AMERICAN UNIVERSITY OF BEIRUT

FEASIBILITY STUDY FOR AN INDEPENDENT POWER PRODUCERPROJECT IN JORDAN

by
RAWAN AMIN HIJAZI

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RAWAN AMIN HIJAZI

Approved by:

Dr. Victor Araman, Associate Professor First Reader
Suliman S. Olayan School of Business

Ziad Younes

Mr. Ziad Younes, General Manager Second Reader
BUTEC s.a.l.

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AN ABSTRACT OF THE PROJECT OF

Rawan Amin Hijazi for Master of Business Administration
Major: Business Administration

Title: Feasibility Study for an Independent Power Producer Project in Jordan

BUTEC s.a.l. is an engineering, procurement and construction (EPC) contractor operating in the MENA and GCC regions. BUTEC is considering applying to the tender of a new potential project for developing a power production plant in Jordan. This is a turnkey project where the Jordanian government is providing general requirements for the design of the plant; while the contractor is appointed to be an independent power producer (IPP) responsible for designing, procuring, constructing and operating it. Fuel will be supplied by the government in turn for buying the electric energy produced at a cost per kWh.

The design of the IPP project involves choosing one power production method among many alternatives; this depends on the technology proposed by the original equipment manufacturers (OEM's), where eventually the most optimal one will be chosen.

A feasibility study is conducted for the IPP project in order to determine the most feasible alternative, based upon which BUTEC will submit its tender documents. This is done by first developing twelve different alternatives for the power production method and calculating the levelized cost (LC) of each. The LC is an indicator used to compare the different alternatives; it is the minimum price of electric energy to be sold at which the project breaks even over its lifetime. It encompasses all costs needed to develop and operate the IPP project which include: capital expenditure, operation and maintenance cost, fuel cost as well as the cost of capital.

The study concludes that the cheapest alternative is to use a reciprocating engine technology supplied from Z, operating as a combined cycle mechanism using natural gas. However, there are many factors, other than the cheapest cost, that should be considered when choosing the optimal alternative to bid upon. These include: the net present value of the project, the actual energy generated to be sold, in addition to the effect of the variability of some factors included in the LC calculations such as the fuel cost.

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CHAPTER I

INTRODUCTION

BUTEC s.a.l. is an engineering, procurement and construction (EPC) contractor operating in the MENA and GCC regions. It is currently considering to apply to the tender of a new potential project for developing a power production plant in Jordan. BUTEC and other contractors will be competing against each other to win this bid. The tender documents to be submitted by BUTEC will be based on an optimal power production technology, with its associated bid price and specifications, which should meet the general requirements given by the government.

The objective of this project is to conduct a feasibility study for this potential power production plant, which involves developing different alternatives for the power production technology and then describing the different steps needed to identify the one to be bid upon. The report starts by describing the power production plant and providing an overview about the company. It is then divided into three main parts: an overview, a financial feasibility and lastly an analysis section. The overview first describes the electric power market in Jordan; it then provides a description of the different alternatives for the power production technologies which are considered for this project. The financial feasibility section provides a detailed breakdown on calculating the costs of the project; these are needed to come up with a financial indicator known as levelized cost (LC) which is used to compare between the different alternatives. As for the analysis part, it first explains how usually the optimal alternative is chosen based on the cheapest cost. Then, it analyzes the validity of this method; explains what other factors should be accounted for when selecting the optimal alternative; and identifies issues that should be considered when studying the profitability of such a project.

It should be noted that some of the information provided in this report was disguised due to confidentiality reasons.

A. Independent Power Producer

As mentioned that there is a new potential project of developing a power production plant in Jordan. This project will be considered an independent power producer (IPP) project. An IPP is an entity which produces electric power to be purchased by public utilities, central governments or any end user to meet their electricity demand. Being independent means that this entity is not part of a public utility; instead it develops, owns and/or operates its facilities to generate the needed electric power (SAIPPA 2011; IPPNY 2014; Leigh 2014). Therefore, the IPP project is a *turnkey* project where the client will be providing general requirements as well as supplying the fuel, while the contractor will be designing, procuring, constructing and operating it. The power produced will be sold to the government at a rate per energy produced (cents/kWh) as set in the submitted tender documents; after which the government is responsible for distributing the generated electric power.

A major phase for the contractor is the design phase which involves choosing one power production system among many possible alternatives; alternatives depend on the most adequate technology proposed by the original equipment manufacturers (OEM’s). Eventually, based on the government’s requirements, the most optimal one will be chosen. The selected OEM will end up providing technical support to the contractor during the operating phase.

B. Company Overview

Established in 1964 as a General Contractor firm in Lebanon, BUTEC has since been expanding its services and branches to become a regional player in the MENA and GCC construction industry. Its services now entail a wide range, varying from execution of pre-designed projects to Engineering, Procurement and Construction (EPC) projects. BUTEC's success in sustaining its position and distinguishing itself from its competitors lies in its professional and innovative approach when tackling each project which ensures the delivery of optimum end results.

BUTEC's vision lies in continuing its successful expansions and ultimately be "able to offer its outstanding quality construction services worldwide" (Younes 2009).

BUTEC's Branches include: Lebanon (Head Office), Abu Dhabi, Qatar, Algeria, Jordan.

BUTEC's fields of expertise include:

- Environmental Projects, such as: Waste Water Treatment Plants, Sewerage Networks, Irrigation, Potable Water Treatment Plants
- Infrastructure , such as: Roads, Bridges
- Oil & Gas, such as: Tank Farms, Refueling Schemes
- Industrial Projects, such as: Industrial Compounds, Power and Renewables
- Buildings, such as: Commercial Buildings, Public Buildings
- Airports
- Services

CHAPTER II

OVERVIEW

A. Electricity Market Analysis

In order to assess the need for developing a new IPP project in Jordan, the forecasted energy demand had to be compared to the expected supply to check whether a shortage is expected in the future.

1. Current Electric Power Production and Demand

Table 1 presents the power production entities currently available and their technologies along with their production capacities for the year 2012; their total capacity sums up to 3,461 MW (MEMR 2011). *Tables 2* and *3* provide a breakdown of the power produced by two of these entities.

Table 1: Power Production Entities in Jordan

Company	**Al Qatraneh Electric Power Company**	**Central Electricity Generating Company (CEGCO)**	**Samra Electric Power Generation Company (SEPGCO)**	**Al Manakher Company – Eastern Amman (AES)**
Technique	Simple cycle – natural gas	Several, see breakdown in *Table 2*	Gas and steam Turbines, see breakdown in *Table 3*	Combined cycle gas-fired power
Production (MW)	373	1687	1031	370

Table 2: Total Installed Capacity of CEGCO's Power Plants (MW) – 2012

Power Plant	Steam	Gas Turbine		Wind	Hydro	Total
		Diesel	N.Gas			
Aqaba	5 x 130				6	656
Hussein	3 x 33					363
	4 x 66					
Rehab Simple Cycle			2×30			357
Rehab Combined Cycle	1×97		2×100			
Risha			5×30			150
Marka		4×20				80
Amman South		2×30				60
Karak		1×20				20
Ibrahimyah				4×0.08		0.32
Hofa				5×0.225		1.125
Total	1110	160	410	1.445	6	1687

Source: CEGCO. 2014. "Total Installed Capacity". Central Electricity Generating Company; available from http://www.cegco.com.jo/?q=en/node/73; Internet; accessed 9 March 2014.

Table 3: SEPCO - Electric Power Generating Units

Phase	Unit	Nominal Capacity	Commercial Operation Date
Phase I	First Gas Turbine	100 MW	1/11/2005
	Second Gas Turbine	100 MW	11/2/2006
	First Steam Turbine	100 MW	8/10/2006
Phase II	Third Gas Turbine	100 MW	13/12/2007
	Fourth Gas Turbine	100 MW	5/7/2008
	Second Steam Turbine	100 MW	2/8/2010
Phase III	Fifth Gas Turbine	142.5 MW	25/01/2011
	Sixth Gas Turbine	142.5 MW	4/5/2011
Phase IV	Seventh Gas Turbine	146 MW	26/06/2013
	Total	**1031 MW**	

Source: SEPCO. "Electric power generated and imported into the Kingdom." Samra Electric Power Co. Website; available from http://www.sepco.com.jo/sepco.com.jo/en/index.php?option=com_content&view=article&id=86&Itemid=81; Internet; accessed 20 February 2014.

On the consumption side, the electric peak load of Jordan reached around 2,880 MW in 2012, which is around 83% of the production capacity of 3,461 MW (MEMR 2013).

2. Future Electric Production and Demand

The future plan of the kingdom in developing new and existing plants is to supply additional power for the increasing demand. It plans to add four projects which would produce almost 1,044 MW in the coming years (MEMR 2013). If this is added to the existing production capacity of 3,461 MW, then once all these power plants are operating, the total power produced would reach around 4,500 MW.

Moreover, it should be noted that new techniques are being considered which include renewable and nuclear energy. The government plans to make these contribute to 7% of the energy mix by 2015 and reach to up to 10% by 2020 (MEMR 2011). In addition, the government has been exploring methods to exploit domestic sources of energy, such as the oil shale which it plans to make it contribute to around 11% of the energy mix by 2015 and to reach to up to 14% by 2020 (MEMR 2011).

As for the future power consumption, the electric demand for 2020 (MEMR 2013) shows an increase of around 7% in demand growth to reach around 4760 MW. This future demand compared to the future supply of 4,500 MW shows that indeed there would be an expected shortage of energy production; this justifies the government’s need to further expand its production capabilities through a potential IPP project.

B. Technical Background

1. Technology

There are many technologies that produce electric power, but for this project, two of them are considered: Gas turbine (GT) and reciprocating engine (RE). Each of these two can also function based on two cycles, either an open cycle (OC) or a combined cycle (CC). These are described as follows:

a. Gas Turbine

i. Open Cycle Gas Turbine (OCGT)

OCGT "is a combustion turbine plant fired by liquid fuel to turn generator rotor that produces electricity" (TWUGBCN 2014). Its process starts with a compressor taking air from the atmosphere and then compressing it through different phases, as shown in *Figure 1*. Then it is fed into a combustion chamber, where fuel is pumped and burned and both are mixed at constant pressure. The resulting fuel-air mixture is ignited to produce a high-velocity hot gas which is then channeled into the turbine; as it expands through the turbines' blades, it turns the shaft which is attached to the generator's rotor. The rotor turns and its movement produces electricity.

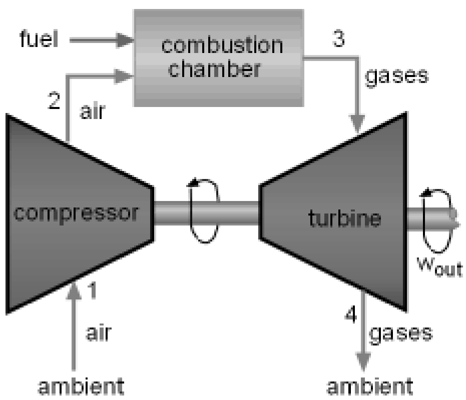

Figure 1: Open Cycle Gas Turbine
Source: Thermodynamics ebook. "Brayton Cycle". Multimedia Engineering Thermodynamics, Chapter 9; available from https://ecourses.ou.edu/cgi-bin/ebook.cgi?doc= &topic=th&chap_sec=09.1&page=theory; Internet; accessed 20 April 2014.

This process also releases byproducts which should be accounted for when running the system; these include: waste heat (which is emitted into the atmosphere where a cooling medium must be used to contain it), and flue gases from combustion (which contain carbon dioxide, water vapor and other greenhouse gases depending on the type of fuel burnt).

As a consequence of having heat losses, the efficiency of such turbines is averaged around 33% (Landis 2014).

ii. Combined Cycle Gas Turbine (CCGT)

In order to address the issue of heat emissions and low efficiency of the OCGT, the CCGT was developed. It differs from the former by recovering the emitted heat to generate steam. As shown in *Figure 2*, this steam would then be run through a steam turbine which in turn generates additional electricity; as such, it uses more than one thermodynamic cycle to generate electricity. The combined efficiency would reach to an average of 55% which shows a considerable improvement from the OCGT (IPIECA 2014).

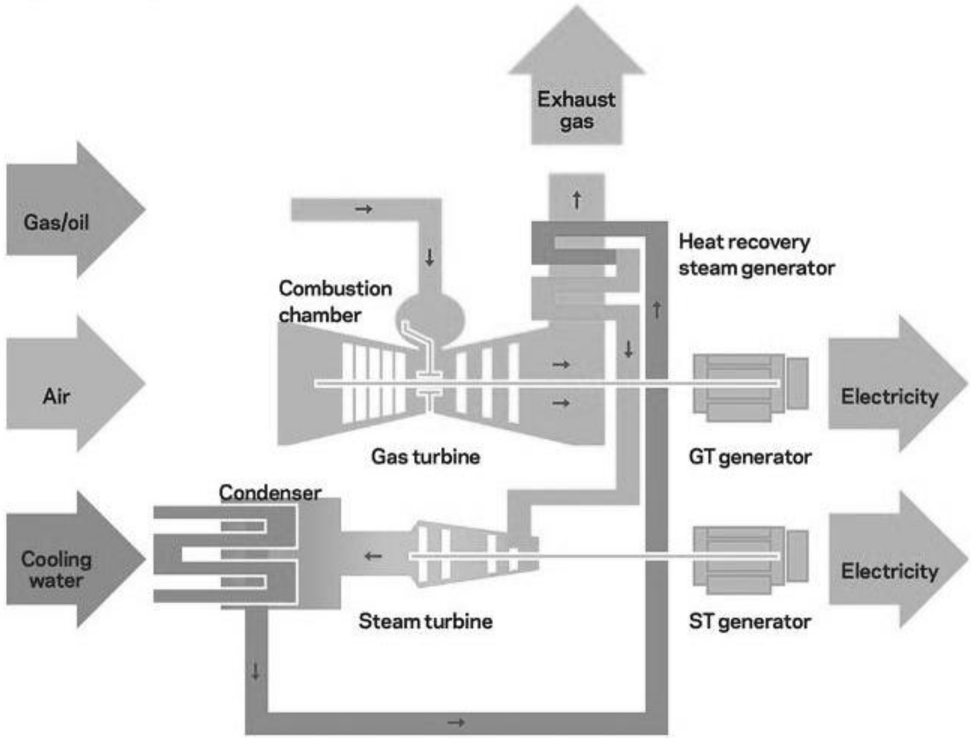

Figure 2: Combined Cycle Gas Turbine
Source: Building Website. 2013. Infrastructure: Combined cycle gas turbine plants Building Company, UK, July 11.

b. <u>Reciprocating Engines (RE)</u>

RE's are used to generate power by a mechanism which expands hot gases that push a piston inside a cylinder; this linear movement of the piston is converted into a rotating movement of a crankshaft; hence, electricity is generated. These engines internally combust an air-fuel mixture based on two types of combustion methods: spark-ignited and compression-ignited (known as diesel); the former requires an external spark to ignite the mixture. While in the latter, air is compressed to raise the temperature high enough to reach the auto-ignition stage of the fuel. The RE undergoes the following four stages to produce electricity, which are illustrated in *Figure 3* (Wärtsilä 2014):

- Intake: an intake valve opens allowing the air-fuel mixture to enter into the cylinder, moving the piston down. Once the cylinder is full, the intake valve closes.
- Compression: the piston then moves upward by the motion of the rest of the engine, which compresses the air-fuel mixture.
- Ignition: depending on the type of combustion method, the mixture ignites resulting in a great deal of pressure and heat in the cylinder, by that powerfully pushing the piston to the bottom of the cylinder; this imparts rotation of the crankshaft and produces electricity.
- Exhaust: an exhaust valve opens to allow the waste gases to vent out.

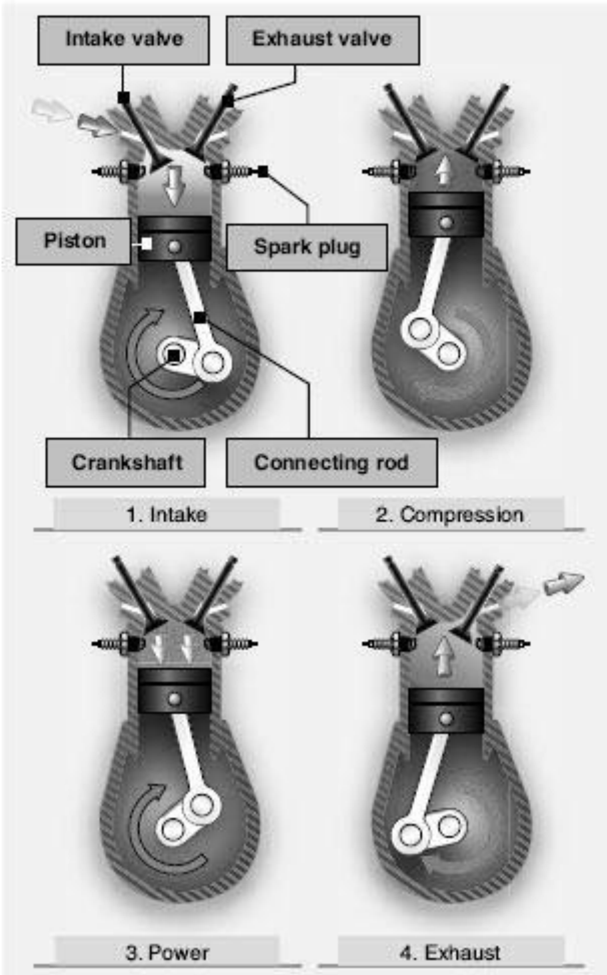

Figure 3: Reciprocating Engine Stages
Source: Flight Learning. 2009. "Reciprocating Engines." Part Three; available from http://www. flightlearnings.com/2009/09/14/reciprocating-engines-part-three/; Internet; accessed 18 February, 2014.

Usually, reciprocating engine capacities range between 4-20 MW; thus, for power production plants, a set of engines is used to generate the needed demand.

Reciprocating engine power plants have higher simple cycle efficiencies of around 50% compared to GT, since they convert more of the fuel energy into mechanical work.

This method also produces waste gases which can be used to produce supplementary electricity using heat recovery steam generators (HRSG) as is the case of

CCGT. However, the gases here are at much lower temperatures than GT which allow for simpler design of the HRSG's; these increase the efficiency by around 20% to reach 60%.

c. Comparison

When comparing both technologies, we observe that the CC definitely increases the thermal efficiency; while an OC offers lower capital costs but is associated with higher running cost per unit of output. *Table 4* shows a comparison between the GT and RE, where both have a mix of advantages (+) and disadvantages (-).

Table 4: Comparison between the GT and RE

	GT	RE	Description
Mechanical efficiency	+	-	Mechanical efficiency of GT is considerably higher (around 90-95%) than that of the RE (85-90%) under full load conditions, which is due to having more frictional losses in RE
Balancing	+	-	Due to the absence of any reciprocating mass in GT engine, balancing can be near perfect. Since the GT is a steady flow machine, it does not produce torsional vibrations
Cost	+	-	Building large output GT can be considerably of a lower cost and in a shorter time than similar output RE’s
Fuel			GT: can operate with lower cost fuel types such as powdered coal , benzene
			For RE - spark ignited: natural gas
			For RE - compression ignited: diesel oil, can also burn natural gas with small portion of diesel which is known as dual-fuel engines
Smokeless exhaust	+	-	If large amount of air is being used for combustion for the reduction of the temperature of gases, then the GT exhausts almost smokeless emissions and generally free pungent odor unlike the RE.
Environmental performance/ emissions			NOx and CO emissions are 60% lower in GT than in RE.
			CO_2 emissions are lower in RE than GT due to the former’s better simple cycle efficiency.
Lubrication	+	-	Lubricating a GT is comparatively simpler which mainly involves lubricating the main bearing compressor shaft as well as bearings of the auxiliaries
Maintenance	+	-	Minimum maintenance is needed for a GT since it is comprised of a smaller number of parts which include a single turbine and compressor unit, shaft and bearings
Lower operating pressures	+	-	GT has a relatively lower combustion pressure so the elements exposed to this pressure can be lighter _ while not disregarding the thermal expansion and contraction effects
Silent operation	+	-	When dynamically balanced, the GT can function smoothly with no vibrational noises due to constant pressure conditions of its exhaust, contrary to the pulsating nature of that of the RE

High operational speed	+	-	Having lighter parts for the GT allows it to run at higher speeds than RE of similar output. "The output of any engine varies directly as the product of the driving shaft torque and its rpm. Therefore, for a given output and higher speed the torque will be lower. It may be noted that the torque characteristic of the gas turbine is much better than that of RE, since the former gives a high initial torque and its variation with speed is comparatively less."
Efficiency	-	+	OCGT: 33% OCRE: 50%
			CCGT: 55% CCRE: 60%
			The overall efficiency of the RE is much higher than a GT because 70% of the latter's output is fed to the compressor and other and auxiliary elements
Temperature limitation	-	+	In a GT, the maximum allowable temperature cannot exceed 1500 K to take into account the nature of the material of the blade. While a RE can reach a temperature of 2000 K, which is only reached for a fraction of second in the piston and cylinder head.
Cooling	-	+	In RE, the heat of the cylinder walls can be kept at a low temperature (around 500k) if the walls' heat is taken away by cooling. These efficient results of cooling cannot be achieved in a GT since it is complicated and hence the lower maximum allowable temperatures for a GT.
Starting difficulties	-	+	A GT requires a more difficult mechanism to start (which involves compressing the air) than a RE.

Source: Wärtsilä (2014); Patel (2011); Ganesan (2006); Hoskins and Booras (1998).

2. *Fuel Type*

There are several options which are expected to be used as an input for the IPP project; these include:

a. Natural gas

b. Heavy fuel oil

c. Diesel oil

According to the statistics released by Jordan's Ministry of Energy and Mineral Resources (MEMR), the dependency of power production on crude oil has been decreasing in recent years as presented in *Tables 5* and *6* (MEMR 2014); the percentage of importing crude oil has decreased from 79% to 51% between 2003 and 1012 and was replaced by importing diesel oil.

The reason behind this is the multiple attacks which took place on the Arab gas pipelines. This has pushed up the prices of energy sources, upon which a new plan for the use of renewable and nuclear energy is created for the coming years.

Table 5: Import of Crude Oil and Petroleum Products (000 Tons)

	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Crude Oil	4023	4244	4602	4258	4040	3795	3630	3481	3189	3623
Fuel Oil	570	100	19	-	-	91	-	307	674	703
LPG	171	179	178	182	233	196	234	219	288	288
Diesel	292	543	785	509	429	320	414	670	1361	2089
Gasoline	40	135	93	65	166	141	231	400	540	426
Jet Fuel	-	1	1	1	1	1	1	1	1	1
Total	5096	5202	5678	5015	4869	4544	4510	5078	6137	7130

Table 6: Percentage of Import of Crude Oil and Petroleum Products

	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Crude Oil	79%	82%	81%	85%	83%	84%	81%	69%	52%	51%
Fuel Oil	11%	2%	0%			2%		6%	11%	10%
LPG	3%	3%	3%	4%	5%	4%	5%	4%	5%	4%
Diesel	6%	10%	14%	10%	9%	7%	9%	13%	22%	29%
Gasoline	1%	3%	2%	1%	3%	3%	5%	8%	9%	6%
Jet Fuel										
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

C. Project Assumptions

Since this project is still in its pre-project planning phase, some data were still not disclosed by the Jordanian government. Accordingly, several assumptions were made which will be adjusted upon the release of the actual requirements by the government.

1. Capacity

The power production capacity is expected to range between 250-350 MW. It will be assumed to be equal to 300 MW until further information is available.

2. Project's Lifetime

The lifetime of the project is assumed to be 25 years.

3. Fuel Type

In the feasibility study, it was assumed that there will be two fuel alternatives which are natural gas (NG) and heavy fuel oil (HFO). This was based on BUTEC's judgment as these two fuel types would be the most probable to be required by the government.

4. OEM and Selected Technology

Based on BUTEC's previous relationships with different OEM's and while considering their qualifications, few of them were shortlisted. The list of potential OEM's was limited to two suppliers for the gas turbine which are *X* and Y, while that of the reciprocating engine was restricted to Z. For each of these OEM's, a model of the gas turbine/reciprocating engine was selected based on BUTEC's technical recommendation.

CHAPTER III

FINANCIAL FEASIBILITY

A. Levelized Cost

Since at this point, the government has not released the IPP project requirements, the following scenarios were assumed: an IPP project either works using HFO or NG; each might either require an open cycle mechanism or a combined cycle one. As such, four scenarios are identified. Having three OEM's (*X*, Y and Z) with either a GT or RE allows for developing three alternatives in each scenario; as such twelve different alternatives are identified as presented in *Table 7*.

Table 7: Scenarios/Alternatives

		Alternative	OEM - Technology
Scenario 1	CC - HFO	1	*X* - GT
		2	Y - GT
		3	Z - RE
Scenario 2	OC - HFO	4	*X* - GT
		5	Y - GT
		6	Z - RE
Scenario 3	CC - NG	7	*X* - GT
		8	Y - GT
		9	Z - RE
Scenario 4	OC - NG	10	X - GT
		11	Y - GT
		12	Z - RE

The need behind developing such scenarios is to recognize the most profitable one and select it for the bid when applying for the tender of the project. Depending on the requirements to be disclosed by the government in the future, BUTEC would be ready to identify the best alternative out of these twelve to submit in its tender.

In order to compare the feasibility of each of these scenarios, a KPI known as the Levelized Cost (LC) is often used. The LC is the minimum price of electricity to be sold at which the project breaks even over its lifetime. “It is an economic assessment of the cost of the energy-generating system including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, cost of capital. A net present value calculation is performed and solved in such a way that for the value of the LC chosen, the project's net present value becomes zero” (NREL 2014). It is measured in cost per energy produced; in this case, it will be taken as cents/kWh. The significance of the LC is that it allows decision makers to compare between several power production methods of unequal factors such as capital cost, capacity factor, efficiency and fuel costs (Ocampo 2009).

The LC is the ratio between the costs paid to construct and operate the plant over the energy produced, calculated over the project’s lifetime. The costs include the initial capital expenditure (Capex) and the operation and maintenance (O&M) costs. The latter is usually divided into fixed and variable costs; the fixed part is a sunk cost since it is independent of the production of the plant while the variable part is directly related to the operation of the plant. A major part of the variable O&M cost is the fuel cost; this is why it was separated and removed from the variable O&M to be accounted for independently and also since the fuel will be supplied by the government. Therefore, the O&M cost would represent both fixed and variable costs except fuel cost. As such, in simple terms, the LC is calculated as follows:

$$\text{LC} = \frac{\text{Capex} + \text{O}\&M\ cost + Fuel\ cost}{\text{Energy Produced}}$$

The three cost components were calculated for each year, after which they were discounted to year zero using the cost of capital of the IPP project.

It should be noted that although the fuel is supplied by the government, the fuel cost had to be calculated and included in the LC because it depends on the efficiency of each alternative. Therefore, the government would require knowing how much fuel cost per kWh it is expected to pay.

The following section provides the breakdown calculations of the LC factors.

1. Energy Produced

In the LC calculations, the energy produced refers to the net electricity produced per year measured in (kWh/year). This is calculated as:

$$\text{Output (MW)} * 1000\text{kW/MW} * 365\ \text{days/yr} * 24\text{hrs/day} * \text{EAF}$$

EAF: Expected Availability Factor, which is the fraction of a time period when the plant is producing electricity. This factor ranges between 85%-95% and depends on the technology in each alternative.

2. Capex

The capital expenditure (capex) includes all the initial investment cost needed to construct the plant. These are divided between direct and indirect costs. The direct costs include the price of land, engineering fees, execution costs (mobilization fees, electrical works, mechanical works, civil works, and instrumentation and control), as well as commissioning and testing. As for the indirect costs, these include: consultancy fees (done by a third-party technical expert), insurance, taxes and head office support fees.

Both direct and indirect capex costs are estimated for the two main components of the plant: the power island and the balance of plant (BOP). These are explained below:

a. Power Island

This consists of the primary components of the chosen technology with their auxiliaries, whether GT or RE, along with the steam engines if a combined cycle was considered.

b. Balance of Plant

This consists of the remaining parts of the plant which include: Cooling tower, water generation plant, fuel tanks, gas insulated system, transformer and switch gears etc.

The Capex is usually measured as a cost per unit output, termed *Capex Unit Cost;* in this case, its unit is $/kW. The cost depends on four factors: the OEM and the corresponding technology (GT vs. RE), the cycle type (OC vs. CC) as well as on the fuel type (NG vs. HFO). As for its value, these were collected from several online sources which estimate different values for the Capex Unit Cost. Using these estimates as a benchmark along with BUTEC's experience in previous projects, the final values of the Capex Unit Cost for each alternative were estimated and are presented in *Table 8*.

Table 8: Capex Unit Costs

OEM-Technology	Fuel	Cycle type	Capex Unit Cost $/kW
X - GT	HFO	OC	xxxx
		CC	1,050
	NG	OC	700
		CC	xxxx
Y - GT	HFO	OC	xxxx
		CC	1,100
	NG	OC	750
		CC	xxxx
Z - RE	HFO	OC	1030
		CC	xxxx
	NG	OC	1030
		CC	xxxx

When it comes to including the Capex in the LC calculations, the total initial cost, which is paid in year 0, is calculated as the product between the Capex Unit Cost ($/kW) and the power output (MW), with the needed unit adjustments.

3. Operation and Maintenance Cost

The Operation and Maintenance (O&M) cost covers the salaries of the staff operating the plant, lubricating oil, as well as equipment and spare parts used during the maintenance phase.

The O&M cost is usually measured as cost per unit output per time; in this case, it is taken as $/kW/yr. Similar to the case of the Capex Unit Cost estimates, several sources provided different estimates of the O&M Unit Costs which were used as a benchmark to come up with the values presented in *Table 9*.

Table 9: O&M Unit Costs

OEM-Technology	Fuel	Cycle type	O&M $/kW/yr
X - GT	HFO	OC	11
		CC	xx
	NG	OC	xx
		CC	7
Y - GT	HFO	OC	14
		CC	xx
	NG	OC	xx
		CC	9
Z - RE	HFO	OC	xx
		CC	16
	NG	OC	xx
		CC	10

When it comes to including the O&M cost in the LC calculations, the total yearly O&M cost ($/year) would be calculated as the product of the O&M Unit Cost ($/kW/yr) and the power output (MW), with the needed unit adjustments.

4. Fuel Cost

As mentioned, the fuel cost is the main component of the variable O&M cost which is why it was taken separately. This depends on the cost of fuel in Jordan which is as follows (MEMR 2014b):

- NG price: 16 US$/mmBTU
- HFO price: 670 US$/ton

When it comes to including the fuel cost in the LC calculations, the yearly fuel cost is calculated in ($/year) and it differs with the type of fuel as follows:

a. Natural Gas

The fuel cost is calculated as:

$$\text{NG price}(\text{US\$}/\text{mmBTU}) * \text{conversion factor } (\text{mmBTU}/\text{kJ}) * \text{NHR}(\text{kJ}/\text{kWh}) * \text{output}(\text{kWh})$$

- Conversion factor: 1 kJ = 9.4708628903179 x10-7mmBTU
- NHR: Net heat rate measured in (kJ/kWh): is a measure of the conversion efficiency of the plant; it is obtained as the ratio between the total energy input over the electricity generated. This is a function of the fuel type as well as the technology of energy production (Wiki 2014).

b. Heavy Fuel Oil

For the HFO calculations, the fuel cost is obtained as:

$$\frac{\text{HFO price}(\$/\text{ton}) * 1000\text{kg}/\text{ton} * \text{NHR}(\text{kJ}/\text{kWh}) * \text{output}(\text{kWh})}{\text{HC}(\text{kJ}/\text{kW})}$$

- HC: Heat content measured in (kJ/kW) (also known as the calorific value) is the amount of heat produced upon the combustion of a fuel under standard pressure and temperature conditions. The HC of HFO is equal to 43000 kJ/kg (The Engineering ToolBox 2014).

B. Discount Rate

In order to find the LC of the different alternatives, the net present value (NPV) of each had to be calculated. To do so, the yearly costs of each alternative had to be discounted.

Based on BUTEC's information, the project will be financed by both debt and equity; with debt making up between 70-80% of the total investment. As such, the discount rate to be used is the cost of capital of the IPP project calculated as the weighted average of the costs of debt and equity, which are calculated as follows:

1. Project's Cost of Debt

An investment loan will be taken by BUTEC to invest in the IPP project. Based on the management's current expectations, the cost of such a loan ranges between 3% to 6.5%.

2. BUTEC's Cost of Equity

The cost of equity (k_e) was calculated using the Capital Asset Pricing Model (CAPM). Since BUTEC is a private firm, then it was not possible to find a correlation between its stock price and that of a market's index. For that, an adjusted CAPM is used whereby the cost of equity $k_e = k'_e$ + Country Risk Premium. k'_e is the cost of equity assuming BUTEC is a public construction firm operating in the U.S. The Country Risk Premium is used to adjust k'_e to reflect BUTEC's operations in other countries.

As such, the cost of equity would be calculated as:

$k_e = k'_e + CRP \rightarrow k_e = R_f + \beta(US\ ERP) + CRP$, where:

- R_f: Risk-free rate
- β: Beta
- ERP: Equity risk premium
- CRP: Country risk premium

Each component was calculated as follow:

a. Risk Free Rate

In the CAPM, the mature equity market is assumed to be that of the U.S., so the risk-free rate of the U.S. market should be used. It is the expected return on a risk-free financial asset. This was taken as the yield to maturity of the U.S. 10-year Treasury bond (Board of Governors of the Federal Reserve System 2013).

→The risk-free rate $R_f = 2.64\%$

b. Equity Risk Premium

The equity risk premium (ERP) is the extra return of an investment over and above a riskfree financial asset. In this case, it is the additional return over the U.S. 10-year Treasury bond. The estimation of the ERP ranges between 5% and 6%. It will be assumed to be equal to 5.5% and any error will be accounted for in the sensitivity analysis (American Appraisal 2014; Damodaran 2013).

→The *U.S. ERP = 5.5%*

c. Beta

For public firms, the equity beta (β) of the stock defines the correlation between its returns and that of the financial market. It accounts for the *systematic* risk which is associated with the market risk which cannot be eliminated even if the investment is part of a diversified portfolio.

In the case of BUTEC, being a private firm, the equity β was estimated as that of U.S. firms working within the same industry as BUTEC which is in construction; this was then adjusted based on BUTEC's capital structure. It should be noted that in case BUTEC decided to expand into other industries in the future, then a weighted average beta corresponding to the different industries should be considered.

According to Damodaran's estimates, the unlevered beta for the construction industry in the U.S. has an average of 0.75. This has to be adjusted to reflect BUTEC's own leverage based on its Debt to Equity ratio (D/E) (Damodaran 2014).

$$\beta \text{ (BUTEC)} = \beta \text{ (unlevered for industry)} * [1+(1-t)*(D/E)]$$

where D/E = xxx since D/E was calculated as the ratio between the interest bearing liabilities (both short- and long-term) and the equity, taken from BUTEC's financial statements.

and the tax rate t = x% using:

tax rate (t) = Income tax expense / Earning Before Tax (EBT)

$\rightarrow \beta$ *(BUTEC) = b*

d. Country Risk Premium

The country risk premium (CRP) needs to be included when calculating the cost of equity in order to account for the additional risk associated with BUTEC being a non-U.S. firm and operates in several foreign countries. The CRP usually reflects the political and economic stability of the country (Investor Words.). Therefore, it is estimated based on the country's riskiness, which is represented by its credit rating.

BUTEC operates in five countries which are Lebanon, Jordan, Abu Dhabi, Qatar and Algeria. For each of these countries, Moody's credit rating for sovereign bonds was identified. Then according to Damodaran’s research, an equivalent default spread for each country can be calculated (Damodaran 2014). Moreover, since equity markets are more volatile than bond markets, then the default spread should be adjusted by a factor which reflects the equity market volatility in order to get the CRP. For emerging markets, this factor is estimated to be 1.5, i.e., the equity market is 50% more volatile than the bonds market. These steps are shown in *Table 10*.

Table 10: Country Risk Premium

Country	Moody’s Credit Rating	Default Spread	Country Risk Premium
Lebanon	B1	4.50%	6.75%
Jordan	B1	4.50%	6.75%
Abu Dhabi	Aa2	0.50%	0.75%
Qatar	Aa2	0.50%	0.75%
Algeria*	B3	6.50%	9.75%

* it was brought to our attention that the banking system in Algeria is quite robust and it might be rated with a higher credit rating; this would yield a lower CRP.

Based on the distribution of BUTEC’s project revenues among these five countries, a weighted average CRP was calculated as shown in *Table 11*.

Table 11: Weighted Country Risk Premium

	Weight	CRP
Qatar	25.00%	0.75%
Algeria	30.00%	9.75%
Lebanon	10.00%	6.75%
Abu Dhabi	20.00%	0.75%
Jordan	15.00%	6.75%

➔ *Weighted Average CRP = 4.95%*

e. Cost of Equity

Based on *Table 12* and using the CAPM where $k_e = R_f + \beta(\text{US ERP}) + \text{CRP}$ the cost of equity was calculated to be *x%.*

Table 12: Components of Cost of Equity

Rf	2.64%
β	b
ERP (US)	5.50%
CRP	4.95%
Re	**x%**

f. Project's Cost of Capital

Given the following breakdown, the cost of capital for the IPP project ranges between x% to y%. An average of 7% was taken to calculate the LC.

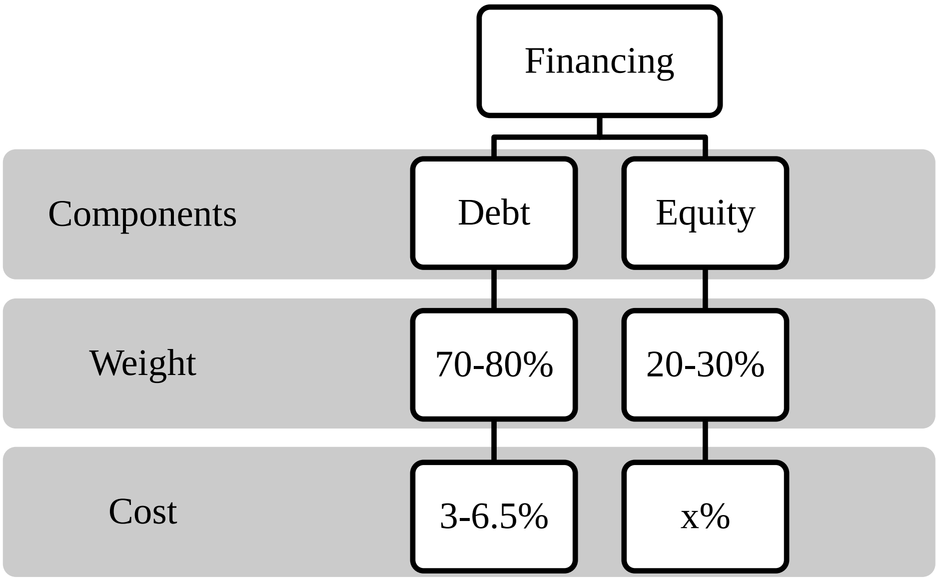

Figure 4: Breakdown of Project's Cost of Capital

C. Cashflow

For each of the twelve alternatives the three cost components were calculated as well as the output produced. After which the cost of capital was used to discount these to time zero and obtain the LC of each alternative.

Over the lifetime of the project of 25 years, the only difference between the costs of these years is between year 1 and the remaining years 2-25. This is because it is assumed that in the first year part of the technology would have been constructed and operating, for instance, in CC technologies the steam turbine (ST) would not have been constructed in year 1, and thus the system would operate as an OC; while as of year 2 the whole plant would be operating.

Depending on each of the technology's capacity, multiple GT/RE's were used to reach a minimum output of 300 MW.

The following section provides the calculations of each of the alternatives. The NPV was calculated using the project's cost of capital (7%). From the NPV, the LC of each cost component was calculated using the annuity formula. The final LC is the sum of the three components = Capex LC + O&M LC + Fuel LC.

As a final note, inflation was not accounted for in these calculations; however, this should be considered in the LC calculation to reflect a more realistic value.

1. *Alternative 1: GT- HFO - CC - X*

Output per Unit (MW)	MW	118.031	
Capex Unit Cost	$/kW	1,050.0	
		Year 1	**Years (2-25)**
Technology		**OC (2 GT)**	**CC (2GT + 1 ST)**
Output	MW	236.062	xxx
O&M	$/kW/year	xx	xx
Net Heat Rate	kJ/kWh	10,801.0	7,727.3
EAF	%	90%	85%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	1,861,112,808.0	2,572,123,902.0
Capex	$/year	$31,124,234.02	31,124,234.02
O&M	$/year	2,478,651.00	7,046,914.80
Fuel Cost	$/year	313,215,330.80	309,690,949.18

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.672	1.210	14.534	1.247
O&M/Output	US¢/kWh	0.133	0.274	3.061	0.263
Fuel cost/Output	US¢/kWh	16.829	12.040	144.788	12.424

➔ *LC = 13.93 cents/kWh*

2. *Alternative 2: GT- HFO - CC - Y*

Output per Unit (MW)	MW	149.70	
Capex Unit Cost	$/kW	1,100.0	
		Year 1	**Years (2-25)**
Technology		**OC (2 GT)**	**CC (2GT + 1 ST)**
Output	MW	299.400	447.960
O&M	$/kW/year	xx	xx
Net Heat Rate	kJ/kWh	xxxx	xxxx
EAF	%	x%	x%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	2,308,014,720.0	3,217,786,272.0
Capex	$/year	42,283,647.22	42,283,647.22
O&M	$/year	4,041,900.00	11,422,980.00
Fuel Cost	$/year	404,825,245.14	375,831,449.99

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.832	1.314	15.798	1.356
O&M/Output	US¢/kWh	0.175	0.355	3.969	0.341
Fuel cost/Output	US¢/kWh	17.540	11.680	141.588	12.150

➔ *LC = 13.85 cents/kWh*

3. Alternative 3: RE- HFO - CC – Z

Output per Unit (MW)	MW	xx	
Capex Unit Cost	$/kW	xxxx	
		Year 1	**Years (2-25)**
Technology		**OC (16 RE)**	**CC (16 RE + 1 ST)**
Output	MW	xxx	xxx
O&M	$/kW/year	10.5	16.0
Net Heat Rate	kJ/kWh	7,511.1	6,933.3
EAF	%	95%	92%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	xxxx	xxxx
Capex	$/year	27,897,952.60	27,897,952.60
O&M	$/year	2,793,000.00	4,728,888.89
Fuel Cost	$/year	259,070,226.41	257,321,914.37

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.260	1.171	13.732	1.178
O&M/Output	US¢/kWh	0.126	0.199	2.246	0.193
Fuel cost/Output	US¢/kWh	11.703	10.803	126.735	10.875

➔ *LC = 12.25 cents/kWh*

4. Alternative 4: GT- HFO - OC – X

Output per Unit (MW)	MW	118.031	
Capex Unit Cost	$/kW	xxxx	
O&M	$/kW/year	10.5	
		Year 1	**Years (2-25)**
Technology		**OC (2GT)**	**OC (3GT)**
Output	MW	236.062	354.093
Net Heat Rate	kJ/kWh	xxxx	xxxx
EAF	%	x%	x%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	1,861,112,808.0	2,791,669,212.0
Capex	$/year	24,307,922.78	24,307,922.78
O&M	$/year	2,478,651.00	3,717,976.50
Fuel Cost	$/year	313,215,330.80	466,734,630.98

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.306	0.871	10.554	0.906
O&M/Output	US¢/kWh	0.133	0.133	1.552	0.133
Fuel cost/Output	US¢/kWh	16.829	16.719	194.938	16.728

➔ *LC = 17.77 cents/kWh*

5. *Alternative 5: GT- HFO - OC – Y*

Output per Unit (MW)	MW		xxx
Capex Unit Cost	$/kW	$	xxxx
O&M	$/kW/year	$	13.5
		Years 1-25	
Technology		**OC (2 GT)**	
Output	MW		299.400
Net Heat Rate	kJ/kWh		11,257.0
EAF	%		88%

Yearly Cashflow			
		Years 1-25	
Net Electricity Output	kWh/year		xxxx
Capex	$/year	$	21,837,918.53
O&M	$/year	$	4,041,900.00
Fuel Cost	$/year	$	404,825,245.14

LC Calculations		**LC**
Capex/Output	US¢/kWh	0.946
O&M/Output	US¢/kWh	0.175
Fuel cost/Output	US¢/kWh	17.540

➔ *LC = 18.66 cents/kWh*

6. Alternative 6: RE- HFO - OC – Z

Output per Unit (MW)	MW		16.63
Capex Unit Cost	$/kW	$	1,030.0
O&M	$/kW/year	$	xxxx
			Years 1-25
Technology			**OC (16 RE)**
Output	MW		266.000
Net Heat Rate	kJ/kWh		xxxx
EAF	%		x%

Yearly Cashflow			
			Years 1-25
Net Electricity Output	kWh/year		2,213,652,000.0
Capex	$/year	$	23,510,365.51
O&M	$/year	$	2,793,000.00
Fuel Cost	$/year	$	259,070,226.41

LC Calculations		**LC**
Capex/Output	US¢/kWh	1.062
O&M/Output	US¢/kWh	0.126
Fuel cost/Output	US¢/kWh	11.703

➔ *LC = 12.89 cents/kWh*

7. *Alternative 7: GT- NG - CC - X*

Output per Unit (MW)	MW	130.302	
Capex Unit Cost	$/kW	xxxx	
		Year 1	**Years (2-25)**
Technology		**OC (2 GT)**	**CC (2GT + 1 ST)**
Output	MW	260.604	379.469
O&M	$/kW/year	3.5	6.8
Net Heat Rate	kJ/kWh	xxxx	xxxx
EAF	%	x%	x%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	2,100,259,756.8	2,858,767,658.4
Capex	$/year	29,306,188.04	29,306,188.04
O&M	$/year	912,114.00	2,580,389.20
Fuel Cost	$/year	339,202,704.05	325,081,948.61

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.395	1.025	12.292	1.055
O&M/Output	US¢/kWh	0.043	0.090	1.008	0.087
Fuel cost/Output	US¢/kWh	16.151	11.371	136.984	11.755

➔ *LC = 12.90 cents/kWh*

8. Alternative 8: GT - NG - CC - Y

Output per Unit (MW)	MW	160.5	
Capex Unit Cost	$/kW	xxxx	
		Year 1	**Years (2-25)**
Output	MW	xxx	509.500
O&M	$/kW/year	4.5	8.5
Net Heat Rate	kJ/kWh	xxxx	xxxx
EAF	%	90%	86%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	2,530,764,000.0	3,838,369,200.0
Capex	$/year	41,534,435.60	41,534,435.60
O&M	$/year	1,444,500.00	4,330,750.00
Fuel Cost	$/year	406,927,552.61	388,539,075.80

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.641	1.082	13.133	1.127
O&M/Output	US¢/kWh	0.057	0.113	1.263	0.108
Fuel cost/Output	US¢/kWh	16.079	10.123	123.530	10.600

➔ *LC = 11.84 cents/kWh*

9. *Alternative 9: RE - NG - CC - Z*

Output per Unit (MW)	MW	18.32	
Capex Unit Cost	$/kW	xxxx	
		Year 1	**Years (2-25)**
Technology		**OC (16 RE)**	**CC (16 RE + 1 ST)**
Output	MW	293.120	325.689
O&M	$/kW/year	6.5	10.0
Net Heat Rate	kJ/kWh	xxxx	xxxx
EAF	%	95%	92%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	2,439,344,640.0	2,624,791,893.3
Capex	$/year	30,742,285.21	30,742,285.21
O&M	$/year	1,905,280.00	3,256,888.89
Fuel Cost	$/year	272,180,275.05	270,768,934.93

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.260	1.171	13.732	1.178
O&M/Output	US¢/kWh	0.078	0.124	1.403	0.120
Fuel cost/Output	US¢/kWh	11.158	10.316	121.003	10.383

➔ *LC = 11.68 cents/kWh*

10. Alternative 10: GT- NG - OC – X

Output per Unit (MW)	MW	130.302	
Capex Unit Cost	$/kW	700.0	
O&M	$/kW/year	xxxx	
		Year 1	**Years (2-25)**
Technology		**OC (2 GT)**	**OC (3GT)**
Output	MW	260.604	390.906
Net Heat Rate	kJ/kWh	xxxx	xxxx
EAF	%	92%	92%

Yearly Cashflow			
		Year 1	**Years (2-25)**
Net Electricity Output	kWh/year	2,100,259,756.8	3,150,389,635.2
Capex	$/year	23,480,692.23	23,480,692.23
O&M	$/year	912,114.00	1,368,171.00
Fuel Cost	$/year	339,202,704.05	496,860,298.89

LC Calculations		**Year 1**	**Years (2-25)**	**NPV**	**LC**
Capex/Output	US¢/kWh	1.118	0.745	9.034	0.775
O&M/Output	US¢/kWh	0.043	0.043	0.506	0.043
Fuel cost/Output	US¢/kWh	16.151	15.771	184.148	15.802

➔ *LC = 16.62 cents/kWh*

11. Alternative 11: GT - NG - OC – Y

Output per Unit (MW)	MW	xxx
Capex Unit Cost	$/kW	$ 750.0
O&M	$/kW/year	$ xxx
		Years 1-25
Technology		**OC (2 GT)**
Output	MW	321.000
Net Heat Rate	kJ/kWh	10,603.0
EAF	%	90%

Yearly Cashflow		
		Years 1-25
Net Electricity Output	kWh/year	xxxx
Capex	$/year	$ 20,658,882.02
O&M	$/year	$ 1,444,500.00
Fuel Cost	$/year	$ 406,927,552.61

LC Calculations		**LC**
Capex/Output	US¢/kWh	0.816
O&M/Output	US¢/kWh	0.057
Fuel cost/Output	US¢/kWh	16.079

➔ *LC = 16.95 cents/kWh*

12. Alternative 12: RE - NG - OC - Z

Output per Unit (MW)	MW	xxx
Capex Unit Cost	$/kW	$ 1,030.0
O&M	$/kW/year	$ xxx
		Years 1-25
Technology		**OC (16 RE)**
Output	MW	293.120
Net Heat Rate	kJ/kWh	xxxx
EAF	%	95%

Yearly Cashflow		
		Years 1-25
Net Electricity Output	kWh/year	xxxx
Capex	$/year	$ 25,907,362.17
O&M	$/year	$ 1,905,280.00
Fuel Cost	$/year	$ 272,180,275.05

LC Calculations		**LC**
Capex/Output	US¢/kWh	1.062
O&M/Output	US¢/kWh	0.078
Fuel cost/Output	US¢/kWh	11.158

➔ *LC = 12.30 cents/kWh*

CHAPTER IV

ANALYSIS

A. Best Alternative

1. Cheapest Alternative

Usually, companies identify the best alternative as that having the cheapest LC; which is presented in this section. However, other factors should be taken into account which might change the choice of the best alternative; these are presented in the subsequent sections.

Table 13 summarizes the LC of the different alternatives (unit: cents/kWh)

Table 13: LC of Alternatives

			Capex	O&M	Fuel	**LC**
Scenario 1	CC - HFO	X - GT	1.247	0.263	12.424	**13.93**
		Y - GT	1.356	0.341	12.15	**13.85**
		Z - RE	1.178	0.193	10.875	**12.25**
Scenario 2	OC - HFO	X - GT	0.906	0.133	16.728	**17.77**
		Y - GT	0.946	0.175	17.54	**18.66**
		Z - RE	1.062	0.126	11.703	**12.89**
Scenario 3	CC - NG	X - GT	1.055	0.087	11.755	**12.9**
		Y - GT	1.127	0.108	10.6	**11.84**
		Z - RE	1.178	0.12	10.383	**11.68**
Scenario 4	OC - NG	X - GT	0.775	0.043	15.802	**16.62**
		Y - GT	0.816	0.057	16.079	**16.95**
		Z - RE	1.062	0.078	11.158	**12.3**

When comparing the three alternatives in each scenario, the one scoring the lowest LC happens to be for a Reciprocating Engine by Z. This is because despite the

RE having higher Capex and O&M costs, its significantly lower fuel cost is the deal breaker. As can be seen in *Figure 5*, the fuel cost make up more than 91% of the LC, while the Capex makes up 8% and the remaining 1% is left for O&M costs.

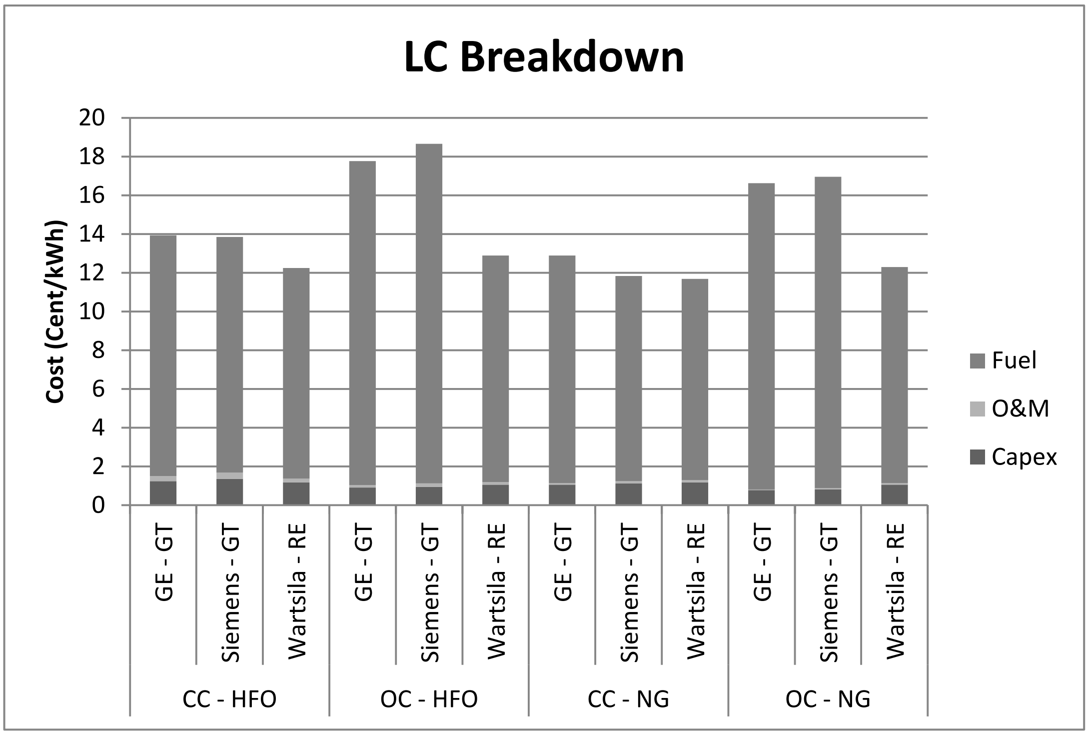

Figure 5: LC Breakdown

Moreover, if BUTEC has the possibility to select one alternative among the twelve assuming that the government does not pose any requirements, then the ranks of each of the twelve alternatives are presented in *Table 14*.

Table 14: Ranking of Alternatives

	Alternative		**LC**	Rank
CC - HFO	1	X - GT	**13.93**	*8*
	2	Y - GT	**13.85**	7
	3	Z - RE	**12.25**	3
OC - HFO	4	X - GT	**17.77**	11
	5	Y - GT	**18.66**	12
	6	Z - RE	**12.89**	5
CC - NG	7	X - GT	**12.9**	6
	8	Y - GT	**11.84**	2
	9	Z - RE	**11.68**	1
OC - NG	10	X - GT	**16.62**	9
	11	Y - GT	**16.95**	10
	12	Z - RE	**12.3**	4

The cheapest LC corresponds to alternative 9which is having a RE (Z) operating with NG and CC mechanism; this is essentially due to the fact that CC is more efficient than OC and that the NG prices are relatively cheaper than HFO’s in Jordan.

2. Yearly Saving

Although the LC is in cents/kWh; a slight saving of even 1 cent can lead to a huge saving on a yearly basis. As an illustration, for a plant with 300 MW capacity and assuming it has an EAF of 90%, the yearly electric energy produced is equal to 2,365,200,000 kWh. Therefore, saving one cent from the LC would save $23.65 M per year. As such, if alternative 9 is chosen, then the yearly savings for each of the remaining alternatives is presented in *Table 15*.

Table 15: Yearly Savings

	Alternative		LC	Total cost $	Savings $
CC - HFO	1	X - GT	13.93	329,571,064	**53,265,522**
	2	Y - GT	13.85	327,484,409	**51,178,867**
	3	Z - RE	12.25	289,650,139	**13,344,597**
OC - HFO	4	X - GT	17.77	420,214,109	**143,908,568**
	5	Y - GT	18.66	441,376,568	**165,071,027**
	6	Z - RE	12.89	304,910,446	**28,604,905**
CC - NG	7	X - GT	12.9	305,016,229	**28,710,688**
	8	Y - GT	11.84	279,933,120	**3,627,579**
	9	Z - RE	11.68	276,305,542	**-**
OC - NG	10	X - GT	16.62	393,106,595	**116,801,054**
	11	Y - GT	16.95	400,963,490	**124,657,949**
	12	Z - RE	12.3	290,874,539	**14,568,998**

3. Variation of Cost of Capital

Given that the cost of capital of the IPP project was calculated as a range between x% and y%, the variation of the LC was studied as a function of the cost of capital as shown in *Table 16*.

Table 16: Variation of LC with Cost of Capital

Cost of Capital		**6%**	**7%**	**8%**	**9%**
CC - HFO	X	13.79	13.93	14.08	14.24
	Y	13.69	13.85	14.01	14.18
	Z	**12.14**	**12.25**	**12.36**	**12.48**
OC - HFO	X	17.68	17.77	17.85	17.94
	Y	18.58	18.66	18.75	18.84
	Z	**12.8**	**12.89**	**12.99**	**13.09**
CC - NG	X	12.77	12.9	13.03	13.16
	Y	11.69	11.84	11.98	12.13
	Z	**11.57**	**11.68**	**11.8**	**11.91**
OC - NG	X	16.55	16.62	16.7	16.78
	Y	16.88	16.95	17.03	17.1
	Z	**12.2**	**12.3**	**12.4**	**12.5**

The same results were obtained; using a RE always gave the cheapest LC.

B. Variability of Fuel Prices

The LC calculations so far have assumed that the fuel prices for both the NG and HFO remain constant, which is not always the case in reality. As such, this section provides an illustration on the effect of having varying fuel prices on the LC and in turn on the choice of the best alternative.

Based on the U.S. Energy Information Administration (EIA), NG prices have fluctuated between the years of 2009-2010 with a standard of deviation ranging between $2-4 (EIA 2009). For the purpose of this study, the worst case scenario of $4 was considered. The growth process for the prices of NG was assumed to follow a lognormal distribution. The purpose is to find the variability of the LC reflected in an LC standard deviation (**σ**). Since all factors of the LC, except the NG price, are constants, then the LC would also follow a normal distribution. The obtained **σ** is presented in *Table 17*.

Table 17: Variation of LC with Fuel Price

	Alternative		LC	σ	2σ	mean + 2σ	Yearly Cost $
CC - NG	7	X	12.896	5.678	11.3552	24.2512	
	8	Y	**11.835**	5.056	10.1122	**21.9477**	519,107,549
	9	Z	**11.682**	5.147	10.2941	**21.9762**	519,781,887
OC - NG	10	X	16.62	7.868	15.7367	32.3571	
	11	Y	16.953	8.022	16.0432	32.9958	
	12	Z	12.298	5.566	11.1329	23.431	

When considering the 95% confidence interval of the LC normal distribution, the upper limit for the LC of alternative 9 becomes higher than that of alternative 8. This means that there a certain possibility that the cheapest alternative might, in fact, not end up being the cheapest after considering the effect of variations in fuel prices.

The same applies when considering HFO price variations as well as varying any other factor which has been assumed to be constant but might vary in reality; such as, the efficiency of the system which usually has a certain range rather than just being a given number. This is an issue that has to be considered when BUTEC makes the choice of choosing the best alternative.

C. Validity of the LC Method

Recalling the LC formula as follows:

$$\text{LC} = \frac{\text{Annualized Capex} + \text{O\&}M\ Cost + Fuel\ Cost}{\text{Energy Produced}}$$

$$\Rightarrow \text{LC} = \frac{\text{Annualized Capex}}{\text{Energy Produced}} + \frac{\text{O\&}M\ Cost}{\text{Energy Produced}} + \frac{\text{Fuel Cost}}{\text{Energy Produced}}$$

$$= \text{Capex LC} + \text{O\&M LC} + \text{Fuel LC}$$

1. Markup

Based on BUTEC's pricing strategy, the following factors are considered when adding a markup on the cost of the project:

- Risk
- Overhead

- Profit Margin
- Total Markup: would range between x-y% → assume an average of *m%*

When bidding for the IPP project, BUTEC has to include the markup on the LC components associated with the Capex and O&M without that of the fuel. Therefore, the bid price to government =(1 + markup) * (Capex LC + O&M LC) + Fuel LC

While what BUTEC will be actually gaining from the project is its Unit Revenue = (1 + markup) * (Capex LC + O&M LC)

2. *Breaking Even over Project's Lifetime*

The question here is to check whether the LC calculation method does indeed allow for the breakeven of the project over its lifetime. To do this, two approaches were used.

One approach is to price the project with BUTEC's unit revenue equal to the LC (excluding fuel cost) = (Capex LC + O&M LC). Two result patterns were obtained:

- When energy generated in all years is the same:

NPV = 0 which means that the project did breakeven over its lifetime and thus, the LC method is valid.

- When the energy produced in year 1 is less than that produced in the remaining years:

NPV > 0 which means that pricing at the LC is in fact generating some money rather than just breaking even the project.

The second approach is to show how much extra revenue is generated with a planned markup of m%. This was done by pricing the project with a unit revenue having m% markup. The actual profit margins obtained were higher than m% for alternatives that have an energy production lower in the first year. These are presented in *Table 18*:

Table 18: Actual Markup

		Markup
CC - HFO	X - GT	m.50%
	Y - GT	m.48%
	Z - RE	m.01%
OC - HFO	X - GT	m.21%
	Y - GT	m.00%
	Z - RE	m.00%
CC - NG	X - GT	m.64%
	Y - GT	m.20%
	Z - RE	m.02%
OC - NG	X - GT	m.31%
	Y - GT	m.00%
	Z - RE	m.00%

It should be noted that the ranking of the bid price is the same as that of the LC since the fuel cost makes up around 91% of the LC.

3. Capacity

All LC calculations done so far assume that every alternative is operating at its full power and generating its maximum capacity, which might differ from the 300 MW government requirement.

The issue here is to check whether the LC ranking, and in turn the choice of the best alternative, would change if each system operates to generate 300 MW instead of its full capacity. To do this, the energy produced in the second year was changed to 300 MW for all alternatives having a capacity higher than 300 MW. *Table 19* presents a comparison between the previously calculated LC and its rankings with that calculated for a 300 MW power generation.

Table 19: LC for 300 MW Power Generation

	Alt.	**OEM**	**Capacity MW**	**LC (cap)**	**LC (300MW)**	**Rank (cap)**	**Rank (300MW)**
CC - HFO	1	X	xxx	13.934	14.103	8	7
	2	Y	448	13.846	14.442	7	8
	3	Z	xxx	12.246	12.246	3	2
OC - HFO	4	X	354	17.767	17.911	11	11
	5	Y	xxx	18.661	18.661	12	12
	6	Z	266	12.892	12.892	5	5
CC - NG	7	X	379	12.896	13.146	6	6
	8	Y	510	11.835	12.531	2	4
	9	Z	326	11.682	11.774	1	1
OC - NG	10	X	391	16.62	16.828	9	9
	11	Y	xxx	16.953	17.005	10	10
	12	Z	xxx	12.298	12.298	4	3

It turned out that the energy generated affects the LC calculations and as such the ranking of the alternatives. The reason behind it lies in the variability in the Capex LC part, shown in *Table 20*.

Table 20: Capex LC for 300 MW Power Generation

	Alternative		**Capex LC (Cap)**	**Capex LC (300MW)**
CC - HFO	1	X - GT	1.247	1.416
	2	Y - GT	1.356	1.952
	3	Z - RE	1.178	1.178
OC - HFO	4	X - GT	0.906	1.05
	5	Y - GT	0.946	0.946
	6	Z - RE	1.062	1.062
CC - NG	7	X - GT	1.055	1.305
	8	Y - GT	1.127	1.822
	9	Z - RE	1.178	1.271
OC - NG	10	X - GT	0.775	0.983
	11	Y - GT	0.816	0.869
	12	Z - RE	1.062	1.062

As an example, alternative 8 was previously assuming to generate 510 MW based on which the Capex LC part was calculated as 1.127 cents/kWh; this means that if 510 MW were sold at an LC value of 11.835 cents/kWh that includes this Capex cost, then the project will break even over its lifetime. However, if only 300 MW will be sold, then the same initial investment for constructing the same plant with capacity of 510 MW has now to be recovered by selling less output. Therefore, the Capex LC should be higher in order for the project to break even by recovering its initial cost. As such, alternatives which have a capacity much higher than 300 MW ended up with a significantly higher LC and, as a result, the ranking of the alternatives changed.

This issue is highly critical and it is recommended that all decisions be made based on a LC method that considers the actual output to be sold rather than the capacity of the system. However, all the sections of the report assume that the alternatives are generating their full capacity and should be adjusted accordingly if the 300 MW option is to be considered.

D. Profitability

This section discusses the strategic perspective of taking on the IPP project as part of BUTEC's project portfolio.

1. NPV vs. Cheapest Alternative

The choice of alternative to be included in the bid should not solely be based upon choosing the lowest LC alternative. The profitability of each alternative should be considered as well. The following is an example to illustrate this point.

Based on a markup of m% for each alternative, BUTEC's cashflow was constructed with costs being the initial Capex cost at year 0, and yearly O&M costs while revenues include the unit revenue times the energy sold (fuel costs were totally excluded from the cashflow). The Net Present Value (NPV) and Internal Rate of Return (IRR) were calculated for each alternative as shown in *Table 21*.

Table 21: IRR and NPV of Alternatives

	Alt.		LC	Bid Price	unit Rev	IRR	NPV $ for 7%
			Cent/ kWh	Cent/ kWh	Cent/ kWh		
CC - HFO	1	X	13.93	14.13	1.71	x%	xxxx
	2	Y	13.85	14.07	1.92	x%	xxxx
	3	Z	12.25	12.42	1.55	x%	xxxx
OC - HFO	4	X	17.77	17.9	1.17	x%	xxxx
	5	Y	18.66	18.81	1.27	x%	xxxx
	6	Z	12.89	13.05	1.34	x%	xxxx
CC - NG	7	X	12.9	13.04	1.29	x%	xxxx
	8	**Y**	**11.84**	**12**	**1.4**	**x%**	**70 M**
	9	**Z**	**11.68**	**11.85**	**1.47**	**x%**	**50 M**
OC - NG	10	X	16.62	16.73	0.93	x%	xxxx
	11	Y	16.95	17.07	0.99	x%	xxxx
	12	Z	12.3	12.45	1.29	x%	xxxx

The first thing to notice is that the IRR of all alternatives is higher than the 7% cost of capital of the IPP project. This proves that investing in this project is profitable and would have a positive NPV. The more important thing here is the value of the NPV of the different alternatives. Is a higher NPV associated with a higher bid price? To answer this question, the NPV was plotted versus the bid price as shown in *Figure 6*.

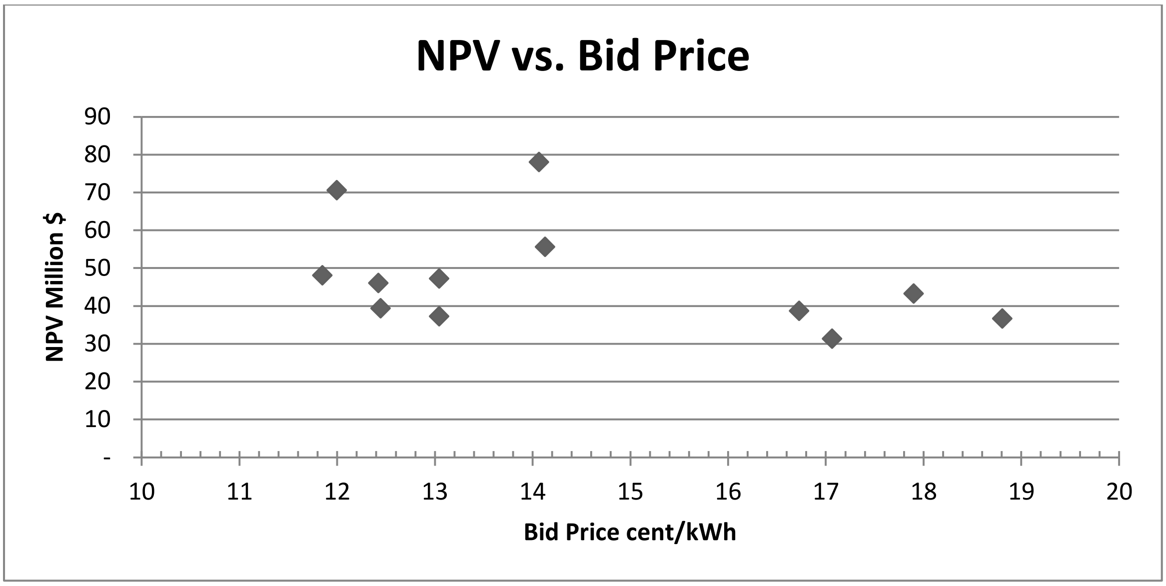

Figure 6: NPV vs. Bid Price

This shows that the relationship between NPV and bid price is very random. If alternative 9 is chosen to be bid upon, the bid price to be submitted to the government is 11.85 cents/kWh and the estimated NPV for BUTEC would be $50 M. But why not choose alternative 8 instead with a bid value of 12.00 cents/kWh which is only 1.25% higher than that of alternative 9. However, the estimated NPV of alternative 8 is $70.6Mwhich generates a 32% higher NPV compared to alternative 9.

One of the possible ways that can address this issue is to first assign a certain cut-off point for the bid price as a value above which BUTEC would not win the bid, for instance take a value of 12 cents/kWh. In this case, if BUTEC chooses any alternative except 8 and 9, then they will have a zero chance of winning the bid. Then for the remaining alternatives, one can assign a probability of winning based on the corresponding bid price. Assume in this case that alternative 8 has a probability of 60% to be won with its current bid price of 12 cents/kWh, while a higher percentage of winning (for example 80%) is assigned to alternative 9 which has a cheaper bid price. Then, the expected NPV, which is the product of the estimated NPV and the probability of winning, can be calculated as shown in *Table 22.*

Table 22: Expected NPV based on Probability of Winning

	LC	**Bid Price**	**NPV for 7%**	**Prob. of winning**	**Expected NPV $**
X - GT	12.9	13.04	xxx	0%	0
Y - GT	11.84	12	70 M	60%	42 M
Z - RE	11.68	11.85	50 M	80%	38 M

Whether to end up choosing alternative 8 which has a higher NPV as compared to alternative 9 depends on the risk appetite of BUTEC as well as other strategic factors such as its backlog of projects, relationship with the client, etc. However, this analysis should be done in order to reduce the risk of leaving money on the table and to instead maximize BUTEC's revenues.

2. *IRR vs. BUTEC's WACC*

Another issue that BUTEC should consider on a strategic level is the effect of taking on such a project on its weighted average cost of capital (WACC).

a. BUTEC's Cost of Debt

The cost of debt (k_d) is calculated as the interest expense relative to the interest bearing liabilities both short- and long-term while accounting for the tax shield on debt, using $k_d = k_d(\text{before tax}) * (1-t)$

Tax rate (t) = Income tax expense / Earning Before Tax (EBT); where:

As such, the cost of debt k_d is calculated.

b. <u>BUTEC's Cost of Equity</u>

This was previously calculated using the CAPM to be x%.

c. <u>WACC</u>

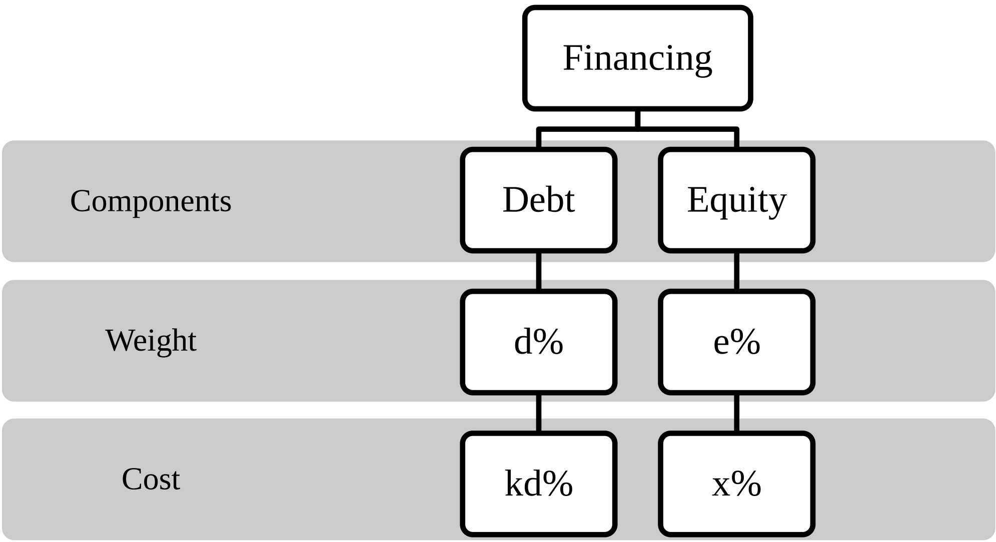

Figure 7: BUTEC's WACC Breakdown

As such, BUTEC's WACC = $K_eW_e + K_{d(effective)}$ = 14.66%

d. <u>Effect of New Project on WACC</u>

Usually if the project has a return on investment (ROI) or return on equity (ROE) which exceeds the company's minimum acceptable rate of return, then the company will invest in this project. In this case, the ROI/ROE cannot be calculated at this stage due to not having sufficient information.

As such, one of the things that BUTEC can consider is the effect of taking on the new IPP project on its WACC; i.e., the new WACC should be calculated assuming that BUTEC invests in this IPP project. The WACC usually reflects the riskiness of the firm; the riskier the firm, the higher the cost that investors and creditors are willing to take and the higher is their expected return. In an ideal situation, it is favorable to decrease the WACC of a firm, decreasing by that its riskiness. Therefore, along with evaluating the ROI/ROE, the new WACC shall be evaluated as well favoring for it to be lower.

CHAPTER V

CONCLUSION

The feasibility study was conducted to first develop twelve alternatives for the power production methods. Each is characterized by the technology (gas turbine GT vs. reciprocating engine RE), fuel type (natural gas vs. heavy fuel oil), cycle mechanism (open cycle vs. combined cycle) as well as its OEM (X vs. Y for the GT and Z for the RE). The initial capital expenditure, operation and maintenance cost and fuel cost were estimated for each of the twelve alternatives. After which the levelized cost (LC) was calculated using the project's cost of capital. The LC, being the minimum price of electric energy to be sold at which the project breaks even over its lifetime, was used to compare the different alternatives.

Considering the following three factors has led to having the RE working on natural gas with a combined cycle to yield the lowest LC: the first is due to the RE having higher efficiencies than the GT, the RE scored lower on the fuel part of the LC which makes up more than 90% of it; second, the combined cycle guarantees a higher efficiency than an open cycle; and lastly, natural gas in Jordan is relatively cheaper than heavy fuel oil.

However, the choice of the best alternative to bid upon could consider additional factors instead of simply choosing the lowest LC. For instance, BUTEC could evaluate and compare the net present value of the alternatives along with their bid prices; depending on BUTEC's risk appetite, it might turn out that cheapest alternative is not the most profitable. Another critical issue is to consider the actual energy generated to be sold when calculating the LC of the alternatives, rather than assume that the full capacity will be sold. In addition, some of the factors used in the LC calculations were assumed to be constant but might vary in reality, such as the fuel prices. Therefore, the effect of their variability should not be eliminated as this might change the choice of the best alternative.

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