \frac{0.022\,ML}{kwh} \times \frac{day}{300ton\ of\ \ fuel} \quad = 0.0012 \text{ ML/ton of fuel.}$$

8. **Conclusion**.

The advantages of using PEP99 Technology outweigh the disadvantages. Moreover, savings will be made in the running costs of the station. Another aspect of this technology is the considerable reduction of the particulates in the Flue Gases emitted from the stacks.

At the Marsa Power Station an average of 2800 MWh are generated daily. This power generated is distributed as follows: -

Units	Generated	Fuel Consumed	Ash Value	Ash Emitted	% of Total
Blr 7 + 8	66 %	650 tons/day	580 mg/Nm^3	4.52 ton/day	37 %
Blr 5 + 6	13 %	150 tons/day	1000 mg/Nm^3	1.80 ton/day	15 %
Blr 2,3 + 4	21 %	200 tons/day	2500 mg/Nm^3	6.00 ton/day	48 %

The above table clearly indicates that the majority of particulates which are emitted are from Boilers 2, 3, 4, 5 and 6. If PEP99 is utilised the particulates from all boilers will be reduced to around 150mg/Nm3, hence the following table: -

	100 % Oil		Emulsion Oil	
Units	Ash Value	Ash Emitted	Ash Value	Ash Emitted
Blr 7 + 8	580 mg/Nm^3	4.52 ton/day	150 mg/Nm^3	1.17 ton/day
Blr 5 + 6	1000 mg/Nm^3	1.80 ton/day	150 mg/Nm^3	0.27 ton/day
Blr 2,3 + 4	2500 mg/Nm^3	6.00 ton/day	150 mg/Nm^3	0.36 ton/day
Total Ash per day		12.32 tons		1.80 tons

The above implies that the particulates emitted from the stacks will be reduced by 85 % and will be equal to the amount being emitted today by boiler 5 or 6.

9. **Recommendations.**

Considering all the above it is therefore recommended that PEP99 will be utilised on Boilers 2, 3, 4, 5 and 6. The total apparent expenditure for only these Boilers is that required to dose 350 Tons of Fuel Oil per day.

$$\text{Cost}= \frac{350 ton\ of\ \ fuel}{day} \times \frac{365 days}{year} \times \frac{5700 ITL}{kg} \times \frac{1 ML}{4494 ITL} \times \frac{0.7 kg\ of\ \ PEP}{ton\ of\ \ fuel}$$

=113,423 ML/year.

The reason why it is recommended to use PEP99 on only Boilers 2 to 6 is because the conversion of Boilers 7 and 8 has only been performed lately. And not enough experience has been gain on the effects or adverse action that might appear in future by burning 100 % Oil on these Boilers. Moreover, this Technology does not offer the same pay back as on the other Boilers since the particulates being emitted from these Boilers are far less. The Combustion Efficiency of these Boilers is already relatively high and there is only a little space for improvement. However, in future if it is decided to start dosing also these Boilers with PEP99 the cost per year would amount to the dosing of 1000 Tons of Fuel per day:-

$$\text{Cost}= \frac{1000 ton\ of\ \ fuel}{day} \times \frac{365 days}{year} \times \frac{5700 ITL}{kg} \times \frac{1 ML}{4494 ITL} \times \frac{0.7 kg\ of\ \ PEP}{ton\ of\ \ fuel}$$

=324,065 ML/year.

Edwin Gauci
Assistant Manager Operations.

Attachment 4

EdF Report (Cable Interconnection)

EDF
Electricité
de France

MALTA-SICILY INTERCONNECTION
PRE-FEASIBILITY STUDY

FINAL REPORT

OCTOBER 1995

VOL. 1

MAIN REPORT

AKNOWLEDGEMENTS

We would like to express our gratitude to all ENEMALTA management and experts involved in the project for their fruitful cooperation and their kind welcome during EDF's missions in Malta.

Special thanks should be made to :

- **Mr. MIFSUD**
- **Mr. BONELLO**
- **Mr. PACE**
- **Mr. VELLA**
- **Mr. CASSAR**

for their active contribution to the study.

The Project team

EXECUTIVE SUMMARY

Energy is of prime importance in Malta. The Maltese islands have no large scale energy sources and a policy of diversification of energy suppliers is in process. Moreover environmental aspects (space, pollution...) are fundamental in the islands.

In this context, an interconnection with Sicily is a possible alternative to generation expansion plans in Malta after 2005. The present study aimed at estimating the value of such alternative from a technico-economic point of view and appreciate its feasibility key elements.

The main conclusions of the study are detailed below :

* <u>General design</u>

Due to the characteristics of the interconnection (length, submarine...) HVDC technique should be preferred for technical and economic reasons. The reasonable size for the interconnection is of 100-200 MW with a voltage of 200 kV, the 100 MW value being more in line with the size of Malta system for the time horizon involved (it will correspond to the biggest unit in operation in Malta).

The HVDC technique also offers various possibilities of modular design and construction, allowing for a progressive implementation of the link according to power exchange levels and/or financial capabilities (100 MW in a first step for instance, upgraded to 200 MW at a later horizon).

No major problem has been detected for the design and construction of the link. The study identified key elements to be investigated further at the feasibility stage.

* <u>Economic considerations</u>

The cost/benefit comparison pointed out the major elements having a significant impact on the value of the interconnection :

- as regards costs, the cost of the cable link and the associated sea works, depending on numerous parameters (especially the soil characteristics for embedding) and showing important fluctuations.
- as regards benefits, the evolution of fuel costs and principally the market price of natural gas, as the standard development unit in Italy can be expected to run with natural gas for the study horizon.

- Cost/benefit comparison

From an economic point of view, it can be said that, on the basis of the set of assumptions considered, the interconnection is hardly profitable.

Although the orders of magnitude do not differ so much, the annual benefits brought by the interconnection are in general rather lower than its cost annuity.

Profitability can be reached however under favourable conditions, such as cost of gas and/or cost of sea works lower than expected. As the per unit cost of an HVDC link generally decreases with the power transferred the cost/benefit comparison gives advantage to stronger configurations (200 MW for instance) but a later horizon, such as 2010, would be more appropriate for this level of power compared to Malta demand.

Low cost interconnection can be achieved with a monopolar configuration but the drawbacks are : low reliability, uncertainties on spot exchanges (volume and prices), back-up unnecessary in the mid-term (gas turbines have just been commissioned in Malta with a probable lifetime of 20-25 years). There is the financial risk to rely upon future uncertain short-term incomes (spot market) to pay for the long-term investment.

- Negotiation possibilities

By comparison of the generation development cost in Malta for base-load operation and the equivalent cost in cents/kWh of the interconnection, it has been outlined that, to be profitable for Malta, the purchase price of imported electricity, assuming Malta supports the total costs of the interconnection, should be lower than 3 to 4 cents/kWh.

According to the study hypotheses, the Italian system might not be in a position to provide a supply at such a cost from its own national generation mix at the time horizon involved ; this point has to be investigated further with ENEL at the feasibility stage and/or within the frame of first negotiations.

- Decision taking

On the other hand, a decision can be taken on more general bases : considerations of space limitations, pollution, political, commercial aspects can be in favour of the interconnection alternative.

According to the scenarios considered the resulting overcost from a purely economic point of view could reach a value of up to 1 US cent/kWh for a base load type interconnection.

MALTA-SICILY INTERCONNECTION

PRE-FEASIBILITY STUDY

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GROUP Gas & Power

MALTA GAS PROJECT

Feasibility Study
Final Report

July 2003

MALTA GAS PROJECT
FEASIBILITY STUDY ("EVALUATION")

FINAL REPORT

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1. INTRODUCTION.

On January 11th, 2002, Enemalta and Eni signed a Memorandum of Understanding (Encl. 1) in order to jointly carry out the technical and economic Feasibility Study of the project to supply natural gas to Malta (the "Malta Gas Project) by a submarine gas line (sea line) coming from Sicily.

The Feasibility Study goal is to assess the subject to the required level of detail in order to allow both Parties to evaluate the opportunity to start negotiations for the definition of the Final Agreements necessary to develop and to implement the Project.

The Feasibility Study dealt basically with two main issues:

- the definition of the quantities of natural gas to be supplied and of its market value;
- the technical feasibility and the investment costs of the pipelines to be built.

Other topics, such as the cost of conversion of existing power generation units to natural gas, the present Maltese Legal Framework and Tax Regime related to the natural gas business and the Main Terms characteristic of a Gas Sales Agreement, have been analysed.

The main results are synthesized in the Executive Summary and the single topics are analysed in detail in the following chapters.

IMPORTANT NOTE:

FOR CONFIDENTIALITY PURPOSES CERTAIN SENSITIVE DATA HAS BEEN MASKED OR DELETED IN THE EXECUTIVE SUMMARY SECTION.

2. EXECUTIVE SUMMARY.

a) Given the high construction cost of the pipeline when compared with the expected gas volumes to be delivered to Malta, several **assumptions** where agreed at the beginning of the Study in order to optimise the gas transport costs and therefore to improve the economic feasibility of the project.
The most important are:

- All the existing power generation units will be converted to natural gas fuel as soon as it will be available;
- All the new power generation units will be natural gas fired CCGT's;
- Liquid fuels for power generation to be considered only as back-up ones (all units will be dual fuel ones for production security reasons);
- Only major Industrial & Commercial customers located near the pipeline will have the opportunity to switch to gas;
- No gas supplies are foreseen for households.

Another basic assumption was that the cost of the gas fired power production in Malta won't have to be more expensive than by the alternative fuels.

b) Gas deliveries have been assumed to start on January 1st, 2005 and to last for 25 years up to the end of 2029.
All the **"physical" quantities** have been considered to evolve until 2015 and then to remain constant until 2029.

The power demand evolution considered is typical of a mature electricity market and varies in the years between 2,5% an 1,5%.
The total country's expected Gross Power Production rises consequently from [redacted] GWh in 2005 to [redacted] GWh in 2015.
The related Consumption of Natural Gas in this period of time varies between a maximum of [redacted] Million cubic meters in 2008 and a minimum of [redacted] Million cubic meters in 2013.

Table 1. Expected Power Production and related Gas Consumption in Malta.

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The above gas consumption has been computed according to the Enemalta's three new CCGT's construction programme and by the agreed despatching model which establishes the production "Merit Order" according to the units' electric efficiency and takes into account specific requirements of the electric system such as the spinning reserve and the minimum required production per power station.

The three new CCGT's are scheduled to start production in 2005, 2009 and 2013 respectively.
The decrease of the gas consumption in 2009 and 2013 respect to the previous years is the direct consequence of the high efficiency (50%) of the new combined cycle being commissioned in those two years and substituting old, less efficient steam units (efficiency less than 30%).

Table 2. Expected Gas Consumption for Power Generation and overall Electricity Production Efficiency in Malta.

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Gas consumption for other uses has been quantified as [redacted] Million cubic meters whose build up will take several years.

Power generation has therefore confirmed to be the Malta Gas Project's "Real Customer".

A "High" and a "Low" Demand cases have been defined too.
Given the low power demand growth considered in the "Base Demand" case and the maturity of the Maltese power market, the variations of the Gross Power Production and of the related Gas Consumption are negligible in both cases (Power Production in 2015 would be [redacted] GWh in the High Demand case and [redacted] GWh in the Low Demand one, versus [redacted] GWh in the Base Demand case).

c) The fuels alternative to natural gas for power generation in Malta are fuel oil (for steam units) and gasoil (for gas turbines equipped units).
The **Market Value** of **Natural Gas** in Malta has therefore been identified as the unit value of gas (expressed in US$/MMBTU) which generates the same total expenditure that would be incurred by using fuel oil and gasoil for power generation, taking into account both the higher electric efficiencies and the Operation & Maintenance savings deriving from the use of natural gas.

This approach is coherent with the assumption that the use of natural gas in Malta has not to lead to higher costs respect to the alternative fuels utilisation and will represent a sound starting point for the negotiation of the Final Agreements, if the Parties will decide to proceed with the development of the Project.

Table 3. shows the gas market value in Malta computed for an Energy Scenario of the "Brent" oil price varying between [redacted] and [redacted] US$/bbl, which is the expected range of oscillation of the Brent price in the time period 2005-2015. The computation refers to a fuel oil with a sulphur content of 0,5%.
The exact concentration to be taken into account will be determined during the implementation phase of the Project. Sensitivities in the possible range of this parameter ([redacted]% ÷ [redacted]%) have been made.

Table 3.

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The increase in the gas value in 2009 and 2013 is due to the introduction of the new combined cycles, which, as an alternative to natural gas, have to be gasoil fuelled. Each of them substitutes part of the electric production by steam units which would use fuel oil, thus increasing the weight of gasoil in the alternative fuels mix and consequently increasing the weighted average unit cost of fuel.

d) The **pipeline** route **from Italy to Malta** has been identified after the execution of a seabed bathymetric survey. It will start from Gela and, with a total length varying between [redacted] and [redacted] km, it will reach the Maltese coast at one of the three possible landfalls which have been identified.
Several technical alternatives for the sealine sizing have been defined. The most likely to be adopted is the solution with a 16" nominal diameter pipeline with no compressor station at Gela.
Its **investment cos**t will vary between about [redacted] (± [redacted]%) **Million USD**, according to the actual landfall which will be chosen.
Two **Maltese onshore pipeline** routes have been identified, coherently with the above-mentioned landfalls. Their lengths vary between [redacted] and [redacted] km and the investment cost between [redacted] and [redacted] Million USD.

The total estimated investment cost, taking into account also development, financing and other costs related to the project implementation (estimated as [redacted] Million USD), varies therefore between about [redacted] and [redacted] Million USD.

e) The **Gas Sales Agreement** will be negotiated in case the Parties decide to proceed with the project implementation. It is anyway envisaged that, in order to be consistent with the Project's needs and make it economically feasible, it will have to be a "Long Term - Take or Pay" one.

f) Some **main observations** can be made at the end of this Feasibility Study, which should be taken into consideration by the Parties while evaluating if and how to proceed with the Project implementation:

i. From the **technical point of view** the construction of the gas lines **doesn't present particular difficulties**;

ii. The **high construction costs** of the pipelines, when compared to the volumes of gas to be supplied, determine high specific transportation costs. These costs have to be minimised in order to improve the **economic feasibility** of the Project.
In particular a substantial **Grant** from the International Institutions, as well as strong financial support, will be necessary as well as the optimisation of the **fiscal regime** applied;

iii. Following the issue of the "Natural Gas (Market) Regulations, 2002", the specific **legislation** for the gas sector (permitting, operations, commercial activities, fiscal regime, ….), where necessary, will have **to be completed** in order to guarantee the feasibility of the Project;

iv. The assumed **construction programme** of the **new CCGT's** is of fundamental importance for the Project. Any delay or change in it could require to shift the Project implementation or could change significantly its economics and consequently its economic feasibility for one or both the Parties.

Even if beyond the specific scope of this study, it has to be highlighted that, in order to maximise the confidence in the Project's feasibility by all the "actors" involved in it (shareholders, institutions, lenders, …), the structure of the electricity prices in Malta will have to be more cost reflective in the future.

Attachment 6

Basic Elements of Proposed Environment Management System

Basic Elements of Proposed Environment Management System