CDC
Investment works

Guidance Note

Heavy Fuel Oil Fired Power Plants

1. Introduction

What is HFO?

Heavy Fuel Oil (HFO) is a general term used to describe a range of fuel oils made from the heavier parts of crude oil after the lighter parts are removed to produce petrol, diesel and other light products. The most common technologies used to generate power from HFO are reciprocating engines and gas turbines.

The choice of meeting energy demands through fossil-fuel power plants, including those that use HFO as a fuel is coming under increasing scrutiny. This Guidance Note is an initial step in the due diligence process for investment opportunities involving HFO fired plants. It provides a framework to improve consistency in identifying technical and environmental considerations, and helps develop a rationale for accepting or declining HFO prospects.

CDC's position on HFO

CDC aims to provide least-cost power to help address energy poverty while comprehensively evaluating potential climate impacts, in order to increase the supply of energy across our markets. CDC recognises the role of private sector investment in mitigating the impacts of climate change and in financing climate friendly energy generation. CDC always prefers renewables where they make sense from both cost and grid perspectives.

CDC is required to consider the environmental and social risks, impacts, and opportunities associated with investing in a business. Given the potential significant impacts associated with HFO plants, and in line with the objectives of its Code of Responsible Investing[1], CDC requires an appraisal to be undertaken to determine if the use of HFO is appropriate and can be robustly justified.

Purpose of the guidance note

This Guidance Note provides an initial screening approach to help determine whether a HFO fired plant warrants further consideration for investment. It can be applied to an existing or new HFO fired plant.

Key considerations in the approach are:

- Whether development of an HFO fired plant is allowable under existing or emerging relevant policy (i.e. national policy that relates to energy development and supply);
- Whether alternative fuels/ technologies could meet the objectives of the project, and therefore should be explored further; and
- If an HFO fired plant is appropriate, whether key environmental impacts are likely to be acceptable.

[1] CDC's Code of Responsible Investing can be found here: http://toolkit.cdcgroup.com/assets/uploads/Code_of_Responsible_Investing__Final_Annotated_.pdf

2. How to use this guidance note

Approach

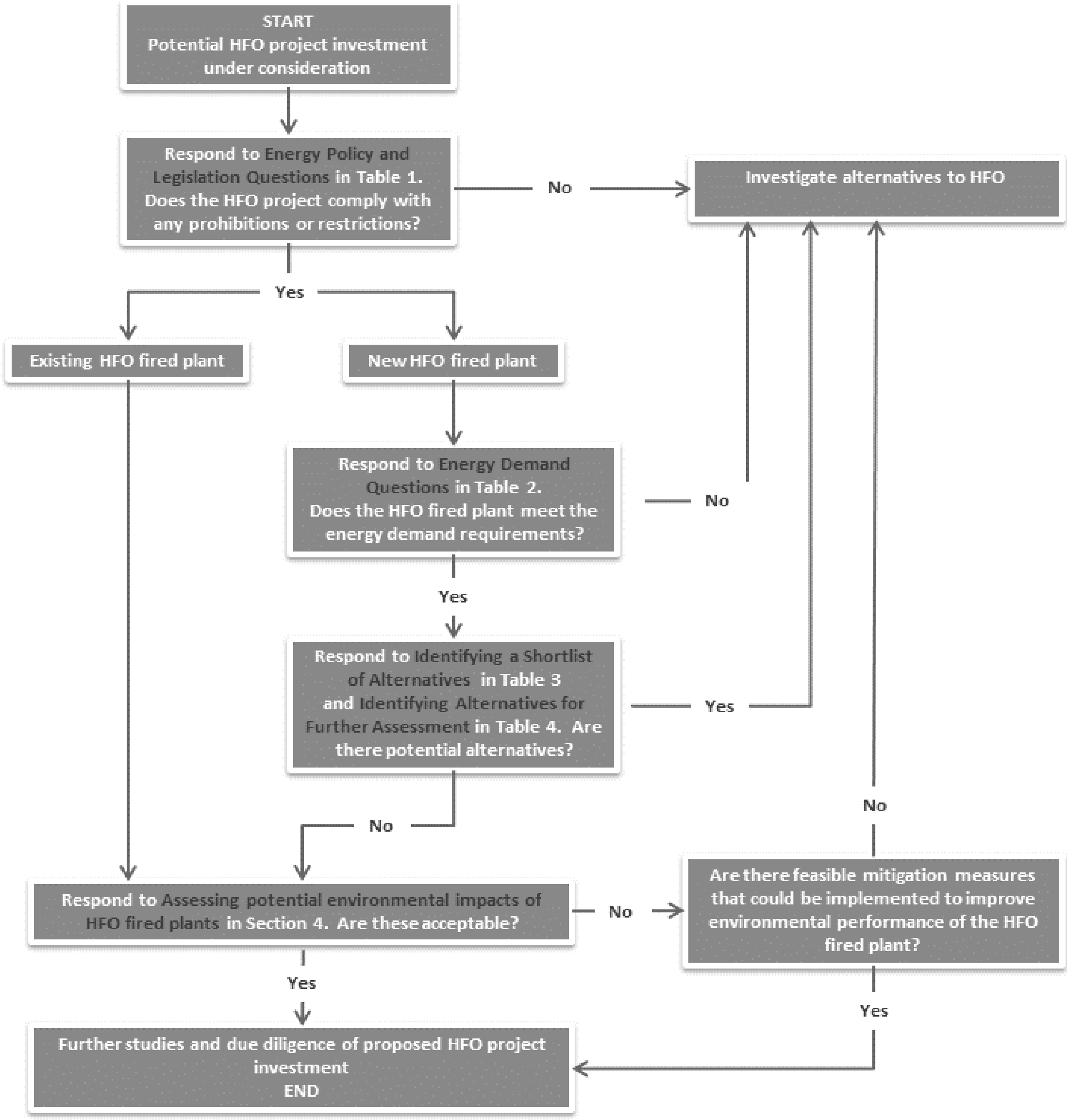
The decision flow chart in Figure 1 shows how this Guidance Note should be used. Follow the steps that are relevant to the project being reviewed. The flow chart refers to questions in the tables presented in Sections 3 and 4. Information to complete the guidance note shall be requested from project stakeholders.

It should be noted that answers to the questions below will normally be based on a combination of project information and professional judgement. Some level of uncertainty will exist. Where uncertainty is too high to allow a robust answer to be provided, the process can either be halted until that information is made available, or, the alternative technologies can be taken forward for further consideration with additional work being carried out at a later stage.

To assist in answering the questions, Appendix B provides a description of common features of HFO fired plants and Appendix C provides descriptions of common features of alternative generation technologies and fuels.

Once responses have been provided to the applicable questions in Chapters 3 and 4, the investor will review the responses to determine if the proposed investment should be considered further. It is anticipated that in all cases a detailed due diligence process will be required.

Figure 1: Decision Flow Chart



3. Review of HFO fired plants and alternative fuels/technologies

Energy policy and legislation requirements

The questions in Table 1 below are intended to identify whether there are any prohibitions or restrictions on the use of HFO. Consideration should be given to whether these are present in current policy or legislation, and whether they could come into force within the lifetime of the project, to the extent that this can be reasonably predicted.

Table 1: Energy policy and legislation questions

Ref.	Question	Notes
T1(a)	Are there restrictions on use of HFO such as through operating hours, load factors or mass emissions of pollutants?	Restrictions on the use of HFO may be present. These can exist in a number of regulatory forms.
T1(b)	Are there restrictions on the sulphur content of HFO?	Unlike other air pollutants, impacts from sulphur emissions are often controlled by placing limits in legislation or policy that governs fuel specifications.
T1(c)	If restrictions exist, is it possible to find a compliant HFO fuelling option that meets the energy demand/planting requirements?	This could include the use of low sulphur HFO or HFO/distillate blends, etc.
T1(d)	Does the host country's existing or emerging energy, climate change or other sector-relevant policies restrict the development of high emission projects or imply potential restrictions on such projects in the future?	Some individual countries may have developed climate or energy policies which place limitations on certain types of power project (e.g. performance requirements). This would include National Communications and Intended Nationally Determined Contributions (as per the UNFCCC agreements) which may also provide an indication of future policy direction.

Potential for alternative fuels or technologies

The questions in Table 2 below are intended to promote an understanding of the energy demand requirements that the project is designed to meet. If the answer to <u>all of these</u> questions is 'no' it is very unlikely that HFO could be justified and therefore (as per Figure 1) alternatives should be considered.

Table 2: Energy demand questions

Ref	Question	Notes
T2(a)	Is there a requirement for firm capacity?	Firm capacity is the ability to offer a stated amount of MW of power on an all year call-off basis.
T2(b)	Is there a requirement for flexible and dispatchable capacity?	Flexible and dispatchable capacity means that a power plant can provide varying levels of power at short notice.
T2(c)	Is there a requirement for balancing energy to accommodate variable renewable energy?	Where significant levels of energy are provided by renewable power generation, the supply can often be very variable. In these cases, there can be a need for supply to be supplemented (or 'balanced') by more consistent generation.
T2(d)	Is there a requirement for baseload energy? If so, over what period is this likely to be needed?	HFO can provide baseload energy but generally this should be viewed as a short-term solution.

Notes: (a) Baseload power is continuous (normally full plant capacity) generation. It is normally from plant that provides firm (all year) power (subject to normal service outages)

The questions in Table 3 are intended to identify whether the fundamental conditions are available to support potential alternative fuels or technologies. Answer the relevant questions for each potential alternative. A 'yes' for any alternative means it should be shortlisted for consideration in Table 4.

Table 3: Identifying a shortlist of alternatives

Ref	Questions	Comment	Alternative technology						
			Wind	Solar	Hydro	Natural Gas	Distillate	Bioenergy	Interconnections
T3(a)	Where firm capacity is needed, does existing storage (*) or back-up generation provide sufficient reserve to cover low generation periods?	Storage and backup system needs to be able to carry large enough reserve to cover eventuality of prolonged period of low/no generation. This could already be available	Yes/No	Yes/No	Yes/No				
T3(b)	Where firm capacity is needed, could storage (*) or back-up generation be provided as part of the project to cover low generation periods?	Where storage or backup is not already available, this could be introduced as part of the project. Such as combined variable renewables with distillate fired plant	Yes/No	Yes/No	Yes/No				
T3(c)	Is the feedstock/fuel network supply reliable and available?	This applies to physical supplies and also needs to ensure feedstock spec within agreed bounds				Yes/No	Yes/No	Yes/No	
T3(d)	Is there an existing link or is another network sufficiently close to allow connection in time meet demand requirements?	Access to an adjacent power system, if it has adequate supply, could provide an alternative to in-country generation							Yes/No

(*) Refers to any kind of bulk energy storage such as pumped hydro or batteries
Grey cells indicate question not applicable

The questions in Table 4 allow more detailed analysis against specific attributes, to further refine which alternative technologies or fuels have the potential to be considered further. These questions should be applied only to those technologies or fuels which have been shortlisted.

Table 4: Identifying alternatives for further assessment

Technology	Typical Key Risks / Challenges	Risks / Challenges Acceptable?	Potential Alternative?
Wind	Sufficient wind yield available High capital cost (particularly for remote locations) End user tariff/price impacts High skill level required during development Ecology impacts Noise impacts Land take	Yes/No	Yes/No
Solar	Sufficient solar resource available High capital cost End user tariff/price impacts High skill level required Land take	Yes/No	Yes/No
Hydro	Sufficient hydro resource available High capital cost End user tariff/price impacts High skill level required Aquatic impacts Land-take Long lead times for development	Yes/No	Yes/No
Natural Gas	Fuel supply risk End user tariff/price impacts Fuel price volatility	Yes/No	Yes/No
Distillate	Fuel supply risk Fuel price volatility End user tariff/price impacts Air quality impacts	Yes/No	Yes/No
Bioenergy	Long lead times Fuel supply risk Food security impacts High capital cost High fixed operating cost End user tariff/price impacts Air quality impacts	Yes/No	Yes/No
Interconnections	Medium capital cost Long lead times Land-take Price volatility	Yes/No	Yes/No

Price volatility is not a risk to developer if passed to the off-taker via the Power Purchase Agreement. However, extremely high or low prices could lead to default of off-taker or supplier.

4. Assessing potential environmental impacts of HFO fired plants

Introduction

This section provides a pro forma set of key environmental issues for HFO fired plant, covering:

- Greenhouse gases / efficiency
- Emissions to water
- Ecology
- Emissions to air
- Waste
- Noise
- Contaminated land
- Emergency preparedness and response

Under each environmental issue, a set of key questions is provided along with related notes, and reference to relevant parts of the International Finance Corporation (IFC) General Environmental Health and Safety (EHS) Guidelines and EHS Guidelines for Thermal Power Plants. The IFC Guidelines require that national standards are met. It is worth noting that, whilst IFC Guidelines are normally more stringent than national standards, this is not always the case.

The key questions are intended to address the most important issues under each environmental topic at a basic level. It is expected that most projects beyond feasibility stage will have information available to answer these questions, including from existing documentation such as technical specifications and environmental scoping reports or assessments. It should be noted that answering these key questions is not a substitute for performing environmental and social impact assessment (ESIA), and environmental and social due diligence (ESDD) for either existing or new-build assets. Both the ESIA and ESDD tools are important in understanding location-specific environmental and social impacts as well as the most effective ways of mitigating those impacts.

For greenhouse gases and emissions to air, information is provided on European Union (EU) requirements in order to provide a target benchmark that could be used for some projects where a higher level of environmental protection is desired. Additional information has been provided under the heading 'Special Considerations for Existing Plant'

The key questions are intended to be applied to new or existing plants. When this exercise is being completed for an existing plant, a review of plant performance and compliance with relevant environmental regulations/guidelines, operational history, and any grievances related to plant operation should also be carried out. Further, for greenhouse gases and emissions to air.

Table 5: Key environmental issues for HFO fired plant

Greenhouse Gases / Efficiency			
No.	**Key questions**	**Notes**	**IFC requirements**
GHG1	Does the plant lead to annual emissions greater that 25,000 tCO_2? (alternate: is the plant >5.5MW)	A plant of capacity greater than 5.5MWe operating at full load would likely lead to emissions greater than 25,000 tCO_2 per year. This threshold can be a guideline for identifying plants where CO_2 emissions should receive more scrutiny.	IFC Performance Standard 3 requires that projects expected to have more than 25,000tCO_2 should report annually on the emissions from within the project boundary.
GHG2	Is the emission intensity of the plant greater than 500gCO_2/kWh?	To allow comparison with the IFC benchmarks. The intensity should be expressed as %Net, Low Heating Value (LHV).	The IFC EHS Guidelines for Thermal Power Plants provide 'typical' CO_2 emissions performance of new plants.
GHG3	Is the emission intensity of the plant greater than the national average for that country/region?	Is the project representative of better or worse than average performance for that type of plant for the country/region it will operate in.	The IFC EHS Guidelines for Thermal Power Plants state new facilities should aim (not a 'requirement') to be in the top quartile of the country/region average of the same fuel type and power plant size.
GHG4	What measures are included in the plant to increase/maximise energy efficiency?	The plant should include measures which maximise the efficiency of the plant, which may be from the type/nature of the plant, the way the site is configured, site-loads etc.	IFC Performance Standard 3 requires that developers consider alternatives, implement technically and financially feasible and cost-effective option to reduce project-related GHG emissions during the design and operation of the project. Typically efficiency levels from the IFC EHS Guidelines are 40-45% efficiency (net) for oil-fired engines.

EU benchmarking

Industrial Emission Directive 2010/75/EU requires that for all combustion plant 'energy is used efficiently'. Some specific measures are documented within the EUs BREF note (Best Available Techniques Reference Notes) for Large Combustion Plant and these normally form a consideration during the permitting for any plant. There are no specific benchmarks that plants should achieve at the EU level; although individual member states may include specific policies that limit emissions from plants (for example the UK has a technology-independent limit of 450gCO_2/kWh). The EU Emissions Trading Scheme (ETS) is the principal mechanism that manages GHG emissions by making them a real cost to operating high-emitting facilities. All power plants in the EU are required to participate in the ETS.

Special considerations for existing plant

GHG1: For existing plants that emit above 25,000tCO_2, reporting of GHG emissions should be part of environmental management plans, or a corrective action may be required to undertaken such reporting.

GHG2-4: Existing plants may be above the IFC Guideline 'typical' values. In these cases, and for repowering/rehabilitation, The IFC EHS Guidelines for Thermal Power Plants do not set any specific increment in performance to be achieved but note that an environmental assessment of the proposed works should include consideration of the likely costs of achieving 'alternative' emissions standards and recommend cost-effective measures for improving environmental performance. Therefore, it should be expected that the rehabilitation works should have a positive effect in respect of GHG emissions and intensity.

Emissions to Water			
No.	**Key questions**	**Notes**	**IFC requirements**
WAT1	Do wastewater streams meet relevant guidelines?	The main wastewater streams are usually process effluent, sanitary effluent, oily water drainage and general uncontaminated surface water run-off. A wastewater treatment plant is likely to be used.	The IFC EHS Guidelines for Thermal Power Plants provide effluent guidelines applicable to HFO fired plant.
WAT2	Does the plant design include measures to prevent accidental releases to water?	Relevant where surface and groundwater receptors are present. Plant areas particularly at risk of causing pollution of water are unloading bays; fuel storage areas; ash storage, outdoor transformers etc.	The EHS Guidelines provide control measures for storage of potentially contaminating materials.

Ecology			
No.	**Key questions[(a)]**	**Notes**	**IFC requirements**
E1	Is the project located in a UNESCO Natural World Heritage Site (WHS),	Projects located in WHS are typically not considered to be preferred investment options by DFIs, unless there is a prior consensus with	Natural World WHSs are Internationally Recognised Areas that are treated as critical habitat. IFC Performance Standard 6 does not explicitly state that WHS are 'no go' areas.

	or will it involve conversion of primary rainforest or habitat that would lead to global extinction of one or more species?	both Government and UNESCO that such operations will not adversely affect the Outstanding Universal Value of the Site.	However, meeting requirements is considered to be extremely difficult when the project is inside a WHS.
E2	Is the project located in an internationally recognised area (excluding WHS) or legally protected area?	Internationally Recognised Areas (other than WHS) include: Biosphere Reserves, Wetlands of International Importance (Ramsar Sites), Key Biodiversity Areas. Legally protected areas include sites designated at the national level according to International Union for the Conservation of Nature (IUCN) categories I-VI.	Ramsar Sites and legally protected areas in IUCN category Ia (Strict Nature Reserves), Ib (Wilderness Areas) and II (National Parks) are treated as critical habitat. The relevant IFC requirements are specified in IFC Performance Standard 6 and the accompanying Guidance Note.
E4	Is the project located in modified, natural or critical habitat?	Habitat definitions are provided in IFC Performance Standard 6 and the accompanying Guidance Note. Determination of whether the project is in critical habitat or not needs to be undertaken by experienced biodiversity specialists.	Significant conversion or degradation of natural habitat or implementation of any project in critical habitat is not permitted unless the requirements in IFC Performance Standard 6 are implemented.

Notes: [a] Consideration may need to be given to the location of transmission and distribution infrastructure

Emissions to Air			
No.	**Key questions**	**Notes**	**IFC requirements**
AQ1	What air emission limits does the project meet?	Limits should be identified for oxides of nitrogen (NO_x), sulphur dioxide (SO_2) and particulates (PM) as a minimum. When comparing emission guarantees, limits and standards etc., care should be taken to ensure that these are made on the basis of the same reference conditions (i.e. % water content, % oxygen content, temperature and pressure). For SO_2, emissions can be controlled by limiting the sulphur content of the fuel rather than applying an emission limit.	The IFC EHS Guidelines for Thermal Power Plants provide emission limits applicable to new HFO fired plant.
AQ2	Are the stack heights in accordance with Good International Industry Practice (GIIP)?	For projects using engines, multiple flues are often used. Generally it is better to group multiple flues within a common windshield.	The General EHS Guidelines provide an approach for identifying appropriate stack heights in accordance with GIIP.
AQ3	Is the airshed degraded or non-degraded?	Consideration should be given to each relevant pollutant (NO_x, SO_2 and PM as a minimum). Sufficient baseline monitoring data needs to be available to make a judgement.	Different emission limits can apply depending on whether the airshed is 'degraded' or 'non-degraded'. Baseline air quality is also fundamental to the decision of whether ambient impacts are acceptable or not and what operational monitoring may be needed. The General EHS Guidelines require nationally legislated ambient standards to be applied but, where those do not exist, internationally recognised standards such as those from World Health Organisation or European Union.
AQ4	Are the project's ambient air quality impacts acceptable?	Consideration of cumulative impacts with other future development or expansion may be needed.	The General EHS Guidelines provide a framework for assessing this. Emissions should not result in concentrations that reach or exceed ambient standards. For non-degraded airsheds, the project should not contribute > 25% of the relevant standard. For degraded airsheds and within or next to ecologically sensitive areas, contributions should represent 'a fraction' of the standards. If contributions are excessive (even when the emission guidelines are met) offsets should be pursued.
AQ5	Is there an on-site incinerator?	See related key questions under Waste Section. Sometimes small incineration plants are proposed for managing sludge, waste lubrication	The EHS Guidelines for Waste Management Facilities provide management methods for incinerators. Given that any plant are likely to be small, and the waste types limited, not all of the measures may be appropriate. Emission limits

	oil and some solid wastes such as rags etc.	provided in the General EHS Guidelines for small combustion plant may also be relevant. Key questions AQ2, AQ3 and AQ4, should also consider emissions from an incinerator.

Emission limits for combustion plant of 1-50MWth input are provided in the Medium Combustion Plant Directive (MCPD) 2015/2193.

Emission limits for combustion plant >50MWth input are provided in the Industrial Emissions Directive (IED) 2010/75/EU. In addition, the current IPPC BREF Document provides indicative 'Best Available Technique' (BAT) limits that are often more stringent than those in IED. The Draft IPPC BREF Document provides an indication of more recent BAT conclusions. Note that the threshold for determining which standards apply is based on the megawatt thermal (MWth) input of the plant. ie the potential thermal energy of fuel combusted within a power station in megawatts (ignores plant thermal efficiency).

Emission limits and other requirements for incineration plants are provided in the Industrial Emissions Directive (IED) 2010/75/EU. The regulatory burden (and associated emission limits etc) imposed within the EU mean that it is very unusual for small incinerators (ie the size likely to be needed for HFO projects) ever to be used for the disposal of such waste.

The IFC EHS Guidelines for Thermal Power Plants provide specific emission limits for new plant. The Guidelines note that, for rehabilitation of existing facilities, case by case emission requirements should be established using the results of an environmental assessment and bearing in mind the existing emission levels and the cost of meeting the emission limits for new plant (amongst others). Therefore, it is not appropriate to identify generic requirements for existing plant and, if the existing plant cannot meet the emission limits for new plant, the identification of suitable alternative limits is likely to require relatively detailed and site/project specific assessment.

Noise			
No.	**Key questions**	**Notes**	**IFC requirements**
N1	What noise guarantees will be met?	An assessment of baseline conditions is likely to be required as part of the identification of appropriate guarantees.	The General EHS Guidelines provide noise limits related to both baseline and absolute levels. Requirements are either 55dB(A) (during daytime, 45 dB(A) at night-time or no more than 3dB above baseline. The latter is ambiguous, but may be considered as relevant where baseline is already above guideline values (55dB, daytime) rather than applicable in areas of low background level which would result in an unnecessarily onerous target. EHS Guidelines for Thermal Power Plants also applicable. These repeat General guidelines.
N2	What noise mitigation will be included in the plant design?	Mitigation will need to be evaluated	The EHS General guidelines provide a number of generic mitigation measures e.g. bunds; enclosures; siting of noisy plant; attenuators etc.

Waste			
No.	**Key questions**	**Notes**	**IFC requirements**
W1	Have the waste types generated been identified and characterised (e.g. hazardous, non-hazardous, solid, liquid etc.)?	The characterisation of the waste streams will determine if the proposed treatment / disposal option is appropriate. Typical waste includes sludge, ash, filters, maintenance oils etc.	Information about the classification and management of hazardous and non-hazardous wastes is provided in the General EHS Guidelines.
W2	Are there facilities available for the appropriate recovery and /or disposal of waste generated by the plant?	HFO may be required to be treated (e.g. by centrifuge and automated filters) prior to combustion to remove water and solids. This process produces waste streams that are likely to be classified as hazardous waste. The characterisation of a waste as either a liquid or a sludge can be complex.	The EHS Guideline for Waste Management Facilities covers facilities or projects dedicated to the management of industrial waste, including waste collection and transport; waste receipt, unloading, processing, and storage; landfill disposal; physico-chemical and biological treatment; and incineration projects. The Guidelines also provide information on the siting, design and operation of landfills and the management of leachate and landfill gas.

Contaminated land			
No.	**Key questions**	**Notes**	**IFC requirements**
CL1	Is the generation site currently in use for industry / power generation, and / or has it been under similar uses in the past? What was previous land use and could there be contamination from that?	Former industrial and generation sites often exhibit legacy contamination as a result of previous operations. These sources can also result from waste management or landfilling associated with previous operations. In order to characterise potential contamination sources, the initial step in an Environmental Audit should be a site walkover survey and desk based review of current and historic site operations. Ground investigation data typically provides the most robust means of characterising contamination sources on sites.	IFC Guidance Notes for Performance Standard 1 state that: "Environmental and social audits (or due diligence) can be appropriate in the case of projects that involve existing assets, as well as property and asset acquisitions".
CL2	Does the plant design include measures to prevent accidental releases to land?	Most pollution incidents can be traced back to design and operational management failures. See similar issues for Water.	The EHS Guidelines provide control measures for storage of potentially contaminating materials.

Emergency Preparedness and Response			
No.	**Key questions**	**Notes**	**IFC requirements**
EM1	What standards of design do the storage and piping systems meet?	-	The IFC Environmental Health and Safety Guidelines for Crude Oil and Petroleum Product Terminals give details on appropriate standards
EM2	How is HFO to be delivered to site?	HFO is likely to be delivered by ship, pipeline or rail/road tanker. The safety and environmental impacts of the transport routes should be considered	The IFC Environmental Health and Safety Guidelines for Crude Oil and Petroleum Product Terminals give details on appropriate standards, notably the International Safety Guide for Oil Tankers and Terminals (ISCOTT), 2006, Witherby's Publishing.
EM3	What measures are available to prevent and control fires?	HFO is combustible rather than flammable at ambient conditions. However, the heating systems could heat it above its flash point thus fires and explosions are possible.	The General EHS Guidelines.

Appendices

A. Glossary
B. General Information on HFO Plants
C. Common Features of Other Generation Technologies and Fuels

A Glossary

CO_2	Carbon Dioxide
DC	Direct Current
DFI	Development Finance Institution
EHS	Environmental Health and Safety
ESDD	Environmental and Social Due Diligence
ESIA	Environmental and Social Impact Assessment
EU	European Union
GHG	Greenhouse Gas
HFO	Heavy Fuel Oil
IED	Industrial Emissions Directive
IFC	International Finance Corporation
LHV	Low Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MW	Mega Watt
MWh	Mega Watt Hour
NO_x	Oxides of nitrogen
O&M	Operations & Maintenance
PV	Photovoltaic
SO_2	Sulphur Dioxide
WHO	World Health Organisation

B General information on HFO plants

B.1 What is Heavy Fuel Oil (HFO)?

HFO is a general term describing a range of fuel oils made from the heavier parts of crude oil after the lighter parts are removed to produce petrol, diesel and other light products. Crude oil, as extracted from oil wells, varies greatly in quality and consistency of composition, with light Arabian crude being of a watery consistency and easily flammable whereas some of the heavy crude oils such as those from Venezuela are much more dense and viscous. All crude oils however consist of a spectrum of 'fractions', ranging from the gaseous fractions (that are volatile and can be released to atmosphere) from light crude oils to black tars that form a large part of heavy crude oils. These fractions are separated in the refining process to produce a range of products from light fuel oils such as kerosene and petrol (gasoline), through marine fuel oils and lubricating oil base stocks, to road tars.

The demand for the products of oil refining does not mirror the natural occurrence of the various fractions so heavier fractions are further refined in more sophisticated refining processes to produce more of the lighter oils demanded on the market. Nevertheless residual fractions remain, and have been used to produce fuels referred to, for example, as "Bunker C" (Royal Navy specification) or "no. 6" and used in boiler plant which is more tolerant of the vagaries of fuel quality and can utilise fuels that do not readily lend themselves to use in engines or turbines.

The demand for marine fuels in ships driven by large diesel engines has led to the development of marine oils that are more tightly specified than the residual fuels mentioned above. These are termed "Intermediate Fuel Oil" or IFO, and standard grades include IFO180 and IFO380, where the numbers refer to a measure of viscosity (the higher the number, the more viscous is the fuel). For power generation applications the IFOs dominate in today's market.

Characteristics of HFO other than viscosity are also controlled, in particular levels of sulphur and vanadium. Sulphur levels lead directly to the emission of sulphur oxides (SO_x) from the fuel combustion process, which can have negative health and environmental impacts. Vanadium in combination with sodium can be problematic in engines, causing corrosion to internal components. The best way to deal with the emission of sulphur dioxides, which are almost always constrained by regulation and legislation, is the removal of sulphur from the fuel at source and hence low sulphur HFO is commonly available today.

B.2 What generation technology types commonly use HFO?

HFO requires cleaning and heating before it can be used and a significant amount of equipment is required to process it in a power plant. It is therefore best suited to base load or variable but continuous operation where the cost of the processing equipment can be justified and offset by the relatively low cost of the fuel itself.
HFO may be used in the following equipment.

Large, Four-Stroke Reciprocating Diesel Engines
A great deal of HFO is used in large, four-stroke reciprocating diesel engines. HFO is slow to burn and difficult to ignite and hence is only suitable for use in larger engines which operate at relatively low speeds, normally not exceeding 750 revolutions per minute (rpm). Power outputs from such engines range from some 5MW to around 20MW per machine, and they are suitable for base load and flexible generation output. Net generation efficiency[2] is typically 40% to 45%. This can be increased to 50% to 55% if additional equipment is included to recover otherwise wasted heat to produce steam for a steam turbine to generate

[2] "Net generation efficiency" means the percentage of thermal energy available from the fuel which is converted to electrical energy.

additional power without using additional fuel. Such a plant is termed combined cycle. Economies of scale mean that this is only economically viable on larger plant, of typically at least 50MW.

Large, Two-Stroke Diesel Engines
Large two-stroke diesel engines are heavy-duty, slow speed (typically around 100rpm) engines mostly used for marine propulsion but also suitable for base-load power generation applications under certain circumstances. Power outputs range from around 10MW up to about 50MW per machine. However, the high capital cost of the engines, combined with the cost and visual impact of constructing a very tall power house with exceptionally heavy foundations to accommodate a large two-stroke diesel engine, plus the heavy vibrations that they can cause, means that the larger sizes are not generally used for power generation.
Net generation efficiency of these machines is typically 45% to 50%, and as above this can be boosted by the addition of a steam turbine in combined cycle.

Industrial Gas Turbines
Some heavy duty industrial gas turbines may be operated on HFO, principally "E class[3]" turbines producing some 70MW per machine, though smaller unit sizes are also available down to some 10MW or so. Net generation efficiency is typically around 35% but in combined cycle this can rise to 45% to 50%. However, the cost of providing the combined cycle plant would not normally be justifiable below about 50MW.

Conventional Boiler Plant
Conventional boiler plant can operate on HFO, producing steam which can then be used to generate electricity in a steam turbine. Combustion of HFO in boilers is not normally a good option for economic, efficiency and environmental reasons but may be applicable if steam is also required for a process plant of some sort. Net generation efficiency would not be greater than 35%.

B.3 How is HFO typically stored and transported?

At normal atmospheric temperatures all HFOs are viscous and will not readily flow in pipes without being heated, normally to somewhere between 60°C and 100°C. HFO is therefore stored in thermally insulated tanks equipped with heaters and moved within the power plant through insulated and heated pipes.
Fuel tank heating may be provided by electricity or by steam or hot water. Electric heating is not favoured due to the high value of electricity. Thus steam or hot water are more commonly used and are in turn heated by the generating plant cooling systems or exhaust gases, thus utilising heat that would otherwise typically be lost to atmosphere. Final heating to the maximum temperature required may require electric heaters as it may not be practical to use any other method.

B.4 Rationale for Project's Selection of HFO (engineering perspective only)

B.4.1 Overview

For a thermal power plant, HFO is often selected over other fuels for both practical and cost reasons. Where it is not feasible to bring natural gas or liquefied natural gas (LNG) to a site, a liquid fuel is likely to be the only practical option. If diesel oil were the same price as HFO then all users of HFO would use diesel oil instead because it is easier to handle, less

[3] "E class" is a General Electric term adopted for convenience across the industry to describe a heavy duty and robust turbine in this size range and using very well proven and reliable technology. E class turbines do not use the latest in combustion and blade technology but still find application where reliability and robustness are valued over efficiency.

demanding of the plant and equipment in which it is used, easier to ignite and cleaner to burn. However, the cost premium of diesel oil is likely to make it uneconomic for all but the smallest generators, say those below 1MW, and hence HFO becomes the preferred choice of liquid fuel.

B.4.2 HFO versus the use of other conventional fuels in thermal power plants

HFO is selected for the following reasons.

A) *It is significantly cheaper than other liquid fuels*

Table B. below provides a cost comparison of HFO with other fuels on the market, using typical world prices for 2016:

Table B.1: Comparison of HFO with other fuels on the market

Fuel	Cost per GJ, USD
HFO – IFO180	5.0-6.0
HFO – IFO380	4.5-5.5
Low sulphur diesel oil	7.5-10.0
LNG	6-12, highly dependent on location and supply agreement terms.
Pipeline gas	Cheaper than LNG but price tied to oil price

B) *It is readily available provided an efficient supply route is in place from a suitable oil refinery or a sea port with marine fuelling facilities.*

The great majority of ocean going vessels use HFO as their primary fuel and therefore there is a good supply chain to provide HFO to most ports in the world. Power plants located near a port can therefore count on a reliable supply of HFO via this supply chain.
Proximity to an oil refinery is also likely to mean that HFO will be readily available.
For power plant located some distance from a bulk source of HFO, it is often practical to transport it in suitable quantities by rail or road. For example, there are plants in Pakistan that run base load on HFO delivered by road tanker and consume roughly one road tanker of fuel every hour despite being several hundred miles from the port where the fuel is imported. Though this may seem a challenging supply method, it is workable and often more feasible than the alternative of providing a pipeline.

C) *Alternative fuels may be impractical to deliver to the site in suitable quantities.*

Alternative fuels may include:

Pipeline gas
From a cost perspective HFO would be preferable over gas where a gas pipeline is not already in place, or the construction of a new pipeline would not be economically viable.

LNG

Provision of an LNG regasification facility is generally considered uneconomical for power plant smaller than a few hundred MW due to the cost of providing the regasification facility and the high cost of LNG when purchased in relatively small quantities. (It should be noted however that an LNG facility with a power plant may be considered for strategic reasons with the power plant being an anchor customer to encourage the growth of a wider gas market in the region.) New technology enhancements are leading to an emerging micro LNG to power projects, although this comes at a significant unit cost premium to conventional LNG, but it has won applications where clean energy is a priority.

LPG or CNG

It is not feasible to transport natural gas in a compressed form for any but the smallest power generators, i.e. those in the tens of kW sizes or below that can use compressed gas already available for domestic heating and cooking applications. The need to store and transport compressed gas in heavy, highly pressurised vessels makes it uneconomical on a larger scale and there is little or no facility to do so in the quantities required for CNG power generation anywhere in the world. LPG is fairly easily transportable, and can be fired in many diesel plant and gas turbines (with small modifications); however, it tends to be sold as a premium fuel, so it is only applied in niche applications where clean fuel is required.

C Common Features of Other Generation Technologies and Fuels

Wind power plants (onshore)

Overview

Moving air which is deflected around aerodynamic blades rotates a shaft which converts rotary energy into electricity. Typically, the rotary energy is converted via a gearbox; however other options are used in some designs. The gearbox, brake, generator and controls are housed in the nacelle, which sits on a bearing on top of the tower. Modern wind turbine generators have in recent decades consolidated on three blade horizontal axis machines, although the scale of individual units and wind farms has increased.

Aspect	Description
Meeting demand requirements	✚ Fully Scalable. Wide ranging of rated power from 50kW to approx. 8MW per turbine. Different turbine options depending on average local wind speeds. Typical wind farms between 10-500MW ✚ Modular technology. Size of wind farm determined by land availability. Wind turbines are typically spaced 3-6x rotor diameters apart ✚ Provides non-dispatchable variable supply ✚ The largest units currently available (8MW) have rotor diameters of 160m with a tip height of 200m.
Capital cost drivers	✚ Highly site and jurisdiction dependent ✚ Capital costs (circa. USD 1.5-2m per MW installed) ✚ Technology can only be deployed at sites with sufficient wind yields (determined through feasibility studies); remote locations may require capital expenditure on transmission infrastructure ✚ Onshore wind's costs are largely determined by the initial CAPEX and the extent of fixed cost dilution (which depends largely on the average wind speed). Cost of capital is generally low, although this depends on the certainty of off-take prices.
Operating and maintenance cost drivers	✚ Operation and maintenance cost approximately 1-3% of original investment per annum. Costs due mainly to regular and corrective maintenance ✚ Typical operational lifetime of 20 years
Fuel considerations, including costs and receipt and handling	✚ Potential generation depends on the air density, the diameter of the blades and most importantly the wind speed.

requirements	
Workforce skill requirements	✚ Wind technology requires high skill sets and more specialist training as turbines are complex. Turbine operational performance monitoring increasingly done remotely by the manufacturer, though some maintenance staff will always be required on site ✚ Operational roles require skilled technicians who can be trained locally but are likely to be sourced from abroad in early stages of development in a country
Key environmental considerations	✚ Negligible greenhouse gas emissions in operation ✚ Potential significant impacts on bird and bat populations depending on location ✚ Potential significant visual impacts whether deployed with a few units or on a large wind farm basis. ✚ Has a large land-take, although land can be used for grazing etc. ✚ Potential significant noise impacts in the immediate vicinity

Solar photovoltaic power plants

Overview

Solar Photovoltaic (PV) plants convert sunlight absorbed by the PV modules and generate direct current (DC) electricity through use of the photoelectric effect. Generally, there are three kinds of ground mounted PV plants; fixed tilt systems, single axis tracking systems and dual axis tracking systems. Single axis tracking systems are most commonly found in regions with a high solar resource such as Africa, enabling the plant to utilise more of the available sunshine in to generate electricity.

Aspect	Description
Meeting demand requirements	✚ Scalable technology, typically less capacity is installed compared to other technologies (10s of MW) but dependent on land availability/costs ✚ Provides non-dispatchable intermittent supply. ✚ There are a variety of different commercial solar module types with varying efficiencies including; Monocrystalline Silicon (approx. 17% with higher efficiency modules exceeding 20%), Polycrystalline Silicon (approx. 17%) and thin film modules including Amorphous Silicon (9.1% max), Cadmium Telluride (approx. 16%) and Copper Indium Gallium Selenide, CIGS (approx. 14%).
Capital cost drivers	✚ High CAPEX. Current quotes for bankable (i.e. utility scale market standard components) projects are in the region of USD m 1.7 -2.4 per MW.
Operating and maintenance cost drivers	✚ Usually lower O&M costs than other renewable technologies. ✚ OPEX is small (at approximately 1% of initial CAPEX) given the generally high reliability of components.
Fuel considerations, including costs and receipt and handling requirements	✚ Commercial PV technology is typically developed at sites where sufficient solar resource has been determined through an initial feasibility studies. ✚ The reliability of solar PV plant is generally good. Output is however dependent on weather conditions which is one of the key factors affecting energy generation
Workforce skill requirements	✚ Skilled workforce required specifically for the inverters.
Key environmental considerations	✚ Negligible greenhouse gas emissions in operation. ✚ Negligible noise impacts. ✚ Potentially significant visual impacts when deployed commercially on a large scale. ✚ Ground mounted schemes require a large land area which could mean the destruction of surrounding natural habitat.

Hydro power plants

Overview

Hydropower developments consist of civil, mechanical and electrical components. Civil structures can and typically include dams, weirs, spillways, canals, tunnels, powerhouses and control buildings. Mechanical and electrical components typically include turbines, gates, valves, generators, transformers, switchgears, substations and transmission lines and ancillary works.

Aspect	Description
Meeting demand requirements	✚ Flexibility of scale. Wide ranging from < 1MW to 1000s of MWs. ✚ Feasibility and scale is highly dependent on local features; generally more feasible in areas of high rainfall and hilly / mountainous terrain. ✚ Provides baseload power, although peaking option can be available subject to conditions. ✚ Can be used for energy storage in the form of 'pumped storage hydropower'.
Capital cost drivers	✚ For large scale projects (>100MW), capital costs range from USD 1 million to USD 7.7 million per MW of installed capacity. The range for small and medium hydro (1 to 100 MW) is similar. ✚ Capex costs per MW of installed capacity typically decrease as scale increases. ✚ Capex costs typically higher than for thermal plants. ✚ Favourable terrain, geology, site accessibility, proximity to national grid and access to cheap, locally available material and labour reduces capex costs.
Operating and maintenance cost drivers	✚ Fixed costs lower than for thermal plants (no fuel). ✚ O&M costs typically lower than thermal plants. ✚ Operating lifetime can be considered 50 to 100 years but major overhaul of generating equipment (e.g. turbines and generators) can be expected every 20-30 years.
Fuel considerations, including costs and receipt and handling requirements	✚ Technology can only be developed in the locality of a sufficient hydrological resource (precipitation), which will also determine the size of the plant.
Workforce skill requirements	✚ Mix of highly, semi and low skilled workforce required during construction phase. ✚ Highly skilled workforce required during operation.
Key environmental considerations	✚ Can have significant benefits, for example, in flood management and water storage for drinking or irrigation. ✚ Significant opportunities for local employment and skill capacity building. ✚ Not considered a high GHG emission projects in most cases ✚ Reduced and / or altered flow regime in section/s of the affected river/s affecting river ecosystems. ✚ If not managed, can provide barriers to fish migration affecting river ecosystems.

Natural gas fired plant

Overview

Natural gas is a widely found hydrocarbon which is generally mostly methane (CH_4) but depending on the local geology can include a number of other gases and liquids. The most common other constituents are nitrogen and carbon dioxide. Natural gas with high (>20%) quantities of nitrogen or carbon dioxide can still be burnt in adapted equipment and are generally referred to as "low BTU" gases. Some natural gas streams are associated with oil deposits (usually called associated gas) and can contain sulphur compounds and heavy metals. They are usually less valuable than the oil and so are often reinjected into the oil well for enhanced oil recovery or burnt at the field rather than being cleaned up and sent out for consumption.

Natural gas is usually fired in gas turbines (open or combined cycle) and spark ignition reciprocating engines (recip engines). It can be used in almost any combustion process but its value usually means it is used in high efficiency processes. The low energy density of natural gas (heat content per m^3) means that it is not normally practical to transport by road / rail for more than 10s of km. This means that if pipelines need to be built to service the plant moderate to large plants are required for the economics to work. Liquefied natural gas (LNG) usually delivered by ship to regasification and storage facility. Historically, 500MW was required for an anchor customer for LNG regasification facility but much smaller facilities (~50MW) are now being built enabling some islands to utilise LNG.

LNG and compressed natural gas (CNG) should not be confused with liquefied petroleum gas (LPG) which generally cannot be fired in gas turbines.
Care must always be taken when specifying the heat content of gas as the difference between the higher and lower calorific value is 11% compared with ~4% for coal and ~5-6% for liquid fuels.

Aspect	Description
Meeting demand requirements	✚ Flexibility of scale. Wide ranging from single 0.5MW to 1000s of MW. ✚ Modular technology. One of the most flexible power generation options. Large numbers of units can be installed creating potential for future extensions of plant ✚ Energy efficiency can be increased for gas turbines and reciprocating engines by using heat recovery and a steam turbine to supplement output. ✚ Supply profile includes base-loading and peaking. High degree of control over the output and despatch.
Capital cost drivers	✚ Inherently a cleaner fuel so less abatement required compared to solid and liquid fuels. Though abatement may be required for NO_x with reciprocating engines to meet new limits. ✚ Capital cost increases if fuel supply infrastructure (i.e. pipelines, compressor stations, LNG regasification units) are to be developed in parallel. ✚ Typical capital costs (depending on size, technology and location) – Combined cycle gas turbines USD600/kW to USD1200/kW, efficiency 50% to 60% – Open cycle gas turbines USD300/kW to USD600/kW efficiency 30% to 40%

	– Recip engines USD900 to USD1400/kW efficiency 40% to 45% (open cycle)
Operating and maintenance (O&M) cost drivers	✚ Gas turbines and recip engines have high availability with short periodic major planned outages, usually every 3-4 years. Gas turbines have high cost major outages but low routine O&M. Recip engines have moderate cost major outages but frequent minor planned maintenance outages. ✚ Typical economic lifetime for gas turbines of 25 years and for recip engines of 40 years
Fuel considerations, including costs and receipt and handling requirements	✚ Fuel cost dictated by international market conditions and high capital cost of extraction and processing. Therefore, cheaper if bought in large and predictable quantities over long term contract. Cannot generally get fixed price gas contracts for more than 2 years. Price usually indexed to published benchmark. (e.g. Heron). ✚ LNG competitive with other fuels; USD 6 – USD 12 per GJ (as of 2016) but international price usually moves with oil benchmark prices. ✚ Higher degree of viability where there is an existing natural gas network available near to site. But, development of a gas network requires significant additional capex, regulation and engineering. ✚ No requirements for on-site fuel storage which reduces on site infrastructure requirements (back up fuels sometimes required). Storage expensive but can store as CNG at site or as LNG at a regasification facility.
Workforce skill requirements	✚ If using combustion turbines, higher skill sets and more specialist training is required because they are more complex. Although in low skilled economies specialist teams are usually imported for major outages. Reciprocating engines require more medium skill work and so generally require skilled indigenous workforce.
Key environmental considerations	✚ GHG emissions from natural gas are generally lower than other fossil fuels as half of heat in natural gas comes from the hydrogen content of the methane. GHG potential due to leaks from pipelines usually not considered. ✚ Nitrogen dioxide (NO_2) is the only potential pollutant of concern for local air quality impacts ✚ Reciprocating engine and gas turbine plants have low water consumption and only require cooling if in combined cycle. Can be air cooled.

Distillate oil fired power plants

Overview

Distillate is a generic name given to refined petroleum products similar to road diesel but would include products such as aviation fuel and light gas oil. Distillate fuels are widely used in transport, industry and power generation.

Distillate can be burned most advanced gas turbines but because it does produce some particulates boilers and heat recovery steam generators require better materials and different finned tubes making them more expensive and less efficient. Distillate fuels can be burned directly without fuel treatment. Some gas turbine manufacturers do supply dry low NO_x combustion systems for gas and distillate but often water injection is required for NOx control. The fuel bound nitrogen content of distillate is a major determinant of the NO_x emissions from gas turbines burning it. High nitrogen content (>1200 ppm) often makes it impossible to achieve gas turbine emission limits without water injection which is a major consumer of water in this case.

Aspect	Description
Meeting demand requirements	✚ Often the fuel of choice for small electrical systems and islands due to modular small machines, small cargo sizes and ease of storage. ✚ Recip engines come in two types, small low efficiency high spend engines (similar to lorry engines) 0.5MW to 2MW and large high efficiency medium/low speed engines typically 3MW to 20MW but 100MW engines are available. Industrial gas Turbines can also be used, with units usually ranging from 60MW to 500MW. Aero derivative gas turbines will burn distillate. ✚ Larger recip power plants may be comprised of many engines often utilising heat recovery and a steam turbine to increase output and efficiency.
Capital cost drivers	✚ There is a competitive engine market for recip engines but effectively just Wartsila and MAN for larger unit sizes (>20MW). ✚ Recip engine plant costs of the order of USD1,000/kW depending on fuel storage and abatement costs.
Operating and maintenance cost drivers	✚ Distillate has relatively high (but lower than HFO) O&M costs. ✚ Distillate fuelled recip engines have high reliability but require frequent short planned outages resulting in the need for spare engines on larger plants.
Fuel considerations, including costs and receipt and handling requirements	✚ Distillate is more significantly expensive than natural gas and HFO but is widely available. ✚ Logistically distillate is fairly flexible – can be transported via pipeline and by road / rail from port terminals. Usually, ports have limited unloading facilities, often only one offshore single point mooring.
Workforce skill requirements	✚ There are more requirements for skilled and semi-skilled employment at a recip engine plant than at gas turbine plants. ✚ O&M for a distillate recip engine plant is generally not technically complex. ✚ Steam turbines and gas turbines require more specialist skills
Key environmental considerations	✚ Distillate if spilled generally becomes an environmental hazard as it partially evaporates will flow into underground watercourses if not contained. ✚ Unlikely to be appropriate in areas of existing high pollutant concentrations although a cleaner burning fuel than HFO.

Bioenergy plant

Overview

Bioenergy is taken to include clean biomass (including woody and agricultural biomass), bioliquid (utilisation of not production of) and biogas (from anaerobic digestion processes using clean biomass material as the feedstock). But not biodiesel or bioenergy crops (sugar/ ethanol, jatropha, Palm oil)

Aspect	Description
Meeting demand requirements	✚ Typically biomass projects are between 10-50MWe. Bioliquid projects tend to be less than 30MWe and biogas projects tend to be less than 5MWe. ✚ Generally bioenergy plants provide baseload power although developers/utilities investigating ways in which plant can be dispatched to meet system needs ✚ For biomass, there are a number of well-established furnace types including Pulverised Fuel (100MWe-600MWe), Fluidised Bed (<100MWe-400MWe) and Grate (<100MWe). ✚ Bioliquid and biogas projects for power generation will typically use a reciprocating engine as the prime mover.
Capital cost drivers	✚ Key cost items are up front capital and fuel costs, with fixed and variable non fuel OPEX significant secondary items. Carbon is excluded on the basis of the carbon neutrality assumption. ✚ For biomass projects CAPEX costs are significantly more than unabated super critical coal, given the smaller unit scale, more complex boiler design and additional fuel handling costs. ✚ For biomass projects CAPEX costs vary significantly between ~£5,000/kWe (small project) to ~£2,000/kWe (large project) assuming a well-established international OEM (original equipment manufacturer). For a project of 50MWe can consider CAPEX of ~£3,000/kWe with significant variation (perhaps as little as70% to 80% of this estimate) if the plant is built outside of Northern Europe. ✚ CAPEX for bioliquid facilities will be comparable to liquid fossil fuel fired facilities. ✚ CAPEX for biogas facilities will include many elements of gaseous fossil fuel fired facilities but additional CAPEX will be required for the biomass feedstock handling and preparation and biogas storage. CAPEX costs can vary between £5,000/kWe to £7,000/kWe reflecting the variety of anaerobic digestion (AD) system technologies, capacities and types of feedstock that can be employed.
Operating and maintenance (O&M) cost drivers	✚ For biomass project there will be high O&M costs due to combination of staffing costs and plant maintenance. ✚ For bioliquid and biogas projects the O&M costs will be similar to a reciprocating engine facility using fossil fuel. For the biogas facility there will be additional effort (and hence higher O&M costs) associated with the collection, preparation, storage tanks and digestate management. ✚ Fuel costs will depend on biomass supply but are likely to be much higher than that of other solid fuel plant (such as coal). Similarly bioliquid and biogas fuel costs will depend on the conversion technology used but would be expected to be more expensive (in energy terms) than the equivalent fossil fuel.
Fuel considerations, including	✚ Bioenergy fuel typically transported by road / rail / ship.

costs and receipt and handling requirements	✚ Larger plants that import bioenergy will tend to use ship and rail – it would be unusual to see bioenergy transported by road more than 150km on a regular basis. Furthermore, biogas is typically used adjacent to its production (exception being biogas which is injected into national gas grids). ✚ Bioenergy feedstocks are significantly variable, dependent on location and the level of processing required. ✚ A sustainable bioenergy feedstock for the life of the project should be available that doesn't impact on food security directly or indirectly. ✚ For biomass plant gross electrical efficiency (LHV basis) varies from as low as 21% to as high as 49%, with the upper end only being achieved at large scale and with super critical steam conditions. Net electrical efficiency will be approximately 10% to 15% lower depending on the level of power plant parasitic load. ✚ For bioliquid and biogas projects the gross electrical efficiency will be similar to fossil fuel fired reciprocating engine projects. The net electrical efficiency will be lower for biogas projects since there will be higher station loads associated with the preparation and storage of the feedstock ✚ Biomass storage is challenging due to the space requirement for energy sparse material, degradation, dust generation, asphyxiating atmospheres, self-heating and potential for self-combustion. Often the biomass will need to be stored under cover. ✚ Bioliquid storage is typically similar to equivalent fossil fuels but consideration needs to be taken with respect to "shelf life". ✚ Digester tanks will be required for the production of the biogas and separate storage will be required for the biogas. ✚ Bioenergy handling needs to be considered at an early stage otherwise there will be issues from poor design or the use of inappropriate equipment for the bioenergy feedstock in use. ✚ Careful specifying/monitoring/control of the bioenergy feedstock will be required so that the operational bioenergy feedstock matches the design bioenergy feedstock for the lifetime of the project – failure to control this will lead to issues with storage and handling performance of the bioenergy feedstock and potentially compromise performance and lead to issues such as corrosion for biomass and bioliquid projects and contamination of digestate for biogas projects.
Workforce skill requirements	✚ Range of skillsets required for bioenergy power plant operation. Day-to-day operations are similar to other process industries. ✚ Biomass and biogas plants require larger workforce than other thermal technologies / renewable projects. Bioliquid facilities should have similar workforce requirements since the fuel is already highly processed. ✚ Semi-skilled required for bioenergy feedstock handling who could be trained. Certain aspects may require specialist skills. ✚ Specialists and or OEMs can be drafted in for specific tasks (these skills may exist within country).
Key environmental considerations	✚ Not considered a high GHG emission project provided fuel is sourced sustainably. ✚ Unlikely to be appropriate in areas of existing high pollutant concentrations. ✚ A range of potential pollutants emitted.

Investment works

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