Stochastic-Based Production Costing Model: Evaluation of the Energy Policy Paper for the LEPS

A Master's Thesis submitted to the Department of Electrical & Computer
Engineering
School of Engineering

LEBANESE AMERICAN UNIVERSITY
Lebanon, Byblos

In partial fulfillment of the requirements for the Degree of
MSE in Computer Engineering
Emphasis: Computer & Communication Engineering

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October 2010

To My Parents,
Salma & Abdallah

Acknowledgements

I am heartily thankful to my supervisor and my instructor, Prof. Raymond Ghajar, for the guidance, consistent encouragement, and the moral care he provided from the preliminary to the concluding level of my research.

I also would like to make a special reference to Prof. Samer Saab for giving me the great opportunity of graduate studies at LAU. Without his corporation I could not have gotten this far.

Besides, I offer my regards and blessings to all of those who supported me in any respect during the completion of this thesis.

Finally, honorable mention goes to my family for their understanding and support on me, without their help I would've faced many difficulties.

Stochastic-Based Production Costing Model: Reliability Evaluation of the Energy Policy Paper for the LEPS

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MSE Thesis Submitted to the Department of Electrical & Computer Engineering

OCTOBER 2010

Abstract

The Lebanese Electric Power System (LEPS) suffers from technical and financial deficiencies that required the development of a policy paper to rescue the power sector from the current drastic situation to a new sustainable, reliable, and efficient delivery of electricity. The plan includes ten strategic initiatives and 42 action steps that are integrated and correlated to cover the sector's infrastructure, supply/demand, and the legal aspects. This ambitious but realistic policy was prepared after a review of all previous studies, and in collaboration of all concerned parties, whether internal or external, constitutional and political, and was approved consensually by the Council Of Ministers on June 21, 2010.

It is proposed that the implementation of the energy policy will result in a solid power sector with sufficient generation capacity, reliable transmission and distribution networks, and efficient delivery of electricity to cope with the overall socio-economic development of Lebanon. The policy targets a gradual implementation of the initiatives in the short and medium terms totaling 4870 M\$ (Government in Lebanon up to 1550 M\$, the private sector contribution of 2320 M\$, and the international donor community up to 1000 M\$), and an additional amount of 1650 M\$ in the long term. The full implementation of all the strategic initiatives in this policy will reduce the total losses from 4.4 Billion \$ in 2010 to zero in 2014 where 24/24 hours of service is provided, and the possibility of profit making as of 2015; while it will reach 9.5 Billion \$ in 2015 if no action is taken.

This thesis uses the Load Modification Technique (LMT) as a stochastic tool to assess the impact of implementing the initiatives of the proposed energy policy on energy production, overall cost, technical and commercial losses, reliability and customer service. New modeling capabilities of the traditional LMT method are proposed in this thesis for off-peak energy dispatch. The proposed LMT technique is used to establish a technical and financial baseline of the LEPS against which the full implementation of the energy policy is compared and the resulting tariff is calculated. Selected scenarios are also presented to show the technical and financial impact of individual projects on the system.

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List of Acronyms

LEPS	Lebanese Electric Power System
LDC	Load Duration Curve
IPP	independent power producer
kW	kilowatt
kW-hr	kilowatt-hour
MW	megawatt
MW-hr	megawatt-hour
GW	gigawatt
GW-hr	gigawatt-hour
TW-hr	terawatt-hour
PP	Power Plant
O&M	Operation and Maintenance
ECA	Energy Conversion Agreement
EdL	Electricité du Liban
GoL	Government of Lebanon
LNG	Liquefied Natural Gas
NG	Natural Gas
RBTS	Reliability Based Test System
BOT	Build Operate and Transfer
ToR	Terms of References
AMR	Automatic Reading Meter
LoLE	Loss of Load Expectation
LoLP	Loss of Load Probability
LMT	Load Modification Technique
EENS	Expected Energy not Supplied
EES	Expected Energy Supplied
EIR	Energy Index of Reliability
VoLL	Value of Loss of Load
LENCC	Lebanese Electrical National Control Centre
DMS	Distribution Management System
RE	Reciprocating Engines
CFL	Compact Fluorescent Lamp
SWH	Solar Water Heating
LCEC	Lebanese Center for Energy Conservation
HLI	Hierarchical level I
HLII	Hierarchical level II
HLIII	Hierarchical level III
COPT	Capacity Outage Probability Table
FOR	Forced Outage Rate
LF	Load Factor

CF	Capacity Factor
UF	Utilization Factor
SFOC	Specific Fuel Oil Consumption
CO	Crude Oil
HFO	Heavy Fuel Oil
LFO	Light Fuel Oil
RFO	Residual Fuel Oil
CCGT	Combined Cycle Gas Turbine
OCGT	Open Cycle Gas Turbine

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1. Introduction

1.1. Power System Reliability: Concepts and System Evaluation

Reliability is one of the main and most important aspects that must be considered and accounted during the design and the planning of a power system at different levels (i.e. Generation, Transmission and Distribution). One Universal definition of power system reliability is “the degree to which the performance of the system results in electricity being delivered to customers within accepted standards and in the amount desired.”

A modern power system must serve one primary function, and that is to supply customers with electrical energy as economically as possible and with a reasonable degree of reliability and quality. The high degree of dependence on the electric energy drives consumers to have a rising expectation regarding quality of electric supply. Consumers’ have also come to expect that the supply of electric energy must be continuous and increasing on demand. This expectation however is not technically feasible due to the random failure nature of the system at all levels. Sudden system failures lies beyond the control of power systems engineers, and in a case of failure, generation capacity drops, electric quality deteriorates and there will be a possibility of loss of load.

Given that electric energy plays a vital role in the economic development of any country, energy producing utilities try to provide uninterrupted and highly reliable power supply. On the other hand the attempt to design energy producing utility that is 100% reliable is not economical and most importantly is not technically feasible. The design dilemma is formulated as an optimization problem which is achieving the most reliable power system given several economical and even social constraints. Therefore the basic aim of any electric power utility is to meet the demanded energy at the lowest possible cost while maintaining an acceptable level of quality and continuity of supply.

In power systems and in the context of this thesis, reliability is referred to as the concern regarding the system ability to provide adequate supply of electric energy. On the other hand, reliability of power system, treated as a probabilistic approach, will be used as the basis for a tool that is capable of evaluating the generation infrastructure and developing an energy model for production costing and economic analysis.

In power systems the term reliability is divided into two basic aspects: system adequacy and system security.

Figure 1.1.1: Power Systems Reliability

System adequacy has to do with the existence of sufficient infrastructure to satisfy the consumer load demand and overcome any system operational complications and constraints. On the other hand, system security relates to the capability of the system to respond, at the appropriate time, for disturbances arising from the system itself.

Most of the reliability evaluation techniques tackle the first concept. The work presented in this thesis performs an adequacy assessment of the current electric power system and another adequacy assessment after the implementation of the energy policy that is planned to reform the sector, therefore only adequacy assessment will be considered.

Adequacy assessment by itself can be defined in terms of its application to a specific level of a complete power system. These levels, or sometimes called functional zones are the generation, transmission and distribution.

Figure 1.1.2: Functional Zones of a power system

Adequacy assessment studies can be conducted in each of these functional zones. These zones can be combined together to create the hierarchal levels as shown in the figure below.

Figure 1.1.3: Hierarchical levels of a power system

Hierarchical level I (HLI) embraces the generation infrastructure, at this level of electric power system, the generation capacity is examined and evaluated in terms of its adequacy to meet the total system load demand requirements, and such an assessment is sometimes referred to as “Generating Capacity Reliability Evaluation”. Hierarchical level II (HLII) embraces both generation and transmission. An assessment at this level is known as “Composite System Reliability Evaluation”. Hierarchical level III (HLIII) includes all three power systems infrastructure categories the generation, transmission and distribution. An assessment at HLIII reaches to consumer load point adequacy. Such an assessment can be very complex due to complexity of the system itself and usually is not done in a direct manner. One way to reduce the complexity is to treat the distribution infrastructure as an independent entity which will be assessed separately.

Reliability evaluation of complete electric power system including all three functional zones is normally not conducted because of the enormity and complexity of the problem. Usually in such cases three segments are considered, reliability evaluation of generating capacities, composite system of generation and transmission and the distribution system. The reliability and risk indices obtain for these three independent segments are then combined together to make a certain decision.

The research work presented in this thesis will be at HLI. Adequacy assessment will be performed on the available generating capacity of the Lebanese Electric Power Systems (LEPS) and another assessment will be performed after the implementation of the generation expansion model outlined in the recent energy policy that was approved the Lebanese government (GoL).

1.1.1. The Generating System Model

The Generating model is composed of two main subtitles, Generating unit Availability/Unavailability and the Capacity outage probability tables (COPT).

Generating unit Availability/Unavailability

The main but basic parameter of any generating unit is the probability of finding the unit forced out at some time in the future. From an engineering systems perspective, such parameter is known as the forced outage rate (FOR) and sometimes referred to as Unavailability. It is calculated using the following formula:

$$Unavailability (FOR) = U = \frac{\sum[down\ time]}{\sum[up\ time] + \sum[down\ time]} \quad (1.1)$$

The Availability is the opposite of Unavailability and is presented in the below formula:

$$Availability = A = 1 - U = \frac{\sum[up\ time]}{\sum[up\ time] + \sum[down\ time]} \quad (1.2)$$

Capacity outage probability tables (COPT)

As its name suggests, the COPT is an array or a matrix showing the capacity states of a generating unit along with their probabilities of existence. For a system with several generating units, one COPT table can be obtained for the whole system by simply convolving all COPT's of different units using the binomial distribution, such compound COPT is a larger array showing all states of the system along with their associated probability of existence. It is extremely unlikely that a system will be composed of identical generating units. Therefore the binomial distribution in this case has a limited application. In such a case the units can be combined using basic probability concepts, although such an approach is simple but it

can be extended in a recursive manner such that units will be added sequentially to produce the final generation model or the final COPT array for the generation infrastructure.

Consider a simple numerical example; a system consists of three units, 2 x 3 MW units and 1 x 5 MW unit all with an FOR of 0.02 as shown in the three tables below.

Table 1.1.1: COPT for three units

Capacity in (MW)	Probability	Capacity in (MW)	Probability	Capacity in (MW)	Probability
0	0.02	0	0.02	0	0.02
3	0.98	3	0.98	5	0.98

The two identical units can be combined using binomial distribution to give the COPT shown in the table below.

Table 1.1.2: Identical Units Equivalent COPT

Capacity in (MW)	Probability
0 (both units are out)	$(0.02)(0.02)=0.004$
3 (only one unit is out)	$(0.02)(0.98)=0.0392$
6 (both units are in)	$(0.98)(0.98)=0.9604$

Adding unit 3 (5 MW) will result in the final COPT shown in the table 3, this table is considered the final model of the generating system.

Table 1.1.3: System Equivalent COPT

Capacity in (MW)	Probability
0+0=0 MW	$(0.9604)(0.98)=0.941192$
3+0=3 MW	$(0.0392)(0.98)=0.038416$
6+0=6 MW	$(0.0004)(0.98)=0.000392$
0+5=5 MW	$(0.9604)(0.02)=0.019208$
3+5=8 MW	$(0.0392)(0.02)=0.000784$
6+5=11 MW	$(0.0004)(0.02)=0.000008$

1.1.2. Reliability Indices

Reliability indices play an important role in power systems planning and design; such indices are the result of load characteristics and the system parameters. The load characteristics are usually statistical values obtained from past operation of the system. The rest of the system parameters are historical data about failure and repair.

Common indices for HLI are:

- EES: Expected Energy Supplied, is the energy supplied by a unit in the generating system.
- EENS: Expected Energy not Supplied, which is the aggregate EES for all available units in a generating system subtracted from the energy demanded. EENS is an indicator of the adequacy to supply the load demanded, low EENS indicates an adequate system.
- LoLE: Loss of Load Expectation, gives the expected number of hours/year in which a loss of load occurs. The LoLE gives cumulative time per year. A good power system has LoLE that is below 0.1 days/year which is equivalent to 2.4 hours/year.
- LOLP: Loss of load probability is the probability that the load in a certain year is not met. It is the LoLE in hours/year divide by the total number of hours in one year (8760 hour)
- EIR: Energy Index of Reliability, which is illustrated in the below formula.

$$EIR = 1 - \frac{EENS}{Energy\ Demanded} \quad (1.3)$$

These described indices are used extensively in the energy model developed in this thesis in order to assess the adequacy of the generating system.

The concepts and evaluation techniques for adequacy assessment of a power system discussed in this Chapter will be applied in this thesis to the LEPS. The following sections will discuss the current situation of the LEPS suggesting the need for an energy policy or a plan at the strategic level to rescue the LEPS and ensure a reliable electric sector.

1.2. LEPS Background/Current Situation

The Lebanese electricity sector is at the heart of a deep crisis. The sector is unable to supply the reliable electricity needed by homes, offices and industry. Tariffs do not cover operating costs; plants are in poor and deteriorating condition. Electricity is generated from some relatively modern plants using gas-oil at a

very high cost; the old plants fired using HFO have very high SFOC, very low efficiency and are also costly. There are high levels of technical loss, so the cost of delivered electricity is still further increased. Load-shedding is frequent; conservative estimates of the cost to the Lebanese economy from deficiencies in power supply range from \$1 billion a year to maybe \$1.5 billion a year at present. No new capacity is being built and no new investment is held in the sector for the last 12 years.

The sector is becoming a massive drain on government finances, crowding out more valuable expenditures on education, infrastructure, social protection, and health, and putting macroeconomic stability at risk. The sector is accumulating a huge debt over the years, and with no action taken, the sector may be facing the danger of bankruptcy.

Power outages are a daily occurrence in Lebanon and in some regions of the country; electricity is only supplied for a few hours a day. This has led to a massive investment by consumers and industry in back-up arrangements. Indeed, this form of energy security is estimated to cost the population at least an additional 35% in spending on electricity per month. The interruption in supply by the utility, EdL, is furthermore estimated to cost industry close to US\$400 million in sales losses. This additional spending and revenue loss has an obvious negative impact on these consumer categories, but also makes implementation of other macro-critical, non-electricity sector reforms, difficult; as consumers have difficulty absorbing increased overall spending (for example tax increases).

Even worse, the poor service provided by public sector is costing the Government massive amounts in the form of generalized subsidies. Some subsidization of the sector may be warranted if at least the service was reliable and there was an underlying sound strategy justifying the subsidies (e.g., targeted assistance to the poor). In Lebanon today, however, the subsidies are required to cover insufficient revenue due to a tariff set far below cost recovery, and low billings and collections. In addition, the continued use of gas-oil (diesel) in two major power plants designed to use natural gas (despite the abundance of natural gas in the region), high O&M cost of all power plants due to insufficient regular maintenance and spare parts, as well as high technical losses, result in very high production costs.

Concerning the demand, it is difficult to establish the historical demand growth rate for electricity in Lebanon since EdL meets the peak load for several minutes in the year. Various studies and the recent household survey put self-generation at 35%-40% which would yield a total energy demand (year 2009) of at least 15,000 GW-hr (corresponding to peak demand of 2,450 MW).

On that basis, demand for electricity in Lebanon is likely to increase by 33% by 2015 to reach approximately 22,512 GW-hr. This implies an increase of at least 1,230 MW of power generation capacity (assuming currently installed capacity is maintained and available which is not the case at the moment). This will require capital investments of at least US\$1.2 billion.

Besides the need for massive subsidies to EdL for an unreliable electricity service, there is a very real concern that Lebanon could reach the point of widespread and continuous blackouts as investment falls far behind demand. If that point is reached an economical decision must be taken to shut down the electric sector and force all other sectors relying on the electricity sector to use private generation.

Without rapid action the condition of the system can only deteriorate, possibly to the point of catastrophic failure in the near future.

1.3. The Need for an Immediate Strategic Plan to Rescue the LEPS

Lebanon faces serious challenges in assuring an affordable, reliable, secure and environmentally acceptable supply of energy for its people and its economy. The country has few natural mineral resources; a dilapidated infrastructure; insolvent supply companies; highly unreliable supplies of electricity at high cost; very large unaccounted losses; inefficient final use and no consensus on the way ahead. Regional integration is not well developed. The country benefits from a long coastline relative to its size and population giving it access to international commodity markets, an industrious and educated population and some useful potential renewable resources.

In response to the mentioned problems and available resources an immediate action must be taken in order to embrace the crisis and at least maintain a static grid and not a deteriorating one. In order to resolve these problems a comprehensive energy policy is suggested in this thesis that will rescue the LEPS, ensure a reliable 24/24 energy supply, and a profitable sector by the end of 2014.

The policy will address three main strategic areas:

- **Power Grid Infrastructure** which in turns constitutes of three sub-strategic components. At the generation level, the policy will be targeting an emergency and immediate stop gap capacity in the short term (i.e. Rental Power or Regional imports). It will also consider the capacity reinforcement of the sector to meet the demand by the end of 2014 with 5% peak load reserve. At the Transmission level, all bottlenecks at the network will be removed, and the system

will be widely expanded (building new regional substations) to be able to digest the new added capacity. At the distribution level, the smart grid will be adopted and new services will be introduced to ensure an improvement in quality and a drop in non-technical losses.

- The **Supply and Demand**, which will embrace a fuel sourcing strategy, Renewable energy reinforcement, the spread of energy efficiency standards and the tariff reconstruction. The fuel sourcing policy is based on diversity and security where 2/3 of the fuel mix is based on natural gas with multiple sources of supply; more than 12% are renewable energies; and the remaining from other sources of fuel while selecting technologies that work on both natural gas and fuel oil.

This policy commits to launching, supporting and reinforcing initiatives to adopt the utilization of renewable energies to reach 12% of electric and thermal supply.

This policy also commits to the preparation and spreading of the culture for proper electricity use; adoption of national programs focused on demand side management as the basis for: effective energy use; peak shaving; load shifting; and demand growth control in order to save a minimum of 5% of the total demand.

- The **Legal framework**, which will be introduced generally, will insure of setting norms and standards for the provision of electric services that is safe, equitable and fair with the best quality and lowest cost. Such strategic area is not technical but will have a share in the improvement in the reliability of the overall system. Projects under this strategic area will not be analyzed and will only be financially considered in terms of capital amortization for new investments in the sector.

This thesis will mainly concentrate on the generation expansion, its technical and financial impact on the LEPS, developing fuel sourcing strategy, and the adoption of a proper tariff that will achieve a profitable financial impact by the end of 2015. Other initiative of the policy will be generally explained and will be translated into technically oriented aspects that will contribute to the improvement of the reliability of the electric utility.

1.4. Scope of Work

The preliminary objectives of the research work described in this thesis were to:

- A. Develop an energy model that is a reliability-based production costing model where it will be used to evaluate the existing generating capacity and the generation expansion plan suggested for the LEPS. The properties of the model are:
 - a. The model is interactive software developed under MATLAB (C language) and performs Load Modification Technique based on capacity modification and energy limitation.
 - b. The suggested energy model, assumes a load model (tuned RBTS load model) and performs LMT to estimate the energy output of available generating units
 - c. Another important output of the energy model is the reliability indices (EES, EENS, LoLP, LoLE, Duty Cycle...etc.).
 - d. The software interacts with MS Excel, imports data, performs the necessary execution and dumps data back to Excel in order to make the simulation environment user interactive.
- B. Investigating the LEPS current Situation using the reliability based model (energy model),
 - a. Investigating the technical situation of the current grid at the generation level.
 - b. Projecting the current technical situation up to 2015 with no action taken (no capacity addition, no upgrades, no rehabilitation...etc.).
 - c. Illustrating the catastrophic technical situation of the current grid.
 - d. Investigating the financial situation of the whole grid.
 - e. Projecting the current financial situation up to 2015 with no action taken (no investment, no tariff restructure...etc.).
 - f. Illustrating the financial burden due to the inadequate power system.
- C. Investigating the Energy Policy for the electric sector based on the generation capacity expansion and technical enhancement (5 years Plan),
 - a. Use the energy model to simulate the generation expansion plan of the energy policy.
 - b. Monitoring the technical improvement of the generation and the achievement of a reliable power grid (low EENS, low LoLP/LoLE) by the end of the policy life.
 - c. Using the simulation results, production costing is performed. A financial improvement of the sector is justified.
 - d. Suggestion of a new tariff to achieve a profitable financial impact.

- D. Performing sensitivity analysis on the policy by considering different scenarios of the energy policy.

1.5. Thesis Outline

The basic concepts of reliability evaluation in energy limited generating units is described in Chapter 2. Several techniques used to develop the energy model are explained in this Chapter. The Chapter basically starts defining the load modification technique known as LMT and its application in unlimited generating capacities where the technique is best referred to as capacity modification. Based on the approach of LMT another type of modification used in energy limited generating units where the technique is known as peak shaving or energy modification. A new approach known as Off-peak capacity modification is proposed which will be used in some units of the LEPS. The Chapter finally illustrates the explained techniques on the reliability based test system.

Chapter 3 begins with a discussion on the load duration curve and its use in the reliability applications and production costing. The chapter then proceeds to introduce the idea of the RBTS load model and how this model is tuned to develop a suggested model for the LEPS.

Chapter 4 investigates the current situation of the LEPS. It starts by giving background information of the LEPS and then elaborates to describe the current technical and financial situation.

From a technical perspective, Chapter 4 describes the fuel types, their current and expected future prices, which are being used by the current system. Based on the available fuel it suggests generation options for Lebanon and compare them to the available generation infrastructure to illustrate the deteriorating condition of the LEPS. Chapter 4 also performs reliability evaluation of the current grid by simulating it using the developed energy model presenting all necessary data. It further analyses the simulation results and performs production costing showing the financial burden of the sector. Finally Chapter 4 summarizes the obtained results and discusses their impact on the national economy.

Following up from Chapter 4, Chapter 5 takes this situation and projects it for the upcoming 6 years (up to 2015) to show that if no action is taken, the sector is facing a total technical deterioration and a catastrophic financial situation. Chapter 5 mainly calls for a strategic plan to rescue the sector.

Chapter 6 is the core of the thesis. After describing the current and expected future deteriorating conditions in Chapters 4 and 5, Chapter 6 presents a comprehensive policy for the management,

development and the radical rehabilitation of the LEPS. The suggested policy is global; it does not only consider a generation expansion study, but also suggests a secure fuel sourcing strategy, Transmission system expansion, applications of smart grid, and other legal and institutional aspects that will help in achieving a reliable and profitable electric sector. Chapter 6 launches by giving a detailed executive summary of the suggested policy describing the 10 main initiatives under the three strategic areas that will be used to reform the sector.

Chapter 6 proceeds by implementing the policy using the energy model presenting all technical data throughout the life of the policy. It also analyzes all results along with presenting the necessary figures that illustrate a technical improvement of the sector. Obtained technical data are then used for production costing to show a relief in the financial burden. Chapter 6 also continues the general description of the remaining initiatives and translating steps into technical action that helps in improving reliability risk indices.

Chapter 6 concludes by suggesting a new tariff structure that is based on a gradual increase of the current average tariff to break even and a further increase to reach a profitable financial impact.

Chapter 7 performs sensitivity analysis. It considers several realistic scenarios of the policy (i.e. a delay or elimination of a certain project) and monitors the resulting financial and technical impacts when compared to the full policy implementation.

Chapter 8 is a closing Chapter. It constitutes of the summary and the conclusion of the thesis.

2. Reliability Evaluation in Energy

Limited Generating Units

Most of the reliability studies conducted to assess the adequacy of generating units capacity takes into consideration that energy supplied is not limited and only considers the FOR to calculate the output energy. No energy limitation, in the context of thermal units, means that fossil fuel (coal, gas, oil, uranium...etc.) is available when needed to fire the turbines. In the context of renewable units (Hydro, wind, PV...etc.), no energy limitations assumes that such units will supply the same predicted energy throughout the year of different seasons.

The truth is that the expression of “Unlimited Energy” does not hold, and that limitations must be included in the reliability studies. Note that Energy limitation can be directly applied to renewable generating facilities. Thermal units also assume energy limitation due to fuel restrictions.

This Chapter illustrates a well-known technique for generating capacity evaluation referred to as the Load Modification Technique (LMT) also known as capacity modification indicating no energy limitations. This technique is then illustrated with the application of limited energy concept, which is the core concept for adequacy assessment that will be used in this thesis.

It is important to note here that the technique of reliability evaluation in energy limited generating units is used extensively at assess the adequacy of the units in the LEPS due to fuel restrictions, high fuel prices (i.e. gas oil) and limited storage facilities.

2.1. Capacity Modification – No Energy Limitation

The most popular technique for assessing the adequacy of a generating capacity is the Loss of Load Probability (LoLP) or the Loss of Load Expectation (LoLE). In this technique the COPT of the generating model is convolved with the Load Duration Curve (LDC) to calculate the EENS, LoLP and the LoLE which are the result of the FOR, the main parameter in the model. This technique allows us to know the expected energy (EES) supplied by each unit and thus such data may be used in production costing. Knowing the EES (kW-hr) along with the fuel price in the form of \$/kW-hr, the production cost in dollars can be directly obtained by simple multiplication.

Capacity Modification is one way of LMT, where the load is modeled by the Load Duration Curve (LDC). The LDC is a graphical representation of the load model presenting all necessary parameters to perform LMT (see Chapter 3). The procedures of capacity modification consider the LDC and the COPT of the generating unit which will be used to modify the load model (for the illustration of the procedure of capacity modification it will be assumed that the LDC is estimated using 3 points and the COPT used is for a three state unit). As a first step in the modification process, The LDC will be linearly reduced by the capacity of each state in the COPT of the generating unit considered as shown in figure 2.1.1. This will result in the original LDC, estimated by k points, and the reduced LDC corresponding to the n different states.

The equivalent LDC for the considered generating unit will be composed of $n*k$ points. Each point has coordinates in the form of (Load, Duration). The load part of the coordinated is easily obtained from the equivalent linear LDC's (LDC_1, LDC_2 and LDC_3) corresponding to the de-rated of the COPT.

Figure 2.1.1: LDC and reduced curves

Since the LDC is estimated using k points, then there exist $k-1$ linear segments/lines. The equation of each linear line is calculated in order to calculate the duration part of the coordinates given the load part is known.

For the set of load points calculated, the duration on each LDC (LDC_1, LDC_2 and LDC_3) is calculated from the estimated linear lines. Table 2.1.1 shows the duration of the load points on the three LDC's.

If the points exceed the extremes of the line then it is pegged to the minimum or maximum duration of the LDC considered.

Table 2.1.1: capacity Modification Procedures

-	State 1 Probability P_1	State 2 Probability P_2	State 3 Probability P_3	-
Load (MW)	Duration on original LDC (LDC_1)	Duration on original LDC reduced by X MW (LDC_2)	Duration on original LDC reduced by Y MW (LDC_3)	Duration on "Capacity-modified" LDC
L_1	D_1	T_1	S_1	$E_1 = D_1 * P_1 + T_1 * P_2 + S_1 * P_3$
L_2	D_2	T_2	S_2	$E_2 = D_2 * P_1 + T_2 * P_2 + S_2 * P_3$
L_3	D_3	T_3	S_3	$E_3 = D_3 * P_1 + T_3 * P_2 + S_3 * P_3$
$L_4 = L_1 - R_1$	D_4	T_4	S_4	$E_4 = D_4 * P_1 + T_4 * P_2 + S_4 * P_3$
$L_5 = L_2 - R_1$	D_5	T_5	S_5	$E_5 = D_5 * P_1 + T_5 * P_2 + S_5 * P_3$
$L_6 = L_3 - R_1$	D_6	T_6	S_6	$E_6 = D_6 * P_1 + T_6 * P_2 + S_6 * P_3$
$L_7 = L_1 - R_2$	D_7	T_7	S_7	$E_7 = D_7 * P_1 + T_7 * P_2 + S_7 * P_3$
$L_8 = L_2 - R_2$	D_8	T_8	S_8	$E_8 = D_8 * P_1 + T_8 * P_2 + S_8 * P_3$
$L_9 = L_3 - R_2$	D_9	T_9	S_9	$E_9 = D_9 * P_1 + T_9 * P_2 + S_9 * P_3$

The duration points of the capacity modified LDC is calculated using the formula shown below (last column of table 2.1.1).

$$D(L) = \sum_{i=1}^N d_i(L) \times P_i \quad (1.4)$$

Where $D(L)$ = duration of load L on the "Capacity-modified" curve.

N = Number of the capacity states of the unit.

P_i = probability of the capacity C_i .

C_i = output capacity of i^{th} capacity state of the unit.

$d_i(L)$ = duration of load L on the original LDC when reduced by C_i .

This capacity modified LDC is now considered the equivalent LDC that will be used by other remaining units. The basic simplicity of this technique is best illustrated using a simple numerical example.

System Example - 1

A system contains 3 generating units with no energy limitations. The system is as follows, unit 1 is a unit with three capacity states and comes first in the priority list, the capacity states and their associated probability are given in the table below.

Table 2.1.2: COPT of unit 1 in system example-1

Capacity in (MW)	Probability
0	0.03
10	0.25
15	0.72

Unit 2, and appears second in the priority list, has a capacity of 30 MW and an FOR of 0.03. Unit 3, appears third in the priority list, has a capacity of 20 MW and an FOR of 0.04.

Table 2.1.3: COPT for units 1 & 2 in system example-1

Capacity in (MW)	Probability	Capacity in (MW)	Probability
0	0.05	0	0.02
30	0.95	25	0.98

Figure 2.1.2: System Load Model

The LDC for a period of 100 hours will be considered and is shown in figure 4. The energy demanded by the load is the area under the LDC which is calculated to be 4575 MW-hr. The LDC here is estimated by three points resulting in two linear segments. An LDC estimated with a larger number of points has more accuracy and more linear segments.

First unit, appearing first in the priority list, is convolved with the LDC. This procedure results in three LDC lines that are the result of linear reduction of the original LDC, corresponding to the different states of the unit. The coordinates of the equivalent LDC are calculated and tabulated in the table 2.1.4.

Table 2.1.4: Data for Unit Capacity Modification

-	$P_1 = 0.03$	$P_2 = 0.25$	$P_3 = 0.72$	-
Load (MW)	Duration on original LDC	Duration on original LDC reduced by 10 MW	Duration on original LDC reduced by 15 MW	Duration on "Capacity-modified" LDC
75	0	0	0	0
65	(8.889)	0	(0)	0.2667
60	(13.333)	(4.444)	0	1.5111
52.5	20	(11.111)	(6.667)	8.1778
42.5	(55.556)	20	(15.5567)	17.8667
37.5	(73.333)	37.778	20	26.0444
30	100	(64.444)	(46.667)	52.7111
20	(100)	100	(82.222)	87.2
15	(100)	(100)	100	100
0	100	100	100	100

The Original LDC, the modified LDC, and the reduced LDC's are shown in figure 2.1.3. The EES by this unit is 1330 MW-hr. Figure 2.1.4 shows the Original LDC and the capacity modified LDC which will be used as the main LDC for the next generating unit. The shaded area is the EENS which is calculated to be 4575 MW-hr – 1330 MW-hr = 3245 MW-hr.

Figure 2.1.3: Original LDC, Modified LDC & multi state LDC for unit 1

Figure 2.1.4: Original LDC, EENS and modified LDC for unit 1

Following the same procedures illustrated and considering the capacity modified LDC due to unit 1 as the original LDC, the capacity modification due to unit 2 is illustrated in figures 2.1.5 and 2.1.6.

Figure 2.1.5: Original LDC, Modified LDC & multi state LDC for unit 2

Figure 2.1.6: Original LDC, Modified LDC & multi state LDC for unit 2

The EES by unit 2 is 2534.1 MW-hr. The shaded area is the EENS which is calculated to be 710.82 MW-hr.

Following the same procedures illustrated and considering the capacity modified LDC due to unit 2 as the original LDC, the capacity modification due to unit 3 is illustrated in figures 2.1.7 and 2.1.8.

Figure 2.1.7: Original LDC, Modified LDC & multi state LDC for unit 3

Figure 2.1.8: Original LDC, Modified LDC & multi state LDC for unit 3

The EES by unit 3 is 630.5 MW-hr. The shaded area is the EENS which is calculated to 80.30 MW-hr.

Figure 2.1.9 shows all the three equivalent LDC's on the figure where the shaded area is the EENS of the whole system.

Figure 2.1.9: Equivalent LDC modification due to the three units of system example-1

The overall results are tabulated below.

Table 2.1.5: System example summary

Expected Unit Energy Outputs		
Priority Level	EENS (MW-hr)	EES (MW-hr)
0	4575	0
1	3245	1330
2	710.82	2534.18
3	80.30	630.53

The EIR for a 100 hour period is 0.982449, the LoLP is 0.100740, the EENS is 80.3 MW-hr, the total EES is 4494.71 MW-hr, and the LoLE is 10.073956 hours.

2.2. Energy Limited Units

In the previous section LMT was performed directly using the method of capacity modification. In this section, the concept of energy limitation is explained and the technique of peak shaving is introduced.

Storage facilities for generating units define what type of energy limitation might be used. Therefore energy limited units are defined as units with no storage or units with limited storage.

An important issue to note is that all energy limited units appears first in the priority list, since the energy stored will be used in the next peaking period.

2.2.1. Energy Limited Units with no Storage

The energy from such units may not have enough storage facilities to save the energy for the next peak load period and as a result it must be used at its availability.

Consider for example hydro units with no storage facilities, it is well known that the flow rate of the river is not constant throughout the year, and thus the output energy of hydro units varies widely between winter and summer, sometimes such units does not produce any energy in summer, considering no storage facilities, and it produces its maximum capacity during the winter.

Given that flow rate of the river is known, the capacity of hydro units may be determined. Probability distribution of the flow rate of the river is calculated and must be correlated with the capacity distribution of the unit. This can be seen as a multi-state unit where each rate corresponds to a different flow rate of the river.

Such concepts may also be applied to thermal units, such as units operating on gas where the storage facilities are inadequate and the flow rate of the NG is varying.

Given these data one can construct a COPT based on energy availability of the unit. And the COPT may be used as a capacity modification unit.

2.2.2. Energy Limited Units with Limited Storage – The concept of Peak Shaving

In such generating units, the storage facilities are capable to store energy for a couple of days and therefore this energy may be used in the peaking load periods, replacing generating units operating on expensive fuel.

An example of such a unit is a hydro unit with a dam such that incoming water can be stored for three to four days and then used to produce electric energy. Another example is a thermal unit where fuel supply is limited, such unit may store the fuel for several days to be used in the next peaking load periods.

In such cases, along with the capacity modification, a “peak shaving” technique can be used, such technique uses the COPT along with a certain energy distribution matrix derived from the energy availability of the unit, in order to modify the LDC. This obtained/modified LDC is then used as an equivalent LDC for the remaining units.

In peak shaving technique, first the LDC is capacity modified using the COPT, the conditional probability approach used in capacity modification is then used to perform energy modification using the energy probability distribution of the unit considered.

As an example, consider a big station of hydro units with limited reservoirs or a dam to store the water, the COPT's for each unit are combined together to obtain the equivalent COPT of the whole generating station, based on the storage capability the energy distribution for the whole system is assumed and is used with obtained COPT to peak shave the LDC.

The approach of peak shaving is best illustrated using a simple numerical example.

System Example - 2

Consider the same load model used in system example 1 but this time it is estimated using 100 points. Also consider a hydro station having the equivalent COPT shown in the table 2.2.1.

Table 2.2.1: COPT for the Hydro station

Capacity in (MW)	Probability
0	0.03
10	0.25
15	0.72

The energy limitation of the station is expressed using the energy distribution given in the table 2.2.2 below. The table shows the amount of energy stored along with their cumulative probabilities of being equaled and exceeded.

Table 2.2.2: Energy Distribution for the hydro station

Energy (MW-hr)	Cumulative Probability
200	1
350	0.7
500	0.2

Notice that more energy states can be incorporated for a detailed energy model if more details on the storage infrastructure are available.

As previously stated, the peak shaving technique involves two stages of LMT. In the first stage, the LDC is capacity modified using the capacity distribution assuming no energy limitation, the second stage uses the energy distribution to energy modify the LDC.

Peak shaving and as its name suggests, the energy available by the unit is used in the peaking load periods, and if more energy is available more of the peak will be shaved. Energy modification starts at the top of the LDC, at each value of the load, the area between the LDC and the capacity modified curve is calculated and is compared to the energy distribution in order to calculate the duration of the peak shaved curve at that load point.

If that energy calculated can be produced by that unit, the value of duration at that point is the same as the duration considered by the capacity modified curve, if it is more than the capability of the unit then the duration at that load point is the same as the original LDC.

The final peak shaved LDC is determined using the formula given.

$$D(L) = d_c(L) \times P[E(L)] + d_o(L) \times [1 - P[E(L)]] \quad (1.5)$$

Where $D(L)$ = value of duration of final peak-shaved curve corresponding to a load of L MW.

$d_c(L)$ = value of duration on "capacity-modified" curve corresponding to a load of L MW.

$d_o(L)$ = value of duration on original load duration curve corresponding to a load of L MW.

$E(L)$ = expected energy output of unit if loaded where-ever system load equaled or exceeded L MW, i. e. the area between the "capacity-modified" and original load duration curves above L MW.

$P[E(L)]$ = probability of energy equaling or exceeding $E(L)$ MW.

The LDC of this system is shown in Figure 2.2.1, the shaded area is the energy demanded and is estimated to be 4612 MW-hr.

Figure 2.2.1: LDC for energy limited example estimated by 100 points

Figure 2.2.2 shows the multi-state LDC, the capacity modified curve along with the energy modified curve. Figure 2.2.3 shows the original LDC along with the energy modified LDC. The shaded area is the EENS after the addition of the energy limited units and is estimated to be 336.37 MW-hr. This curve, which is the result of energy modification, will be used as the equivalent LDC for the remaining units.

Figure 2.2.2: Energy Modified LDC for system example – 2 showing all states

Figure 2.2.3: Energy modified LDC for system example - 2

2.3. Off-Peak Capacity Modification – A New Approach

Off-peak capacity modification has the same methodology and concept as capacity modification technique which uses the capacity distribution of the generating unit to modify the LDC.

Instead, Off-peak capacity modification modifies the curve from the middle of the LDC and away from the peak as its name suggests.

Off-peak capacity modification technique is used for generating units that are not available at all times during a certain peaking season (i.e. summer season). In the energy model developed for this thesis, such modification technique is used to represent imported power through regional interconnections, since it is assumed that regional countries exporting power will face shortage in the summer season and will not be able export energy. On the other hand these regional countries will have excess energy during the winter and will be exported to neighboring countries.

This technique calculates the mid-point on the LDC from the capacity (MW) axes and then performs capacity modification from the mid toward the off-peak of the LDC.

As an example, consider a regional interconnection defined by the following COPT. For this example the load model used in system example – 2 is reconsidered here.

Table 2.3.1: COPT for regional interconnection

Capacity in (MW)	Probability
0	0.01
10	0.5
20	0.49

The modified LDC after the addition of this off-peak unit is shown in the Figure 2.3.1. It is important to note here that such units appear after energy limited unit (i.e. hydro units) in the priority list.

The EES of this unit is 942.59 MW-hr, where the demanded energy is 4611.99 MW-hr and thus the EENS after this unit addition is 3669.406 MW-hr.

Figure 2.3.1: Off-peak capacity modification

2.4. Reliability Based Test System (RBTS) – System Example.

The Reliability Based Test System is a universal system, consisting of a certain load model and a set of generating units that is used to illustrate the full technique of LMT and perform risk analysis. This system performs adequacy evaluation at the three functional zones (HLI, HLII & HLIII) of a power system. Only HLI will be considered in this section.

Recall that the basic approach of the generating capacity adequacy assessment is the development of a generating model where this model will be used to modify the load model of the system to produce a risk index. In the context of this thesis, the risk index is a reliability index based on the probability modeling of the generating units.

The most fundamental generating model for a generating system is the COPT. For the RBTS, only a two state model will be used to describe each generating unit. This system has an annual peak load of 185 MW, where the RBTS load model is used (the data for this load model is discussed in Chapter 3). The total number of data points needed to define the daily peak load curve is 364, and for the case of an

hourly peak load it will be 8736 points. The figure below shows the RBTS load model – LDC estimated using 100 points.

Figure 2.4.1: RBTS load Model

The energy required by the load is represented by the area under the LDC, which is estimated to be 993830.1539 MW-hr. The RBTS consists of 11 generating units, six hydro and 5 thermal. The table below shows the generating units along with their FOR arranged in their priority order.

Table 2.4.1: RBTS generating model

Unit #	Unit Type	Capacity in (MW)	FOR
Unit 1	Hydro	40	0.02
Unit 2	Hydro	20	0.015
Unit 3	Hydro	20	0.015
Unit 4	Hydro	20	0.015
Unit 5	Hydro	20	0.015
Unit 6	Hydro	5	0.01
Unit 7	Hydro	5	0.01
Unit 8	Thermal	40	0.03
Unit 9	Thermal	40	0.03
Unit 10	Thermal	20	0.025
Unit 11	Thermal	10	0.02

Each of these units will be convolved with the load model. Such load modifications allow us to know the output energy of each unit.

Table 2.4.2: RBTS simulation results

Priority Level	Unit Type	Capacity in (MW)	EENS after unit addition	Unit EES
1	Hydro	40	651378.95	342451.20
2	Hydro	20	479279.75	172099.20
3	Hydro	20	311300.25	167979.50
4	Hydro	20	174391.59	136908.66
5	Hydro	20	79829.95	94561.64
6	Hydro	5	62668.96	17160.99
7	Hydro	5	48197.70	14471.26
9	Thermal	40	3035.05	45162.65
9	Thermal	40	153.60	2881.45
10	Thermal	20	26.58	127.03
11	Thermal	10	9.48	17.10
Total EES of the system				993820.67

For more details of the RBTS simulation refer to Annex-1.

Figure 2.4.2 below shows the modification of the LDC throughout the addition of all the 11 units.

Figure 2.4.2: Equivalent LDC after the addition of all units

The Total Energy Demanded by this load model is 993830.15 MW-hr. The EENS for the system is 9.47 MW-hr. The EES for all the 11 Units in the system is aggregated to be 993820.67 MW-hr. The EIR for an 8736.00 hr period is 0.99999. The LoLP is 0.000119 and the LoLE is 1.037641 hr/year.

3. Developing a Load Duration Curve

3.1. Load Duration Curve (LDC)

The load of an electric generating system is a critical parameter in assessing the adequacy of the capacity of available generating units. Since load varies with time, then it can be represented as a function of time t , t can be hours, days, weeks and even years. A detailed load model shows the amount of power demanded for each hour. Such procedure is cumbersome, since it requires a lot of load forecasting, more processing time and the need to know the actual demand which is impossible.

One way to represent the load of an electricity generation system is by a diagram that plots the system power outputs as a function of time. To generalize the load model, the demanded power and the time are given in per unit.

The figure below shows a sample load profile in per unit, it is assumed here that the starting month is September, therefore this load curve is a summer peaking curve.

Figure 3.1.1: Sample Load profile

The LDC can be constructed from the load profile. The chronological load data in the load profile can be reordered in a descending manner as shown in figure 3.1.2. The area under the obtained curve is the total energy demanded by the load which will be used for a particular cost-minimizing dispatch of power sources to meet the demand. Such dispatch can be approximated by filling the area underneath the LDC. Following such procedures, one can estimate or precisely calculate which sources will operate at the margin, and for how long.

Figure 3.1.2: Load Duration Curve

The LDC is also used extensively in power systems planning and reliability evaluation. It can be used as the basic load model where the generating units can be convolved with the LDC to obtain the EES for each unit and therefore one can use this data in energy pricing and production costing. From a reliability point of view and after convolving the whole generating model, essential reliability indices and other risk factors can be obtained that assess the adequacy of the system.

Below are some important factors that are used along with the LDC:

1. Load Factor (LF)

The **LF** is measured as the degree of variation of load over a period of time. LF can also be defined as the ratio of the average load (L_{av}) over the maximum load (L_{max}).

$$LF = \frac{\text{Energy}}{(\text{capacity} * \text{time})} = \frac{L_{avg}}{L_{max}} \quad (1.6)$$

L is the load. **L** can be either energy or capacity.

2. Capacity Factor (CF)

The **CF** is the extent of use of the generating units in the PP, also known as the duty cycle of the PP, and can be defined as:

$$CF = \frac{L_{avg}}{PP \text{ capacity (MW)}} \quad (1.7)$$

3. Utilization Factor

The **UF** can be defined as:

$$UF = \frac{L_{max}}{PP \text{ capacity (MW)}} \quad (1.8)$$

3.2. RBTS Load Model

The RBTS load model gives hourly loads for one year on a per unit basis. These loads are expressed on a chronological fashion so that daily, weekly and even seasonal patterns can be modeled. Since all data are in per unit it is enough to know the annual peak load and the time, to model the actual load profile and thus obtain the actual LDC.

Table 3.2.1 gives the weekly peak loads in percent of the annual peak load. It is clear from the table that annual peak occurs in week 51(100%). The table also shows a standard pattern with two seasonal peaks. The first peak in week 51 (100%) and the next peak is in week 23 (90%). To consider the load model as

winter peaking system then week 1 is the first week in January on the other hand, to consider the load model as summer peaking system then week 1 is the first week of a summer month (i.e. September, depending on the region of operation).

Table 3.2.1: Weekly Pweak Load in percent of annual peak load

Week	Peak Load (%)	Week	Peak Load (%)
1	83.2	21	80
2	80.6	22	72.9
3	74	23	72.6
4	73.7	24	70.5
5	71.5	25	78
6	72.7	26	69.5
7	70.4	27	72.4
8	75	28	72.4
9	72.1	29	74.3
10	80	30	74.4
11	75.4	31	80
12	83.7	32	88.1
13	87	33	88.5
14	88	34	90.9
15	85.6	35	94
16	81.1	36	89
17	90	37	94.2
18	88.7	38	97
19	89.6	39	100
20	86.1	40	95.2

Table 3.2.2 gives the daily peak load cycle in percent of the weekly peak. Combining the data in table 13 along with the data in table 14 will define a daily peak load model 52x7=364 days (LDC of 364 points), where Monday is the first day.

Table 3.2.2: Daily Peak load in percent of annual peak load

Day	Peak Load (%)
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table 3.2.3 shows the week days along with the weekends hourly load peak load cycle. The first two columns in the table are modeled as the winter season (winter peaking) while the next two columns are for a summer season (summer peaking). Notice that if table 13 is used as a summer peaking model then the table can be modified accordingly.

Table 3.2.3: Hourly Peak load in percent of annual peak load

Hour	Winter Weeks (1-8 & 44-52)		summer Weeks (18-30)		Spring/Fall Weeks (9-17 & 31-43)	
	Week days	Week Ends	Week days	Week Ends	Week days	Week Ends
12 - 1 am	67	78	64	74	63	75
1 - 2 am	63	72	60	70	62	73
2 - 3 am	60	68	58	66	60	69
3 - 4 am	59	66	56	65	58	66
4 - 5 am	59	64	56	64	59	65
5 - 6 am	60	65	58	62	65	65
6 - 7 am	74	66	64	62	72	68
7 - 8 am	86	70	76	66	85	74
8 - 9 am	95	80	87	81	95	83
9 - 10 am	96	88	95	86	99	89
10 - 11 am	96	90	99	91	100	92
11 - noon	95	91	100	93	99	94
noon - 1 pm	95	90	99	93	93	91
1 - 2 pm	95	88	100	92	92	90
2 - 3 pm	93	87	100	91	90	90
3 - 4 pm	94	87	97	91	88	86
4 - 5 pm	99	91	96	92	90	85
5 - 6 pm	100	100	96	94	92	88
6 - 7 pm	100	99	93	95	96	92
7 - 8 pm	96	97	92	95	98	100
8 - 9 pm	91	94	92	100	96	97
9 - 10 pm	83	92	93	93	90	95
10 - 11 pm	73	87	87	88	80	90
11 -12 pm	63	81	72	80	70	85

Combining Tables 3.2.1, 3.2.2 and 3.2.3 will define a peak load model 364x24=8736 days (LDC of 8736 points).

Figure 3.2.1 shows the stages of constructing a detailed load model of 8736 points, these points can be reordered to construct the LDC as shown in figure 3.2.2.

Figure 3.2.1: Combining Weekly, Daily and Hourly Load models

The annual load factor is calculated to be: $LF = \frac{0.6149}{(1)(1)} = 0.6149 = 61.49\%$

Figure 3.2.2: RBTS LDC

For the rest of this research work a summer peaking system is considered. The RBTS load model discussed in this section will be tuned to create an estimate of the LEPS load model, based on the energy demanded and the LF.

3.3. A Suggested Load Model for the LEPS

Obtaining a precise load model for a power sector is a very difficult task. In Lebanon the issue of load forecast is an impossible task due to lots of load shedding. The ability to know the total demand at a certain hour in a certain day for the whole country is impossible and therefore the construction of a load model must be based on a certain estimate.

It will be assumed that the most effective parameters of the LDC will be the peak power, minimum power, energy demanded and the LF. The shape or the form of the curve is of no importance in the context of this thesis as long as the LDC satisfies the mentioned parameters. As a result the load profile developed for the energy model in this thesis tunes the RBTS load model in order to achieve the correct energy demanded or area under the LDC which will be used as the equivalent LDC for the LEPS.

The peak for the LEPS was estimated to be 2450 MW (summer 2009) and the energy demanded is approximated to be 15 TW-hr with a LF of 0.6989, using the RBTS load model estimated by 20 points for 8760 hours (365 days) is 13.19 TW-hr and a LF of 0.6149 is shown in figure 3.3.1.

It is clear that this load model needs an additional of 1.1 TW-hr in order to achieve the needed demand. This issue is fixed by tuning the RBTS model. The methodology of tuning is based on increasing certain percentages of the hourly annual peak load to achieve the demand of 15 TW-hr. the method is not easy since it is based on an intelligent trial and error calculation. Each time you edit the hourly annual peak load of table 3.2.3 the LDC will be constructed and the energy demanded is estimated, if it is less than or more than 15 TW-hr then the hourly annual peak load table must be re-edited, either increasing or decreasing some percentages until 15 TW-hr is achieved.

Figure 3.3.2 shows the tuned RBTS load model, which will be used as the load profile or the LDC for the LEPS.

Figure 3.3.1: RBTS load model estimated using 20 points

Figure 3.3.2: LEPS estimated LDC using 20 points

It is clear that there is no big difference between the LEPS suggested LDC with RBTS load model except for the area under the LDC and the LF. It is important to note that the form of the LDC is not of great importance since even if the precise load profile for the LEPS is available it was going to be estimated by 20 points to reduce the complexity of calculation and reduce the simulation execution time for the energy model.

4. Investigating The Current Situation of the LEPS

4.1. Background

Lebanon faces serious challenges in assuring an affordable, reliable, secure and environmentally acceptable supply of energy for its people and its economy. The country has few natural mineral resources; a dilapidated infrastructure; insolvent supply companies; highly unreliable supplies of electricity at high cost; very large unaccounted losses; inefficient final use and no consensus on the way ahead. Regional integration is not well developed.

A summary of the current electric sector for the year 2009 is presented in this section in a hierarchal approach.

- I. **Production:** Electric energy is produced in Lebanon from hydroelectric and thermal power plants and purchased from Syria and Egypt through regional interconnections.
 - A. **Power Purchase:** The purchases from Syria (589 GW-hr) and Egypt (527 GW-hr) constituted 7.5% of the total energy production.
 - B. **Hydraulic power plants:** The installed capacity of all hydro plants is 274 MW but the actual generation capacity is 190 MW. The energy produced from the hydro plants (Litani, Nahr Ibrahim, Nahr el Bared & Kadisha) constitutes 4.5% from the total production.
 - C. **Thermal Power Plants:** The installed capacity of thermal power plants is 2038 MW but the actual operating capacity is 1685 MW. Thermal capacity is divided into HFO-fired steam-turbines at Zouk and Jieh, Gas Oil (diesel)-fired Combined Cycle Gas Turbine (CCGT) at Beddawi and Zahrani and Gas Oil (diesel)-fired Open Cycle Gas Turbine (OCGT) at Sour and Baalbek. The energy produced from these plants is 88% of the total production and the fuel cost vary widely from 13 USC/kW-hr to 24 USC/kW-hr.

The average capacity and imports available in 2009 was 1500 MW; the average demand was 2000-2100 MW and the instantaneous peak in the summer was 2450 MW. The total energy

demanded in 2009 was 15,000 GW-hr (7% increase from 2008) whereas the total production and purchases was 11,505 GW-hr (6% increase from 2008) which resulted in energy not supplied (deficit) of 3,495 GW-hr (23%). The supply of energy averaged 21.22 hours for greater Beirut area and 15.79 hours for the South with an average of 18 hours (75%) for the whole country.

- II. **Average Cost:** The average cost of electricity in 2009; including EdL's fixed costs, was 17.14 USC/kW-hr (255 LBP) of which 10.77 USC/kW-hr are fuel (high fuel bill), and 6.37 USC/kW-hr are for generation, transmission and distribution. The contribution of the fuel bill to the total cost was around 1450 M\$ (75%) and 1191 M\$ (62%) in 2008 and 2009 respectively due to fluctuations in the cost of fuel.
- III. **Losses:** The total losses on the system are about 40% (about \$390 million), 15% technical losses; 20% non-technical Losses and 5% uncollected Bills.
- IV. **Distribution of non-technical losses and collection rates:** The non-technical losses are not uniform as they vary between provinces from 9.6% to 58% and then between regions from 15% to 78%. Similarly, there is no uniformity in the collection rates as they vary from 83% to 97% in provinces and from 62% to 97.5% within the regions.
- V. **Transmission:** The transmission system has 1427 km of 66, 150, 220 and 400 kV lines with 1920 meters missing in Mansourieh, for a number of years, to complete the 220 kV loop which, if completed would increase system stability, reduce the technical losses by more than 1% and increase the transmission capability of the system.
- VI. **Distribution and tariffs:** The distribution system has 18,182 transformers and 1,206,499 low voltage customers (plus 82,000 customers are within concessions); 76.4% of which have meters rated (5-20) amps and an average monthly consumption less than 500 kW-hr. The energy charge for low voltage residential customers varies from 35 LBP to 200 LBP per KW-hr in blocks of 100 kW-hr (Tranches). In addition, customers pay a monthly subscription fee of 1,200 LBP/5A and a rehabilitation fee of 5,000 – 10,000 LBP/month based on the rating of the meter. The current tariff structure is not equitable because it subsidizes all customers; large and small, and penalizes small consumers with very large fixed charges.
- VII. **EDL's financial deficit:** The financial deficit of EdL averaged \$1.4 billion for the past three years. The total investment from 1992 to 2009 was only \$1.6 billion (\$50 million from 2002 to 2008)

and the subsidy for the same period was \$6.4 billion, amounting to a total deficit of around \$8 billion without interest.

- VIII. Concessions:** There are different types of concessions for generation, transmission, and distribution. The number of subscribers in all distribution concessions is 82,000 (56% in Zahle, 28% in Jbeil, 12% in Alieh, and 4% in Bhamdoun). EdL provides these concessions with energy at reduced prices (50 to 75 LBP/kW-hr, as compared to the total cost of 255 LBP/kW-hr) which results in accumulated losses of \$185 million in the last eight years.
- IX. EDL's administrative status:** EdL has an organizational chart of 5027 full time employees out of which 3125 (63%) are vacant with a yearly attrition rate of ~8% and an average age of 52 years. However, EdL employs around 2000 contractual and daily workers, many of whom are political appointees and unqualified workers.
- X. Legal Framework:** The legal framework for privatization, liberalization and unbundling of the sector (law 462 – Council of Parliament) exists but is not applied. In parallel, the law implemented by decree 16878/1964 and 4517/1972 which gives EDL exclusive authority in the generation, transmission, and distribution areas is still being applied.
- XI. Losses to the national economy:** The cost of energy not supplied (VoLL) has been estimated by Électricité De France (EDF) and the World Bank in the Public Expenditure Review to vary between 200 and 2,000 \$/MW-hr. An average value of \$700 per MW-hr not supplied (which includes the cost of private generation) has been used to show losses of \$2.5 billion in 2009 for the Lebanese economy, which is divided between \$1.3 billion for private generation and \$1.2 billion for direct consumer losses.

The failure of the GoL to reform the electricity sector is causing an annual deficit of 1.25 billion dollars on the public purse and losses on the national economy estimated at not less than 2.5 billion dollars per year. This crisis is caused by the lack of worthy investments; high fuel bill constituting up to 75% of the budget; the operating status of power plants half of which are old and inefficient and the other half uneconomical; high technical and commercial losses in transmission and distribution; wrong tariff structure and low average tariff; deteriorating financial, administrative, technical and human resources of EdL, all this in the presence of convoluted legal and organizational frameworks.

The totality of these issues needs to be addressed in a prioritized manner in order to find a comprehensive and durable solution, which is the core of this thesis.

In the below sections of this Chapter, the current situation is addressed in more details and is the result of a detailed model development and simulation.

4.2. Current Situation: A Technical Approach

4.2.1. Available Fuel for Lebanon

Today, electric energy in Lebanon is mainly produced with thermal units operating on Heavy Fuel Oil (HFO), Gas-Oil and in very small quantities Natural Gas (NG) is imported from Syria through a short pipeline at the northern borders (partial unit at Deir Ammar in the north is fired using NG when available). However, Lebanon has no known fossil fuel resources and is not an oil producing country, but it is located in proximity to oil producing countries, based on this fact Lebanon meets almost all energy needs with import of petroleum products from such countries. Except for the hydro power generation, all the power plants run today with either HFO (Jieh and Zouk) or Gas-Oil (Baalbek, Sour, Zahrani and Beddawi).

The residual fuel oil (RFO 6) or HFO which is being used by the two largest PP's in Lebanon is among the most polluting petroleum by-products. It is enriched by certain chemicals to enhance its combustion and heat production properties. This increases the pollution resulting from its emissions especially in the absence of filters and other treatment means, which is the case in Lebanon.

On the other hand, the price of oil on the international markets varies in a frequent way according to the geopolitical events and other tensions affecting the world economy. In this thesis all petroleum products are linked to the price of the CO barrel, therefore OPEC prices of the CO barrel will have a great impact on fuel prices and thus on the cost of production.

The fact that there is no diversity of fuel sourcing for the power grid, and the use of only HFO and Gas-Oil, will make the system subject to a very high cost of energy production and a non-secure system. Moving to a more diversified portfolio of energy sources can help mitigate oil price volatility, provided that the prices of these other energy sources are not perfectly correlated with those for oil. LNG, NG and Coal can substitute for HFO and Gas-Oil, and many governments are promoting these alternative fuels to reduce reliance on oil. In the power sector, even though the use of oil is increasingly rare except in small countries (like Lebanon), most of power shortages in recent years are due to high oil prices, this is the

case in Lebanon, and some PP's are not being used to due to high fuel bill. Concerns about high prices of oil and other fossil fuels and emerging scientific evidence on the pace of climate change have prompted several governments to look for other fuel sources or enhance renewable energy targets.

Figure 4.2.1, gives a historical preview of CO Price in \$/barrel for the past 20 years. It is clear that in mid-2008 the price of CO barrel jumped above 140 \$/barrel, which a crisis in the energy history.

Since HFO and Gas-Oil, the only available fuel for Lebanon, are linearly linked to the price of the CO barrel, the oil crisis in 2008 had a great impact on the production cost where the fuel bill accounted up to 90% of the total production cost, resulting in large deficit and additional load shedding which in turns had a severe impact on the national economy.

Figure 4.2.1: Price of the CO barrel for the past five years

In this section some properties of the HFO and Gas-Oil will be addressed in general, and their prices will be linked to the price of the CO barrel using a formula suggested by the World Bank.

4.2.1.1. HFO, Gas-Oil and the Future Prices

HFO is a blended product which is based on the residues from various refineries, distillation and other cracking processes. Physically, HFO is a viscous liquid which requires heating in order to be stored and to be used for a certain combustion process. Mainly HFO is used in medium to large industrial plants, in

Lebanon the main use of HFO is in in combustion equipment's (i.e. boilers or diesel engines) for power stations. HFO is a general name for a range of products usually known as RFO, bunker fuel, black oil or fuel oil no. 6. It is will proved that HFO has a great impact on the environment either when burned or spilled.

HFO is considered an important category of oil product imports in countries with no other fuel source for power generation (Coal, NG, or hydro) which is the typical case of Lebanon.

Gas-Oil, also known as Light Fuel Oil (LFO) and diesel fuel oil, it is the environment friendly type of fuel oil. The main use for Gas-Oil is in transportation and to a lesser extent in power generation due to its high price compared to other fuel types. In the electricity sector, Gas-Oil is an expensive fuel but is used as a backup fuel. In countries with frequent power outages or shortages, small-scale diesel generators are common and are used as private generators in the cases of load-shedding. Gas-Oil also makes an ideal reserve and emergency fuel for power stations using other forms of energy.

In Lebanon Gas-Oil is used to fire more than half of the available thermal units, such units where originally designed to be operating on NG. Since NG is not available to Lebanon Gas-Oil is used as an alternative resulting in a high cost of operation.

A formula suggested by the World Bank is used in the context of this thesis to link the price of HFO and Gas-Oil (\$/ton) to the price of CO (\$/barrel) in order to predict future prices of such fuel oil products and perform production costing. The formula is give below:

$$Fuel\ Oil\ \left(\frac{\$}{tonne}\right) = CO\ \left(\frac{\$}{barrel}\right) * factor + Premium \quad (1.9)$$

Where the factor and premium are two varying figures calculated by the World Bank based on the oil market, cost of oil transportation, and other fixed charges. This figure also varies for different types of oil products and or different countries in which the oil would be transported. The table below shows the values of the premium and the factor for both LFO and HFO used for price linking with CO barrel.

Table 4.2.1: Premium and Factor Figures

Item	HFO	LFO
Factor	4.8024	9.3248
Premium	32.5	63.9

Based on the above relationship, the price of HFO and LFO can be easily calculated given the price of the CO barrel. Figure 4.2.2 compares historical prices of HFO and LFO with the price of the CO barrel, considering only the past 10 years.

Figure 4.2.2: HFO, LFO and CO price History

For the case of future fuel prices, it will be assumed that the price of the CO barrel is held at 80 \$/barrel for the year 2009, and for the upcoming years, up to 2015, it will be increased at a rate of 3%. Notice that such increase will also affect the price of HFO and LFO since the relationship is linear as shown in formula 1.9.

4.2.1.2. Natural Gas & Future Gas Prices

NG is considered the clean and cheap alternative of fuel oil. Compared to solid fuels (i.e. coal) and liquid (i.e. HFO and LFO) combustions on NG emit less carbon dioxide and other harmful pollutants. NG emits about half as much greenhouse gases on a lifecycle basis compared with coal. In power plant applications, natural gas also enables adoption of higher thermal-efficiency technologies. Diversification of energy sources has been another reason for switching to natural gas, the energy policy suggested in

this thesis takes the issue of fuel diversity as the core of the fuel sourcing strategy suggested for the LEPS.

One disadvantage of NG is that it is much more expensive to transport and store than fuel oil. For transporting NG, pipelines must be built. For longer distance, gas liquefaction and regasification plants may need to be constructed for liquefied natural gas (LNG). Long-distance pipelines and LNG facilities are extremely capital intensive, often costing billions of dollars.

In Lebanon the only infrastructure available is a 24 inch pipeline that runs for 32 km from the Lebanese-Syrian borders up to Tripoli Oil Installations in Beddawi. This pipeline is a section of the Arab Gas Pipeline that runs through Syria and Jordan to the gas fields in Egypt. One unit in Deir Ammar PP operates partially on NG due to its unavailability.

The two most recently constructed power plants in Lebanon are designed to be fired by NG. They are combined cycle gas turbines (CCGTs) at Beddawi and Zahrani. Each of these plants has an installed capacity of 435 MW and together they make up more than half of Lebanon's generation capacity. Neither of the two plant has a supply of NG and therefore they are obliged to operate on gas-oil at high cost.

The relation between the price of NG and the CO barrel is not well justified, but historical records shows that the price of NG tends to increase with the increase of the price CO barrel, especially when transportation is considered. Such an increase is not linear. In this research work, and for the case of simplicity, it will be assumed that the price of NG in \$/mmBtu will tend to increase by the same percentage of increase of the CO barrel.

The prices of NG for the last 8 years are shown in the figure 4.2.3. It is clear that the price of NG rose in mid-2008 to its highest level during the high oil prices. Therefore a correlation between Oil prices and NG prices must be considered.

Figure 4.2.3: NG prices in \$/mmBtu for the last 8 years

4.2.2. Existing Generation Infrastructure

The generation infrastructure in Lebanon is divided into thermal generation and hydro generation. Other electric energy is imported through regional interconnection from neighboring countries. In this section the generation infrastructure is discussed, describing the technology and other important parameters that will be used in the energy model.

4.2.2.1. Renewable Energy: Hydro Units

Compared to neighbouring countries, Lebanon enjoys sensible water resources, A quarter of these resources are presently being used and the part of hydropower in the total generation accounts for less than 10%, dropping every year, with the exception of the unusually rainy season in 2002-2003 where the share of hydropower rose to 12.9% of generated power.

The total Lebanese hydropower capacity amounts today to 270 MW. Five small hydroelectric plants belong to EdL. But 70% of the hydropower generation comes from the Litani River Authority with turbines that deliver 34, 108 and 48 MW, amounting to a total capacity of 190 MW. Two other concessions, Bared and Nahr Ibrahim have respectively an installed capacity of 17 and 33 MW. All the

hydropower units are between 40 and 70 years old but are not expected to be retired in the early future. The following table summarizes the current hydropower generation characteristics at the various sites:

Table 4.2.2: Hydro Power Data

River	Installed capacity (MW)	Capacity factor (%)	Annual energy (GW-hr)
Kadisha	25	41	70
Nahr Ibrahim	35	35	100
El Bared	20	34	50
Litani	190	50	780
Total	270	43	1000

In the energy model, all hydro units will be treated as one hydro unit which is energy limited generating unit used to peak shave the LDC. Where the FOR is 8% and the energy distribution will be designed such that the energy output does not exceed 1000 GW-hr, which is the actual energy produced from these units in 2009.

4.2.2.2. Thermal Units

The installed capacity of thermal power plants is 2038 MW but the actual capacity is less than 1700 MW. Lebanon has six thermal units operating on both HFO and LFO. Zouk and Jieh are two old steam turbines burning HFO at a very low efficiency. These two plants are depleted and must be decommissioned at the time new base load is added. Zahrani and Deir Ammar are CCGT PP's operating on LFO at a very high fuel and O & M cost. Sour and Baalbeck are OCGT PP's also operating on LFO at a very high fuel cost.

The energy produced from these plants is 88% of the total production and the fuel cost vary widely from 10 USC/kW-hr to 24 USC/kW-hr.

Below is a detailed description of the available thermal units.

Zouk:

Zouk, Lebanon's largest PP is located in a residential area and local environmental pollution from the power plant is an issue. Lack of spare parts, plant engineers and overall staffing reduces the power output and efficiency significantly below the designed value.

The Zouk plant is fired using HFO. The fuel consumption design value varies from 230 grams/kW-hr to 265 grams/kW-hr. The variation is due to the difference in the unit size, with larger units utilizing fuel more efficiently. The actual fuel consumption is above the design value by as much as 35%. The deviation from the design value has a significant impact on the fuel bill, reflecting an increase in fuel cost. The higher heat consumption is due to overall deterioration of the plant components, lack of spare parts, and inappropriate operation and maintenance practices.

The below table summarizes the technical condition of the Zouk PP.

Table 4.2.3: Zouk PP Data

Unit	Commissioning Year	Decommissioning Year	Fuel Type	FOR (%)	Installed Capacity (MW)	Available Capacity (MW)	Designed SFOC (gr/kW-hr)	Actual SFOC (gr/KW-hr)
Zouk 1	1984	2015	HFO	20	145	100	224.8	258.00
Zouk 2	1985	2016		20	145	100	223.3	264.00
Zouk 3	1986	2018		20	145	100	223.7	262.00
Zouk 4	1986	2018		20	172	120	215.8	239.00

Jieh:

Jieh is the oldest operating plant among Lebanon plants. As in the case of Zouk, the actual value for fuel for fuel consumption compared to the design value varies by as much as 40%. This deviation represents an increase in fuel cost. The higher fuel consumption design value for Jieh as compared to Zouk is due to the fact that Jieh's units are smaller and older than Zouk.

The below table summarizes the technical condition of the Jieh PP.

Table 4.2.4: Jieh PP Data

Unit	Commissioning Year	Decommissioning Year	Fuel Type	FOR (%)	Installed Capacity (MW)	Available Capacity (MW)	Designed SFOC (gr/kW-hr)	Actual SFOC (gr/KW-hr)
Jieh 1	1970	2010	HFO	35	65	25	250	315.12
Jieh 2	1970	2010		35	65	25	250	328.00
Jieh 3	1980	2012		35	72	50	240	300.00
Jieh 4	1981	2013		35	72	50	240	297.33
Jieh 5	1981	2014		35	72	61	240	288.00

The life of both Zouk and Jieh could, through plant refurbishment or rehabilitation, be prolonged by about ten years. The life of the power plants depends on the practice of maintenance and operation.

Deir Ammar and Zahrani PP's

The two most recently constructed power plants are CCGT's, Deir Ammar and Zahrani. These plants each have installed capacity of 435 MW and make up about half of Lebanon's generation capacity. As the most recently added plants, these are important assets in the power system. However, they are not operating under optimal conditions. The most pressing issue is that they use a very uneconomical fuel, Gas-Oil. Although CCGTs are designed to operate on either natural gas or gas-oil, operation on gas-oil can render this generation technology un-economical despite its higher fuel efficiency (50% compared to 38-40% for steam-cycle plants). This is because the price of gas-oil tends to be double or even more that of natural gas to feed the same energy input.

The decision in Lebanon to procure this type of technology was based on an agreement to import natural gas from Syria in the mid-1990's. The agreement provided for sufficient natural gas to supply both of these plants (around 1.5 billion m³ per year at 80% load factor). A gas pipeline was constructed between the Syria borders to the Deir Ammar PP in Lebanon. The pipeline was completed in 2005 but due to insufficient gas in Syria to meet domestic demand, Lebanon is not yet importing gas through this pipeline.

Unfortunately, there is no infrastructure in place to transport the gas further to Zahrani in the south of Lebanon. Options are under consideration, including construction of domestic pipeline connecting north to the south of Lebanon.

In addition, the gas turbines (stators) at both Deir Ammar and Zahrani suffered from manufacturing defects in 2006 and 2007, causing the plants to operate at half load. Temporary measures were taken and units were put back into operation in early 2007. However, until the stators have been permanently replaced, the plants used to run a high risk of generator failure.

The below table summarizes the technical condition of the Deir Ammar and Zahrani PP.

Table 4.2.5: Deir Ammar and Zahrani PP Data

Power Plant	Unit	Commissioning Year	Decommissioning Year	Fuel Type	FOR (%)	Installed Capacity (MW)	Available Capacity (MW)	Designed Efficiency	Actual Efficiency
Zahrani	Zahra1	1998	2022	LFO	13	145	120	-	31.88
	Zahra2	1998	2022		13	145	120	-	32.24
	Zahra3	2001	2025		13	145	120	50.7	50.7
Deir Ammar	DieAm1	1998	2022		13	145	120	-	31.93
	DieAm2	1998	2022		13	145	120	-	32.13
	DieAm3	2002	2026		13	145	120	50.7	50.7

4.2.2.3. Power Import

Lebanon imports power from Syria and Egypt throughout regional Interconnection. The purchases from Syria (589 GW-hr) and Egypt (527 GW-hr) constituted 7.5% of the total energy production.

Power from Syria is drawn through the current 220 and 66 kV connections into the three substations Deir Nbouh, Anjar and Tfiel. The average tariff per kW-hr for power drawn from Syria is 13 cents.

Power from Egypt is drawn through the 400 kV line into Ksara substation (400/220 kV), the average tariff per kW-hr for power drawn from Egypt is 11 cents.

4.2.3. Reliability Evaluation of the Current Generating Capacity: Technical Data and Current System Simulation

The adequacy of the available generating capacity will be assessed using the Load Modification Technique. Based on the proposed load model presented in section 3.3, it will be assumed that this load model corresponds to the demand for year 2009 which will be dealt as the base case. All available generating capacity units will be convolved with this load model in order to assess the adequacy of each unit separately. Several indices will be obtained, which will be analyzed based on the ability to meet the demand.

The available generating units (thermal and hydro) in addition to power import are arranged in a priority list based on the price of kW-hr. The cheapest generating unit appears first in the list (i.e. hydro) and is referred to as a baseload and the most expensive unit (i.e. Diesel fired units) appears last in the list and is referred to as peaking units. In between the base and the peaking, appears the intermediate load

which is more expensive than base loads and yet cheaper than peaking units. In Lebanon all units are used as base load units due to the large gap between supply and demand. Some expensive units like sour and Baalbeck are forced to operate as peaking units by forcing shutdowns at off-peak seasons.

Table 4.2.6 arranges the LEPS unit in their priority order.

Table 4.2.6: Available Units arranged in a priority list

Power Plant	Unit	Priority level
All Hydro Units	-	1
Import: Syria, Egypt	-	2, 3
Zouk	Zouk1	4
	Zouk2	5
	Zouk3	6
	Zouk4	7
Jieh	Jieh1	8
	Jieh2	9
	Jieh3	10
	Jieh4	11
	Jieh5	12
Deir Ammar	DieAm1	13
	DieAm2	14
	DieAm3	15
Zahrani	Zahra1	16
	Zahra2	17
	Zahra3	18
Sour	Sour1	19
	Sour2	20
Baalbeck	BBK1	21
	BBK2	22

Figure 4.2.4 illustrates the LDC or the load model for the year 2009 of the LEPS estimated using 20 points. The energy demanded is estimated to be 15,000 GW-hr which is the area under the LDC. The peak power demanded is approximately 2450 MW and the minimum power is estimated to be 1000 MW. The load factor is 0.6989.

Each unit in the priority list will be considered separately, a COPT and energy distribution will be constructed if needed, and this generating model will be convolved with the load model obtaining the EES the duty cycle for each unit and the utilization factor for the whole plant.

Figure 4.2.4: The Load Model for the LEPS (Year 2009)

I. All Hydro Units

All available hydro units will be treated as one single unit, it will be assumed that this unit is energy limited unit with limited storage.

Table 4.2.7: All Hydro LMT data

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
All Hydro	Energy Limited with Limited Storage	Capacity & Energy Modification	8	190	1

Since this Unit is energy limited unit, therefore an energy distribution is considered such that to limit the output to an acceptable value not exceeding 1 TW-hr.

Table 4.2.8: Energy Distribution for Hydro Units

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
900	1
1000	0.78

The LDC Modified after the addition of this unit is shown in the below figure. It is clear that this unit peak shaved the LDC. This modified LDC will be used as the equivalent LDC for the remaining units in the priority list.

Figure 4.2.5: LDC after peak shaving using hydro units

The EENS before adding the Energy Limited is 15000 GW-hr. The EES is 1000.336 GW-hr. The EENS after the addition of this unit is 13999.664 GW-hr. The Duty Cycle or the Load Factor for this unit is 0.6533.

II. Imports

Power is imported from Syria and Egypt. Each import will be treated as a separate unit. The technique to deal with imported power in the context of this thesis is referred to as the Off-Peak capacity modification.

a. Syria

This unit is an import unit and will be treated as an off-peak unit.

Table 4.2.9: Syria Import LMT data

Power Plant	Category	Type of LMT	FOR (%)	Capacity(MW)	Priority
Imports from Syria	Imported Power	Off-Peak Capacity Modification	1	108	2

The LDC Modified after the addition of this unit is shown in the below figure. It is clear that this unit modified the LDC using the Off-Peak Capacity Modification. This modified LDC will be used as the equivalent LDC for the remaining units in the priority list.

Figure 4.2.6: LDC modified using Off-peak Modification (Syria Import)

The EENS before the Syria Import unit is 13999.664 GW-hr. The EES for this unit is 588.959 GW-hr. The EENS after the addition of this unit is 13410.704 GW-hr. The Duty Cycle or the load factor for this unit is 0.6288.

b. Egypt

This unit is an import unit and will be treated as an off-peak unit.

Table 4.2.10: Egypt Import LMT Data

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Imports from Egypt	Imported Power	Off-Peak Capacity Modification	1	123	3

The LDC Modified after the addition of this unit is shown in the below figure. It is clear that this unit modified the LDC using the Off-Peak Capacity Modification. This modified LDC will be used as the equivalent LDC for the remaining units in the priority list.

Figure 4.2.7: LDC modified using Egypt Import unit

The EENS before adding Egypt Import unit is 13410.704 GW-hr. The EES for this unit is 525.001 GW-hr. The EENS after the addition of this unit is 12885.703 GW-hr. The Duty Cycle or the LF for this unit is 0.4922.

III. Thermal Units

For the case of thermal units (19 units), table 4.2.11 summarizes the simulation data. For detailed simulation results refer to annex 2.

All modified LDC's equivalent to the added generating unit is shown in figure 31. This figure summarizes the behavior of the generation model of the entire system (Unlimited and Limited Units). The shaded area under the LDC is the EENS, which is the remaining energy demanded and not supplied.

The Total Energy Demand is 15000 GW-hr. The EENS for the system is 3495.190 MW-hr which is 25% of the demanded energy. The Expected Energy output for all the 22 Units in the system is 11504.809 GW-hr. The EIR for a year is 0.766987.

Table 4.2.11: Thermal Units Simulation Results (Base Case 2009)

Power Plant	Unit	EES	EENS after Unit addition	Duty Cycle	Plant Utilization Factor
Zouk	Zouk1	515.20	12,370.50	0.59	0.71
	Zouk2	519.87	11,850.64	0.59	
	Zouk3	515.52	11,335.11	0.59	
	Zouk4	547.22	10,787.89	0.52	
Jieh	Jieh1	142.35	10,645.54	0.65	1
	Jieh2	142.35	10,503.19	0.65	
	Jieh3	284.70	10,218.49	0.65	
	Jieh4	284.70	9,933.79	0.65	
	Jieh5	347.33	9,586.46	0.65	
Deir Ammar	DieAm1	914.54	8,671.91	0.87	1
	DieAm2	914.54	7,757.37	0.87	
	DieAm3	914.54	6,842.83	0.87	
Zahrani	Zahra1	914.54	5,928.28	0.87	1
	Zahra2	914.51	5,013.77	0.87	
	Zahra3	912.55	4,101.22	0.87	
Sour	Sour1	152.99	3,948.23	0.50	0.55
	Sour2	153.00	3,795.23	0.50	
Baalbeck	BBK1	153.04	3,642.19	0.50	0.55
	BBK2	153.02	3,489.17	0.50

Figure 4.2.8: Several LDC modification states representing the added units

The LoLP is 0.994784 which is approximately 1.00. This means that the available system is capable of meeting the load for a few hours in the entire year. This issue is illustrated by The LoLE which is 8714.310239 hr/year.

Analyzing these reliability indices, one can conclude that this system is unreliable and will keep on deteriorating at a fast rate in the near future may be to a catastrophic failure.

4.3. Current Situation: An Economical Approach

Lebanon's public finance crisis is and has been for a long period closely linked to a very poor performing electricity sector. The sector costs massive government resources and, on top of it, consumers pay massive additional amounts for energy security. The energy sector in Lebanon is a massive drain on public resources and a symbol of Lebanon's profound challenges of governance, inclusion and accountability.

The subsidy-reducing action are tightly linked to the technical improvement of the sector, in this section the power grid is economically evaluated, such evaluation starts by performing production costing, then calculating the annual gained revenues of the sector based on the current average tariff.

The lack of revenue generation in the sector over many years has resulted in insufficient operation and maintenance of system assets, which in turn has increased the cost of power generation substantially. The widening gap between power supply and demand, the frequent outages and the significant spending on alternatives by all Lebanese has made increasing the electricity tariff challenging. With today's very high cost of oil (Lebanon imports all fossil fuels), the current tariff which covers US\$25/barrel only covers a small portion of operating costs and massive Government subsidies are required.

This section also links the effect of the load shedding to the national economy, and the fact that there is an indirect negative impact to the national economy which is the major result of the poor performance of the power sector.

4.3.1. Production Costing and the Financial Deficit of the Existing Generation Infrastructure

The expected energy supplied by each unit for one year was obtained in section 4.2.3. Using this energy along with the fuel cost and other fixed cost the total production cost for each unit (plant) can be calculated.

The efficiency, represented by the specific fuel oil consumption (SFOC), for each unit is needed in order to calculate the amount of fuel consumed per year to produce that energy.

Other fixed costs that need to be considered are O&M and Fuel transportation. For the case of fuel transportation, it will only be considered for plants that are off shore and needs to be transported deep in the territory.

The procedure to perform the production costing is illustrated in the formula below.

$$EES(GWh) \times \left\{ SFOC \left(\frac{\text{tons}}{GWh} \right) \times Fuel \left(\frac{\$}{\text{ton}} \right) + O \& M \left(\frac{\$}{GWh} \right) + Trans \left(\frac{\$}{GWh} \right) \right\} = Cost(\$) \quad (1.10)$$

The above formula holds for units operating on fuel oil only, given that the efficiency (SFOC) is known. In the production costing for units operating on NG the efficiency is given in the heat rate (joules/kWh or Btu/kWh). For the base case considered here, unit 2 of Deir Ammar PP (DieAm2) is operating on NG. The formula for such production costing is shown below.

$$EES(GWh) \times \left\{ Heat\ Rate \left(\frac{mmBtu}{GWh} \right) \times Fuel \left(\frac{\$}{mmBtu} \right) + O \& M \left(\frac{\$}{GWh} \right) + Trans \left(\frac{\$}{GWh} \right) \right\} = Cost(\$) \quad (1.11)$$

For the case of hydro power, no fuel cost is considered, only fixed cost is accounted. For the case of hydro power in Lebanon the price in cents per kW-hr was obtained to be 4.045. Imported power is similar to Hydro and is calculated using the same formula given below.

$$EES(GWh) \times Cost \left(\frac{\$}{GWh} \right) = Cost(\$) \quad (1.12)$$

Tables 4.3.1, 4.3.2, 4.3.3, and 4.3.4 show the Cost of Production for the entire system.

Table 4.3.1: Cost of imported power (base 2009)

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GW-hr)	Total Cost	Total Import's Cost
Syria	588.96	13.73	\$ 137,324.00	\$ 80,878,205.72	\$ 141,887,521.92
Egypt	525.00	11.62	\$ 116,208.00	\$ 61,009,316.21	

Table 4.3.2: Cost of hydro power (base 2009)

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GW-hr)	Total Cost
ALL-Hydro	1000.34	61.00	\$ 40,666.67	\$ 40,680,330.67

Table 4.3.3: Total Production cost for units operating on Fuel Oil and NG.

Thermal Units													
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh) Oil	Total Consumption (K tons)	Fuel Price (\$/ton)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost of O&M (MM\$)	Transp (\$/ton)	Cost of Transp	Total Unit Cost (MM\$)	Total Plant Cost (MM\$)
Zouk	Zouk1	HFO	515.20	258.00	132.92	416.69	55.39	28.00	14.43	0.00	0.00	69.81	282.09
	Zouk2	HFO	519.87	264.00	137.24	416.69	57.19	28.00	14.56	0.00	0.00	71.74	
	Zouk3	HFO	515.52	262.00	135.07	416.69	56.28	28.00	14.43	0.00	0.00	70.72	
	Zouk3	HFO	547.22	239.00	130.79	416.69	54.50	28.00	15.32	0.00	0.00	69.82	
Jieh	Jieh1	HFO	142.35	315.12	44.86	416.69	18.69	12.00	1.71	0.00	0.00	20.40	162.63
	Jieh2	HFO	142.35	320.23	45.58	416.69	18.99	12.00	1.71	0.00	0.00	20.70	
	Jieh3	HFO	284.70	289.45	82.41	416.69	34.34	12.00	3.42	0.00	0.00	37.75	
	Jieh4	HFO	284.70	297.33	84.65	416.69	35.27	12.00	3.42	0.00	0.00	38.69	
	Jieh5	HFO	347.33	282.72	98.20	416.69	40.92	12.00	4.17	0.00	0.00	45.09	
Deir Ammar	DieAm1	Diesel	914.54	275.00	251.50	809.88	203.69	21.00	19.21	0.00	0.00	222.89	316.14
	DieAm3	HRS	914.54	0.00	0.00	0.00	0.00	21.00	19.21	0.00	0.00	19.21	
Zahrani	Zahra1	Diesel	914.54	281.00	256.99	809.88	208.13	8.00	7.32	0.00	0.00	215.45	435.96
	Zahra2	Diesel	914.51	278.00	254.23	809.88	205.90	8.00	7.32	0.00	0.00	213.22	
	Zahra3	HRS	912.55	0.00	0.00	0.00	0.00	8.00	7.30	0.00	0.00	7.30	
Tyre	Tyre1	Diesel	151.50	297.00	45.00	809.88	36.44	2.00	0.30	12.00	0.54	37.28	75.33
	Tyre2	Diesel	151.54	303.00	45.92	809.88	37.19	2.00	0.30	12.00	0.55	38.04	
Baalbeck	BBK1	Diesel	151.50	303.00	45.90	809.88	37.18	6.00	0.91	4.00	0.18	38.27	75.92
	BBK2	Diesel	151.49	298.00	45.14	809.88	36.56	6.00	0.91	4.00	0.18	37.65	

Unit operating on NG													
Power Plant	Unit	Fuel Type	EES (GWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Cost (\$/GWh)	Unit Production Cost (MM \$)	O&M (\$/MWh)	Unit Cost of O&M (MM \$)	Transp (\$/ton)	Cost of Transp	Total Unit Cost (MM\$)	
DieAm	DieAm2	NG	914.54	10612.42	5.65	59,960.18	54.84	21.00	19.21	0.00	0.00	74.04	

4.3.2. LEPS Financial Burden

It is given that the existing generating units are supplying 11504.8 GW-hr. A significant portion of this energy supplied is lost either due to technical losses or non-technical losses.

Technical losses are reported to be in the order of 15% for year 2009. Such losses are due to poor transmission lines where several bottlenecks exist on the transmission of the system. Non-technical losses, also referred to as the Energy consumed but not billed, is due to the illegal connections on the network (Energy theft) at the distribution level. Non-Technical losses are reported to be in the order of 20%. Other type of losses is the Energy billed but not collected, such losses are due to the inadequate billing and metering system.

Figure4.3.1 shows the energy distribution between losses, uncollected energy and collected energy.

Figure 4.3.1: Energy Produced and the losses

The average tariff is provided to be 9.58 cents/kW-hr including all types of fixed charges, based on this number the 15% of technical losses translates in to \$ 165.3 million, whereas the non-technical losses translates into \$ 187.36 million and the uncollected billed energy to be \$ 37.47 million. The remaining

energy which is billed and collected accounts up to 65% which is \$ 711.995 million. These data are summarized in the table below.

Table 4.3.4: Value of Losses and total gained revenues

Item	Energy (GW-hr)	Financial Losses (MM\$)
Technical Losses	1725.72	165.3
Non-Technical Losses	1955.82	187.36
Not collected Billed Energy	391.16	37.74
Total Losses	4072.7	390.164
Collected Billed Energy (Revenues)	7432.10	1,102.160

The financial losses and subsidies are tabulated below.

Table 4.3.5: Deficit/Subsidies for year 2009

Item	(MM\$)
Total Gained Revenues	\$ 711,995,380.41
Losses	\$ 818,645,580.71
Capital Amortization	\$ 381,354,419.29
Deficit/Subsidies	\$ 1,200,000,000.00

Capital Amortization by definition is the paying off debt in regular installments over a period of time. In the hereby context capital amortization is the payments of older projects in the sector where EdL must pay.

The Deficit/Subsidies are calculated to be \$ 1.2 Billion, which is a huge financial burden. It is clear from table 30 that weighing factor for the cost of production is the price of fuel which is accounting up to 80% of the expenses. Reducing the fuel price would reduce the deficit tremendously.

4.3.2.1. Losses to the National Economy

In addition to the direct losses, which are the deficits calculated in section 4.3.2, there exist an indirect losses to the national economy. Such losses are due to the high EENS. It is widely known that a good performing energy sector will contribute in a positive way to the economy whereas a deteriorating one will have a negative impact on the economy.

In the context of this thesis the losses to the national economy are due to private generation and to the suppressed demand known as the value of loss of load VoLL. It will be assumed that 80% of the EENS is supplied using self-generation and the other 20% is a suppressed demand that is subject to the VoLL.

4.3.2.1.1. Self-Generation

The use of back-up and self-generation play a very important role to satisfy the need for electricity. Most commonly, individual or community-based back-up generators are used, kicking-in when EdL's supply is unable to meet demand; or, as in the case with large industries, when industries find it more economical to generate their own electricity due to the tariff charged by EdL as well as the risk (and cost) of interrupted supply. In essence, most consumers retain a connection both to EdL and to an alternative supply point.

The need for alternative supply arrangements is costly for Lebanese household consumers. Residential users consuming from a community-based generator usually pay a flat monthly fee, regardless of their level of consumption. This fee is reported to be ranging from 50 to 70 \$/month and even more in peaking seasons. In addition, these consumers pay for the electricity supplied by EdL. Consumers are therefore forced to pay up to an additional 35% for "security of supply".

Such security of supply is considered illegal in Lebanon, they are not subject to any kind of taxes, they operate freely without any monitoring in addition they use EdL infrastructure at some points to deliver power to their consumers, all of these aspect have a negative impact on the economy.

It will be assumed that for each kW-hr not supplied by EdL and is supplied by the private generation will have a negative impact of 46.43 cents.

For the base case of year 2009, the EENS is calculated to be 3495.2 GW-hr, 80% of this energy uses private generation (2796.16 GW-hr), as a result the economic losses due to private generation is calculated to be \$ 1,304.87 billion which is a huge burden.

Self-generation can be reduced, thus reducing the economic losses, by reducing the EENS. Therefore a generation expansion is needed to overcome the fact of self-generation.

4.3.2.1.2. Value of Loss of Load (VOLL)

The economics of the "rescue" of the system are not conventional cost-benefit economics governed by tangible prices. They are governed by the value of the energy not supplied by EdL that consumers would like to have and are ready to pay for. The value of the energy not supplied, generally, but improperly, known as the value of loss of load or VoLL, is extremely difficult to assess. Estimating such figure for Lebanon is very difficult, because the existence of a large volume of privately owned generation reduces to some extent the cost to some parts, but not all, of the economy. This generation is in itself

expensive, but to the individual, not to EdL or to the state. As a base case the value of \$1633/ MWh is considered; this is a very modest value.

For the base case of year 2009, the EENS is calculated to be 3495.2 GW-hr, 20% of this energy is suppressed and is subject to VoLL (699.04 GW-hr), as a result the economic losses due to VoLL is calculated to be \$ 1,141.53 billion which is another huge burden on the national economy.

4.3.3. Electric Sector financial summary

The table below summarizes the LEPS financial burden.

Table 4.3.6: Financial and Economical Summary for Year 2009

2009 Summary	
Energy Demanded	15000.00 GW-hr
EES	11504.80 GW-hr
EENS	3495.20 GW-hr
Total Production Cost	\$ 1,530,640,961.12
Technical Losses	1725.72 GW-hr
Non-Technical Losses	1955.82 GW-hr
Energy Available for Sale	9779.08 GW-hr
Energy Billed	7823.27 GW-hr
Not collected Billed Energy	391.16 GW-hr
Collected Billed Energy	7432.10 GW-hr
Total Gained Revenues	\$ 711,995,380.41
Losses	\$ 818,645,580.71
Capital Amortization	\$ 381,354,419.29
Deficit/Subsidies	\$ 1,200,000,000.00
Cost of Private Generation	\$ 1,304,873,920.00
Economic Cost VOLL	\$ 1,141,531,666.80
Total Economic Losses	\$ 2,446,405,586.80
Grand Total Losses	\$ 3,646,405,586.80

The grand total losses are approximately \$ 3.65 Billion for year 2009. It is clear that the energy sector, with this huge loss, is putting a lot of pressure on the public purse.

The Levelized cost of generation, is the constant price per kWh that would have to be paid for the output from a plant over its lifetime in order to recover exactly the costs of capital, fuel and operation. In this part the capital will not be considered, only fuel cost and other fixed costs like O&M is accounted.

The table below shows the Levelized cost of generation for each plant and is compared to the tariff.

Table 4.3.7: Levelized Cost of current generation

Generating Unit	Cost per kW/hr
Tariff	\$ 0.095800
Hydro	\$ 0.04067
Syria	\$ 0.13732
Egypt	\$ 0.11621
Zouk	\$ 0.13457
Jieh	\$ 0.13741
Deir Ammar	\$ 0.11523
Zahrani	\$ 0.15902
Tyre	\$ 0.24857
Baalbeck	\$ 0.25057
Total Production Cost	\$ 0.133044

It is clear that all thermal units' even imports are operating at a cost exceeding the tariff, which is the main reason behind the losses and the deficits.

4.4. Conclusion

From the simulation results, risk indices obtained, the financial figures calculated and the ensuing analysis performed on the current generation capacity infrastructure, illustrates the conclusive characteristics of the LEPS current situation and the main challenges it is currently facing.

The analysis concludes that the present situation of the electric sector is suffering from combined technical and financial problems. The study shows that the sector has reached a critical technical situation (very high EENS, LoLE, and LoLP) and its becoming a massive drain on the public resources (very high deficits and economic losses).

5. Future Projection of Current Situation of the LEPS – No Action taken

In order to perform future technical and financial forecasting for the current situation, the technical and financial data presented in Chapter 4 will be considered as the base case data. Based on the base case data several deterioration assumptions are assumed and therefore, using the same methodology and the energy model, the system is simulated for each year, production costing is performed and an economic analysis is ensued.

The current system presented by the base case will be projected up to 2015. This projection will assume no action is taken in the grid at all levels, and no investment of any kind is considered. Such analysis is performed to stress on the fact that an immediate action must be taken at the current time to rescue the system otherwise, as will be illustrated in this Chapter; the system will be facing a technical catastrophic deterioration and a financial crisis.

5.1. System Technical Deterioration

Given the technical data presented in the previous Chapter as a base case, the following measures are considered for each year passing on the generating system.

- The Power Demand will increase by 7%.
- The FOR of each unit will increase by 2%.
- The capacity (MW) for each unit will decrease by 2%.

Based on the above mentioned deteriorating measures, the system was simulated each year exclusively. The summary of the system performance from 2009 till 2015 is summarized in table 5.1.1. The figures following the table illustrate the performance of some reliability indices throughout the years.

Table 5.1.1: 2009-2015 technical Data (no policy)

Reliability Indices	Year						
	2009	2010	2011	2012	2013	2014	2015
Peak Power (MW)	2450	2622	2805	3001	3211	3436	3677
Maximum Generation (MW)	1681	1651	1622	1593	1565	1538	1511
Energy Demanded (GW-hr)	15000	16053	17173	18373	19659	21037	22512
EES (GW-hr)	11505	11326	11051	10871	10665	10476	10246
EENS (GW-hr)	3495	4727	6122	7502	8994	10561	12266
LoLP	0.99478	0.99935	1.00000	1.00000	1.00000	1.00000	1.00000
LoLE (hrs./year)	8714	8754	8760	8760	8760	8760	8760
EIR	0.76699	0.70204	0.63985	0.58586	0.53593	0.49101	0.44819

Figure 5.1.1: Energy/Power Demanded Vs. Energy/Power Supplied (2009-2015 no policy)

Figure 5.1.2: EENS increase from 2009 to 2015 (no policy)

Figure 5.1.3: EIR deterioration from 2009 -2015

Based on the simulation data, by year 2015 the system is facing a total technical deterioration. The LoLP is 1.00 (LoLE=8760hrs/year), that is the available generating capacity will never meet the load throughout the entire year. By the end of 2015 the power demanded will reach approximately 3700 MW (22512 GW-hr) whereas the available capacity (including imports and hydro) is less than 1750 MW (10246 GW-hr), which means that the system is approximately 50% short to demand and therefore the EENS is approximately 12266 GW-hr.

It will be shown in the next section of this Chapter that such large EENS will impact the national economy putting large pressure on the public purse.

The details of the system simulation for the years 2009 till 2015 are presented in Annex 3.

5.2. System Financial Deterioration

Based on the base case financial data presented in the previous Chapter, it will be assumed that the price of the CO barrel will increase by 3% for each passing, thus affecting the price of all petroleum products by the same percent. It will also be assumed that the efficiency of the available generating units will deteriorate by 2% for each passing year, thus the units will consume more fuel/Gas than previous years.

It will also be assumed that the percentage of losses (technical, non-technical and uncollected bills) will remain the same and will not be deteriorated, but the amount (in energy of these losses will vary since the generating capacity itself is decreasing throughout the years.

Concerning the issue of capital amortization discussed in the previous section, this figure will remain the same throughout the years since no new investments is being considered and therefore no new capital is being amortized through the years.

Based on the simulation data for the years 2009 - 2015 obtained in section 5.1, production costing is performed and an economic analysis is ensued for the entire forecasted years. A summary of the obtained data is presented in table 35. Tabulated data will also be illustrated using figures.

The details of the system production costing and economic analysis for the years 2009 till 2015 are presented in Annex 4.

Table 5.2.1: financial and economic data summary of the current system (years 2009-2015)

Total Losses & Subsidies on the Economy and the Government							
Item	2009	2010	2011	2012	2013	2014	2015
Energy Demanded (GWh)	15000.00	16053.00	17173.00	18373.00	19659.00	21037.00	22512.00
EES (GW-hr)	11504.80	11326.16	11050.91	10871.48	10664.88	10476.14	10245.51
EENS (GW-hr)	3495.20	4726.84	6122.10	7501.52	8994.12	10560.87	12266.49
Total Production Cost (\$ MM)	\$ 1.53	\$ 1.565	\$ 1.586	\$ 1.622	\$ 1.654	\$ 1.689	\$ 1.717
Technical Loss (GWh)	1725.72	1698.92	1657.64	1630.72	1599.73	1571.42	1536.83
Non-Technical Loss (GWh)	1955.82	1925.45	1878.65	1848.15	1813.03	1780.94	1741.74
Energy Available for Sale (GWh)	9779.08	9627.24	9393.27	9240.76	9065.15	8904.71	8708.68
Energy Billed (GWh)	7823.27	7701.79	7514.62	7392.61	7252.12	7123.77	6966.95
Not collected Billed Energy(GWh)	391.16	385.09	375.73	369.63	362.61	356.19	348.35
Collected Billed Energy (GWh)	7432.10	7316.70	7138.88	7022.98	6889.51	6767.58	6618.60
Total Gained Revenues (\$ MM)	\$ 712	\$ 700.9	\$ 683	\$ 672	\$ 660	\$ 648	\$ 634
Losses (\$ MM)	\$ 818.6	\$ 864.6	\$ 902	\$ 949	\$ 994	\$ 1,041	\$1,083
Capital Amortization (\$ MM)	\$ 381.3	\$ 381.3	\$ 381	\$ 381	\$ 381	\$ 381	\$ 381
Deficit/Subsidies (\$ MM)	\$ 1,200	\$ 1,245.9	\$ 1,284	\$ 1,330	\$ 1,375	\$ 1,422	\$ 1,464
Cost of self-Generation (\$ MM)	\$ 1,304.8	\$ 1,764.6	\$ 2,285	\$ 2,800	\$ 3,357	\$ 3,942	\$ 4,579
Economic Cost VOLL (\$ MM)	\$ 1,141.5	\$ 1,543.7	\$ 1,999	\$ 2,449	\$ 2,937	\$ 3,449	\$ 4,006
Total Economic Losses (\$ MM)	\$ 2,446.7	\$ 3,308.4	\$ 4,285	\$ 5,250	\$ 6,295	\$ 7,391	\$ 8,585
Grand Total Losses/Subsidies (\$ MM)	\$ 3,646.4	\$ 4,554.4	\$5,569.1	\$6,581	\$7,670	\$ 8,814	\$ 10,050

Figure 5.2.1 illustrates the losses in the system. It shows the EES, removing the non-technical losses, the energy remaining is the energy available for sale. Removing the technical losses, the energy remaining is the billed energy. Another loss is the uncollected billed energy, therefore the last bar (dark red) represent the amount of energy billed and collected. It is clear that the system losses accumulates to exceed 40%.

Figure 5.2.1: Presenting system losses (2009-2015) no policy

The financial burden represented by both direct financial losses and the economic losses (VoLL and self-generation) are represented shown in figure 5.2.2. By 2015 it is expected that the losses in that year will exceed \$ 10 Billion. Figure 5.2.3 shows the accumulation of the losses throughout the years in a cumulative manner. By 2015 the accumulated losses are expected to exceed \$ 45 Billion.

The remaining figures address the financial deficits of EdL, economic losses and the grand total losses exclusively. It illustrates the yearly and the accumulated losses up to 2015.

Figure 5.2.2: system yearly financial burden 2009-2015 no policy

Figure 5.2.3: financial burden (cumulative) - no policy

Figure 5.2.4: total economic losses (2009 - 2015) no policy

Figure 5.2.5: Total economic losses (cumulative) - no policy

Figure 5.2.6: Grand total losses/deficits (2009 - 2015) no policy

Figure 5.2.7: Grand Total losses/deficits (Cumulative) - no policy

5.3. Future Levelized Cost of Generation

The Levelized cost of generation (operation cost in \$/kW-hr) for all plants is calculated from year 2009 till 2015. Table 5.3.1 shows the cost of generation for each unit in addition to the production cost of the entire generating capacities.

Table 5.3.1: Levelized cost of generation for all units (2009-2015) no policy

Item	Plants Total Cost in \$/kW-hr (Including O&M and Transportation)						
	2009	2010	2011	2012	2013	2014	2015
Hydro	0.04067	0.04067	0.04067	0.04067	0.04067	0.04067	0.04067
Syria	0.13732	0.14144	0.14569	0.15006	0.15456	0.15920	0.16397
Egypt	0.11621	0.11969	0.12329	0.12698	0.13079	0.13472	0.13876
Zouk	0.13457	0.13971	0.14510	0.15076	0.15670	0.16294	0.16949
Jieh	0.13741	0.14346	0.14981	0.15647	0.16346	0.17080	0.17850
Deir Ammar	0.11523	0.11782	0.11807	0.12072	0.12344	0.12495	0.12637
Zahrani	0.15902	0.16353	0.16478	0.16937	0.17407	0.17706	0.17992
Tyre	0.24857	0.26034	0.27271	0.28568	0.29929	0.31358	0.32858
Baalbeck	0.25057	0.26232	0.27466	0.28760	0.30119	0.31545	0.33042
Tariff	0.09580	0.09580	0.09580	0.09580	0.09580	0.09580	0.09580
Total Production Cost	0.13304	0.13823	0.14358	0.14923	0.15511	0.16130	0.16763

Figure 5.3.1: Cost of PP's in \$/kW-hr for 2009-2015 - no policy

The average tariff is less than the total production costing and is less than the Levelized cost of all the generating plants (except hydro). It can be concluded that the production cost is very high (high fuel bill) and the average tariff (must be reconsidered) is very low resulting in a yearly deficit of more than \$ 1 Billion.

One important note is that the total production cost is increasing at each year (Oil price changing) whereas the tariff is held constant increasing the gap between the cost of production and the gained revenues and thus increasing yearly deficits.

Figure 5.3.2 compares the behavior of the total cost of production (\$/kW-hr) with the average tariff for 2009-2015. By the end of 2015 the cost of production will reach 17 cents/kW-hr whereas the average tariff remains to be 9.58 cents/kW-hr with a deficit of 7 cents for each kW-hr produced.

Figure 5.3.2: Total production cost compared to the tariff - no policy

Figure 5.3.3 shows the plant's production cost (\$/MW-hr) throughout the years and compared to the tariff. The below chart is used for the ease of comparison and will be used later for comparison after the policy implementation (Chapter 6).

Figure 5.3.3: Future Levelized cost compared to the tariff - no policy

6. A Comprehensive Policy for the Management, development and Radical Rehabilitation of the LEPS

Based on the current sector technical and financial evaluation performed in Chapter 4 and forecasted in Chapter 5, an emergency strategic plan must be considered to rescue the LEPS before it collapse.

A comprehensive policy to restructure and rescue the sector will be presented in this section. The policy will be implemented and simulated by the use of the energy model focusing on the generation expansion initiative (largest and most important part of the considered policy).

The LEPS will be re-evaluated, based on the adequacy of the generation capacity, throughout the years of the policy implementation. Other initiatives of the policy will translated into a technical aspect and others will only count through capital amortization (only investment) and will have no technical meaning.

6.1. Introduction

This plan presents a comprehensive policy and a realistic implementation program for the radical rehabilitation and development of the electric sector to respond to the economic, social needs and aspirations of Lebanon. This suggested plan can be considered as the cornerstone of the integrated national energy program for Lebanon.

This strategic plan covers three distinct strategic areas with ten specific initiatives in a comprehensive program of wide action steps:

- I. Infrastructure:
 - a. Generation – Capacity re-enforcement and generation expansion
 - b. Transmission – Transmission network expansion
 - c. Distribution – Enhancement of the Distribution system

II. Supply and demand:

- a. Fuel Sourcing strategy – diversity and security of fuel supply
- b. Renewable Energies – enhancing the share of green energy
- c. Demand Side Management - Energy Efficiency
- d. Tariffs Restructure

III. Legal framework (no technical effect):

- a. Norms and Standards
- b. Corporatization of EDL
- c. Legal Status

The implementation of the program will be phased according to the following planning horizons:

1. **Short term 2010-2012:** (Immediate and urgent, 2010– 2013 years);
2. **Medium term 2012-2015:** (2014 – 2015 years)

6.2. Energy Policy Executive Summary

This thesis constitutes a global framework for the electric energy sector in Lebanon, and includes ten strategic initiatives that are integrated and correlated to cover the sector's infrastructure, supply/demand, and the legal aspects. The initiatives are developed into identified plans of action with required budget, financing schemes, and timeframe. The elimination/delay of any initiative and action will lead to losing the policy objective of rescuing the power sector from the current drastic situation to a new sustainable, reliable, and efficient delivery of electricity.

The policy remedies most of the problems of the electric energy sector stated in Chapter 4, starting by the addition of generating capacity to cover the existing gap, demand forecast and required reserve together with the necessary infrastructure to transmit and distribute the generated energy to consumers throughout the Lebanese service territory in a secure and economical manner. The transmission and distribution infrastructures will be upgraded to cope with the capacity additions and to improve the operability of the system, thus decreasing the technical losses. The policy calls for the establishment of a smart grid using meters with remote disconnects from control centers that will be operated with specialized service providers for the transitional period to modulate consumption and reduce non-technical losses.

On the supply side, the capacity addition shall include conventional energy sources that are the most economical with the least environmental impact mainly the natural gas; and renewable energies such as wind, solar, waste to energy, etc. The infrastructure requirements for the natural gas (LNG terminal, pipeline along the coast, etc.) are included in the policy. On the demand side, the policy aims to develop several demand side management and energy efficiency initiatives (e.g., CFL, SWH, etc.) to curb the load growth and improve the load factor which translates into guaranteed savings for the economy. To help increase the penetration of energy efficient devices, the policy calls for the adoption of standards and labels to promote them. Furthermore, a restructuring of the tariff, leading to a gradual balance in the fiscal budget of EDL, is necessary to both generate needed revenues on the treasury side and to unload the financial burden on the economy and the consumer side by eliminating the need for private generators and providing reliable 24/24 hour service.

The multitude of the projects included in this policy will require a proper legal framework for a transition phase until a permanent and stable situation for the sector is established. Similarly, the necessary financial, administrative and human resources will be given to EdL to manage the transition phase until the corporatization of EdL is accomplished. All this will be done in collaboration and partnership with the private sector and the donor community to benefit from their vast experiences and resources.

The policy will result in a solid power sector with more than 4000 MW generation capacity at the end of 2015, reliable transmission and distribution networks, and efficient delivery of electricity to cope with the overall socio-economic development of Lebanon. The policy targets a gradual implementation of the initiatives in the short and medium terms totaling 4872 M\$ for 4000 MW (Government in Lebanon up to 1560 M\$, the private sector contribution of 2322 M\$, and the international donor community up to 990 M\$). The full implementation of all the strategic initiatives in this policy will reduce the total losses from 4.5 B\$ in 2010 to zero in 2015 where 24/24 hours of service is provided, and the possibility of profit making as of 2015; while it will reach 10.5 B\$ in 2015 if no action is taken.

This thesis will consider all above mentioned reforms and initiatives translates them into technical parameters so that they can be used as an input parameter for the energy model. The main objective is to implement the policy by performing real time simulation where the obtained figures (reliability indices and financial figures) will be analyzed for the technical and financial justification. The following sections provide brief discussion for the three strategic areas including the main ten initiatives and the necessary action steps of the plan.

6.2.1. Power Grid Infrastructure

The Power Grid infrastructure consists of three important sub-strategic areas: Generation, Transmission & Distribution. In the below sections the policy address each sub-strategic area separately, briefly describing the initiatives of the policy in the mentioned strategic area, where the developed detailed model and other simulation results will be shown later in this Chapter.

6.2.1.1. Generation System Expansion

The generation policy is targeting a total installed capacity of 4,000 MW by the end of 2014 to meet a load of 2500 MW, 500 MW of demand not currently supplied (i.e. self-generation), future demand corresponding to an annual load growth of 7%, and ~5% of peak load reserve.

The below steps describes the initiatives in the Generation strategic area, it preliminary shows the financing party, time of execution (1 is considered to be year 2010 and 5 is the last year in the policy which is 2015), capacity expected to be installed and the project cost/budget.

- a. **Immediate stop-gap solution**, Renting 250 MW (barges or small generators) in the immediate term for summer 2010 and to provide the standby capacity needed for 2 – 3 years to rehabilitate and/or replace old power plants. In addition an import from turkey of about 100 MW through regional interconnection.

Table 6.2.1: Rental and Imports initiative summary

Item	Financed by	Implementation		Capacity (MW)	Budget
		From Year	To Year (s)		
Barges	GoL	2010	3	110-280	4.8 USC/kWh
Import from Turkey	GoL	2010	3	100-150	12.66 USC/kWh

- b. **New PP1**, rapid increase of the installed capacity by 600 – 700 MW using Combined Cycle Gas Turbine (CCGT) and/or Reciprocating Engines with a probable distribution of 200-300 MW reciprocating engines (RE) and 400-500 CCGT.

Table 6.2.2: New PP1 initiative summary

Item	Financed by	Implementation		Capacity (MW)	Budget (Million \$)
		From Year	To Year (s)		
New Power Plants	GoL	1	3	600-700	750-875

- c. **Rehabilitate, maintain, replace, or upgrade** existing plants to increase their overall capacity by about 245 MW.

Table 6.2.3: Rehabilitation and upgrades initiatives summary

Item	Financed by	Implementation		Capacity (MW)	Budget (Million \$)
		From Year	To Year (s)		
Rehabilitate Zouk , Jieh	International Loans	1	5	~100	180
Upgrade Deir Amar, Zahrani	GoL	1	3	75	108
Add CC to Tyr, Baalbeck	GoL	1	2	70	130

- d. **New PP2**, Start the process of increasing the installed capacity by 1,500 MW using the modality of Independent Power Producer (IPP).

Table 6.2.4: New PP2 (IPP modality) initiative summary

Item	Financed by	Implementation		Capacity (MW)	Budget (Million \$)
		From Year	To Year (s)		
New Power Plants	Private Sector International Loans	0	4	1,500	1,500

- e. Increase the share of **hydraulic power production** through maintenance, rehabilitation and/or replacement of existing hydro plants.

Table 6.2.5: Hydro Power initiative summary

Item	Financed by	Implementation		Capacity (MW)	Budget (Million \$)
		From Year	To Year (s)		
Hydraulic Power	Private Sector International Loans	2	5	40	200

- f. Introduce **wind power** via the private sector by building wind farms (60 – 100 MW).

Table 6.2.6: Wind Power initiative summary

Item	Financed by	Implementation		Capacity (MW)	Budget (Million \$)
		From Year	To Year (s)		
Wind Power	Private Sector	1	3	60-100	115-195

- g. Adoption of “**waste to energy**” for power generation.

Table 6.2.7: Waste power initiative summary

Item	Financed by	Implementation		Capacity (MW)	Budget (Million \$)
		From Year	To Year (s)		
Waste to Energy	Private Sector	3	4	15-25	30-50

6.2.1.2. Transmission System Expansion

The transmission policy will focus on removing bottlenecks, reducing transmission losses, completing a control facility to ensure adequate connection between power plants and load centers together with high reliability and stability at the lowest cost.

- a. **Complete the 220 kV loop** at Mansourieh in 2010.

Table 6.2.8: 220kV loop initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
220 kV loop at Mansourieh	GoL	0	1	1

- b. **Complete the infrastructure at the 400 kV Ksara substation** for the Arab interconnection.

Table 6.2.9: Ksara substation initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
Infrastructure at KSARA substation	International Loans	1	2	20-30

- c. Complete the **Lebanese Electricity National Control Center (LENCC)**.

Table 6.2.10: LENCC initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
LENCC	International Loans	1	2	20

- d. **Build regional substations**, reinforce existing system to reduce technical losses and remove bottlenecks, and expand the transmission system to increase evacuation capacity in accordance with the increase in generating capacity.

Table 6.2.11: Substations initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
Regional Substations / Transmission System	GoL	1	3	250
Transmission System Expansion	International Loans	3	5	400

6.2.1.3. Enhancing Distribution System

The distribution sector policy is based on implementing a transitional and realistic program aiming at investing in planning, constructing, operating and maintaining the distribution activities including metering, billing and collection based on modern and smart systems. Projects at this level will reduce technical and nontechnical losses and will insure an adequate way of billing and bill collection.

- a. **Improve the distribution services** in 2010 and equalize respectively the supply and collection between regions. Thus, a set of “quick fixes” will be used to reinforce collection and limit all types of theft and losses.
- b. Prepare the Terms of Reference (ToR) and implement a bidding process to select specialized companies in a transparent manner as service providers (SP's) whose responsibility is to **provide distribution services** and improve quality and adhere to performance benchmarks that would result in progressive increase of revenues. This will be implemented after dividing Lebanon into electrical regions.

Table 6.2.12: Distribution initiatives summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
Bidding Process	GoL	0	1	1
Distribution Network Facilities, AMR and Billing System	Private Sector	2	4	300
Upgrade / Rehabilitate Distribution System	Private Sector	2	4	50
Program Management	GoL	2	4	10

- c. Develop simultaneously a center able to **monitor automatic meter reading**, perform remote connection/disconnection of supply and demand management functions and its reduction (Smart Grid).

Table 6.2.13: Distribution monitoring center initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
Monitoring Center	Private Sector	2	4	30

- d. Introduce new services for consumers, and payment facilities and adopt **new tariff structures** and mechanisms (feed-in tariff, prepaid cards, net metering, etc.).
- e. Envisage the possibility of developing a **Distribution Management System** (DMS).

Table 6.2.14: DMS initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
Distribution Management Center	International Loans	2	4	25

6.2.2. Supply and Demand

The supply and demand covers four major aspects of the policy. *Fuel sourcing strategy*, which ensures a diversity of fuel sourcing for the thermal generation, it considers NG and LNG as a major source of fuel; it also takes HFO and LFO as a substitute for LNG if it is not available. *Renewable energy*, set strategic plans to ensure that the share of renewable energy achieve is at least 12% the total electric supply. *Energy efficiency*, which focuses' on the demand side management and ensures a proper and efficient use of energy. *Tariff restructure*, takes into consideration an increase in the existing tariff to eliminate the financial deficit in addition to the adoption of a special (non-uniform) tariff structure.

6.2.2.1. Fuel Sourcing Strategy

The fuel sourcing policy is based on diversity and security where 2/3 of the fuel mix is based on natural gas with multiple sources of supply; more than 12% are renewable energies; and the remaining from other sources of fuel while selecting technologies that work on both natural gas and fuel oil.

- a. Study and develop a plan for an infrastructure to supply and distribute natural gas based on the land pipeline in Beddawi and LNG marine station(s) and interconnect them with the power plants; thus providing a flexible and stable supply of natural gas.

- b. Gradually convert / build most power plants on natural gas while diversifying the sources of supply through contracts from: Turkey, former Soviet republics, Russia, Syria, Egypt, Qatar, Algeria, etc. while stressing on the potential of finding natural gas in the territorial waters of Lebanon.
- c. Construct a Liquefied Natural Gas (LNG) marine terminal in (2011).

Table 6.2.15: LNG terminal initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
LNG Terminal	Private Sector GoL	1	3	70-550

- d. Build a gas pipeline along the coast (onshore and subsea where necessary) to feed all power plants from the north to the south to reduce their operating costs.

Table 6.2.16: Gas Pipeline initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
Gas Pipeline	GoL Private sector	1	3	120

6.2.2.2. Renewable Energy

This policy commits to launching, supporting and reinforcing all public, private and individual initiatives to adopt the utilization of renewable energies to reach 12% of electric and thermal supply.

- a. Complete a wind atlas for Lebanon and launch IPP wind farms with the private sector (2010).
- b. Start a pre-feasibility study on Photovoltaic (PV) farms.
- c. Encourage public and the private sectors to adopt incineration technologies to produce electricity from waste.
- d. Encourage all individual and private initiatives to produce hydro power; even micro-hydro.

6.2.2.3. Demand Side Management / Energy Efficiency

This policy commits to the preparation and spreading of the culture for proper electricity use; adoption of national programs focused on demand side management as the basis for: effective energy use; peak

shaving; load shifting; and demand growth control in order to save a minimum of 5% of the total demand.

- a. Widely spread the use of CFL, with the aim of banning energy guzzling devices in the future.
- b. Increase the penetration of SWH and devise innovative financing schemes in collaboration with the banking sector to achieve the slogan “A solar heater for each household”.
- c. Encourage the use of energy saving public lighting.

Table 6.2.17: Energy Efficiency initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
LCEC / CFL / SWH / Public Lighting	GoL	0	4	25

6.2.2.4. Tariffs Restructure

The policy will gradually restructure and increase the existing tariff to eliminate the financial deficit in the electricity sector and establish a balanced budget for EdL, on one hand; and reduce the financial burden on the citizens caused by the utilization of costly private generators, on the other hand.

- a. Gradually increase the tariff in conjunction with improvements in the electric service provision until reaching the goal of a sustainable 24/24 electric service hence eliminating the need for private generators and abolishing the financial deficit.
- b. Adopt special tariffs and fees for low income consumers and productive sectors.
- c. Implement Time of Use (TOU) tariffs (e.g., night-reduced) in conjunction with the implementation of AMR schemes.

6.2.3. Legal Framework

The legal framework of the policy insists on the development of new rules and regulations that governs the electric sector such that it ensures safe, fair, respect for international norms and standards and best electric quality. It also considers corporatization of EdL as an ideal solution to be first step in the development of a non-corrupted institution, since EdL is considered the core entity of the sector.

This Section of the policy will be addressed in a summarized manner since the core of this thesis is the development of the power sector infrastructure and adopting a fuel sourcing strategy.

6.2.3.1. Norms & Standards

Part of the objective of this policy consists of setting norms and standards for the provision of electric services that is safe, equitable and fair with the best quality and lowest cost.

- a. Resolve the problems with the current concessions through a fair and equitable compromise for the owners and the Government using a financial settlement that gives the GoL its rights and the concession owners' incentives and encouragements to have them enter in operation of IPP and distribution service provision (SP).
- b. Develop rules and laws that promote the largest penetration of "Green Buildings (GB)" and "Energy Efficiency (EE)" in collaboration with concerned institutions.
- c. Comply and respect international norms and standards in the energy efficiency, environmental and public safety domains.

6.2.3.2. Corporatization of EdL

The success of this policy necessitates the "revitalization" of EdL because it is the core entity of the sector. This entails providing the financial, administrative and human resource flexibility needed to cope with the rapid and vital changes. To achieve this goal, this paper considers corporatization as the ideal solution.

Increase the human resource capacity of EdL by direct and gradual hiring and by relying on the private sector using outsourcing contracts for: the administrative, engineering, technical, and contracts of installation, operation and maintenance.

Table 6.2.18: EdL Corporatization initiative summary

Item	Financed by	Implementation		Budget (Million \$)
		From Year	To Year (s)	
EDL Human Resource	GoL	0	2	15
Corporatization Procedures	GoL	1	3	165

6.3. Policy Implementation: Energy Perspective

In this section the technical aspects of the policy will be considered. The sector will be evaluated each year after implementing the policy initiatives corresponding to that year (see initiatives timeline). Generation expansion initiatives are the points represented by the added capacity (HLI). Other technical issues in transmission and distribution are translated in losses and demand reduction.

6.3.1. Initiatives Timeline

Table 6.3.1 and 6.3.2 illustrates the technical initiatives timeline. The energy policy will be implemented year by year, each exclusive from previous year, in other words, based on the initiatives time line, each initiative presented in a year will be implemented and at the end of the year the LEPS will be simulated and evaluated based on the adequacy of the generating capacity. This procedure will hold up to the year 2015 which is the last year of the policy implementation. Year 2015 represents the addition of all initiatives and the reliability indices obtained on that year evaluates the total added generating capacity.

It is important to note that this timeline was constructed based on a realistic facts. For example the inability to install large amount of capacity in one year, the rehabilitation of available units is performed by shutting down one unit to be rehabilitated at a certain year, this unit will go back online in the consecutive year where another unit will go off for rehabilitation. The same fact also holds for upgrade, it is not feasible to upgrade the available CCGT's in one year; instead this project is intended to be on the scale of three years. Section 6.3.2 will illustrate the impact of each initiative on the performance of the LEPS, where simulation results are presented in details.

Table 6.3.1: Technical Initiatives time line (b)

Supply & Demand						
Year	2010	2011	2012	2013	2014	2015
LNG terminal					No decrease in Demand	
Gas Pipeline		No decrease in Demand				
LCEC / CFL / SWH / Public Lighting		1%	2%	1%	1%	
Total	Demand Decrease	0%	1%	2%	1%	0%
	Cumulative Demand Decrease	0%	1%	3%	4%	5%
Legal Framework						
Year	2010	2011	2012	2013	2014	2015
EDL Human Resources	No Technical Effect					
Corporatization Procedures		No Technical Effect				

The total decrease in demand will accumulate to reach 5% by the end of 2014. Other initiatives not mentioned have no technical effect on the generating system and will only be considered as capital.

Table 6.3.2: Technical Initiatives time line (a)

Capacity Installed (MW), Losses reduction (%) & demand Reduction (%)								
Generation Expansion								
Year			2010	2011	2012	2013	2014	2015
Power Rental(Barges)			280	280	280	280		
Imports from Turkey			100	100				
New PP	Sub-Plant 1	Unit 1: 5 Reciprocating Engines			100			
		Unit 2: 5 Reciprocating Engines				100		
	Sub-Plant 2	Unit 1: GT			150			
		Unit 2: GT			150			
		Unit 3: HRSG				150		
Rehabilitate Zouk & Jieh	Rehabilitate Zouk Unit 1				20			
	Rehabilitate Jieh Unit 3				5			
	Rehabilitate Zouk Unit 2					20		
	Rehabilitate Jieh Unit 4					5		
	Rehabilitate Zouk Unit 3						20	
	Rehabilitate Jieh Unit 5						5	
Rehabilitate Zouk Unit 4							25	
Upgrade Deir Ammar & Zahrani	Upgrade Deir Ammar: Unit 1 -GT			4	4	4		
	Upgrade Deir Ammar: Unit 2 -GT			4	4	4		
	Upgrade Deir Ammar: HRSG			4	4	4		
	Upgrade Zahrani: Unit 1 -GT			4	4	4		
	Upgrade Zahrani: Unit 2 -GT			4	4	4		
	Upgrade Zahrani: HRSG			4	4	4		
Upgrade Tyre & Baalbeck	Add HRSG to Tyre			35				
	Add HRSG to Baalbeck				35			
New Power Plant (IPP Modality)	Sub-Plant 1	Unit 1: GT					125	
		Unit 2: GT					125	
		Unit 3: HRSG						125
	Sub-Plant 2	Unit 1: GT					125	
		Unit 2: GT					125	
		Unit 3: HRSG						125
	Sub-Plant 3	Unit 1: GT					125	
		Unit 2: GT					125	
		Unit 3: HRSG						125
	Sub-Plant 4	Unit 1: GT						125
		Unit 2: GT						125
		Unit 3: HRSG						125
New Hydro Power							20	20
Wind Power					50	30		
Waste to Energy						12	8	
Total	MW Addition		0	59	534	341	803	795
	Cumulative MW		1651	1681	2186	2499	2341	4043

The total newly added capacity is 2532 MW. The total available generation capacity will reach 4043 MW by the end of 2014.

6.3.2. Reliability Evaluation of Policy Implementation: Technical Data and Policy Simulation

Holding the current situation technical data of year 2009 and the forecasted years 2010 – 2015 as a base case, all new generation initiatives for each year will be added to the base case. After addition of initiatives the year will be re-simulated and compared to the base case, this procedure will be repeated for all the years (policy life) up to 2015.

In this section a summary of the results are presented, for detailed data and methodology refer to Annex 5.

6.3.2.1. Energy Policy Implementation: Year 2010

Year 2010 is the start of the policy implementation, in that specific year the added capacity (barges or small generators or imports) is considered an immediate action as a stop-gap solution. It is also a preventive action not to face an extreme power shortage in the peaking season (summer 2010)

This capacity will stay operational for four consecutive years in order to provide the standby capacity needed for 2 – 3 years to rehabilitate and/or replace old power plants (later initiatives) table 6.3.3 shows the LMT data for this initiative.

Table 6.3.3: Year 2010 initiatives data

Initiative	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)	Priority Level
Import	Unlimited Energy	Capacity Modification	-	5	100	4
Rental (Barges)			ECA - HFO	2	280	5

The added capacity is placed on the right priority level based on the fuel price and other fixed costs. The new import comes directly after Syria and Egypt imports (priority level 4) followed by rental power (priority level 5) which will be treated as base load.

Table 6.3.4 (simulation results) shows the generating capacity units (newly added capacity is highlighted with yellow), its priority level, the EES and the duty cycle. Given the energy demanded in year 2010 is 16053 GW-hr, the EENS after adding the new initiatives is 1648.845 GW-hr which corresponds to a load shedding of 2.47 hours on average. An improvement can be sensed after the addition of the emergency stop gap capacity when compared to the base case year 2010.

Table 6.3.4: Simulation results year 2010 (EES and LF)

Power Plant	Priority level	Unit	EES (GWh)	EENS (GWh) after capacity addition	Duty Cycle	Plant Utilization factor
All-Hydro	1	-	1000.336	15052.664	0.00	-
Imports: Syria	2	-	588.959	14463.705	0.63	-
Imports: Egypt	3	-	525.001	13938.704	0.49	-
Imports: Turkey	4	-	832.2	13106.504	1.00	-
Rental: Barges	5	-	2403.744	10702.76	0.00	-
Deir Ammar	6	DieAm1	899.301	9803.459	1.00	1.000
	7	DieAm2	899.301	8904.158	1.00	
	8	DieAm3	899.301	8004.857	1.00	
Zouk	9	Zouk1	506.833	7498.024	0.74	0.720
	10	Zouk2	507.208	6990.816	0.74	
	11	Zouk3	506.781	6484.035	0.74	
	12	Zouk4	540.108	5943.927	0.65	
Jieh	13	Jieh1	140.16	5803.767	1.00	1.000
	14	Jieh2	140.16	5663.607	1.00	
	15	Jieh3	274.713	5388.894	1.00	
	16	Jieh4	274.651	5114.243	1.00	
	17	Jieh5	335.926	4778.317	1.00	
Zahrani	18	Zahra1	892.949	3885.368	0.99	0.946
	19	Zahra2	873.016	3012.352	0.97	
	20	Zahra3	769.557	2242.795	0.86	
Sour	21	Sour1	148.507	2094.288	0.55	0.550
	22	Sour2	148.48	1945.808	0.55	
Baalbeck	23	BBK1	148.514	1797.294	0.55	0.550
	24	BBK2	148.449	1648.845	0.55	

The EENS (bold red) is calculated to be 1648.845 GW-hr. the LoLP is 0.757 corresponding to an LOLE of 6630.7 hrs/year and the EIR will rise to reach 0.89. Figure 6.3.1 shows the equivalent and modified LDC for all the units tabulated, the shaded area represents the EENS.

Figure 6.3.1: Modified LDC for year 2010 capacity units

6.3.2.2. Energy Policy Implementation: Year 2011

Year 2011 experience the shutdown of Zouk1 and Jieh3 units to be rehabilitated (Units Jieh1 and Jieh2 will be decommission later). The rental and imports capacity installed in year 2010 will stay operational to provide the standby power that will replace the two offline units.

In this year the upgrade of Deir Ammar and Zahrani will start resulting in an added capacity of 24 MW distributed evenly on the 6 units of both plants (4 MW for each unit), the upgrades includes blade change, inlet cooling and wet injection.

Another initiative considered in this year is the addition of the HRSG to Sour PP to be converted from an OCGT plant into a CCGT plant, this initiative will result in added capacity of 35 MW. The HRSG unit added will be treated as energy limited unit (until converted to LNG) similar to the GT's available in Sour.

The total installed capacity for year 2011 will add up to be 59 MW. Table 6.3.5 (simulation results) shows the generating capacity units (newly added capacity with upgrades).

Given the energy demanded in year 2011 to be 17173 GW-hr, the EENS after implementing capacity initiatives will be 3352.616 GW-hr which correspond to a load shedding of 4.69 hours on average. The EENS in year 2011 is more than year 2010; this is due to the offline units subject to rehabilitation.

Table 6.3.5: Simulation results year 2011 (EES and LF)

Power Plant	Priority level	Unit	EES	EENS after capacity addition	Duty Cycle	Plant Utilization factor
All-Hydro	1	-	1000.336	16172.664	0	-
Imports: Syria	2	-	588.959	15583.705	0.6288	-
Imports: Egypt	3	-	525.001	15058.704	0.4922	-
Imports: Turkey	4	-	832.2	14226.504	1	-
Rental: Barges	5	-	2403.744	11822.76	0	-
Deir Ammar	6	DieAm1	896.498	10926.262	1.00	1.000
	7	DieAm2	896.498	10029.764	1.00	
	8	DieAm3	896.498	9133.266	1.00	
Zouk	Unit is OFF due to Rehabilitation					0.710
	9	Zouk2	496.812	8636.454	0.75	
	10	Zouk3	497.349	8139.105	0.75	
	11	Zouk4	528.794	7610.311	0.66	
Jieh	12	Jieh2	134.553	7475.758	1.00	1.000
	13	Jieh2	134.553	7341.205	1.00	
	Unit is OFF due to Rehabilitation					
	14	Jieh4	269.107	7072.098	1.00	
	15	Jieh5	330.777	6741.321	1.00	
Zahrani	16	Zahra1	896.011	5845.31	1.00	1.000
	17	Zahra2	890.951	4954.359	1.00	
	18	Zahra3	874.237	4080.122	1.00	
Sour	19	Sour1	145.503	3934.619	0.54	0.550
	20	Sour2	145.506	3789.113	0.54	
	21	HRSB	145.504	3643.609	0.54	
Baalbeck	22	BBK1	145.51	3498.099	0.54	0.550
	23	BBK2	145.483	3352.616	0.54	

The EENS (bold red) is calculated to be 3352.616 GW-hr. the LoLP is 0.962 corresponding to an LOLE of 8427 hrs/year and the EIR will drop to 0.8. Figure 6.3.2 shows the equivalent and modified LDC for all the units tabulated, the shaded area represents the EENS.

Figure 6.3.2: Modified LDC for year 2010 capacity units

6.3.2.3. Energy Policy Implementation: Year 2012

In year 2012 imported power from turkey will be abandoned but the rental power stays in operation. Year 2012 experience the first step in building PP1 which is a mix of 200 MW reciprocating engines and 450 MW CCGT plant. In this specific year the first 100 MW reciprocating engines along with two gas turbines operating as OCGT, these units will make a lump sum of 400 MW power installed. The remaining 100 MW reciprocating engines and the HRSG that will convert the technology from OCGT to CCGT will be installed in the later year. The data of PP1 is presented in the table below.

Table 6.3.6: LMT data for New PP1

Initiative	Unit	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)	Priority Level
New PP1	RE1	Unlimited Energy	Capacity Modification	HFO-Engines	4	100	6
	GT1			HFO-GT	15	150	7
	GT2			HFO-GT	15	150	8

The GT units of PP1 will operate temporarily at HFO until the fuel sourcing strategy is set and LNG is available to operate on NG. Note also that upon the availability of LNG reciprocating engines will operate mainly on LNG (80%) and partially on HFO (20%)

Zouk1 will return online with an additional capacity of 20 MW, improved efficiency, reduced FOR and an unlimited unit. Zouk2 will shut down to start the rehabilitation process (will come back online next year). Similarly Jieh3 will return online with an additional capacity of 5 MW, improved efficiency, reduced FOR and an unlimited unit. Jieh4 will shut down to start the rehabilitation process (will come back online next year). In addition units Jieh1 and Jieh2 will be decommissioned and pegged out of the grid.

Table 6.3.7: Zouk1 & Jieh3 rehabilitation data

Initiative	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)
Zouk1	Unlimited Energy	Capacity Modification	HFO-Steam	10	118
Jieh3				18	54

The upgrade process of Deir Ammar and Zahrani will continue in this year resulting in another additional 24 MW distributed evenly on the 6 units of both plants (4 MW for each unit).

Year 2012 will experience the installment of the HRSG unit to Baalbeck PP to convert it from OCGT to CCGT. This initiative will result in an installed capacity of 35 MW. The HRSG unit added will be treated as energy limited unit (until converted to LNG) similar to the GT's available in Baalbeck.

2012 will also experience the introduction of wind power to enhance the share of the renewable energy. The installed capacity of wind power is 50 MW. The data of wind power is presented in the table below.

Table 6.3.8: LMT data for Wind Power

Initiative	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)	Priority Level
Wind Power	Limited Energy	Capacity & Energy Modification	Renewable Energy	10	50	2

The total installed capacity for year 2012 will add up to be 534 MW. Table 6.3.9 (simulation results) shows the generating capacity units (newly added capacity with upgrades).

Given the energy demanded in year 2012 to be 18190 GW-hr, the EENS after implementing capacity initiatives will be 1828 GW-hr which corresponds to a load shedding of 2.41 hours on average.

Table 6.3.9: Simulation results year 2012 (EES and LF)

Power Plant	Priority level	Unit	EES	EENS after capacity addition	Duty Cycle	Plant Utilization factor
All-Hydro	1	-	1000.336	17189.664	0.653	-
Wind Power	2	-	128.532	17061.132	0.326	-
Imports: Syria	3	-	588.959	16472.173	0.628	-
Imports: Egypt	4	-	525.001	15947.172	0.492	-
Rental: Barges	5	-	2403.744	13543.428	1.000	-
New PP1	6	RE1	840.96	12702.468	1.000	1
	7	GT1	1116.9	11585.568	1.000	
	8	GT2	1116.9	10468.668	1.000	
Deir Ammar	9	DieAm1	911.565	9557.103	1.000	0.998
	10	DieAm2	911.565	8645.538	1.000	
	11	DieAm3	911.12	7734.418	0.997	
Zouk	12	Zouk1	925.146	6809.272	0.9950	0.823
	Unit is OFF due to Rehabilitation					
	13	Zouk3	487.205	6322.067	0.759	
	14	Zouk4	518.739	5803.328	0.663	
Jieh	Decommissioned Unit					0.970
	Decommissioned Unit					
	15	Jieh3	382.111	5421.217	0.9851	
	Unit is OFF due to Rehabilitation					
	16	Jieh5	306.681	5114.536	0.9749	
Zahrani	17	Zahra1	868.668	4245.868	0.9529	0.888
	18	Zahra2	826.69	3419.178	0.9069	
	19	Zahra3	735.854	2683.324	0.8072	
Sour	20	Sour1	142.521	2540.803	0.55	0.550
	21	Sour2	142.49	2398.313	0.55	
	22	HRSg	142.524	2255.789	0.55	
Baalbeck	23	BBK1	142.574	2113.215	0.55	0.550
	24	BBK2	142.549	1970.666	0.55	
	25	HRSg	142.454	1828.212	0.55	

The EENS (bold red) is calculated to be 1828.212 GW-hr. the LoLP is 0.731 corresponding to an LOLE of 6407 hrs/year and the EIR will drop to 0.897. Figure 6.3.3 shows the equivalent and modified LDC for all the units tabulated, the shaded area represents the EENS.

Figure 6.3.3: Modified LDC for year 2010 capacity units

6.3.2.4. Energy Policy Implementation: Year 2013

The remaining units of New PP1 will be installed in this year. The units are a set of reciprocating engines RE2 having a capacity of 100 MW and the HRSG that will convert the OCGT at PP1 to CCGT enhancing the plant by an additional 150 MW. This process will finalize the New PP1 with a total capacity of 600 MW. The data of new units of PP1 is presented in the table below.

Table 6.3.10: LMT data for New PP1 added units

Initiative	Unit	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)	Priority Level
New PP1	RE2	limited Energy	Capacity Modification	HFO-Engines	4	100	7
	HRSG1			HRSG	15	150	10

Zouk2 will return online with an additional capacity of 20 MW, improved efficiency, reduced FOR and an unlimited unit. Zouk3 will shut down to start the rehabilitation process (will come back online next year). Similarly Jieh4 will return online with an additional capacity of 5 MW, improved efficiency, reduced FOR and an unlimited unit. Jieh5 will shut down to start the rehabilitation process (will come back online next year).

Rental power will stay in operation in this year. The upgrade process of Deir Ammar and Zahrani will continue in this year resulting in another additional 24 MW distributed evenly on the 6 units of both plants (4 MW for each unit). Year 2013 will be the end year for upgrades of the CCGTS.

In 2013 the waste to energy technology will be introduced with a capacity of 12 MW.

Table 6.3.11: LMT data for Waste Power

Initiative	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)	Priority Level
Waste Power	Limited Energy	Capacity & Energy Modification	Renewable Energy	10	12	3

In addition, Wind power will be enhanced by an additional 30 MW to make a total of 80 MW wind power in the process of increasing the share of renewable energy.

It is also important to note that LNG will be available to thermal power plants in this year and that all of the thermal units will operate on LNG (except for Jieh and Zouk) at a low price relative to fuel oil (discusses in section 6.4). This action will arrange the units in a priority list making Zouk and Jieh the most two expensive units (see table 64).

The total installed capacity for year 2013 will add up to be 341 MW. Table 6.3.12 (simulation results) shows the generating capacity units (newly added capacity with upgrades).

Given the energy demanded in year 2013 to be 19267 GW-hr, the EENS after implementing capacity initiatives will be 988 GW-hr which corresponds to a load shedding of 1.23 hours on average. Table 66 (simulation results) shows the generating capacity units.

The EENS (bold red) is calculated to be 988 GW-hr. the LoLP is 0.371 corresponding to an LOLE of 3243 hrs/year (improvement compared to year 2012) and the EIR will converge to 0.945. Figure 6.3.4 shows the equivalent and modified LDC for all the units tabulated, the shaded area represents the EENS.

Table 6.3.12: Simulation results year 2013 (EES and LF)

Power Plant	Priority level	Unit	EES	EENS after capacity addition	Duty Cycle	Plant Utilization factor
All-Hydro	1	-	1000.336	18266.664	0.653	-
Wind Power	2	-	197.44	18069.224	0.326	-
Waste Power	3		63.241	18005.983		
Imports: Syria	4	-	588.959	17417.024	0.628	-
Imports: Egypt	5	-	525.001	16892.023	0.492	-
Rental: Barges	6	-	2403.744	14488.279	1.000	-
New PP1	7	RE1	824.14	13664.139	1.000	1.000
	8	RE2	840.96	12823.179	1.000	
	9	GT1	1210.456	11612.723	1.000	
	10	GT2	1210.456	10402.267	1.000	
	11	HRSO	1210.456	9191.811	1.000	
Deir Ammar	15	DieAm1	911.386	8280.425	0.9582	0.999
	16	DieAm2	867.492	7412.933	0.9210	
	17	DieAm3	810.809	6602.124	0.8524	
Zouk	24	Zouk1	557.203	6044.921	0.6090	0.540
	25	Zouk2	482.197	5562.724	0.5270	
	Unit is OFF due to Rehabilitation					
	26	Zouk3	342.791	5219.933	0.452	
Jieh	Decommissioned Unit					0.400
	Decommissioned Unit					
	27	Jieh3	156.559	5063.374	0.4110	
	28	Jieh4	145.234	4918.14	0.3820	
	Unit is OFF due to Rehabilitation					
Zahrani	12	Zahra1	951.16	3966.98	1	1.000
	13	Zahra2	949.024	3017.956	0.9978	
	14	Zahra3	938.183	2079.773	0.9864	
Sour	18	Sour1	200.116	1879.657	0.80	0.760
	19	Sour2	191.814	1687.843	0.77	
	20	HRSO	183.804	1504.039	0.74	
Baalbeck	21	BBK1	177.945	1326.094	0.71	0.680
	22	BBK2	172.386	1153.708	0.69	
	23	HRSO	166.105	987.603	0.67

Figure 6.3.4: Modified LDC for year 2013 capacity units

6.3.2.5. Energy Policy Implementation: Year 2014

In year 2014 a new base load will be partially introduced. New PP2 (IPP modality) is a 1500 MW power plant consisting of 8 GT's and 4 HRSG's, this power plant will operate as the base load of the power system. In this year 6 GT's are introduced operating as OC with a total installed capacity of 750 MW where the remaining GT's and the HRSG's will be installed next year. The data of new units of PP2 is presented in the table below.

Table 6.3.13: New PP2 LMT data

Initiative	Unit	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)	Priority Level
New PP2	GT1	Unlimited Energy	Capacity Modification	LNG - OCGT	6	125	6
	GT2				6	125	7
	GT3				6	125	8
	GT4				6	125	9
	GT5				6	125	10
	GT6				6	125	11
	GT7				6	125	12

Zouk3 will return online with an additional capacity of 20 MW, improved efficiency, reduced FOR and an unlimited unit. Zouk4 will shut down to start the rehabilitation process (will come back online next year).

Similarly Jieh5 will return online with an additional capacity of 5 MW, improved efficiency, reduced FOR and an unlimited unit. At this level the rehabilitation of Jieh PP ends with an added capacity, better efficiency (to a certain extent) and longer life.

The hydro power will be reinforced by an additional 20 MW and the waste to energy power will also be enhanced by another additional 8 MW. These initiatives will make a total hydro of 210 MW operational and 20 MW waste to energy.

The total installed capacity for year 2014 will add up to be 803 MW. Table 6.3.14 (simulation results) shows the generating capacity units (newly added capacity with upgrades).

Given the energy demanded in year 2014 to be 20828.571 GW-hr, the EENS after implementing capacity initiatives will be 406 GW-hr which corresponds to a load shedding of 0.6 hours on average. Table 68 (simulation results) shows the generating capacity units.

The EENS (bold red) is calculated to be 406 GW-hr. the LoLP is 0.185 corresponding to an LOLE of 3243 hrs/year (improvement compared to year 2012) and the EIR will converge to 0.9813. Figure 6.3.5 shows the equivalent and modified LDC for all the units tabulated, the shaded area represents the EENS.

Figure 6.3.5: Modified LDC for year 2014 capacity units

Table 6.3.14: Simulation results year 2014 (EES and LF)

Power Plant	Priority level	Unit	EES	EENS after capacity addition	Duty Cycle	Plant Utilization factor
All-Hydro	1	-	1100.971	19727.6	0.630	-
Wind Power	2	-	197.44	19530.16	0.310	-
Waste Power	3		112.495	19417.665	0.713	
Imports: Syria	4	-	588.959	18828.706	0.628	-
Imports: Egypt	5	-	525.001	18303.705	0.492	-
New PP2	6	GT1	1029.3	17274.405	1.000	1.000
	7	GT2	1029.3	16245.105	1.000	
	8	GT3	1029.3	15215.805	1.000	
	9	GT4	1029.3	14186.505	1.000	
	10	GT5	1029.3	13157.205	1.000	
	11	GT6	1029.3	12127.905	1.000	
New PP1	12	RE1	807.321	11320.584	1.000	1.000
	13	RE2	824.14	10496.444	1.000	
	14	GT1	1185.753	9310.691	0.999	
	15	GT2	1185.001	8125.69	0.999	
	16	HRSB	1200.244	6925.446	0.992	
Zahrani	17	Zahra1	906.213	6019.233	0.9686	0.930
	18	Zahra2	871.102	5148.131	0.9311	
	19	Zahra3	824.699	4323.432	0.8815	
Deir Ammar	20	DieAm1	756.271	3567.161	0.8084	0.706
	21	DieAm2	652.608	2914.553	0.6976	
	22	DieAm3	564.761	2349.792	0.6037	
Sour	23	Sour1	138.789	2211.003	0.56	0.543
	24	Sour2	133.952	2077.051	0.54	
	25	HRSB	128.764	1948.287	0.51	
Baalbeck	26	BBK1	123.158	1825.129	0.49	0.720
	27	BBK2	118.068	1707.061	0.47	
	28	HRSB	113.775	1593.286	0.46	
Zouk	29	Zouk1	363.889	1229.397	0.4130	0.348
	30	Zouk2	310.927	918.47	0.3498	
	31	Zouk3	254.826	663.644	0.2867	
	Unit is OFF due to Rehabilitation					
Jieh	Decommissioned Unit					0.220
	Decommissioned Unit					
	32	Jieh3	90.332	573.312	0.2448	
	33	Jieh4	81.453	491.859	0.2208	
	34	Jieh5	85.957	405.902	0.1954	

6.3.2.6. Energy Policy Implementation: Year 2015

Year 2015 is the last year in implementing the policy. In this specific year New PP2 will be fully installed, this PP will consist mainly of four CCGT plants operating as a base load. The table below shows the technical data of this plant.

Table 6.3.15: New PP1 Plant LMT data

Initiative	Unit	Category	Type of Modification	Type & Fuel	FOR (%)	Capacity (MW)	Priority Level
New PP2	GT1	Unlimited Energy	Capacity Modification	LNG - OCGT	6	123	6
	GT2				6	123	7
	HRS1				6	123	8
	GT3				6	123	9
	GT4				6	123	10
	HRS2				6	123	11
	GT5				6	123	12
	GT6				6	123	13
	HRS3				6	123	14
	GT7				6	125	15
	GT8				6	125	16
	HRS4				6	125	17

Zouk4 will return online with an additional capacity of 25 MW, improved efficiency, reduced FOR and an unlimited unit. At this level the rehabilitation of Zouk PP ends with an added capacity, better efficiency (to a certain extent) and longer life.

In addition, year 2015 will experience enforcement for the hydro power capacity by 20 MW, by this addition the total installed capacity of the hydro power will add up to be 230 MW which is 6% of the total installed capacity.

Table 6.3.16: All hydro units LMT data (after capacity reinforcement)

Power Plant	Category	Type Of Modification	FOR %	Maximum Generation (MW)	Energy (GW-hr) Simulated Results	Duty Cycle	Energy distribution		Priority
							Energy (GW-hr)	Cumulative Probability	
Nahr Ibrahim	Energy Limited with Limited Storage	Capacity & Energy Modification	230	190	1205.825	0.63	1150	1	1
Nahr el Bared									
Litani									
Kadisha							1175	0.3	

The total installed capacity for year 2015 will add up to be 795 MW. Table 6.3.17 (simulation results) shows the generating capacity units (newly added capacity with upgrades).

Given the energy demanded in year 2015 to be 22286 GW-hr, the EENS after implementing capacity initiatives will be 32 GW-hr which corresponds to a load shedding of 0.03 hours on average. Table 68 (simulation results) shows the generating capacity units.

The EENS (bold red) is calculated to be 32 GW-hr. the LoLP is 0.0135 corresponding to an LOLE of 118.72 hrs/year (improvement compared to year 2012) and the EIR will converge to 0.9993. Figure 6.3.6 shows the equivalent and modified LDC for all the units tabulated, the shaded area represents the EENS.

Figure 6.3.6: Modified LDC for year 2015 capacity units

Table 6.3.17: Simulation results year 2015 (EES and LF)

Power Plant	Priority level	Unit	EES	EENS after capacity addition	Duty Cycle	Plant Utilization factor
All-Hydro	1	-	1205.825	21080.175	0.630	-
Wind Power	2	-	197.44	20882.735	0.310	-
Waste Power	3		112.495	20770.24	0.713	
Imports: Syria	4	-	588.959	20181.281	0.628	-
Imports: Egypt	5	-	525.001	19656.28	0.492	-
New PP2	6	GT1	1012.831	18643.449	1.000	1.00
	7	GT2	1012.831	17630.618	1.000	
	8	HRSG1	1012.831	16617.787	1.000	
	9	GT3	1012.831	15604.956	1.000	
	10	GT4	1012.831	14592.125	1.000	
	11	HRSG2	1012.831	13579.294	1.000	
	12	GT5	1012.831	12566.463	1.000	
	13	GT6	1012.831	11553.632	1.000	
	14	HRSG3	1012.831	10540.801	1.000	
	15	GT7	1029.3	9511.501	1.000	
	16	GT8	1028.053	8483.448	0.999	
17	HRSG4	1020.849	7462.599	0.992		
New PP1	18	RE1	771.776	6690.823	0.976	0.870
	19	RE2	768.635	5922.188	0.952	
	20	GT1	1053.344	4868.844	0.907	
	21	GT2	977.079	3891.765	0.842	
	22	HRSG	845.29	3046.475	0.713	
Zahrani	23	Zahra1	546.988	2499.487	0.6013	0.530
	24	Zahra2	482.913	2016.574	0.5309	
	25	Zahra3	418.85	1597.724	0.4605	
Deir Ammar	26	DieAm1	363.364	1234.36	0.3995	0.340
	27	DieAm2	308.036	926.324	0.3386	
	28	DieAm3	252.65	673.674	0.2777	
Sour	29	Sour1	58.855	614.819	0.24	0.230
	30	Sour2	55.191	559.628	0.23	
	31	HRSG	51.875	507.753	0.21	
Baalbeck	32	BBK1	48.52	459.233	0.20	0.190
	33	BBK2	45.114	414.119	0.19	
	34	HRSG	41.817	372.302	0.17	
Zouk	35	Zouk1	123.412	248.89	0.1426	0.090
	36	Zouk2	88.819	160.071	0.1026	
	37	Zouk3	60.459	99.612	0.0692	
	38	Zouk4	43.317	56.295	0.0409	
Jieh	Decommissioned Unit					0.020
	Decommissioned Unit					
	39	Jieh3	9.56	46.735	0.0264	
	40	Jieh4	7.464	39.271	0.0206	
	41	Jieh5	6.628	32.643	0.0153	

6.3.3. Policy Implementation Summary – Energy Perspective

Table 6.3.18 provides a summary of the important energy figures and reliability indices obtained during the simulation of the policy implementation throughout the year's 2010-2015.

Table 6.3.18: Policy Implementation summary – Energy Perspective

Policy Implementation (Energy Data)						
Reliability Indices	Year					
	2010	2011	2012	2013	2014	2015
Peak Power (MW)	2622	2805	2971	3147	3402	3640
Maximum Generation (MW)	1651	1536	1999	2298	3103	3947
Energy Demanded (GW-hr)	16053	17173	18190	19267	20829	22286
EES (GW-hr)	14404	13820	16362	18279	20309	22253
EENS (GW-hr)	1649	3353	1828	988	520	32
LoLP	0.75694	0.96199	0.73148	0.37024	0.18526	0.01355
LoLE (hrs./year)	6631	8427	6408	3243	1623	119
EIR	0.89374	0.80111	0.89361	0.94579	0.98132	0.99933

A reliable power supply is achieved by the end of 2015 with 8% of peak load reserve. The EENS is 32 GW-hr which is a low figure relative to the demanded energy. The LoLP is 0.0135 corresponding to a LoLE of 119 hours/year which indicates a reliable service of the grid. The EIR is 0.9993 indicating a good supply of energy (EES) as compared to the demand.

Figure 6.3.7 and 6.3.8 shows the behavior of the Energy/Power demanded and the Energy/Power supplied throughout the years of the policy implementation. It can be seen that the energy supplied is converging to the energy demanded and the power supplied is above the power demanded with a reserve of approximately 8%.

Figure 6.3.9 and 6.3.10 shows the behavior of the EIR and the EENS throughout the years of the policy implementation. The EENS, by the end of 2015, is approximately 32 GW-hr and the EIR is converging to 1.00 with a value estimated to be 0.999.

Such figures and indices are indicators to the achievement of a reliable and economical electric sector. After policy simulation, it can be justified that the suggested plan enforced the available capacity to ensure a good and continuous supply of energy for the end user. Section 6.4 will discuss the financial and economic impacts of the policy.

Figure 6.3.7: The power demanded vs. power supplied 2010-2015 (policy implementation)

Figure 6.3.8: The Energy demanded Vs. Energy Supplied for 2010-2015 (policy implementation)

Figure 6.3.9: The EIR for 2010-2015 (policy implementation)

Figure 6.3.10: The EENS for 2010-2015 (policy implementation)

6.4. Policy Implementation: Financial Perspective

In this section the financial and economic aspects of the policy will be considered. Based on the simulation data obtained in section 6.3 production costing will be performed for each year. It will be justified throughout the years of the policy implementation, and after acquiring the fuel sourcing strategy (NG as the main fuel for thermal plants), a significant drop in the cost of each kW-hr produced is achieved.

Before the production costing is performed, the policy new investments and the new projects capital amortization are calculated and are added to the yearly expenses in the production costing.

In addition an economic analysis is also considered, where the positive impact of the policy implementation on the national economy is justified.

6.4.1. Initiatives Timeline

Tables 6.4.1, 6.4.2, 6.4.3 and 6.4.4 illustrate the financial/economic initiatives timeline corresponding to the three strategic areas. For each project/initiative, the cost and starting year for capital amortization (discussed in section 6.4.2) is specified.

Table 6.4.1: Generation Expansion financial timeline

Generation Expansion							
Year		2010	2011	2012	2013	2014	2015
Power Rental(Barges) (MM\$)							
Imports from Turkey(MM\$)							
New PP1 (Reciprocating Engines / CCGT) (MM\$)				\$500	\$312		
Rehabilitate Zouk& Jieh(MM\$)				\$45	\$45	\$45	\$45
Upgrade Deir Ammar & Zahrani(MM\$)			\$36	\$36	\$36		
Add Combined Cycle Unit to Tyre & Baalbeck(MM\$)			\$65	\$65			
New PP2 (IPP Modality) (MM\$)						\$750	\$750
New Hydro Power(MM\$)						\$100	\$100
Wind Power(MM\$)				\$95	\$60		
Waste to Energy(MM\$)					\$24	\$16	
Total	Total Investment	\$0.00	\$101	\$741	\$477	\$911	\$895
	Cumulative Investment	\$0.00	\$101	\$842	\$1,319	\$2,230	\$3,125

Table 6.4.2: Transmission and distribution financial timeline

Transmission & Distribution Rehabilitation							
Year		2010	2011	2012	2013	2014	2015
Completing the 220 kV loop at Mansourieh (MM\$)			\$1				
Complete the Infrastructure at Ksara Substation (MM\$)			\$12	\$13			
Completing LENCC (MM\$)			\$10	\$10			
Regional Substation / Transmission System (MM\$)			\$25	\$25	\$200		
Transmission System Expansion (MM\$)					\$100	\$100	\$200
Improve the Distribution (MM\$)			\$1				
Distribution Network Facilities / AMR / Billing (MM\$)				\$100	\$100	\$100	
Upgrade / Rehabilitate Distribution System (MM\$)				\$10	\$20	\$20	
Program Management (MM\$)					\$5	\$5	
Monitoring Center (MM\$)					\$10	\$20	
Distribution Management Center (MM\$)					\$10	\$15	
Total	Total Investment	\$0.00	\$49	\$158	\$445	\$260	\$200
	Cumulative Investment	\$0.00	\$49	\$207	\$652	\$912	\$1,112

Table 6.4.3: Supply and Demand financial timeline

Supply & Demand							
Year		2010	2011	2012	2013	2014	2015
LNG terminal (MM\$)			\$70	\$120	\$120		
Gas Pipeline (MM\$)			\$40	\$40	\$40		
LCEC / CFL / SWH / Public Lighting (MM\$)			\$7	\$8	\$5	\$5	
Total	Total Investment	\$0.00	\$117	\$168	\$165	\$5	\$0.00
	Cumulative Investment	\$0.00	\$117	\$285	\$450	\$455	\$455

Table 6.4.4: Legal framework timeline

Legal Framework							
Year		2010	2011	2012	2013	2014	2015
EDL Human Resources		\$5	\$10				
Corporatization Procedures			\$50	\$50	\$65		
Total	Total Investment	\$5	\$60	\$50	\$65	\$0.00	\$0.00
	Cumulative Investment	\$5	\$65	\$115	\$180	\$180	\$180

Table 6.4.5: Cumulative investment of the policy

Cumulative investment of the policy						
Year	2010	2011	2012	2013	2014	2015
Cumulative Investment (MM\$)	\$5	\$332	\$1,449	\$2,601	\$3,777	\$4,872

Figure 6.4.1: Cumulative investment of the policy

6.4.2. Policy Investment and New Project Capital Amortization

As every project has a limited life, the capital invested in it must be redeemed during the life time of the project. Capital amortization is best defined to be, the paying off of debt in regular installments over a period of time usually the project life time which is an estimated time. The simple annuity calculation for the capital amortization is given by the formula shown below.

$$A = P(A/P, i, N) = P \left[\frac{i(1+i)^N}{(1+i)^N - 1} \right] \quad (1.13)$$

Where i = interest rate (%)

N = project life time (years)

P = Cost of project (\$)

Using Microsoft Office Excel the above formula can be computed using the command $PMT(i, N, P)$ the output of this command is the yearly debt that must be paid throughout the project lifetime N .

The interest rate i depends on the source of the money or the financing party (bank loan, government, international loan...etc.), the table below shows the interest rates considered and dealt with in the context of this thesis. It can be noted that more than two parties can finance one project where the interest rate are combined in the appropriate manner.

Table 6.4.6: Financing parties interest rate

Financed By	Interest rate (%)
Government of Lebanon	5
Private Sector	15
International Loans	10

Capital amortization will be calculated based on the timeline presented above, and the values of debt will be shown only for the policy life time (year 2015). This issue is discussed in the below sections where each project is analyzed separately.

6.4.2.1. Generation Investments

Investments in the generation infrastructure are summarized in table 6.4.7. These data will be used to calculate the yearly debt over the given life time for each project. The following tables shows the capital amortization for each project over all phases of payments

Table 6.4.7: Generation Investment data

Project	Life time	Financed By	Percent Invest.	Interest Rate
New Power Plant (Reciprocating Engines / CCGT)	30	GoL	100%	5%
Rehabilitate Zouk& Jieh	10	Int'l Loan	100%	10%
Upgrade Deir Ammar & Zahrani	10	GoL	100%	5%
Add Combined Cycle Unit to Tyre & Baalbeck	10	GoL	100%	5%
New Power Plant (IPP Modality)	30	Private Sector	80%	15%
		Int'l Loan	20%	10%
New Hydro Power	30	Private Sector	80%	15%
		Int'l Loan	20%	10%
Wind Power	20	Private Sector	100%	15%
Waste to Energy	20	Private Sector	100%	15%

Table 6.4.8: New PP1 Project Capital Amortization

Project Capital Amortization			
Year	New Power Plant (Reciprocating Engines / CCGT)		Total Amortization
2010	\$0	\$0	\$0
2011	\$0	\$0	\$0
2012	\$32,525,718	\$0	\$32,525,718
2013	\$32,525,718	\$20,296,048	\$52,821,765
2014	\$32,525,718	\$20,296,048	\$52,821,765
2015	\$32,525,718	\$20,296,048	\$52,821,765

Table 6.4.9: Rehabilitation Project Capital Amortization

Project Capital Amortization					
Year	Rehabilitate Zouk & Jieh				Total Amortization
2010	\$0	\$0	\$0	\$0	\$0
2011	\$0	\$0	\$0	\$0	\$0
2012	\$7,323,543	\$0	\$0	\$0	\$7,323,543
2013	\$7,323,543	\$7,323,543	\$0	\$0	\$14,647,086
2014	\$7,323,543	\$7,323,543	\$7,323,543	\$0	\$21,970,628
2015	\$7,323,543	\$7,323,543	\$7,323,543	\$7,323,543	\$29,294,171

Table 6.4.10: Upgrade Project Capital Amortization

Project Capital Amortization				
Year	Upgrade Deir Ammar & Zahrani			Total Amortization
2010	\$0	\$0	\$0	\$0
2011	\$4,662,165	\$0	\$0	\$4,662,165
2012	\$4,662,165	\$4,662,165	\$0	\$9,324,329
2013	\$4,662,165	\$4,662,165	\$4,662,165	\$13,986,494
2014	\$4,662,165	\$4,662,165	\$4,662,165	\$13,986,494
2015	\$4,662,165	\$4,662,165	\$4,662,165	\$13,986,494

Table 6.4.11: Sour and BBK HRSG Project Capital Amortization

Year	Project Capital Amortization		
	Add Combined Cycle Unit to Tyre & Baalbeck		Total Amortization
2010	\$0	\$0	\$0
2011	\$8,417,797	\$0	\$8,417,797
2012	\$8,417,797	\$8,417,797	\$16,835,595
2013	\$8,417,797	\$8,417,797	\$16,835,595
2014	\$8,417,797	\$8,417,797	\$16,835,595
2015	\$8,417,797	\$8,417,797	\$16,835,595

Table 6.4.12: New PP2 Project Capital Amortization

Year	Project Capital Amortization		
	New Power Plant (IPP Modality)		Total Amortization
2010	\$0	\$0	\$0
2011	\$0	\$0	\$0
2012	\$0	\$0	\$0
2013	\$0	\$0	\$0
2014	\$107,292,006	\$0	\$107,292,006
2015	\$107,292,006	\$107,292,006	\$214,584,012

Table 6.4.13: Hydro Power Project Capital Amortization

Year	Project Capital Amortization		
	New Hydro Power		Total Amortization
2010	\$0	\$0	\$0
2011	\$0	\$0	\$0
2012	\$0	\$0	\$0
2013	\$0	\$0	\$0
2014	\$14,305,601	\$0	\$14,305,601
2015	\$14,305,601	\$14,305,601	\$28,611,202

Table 6.4.14: Wind Power Project Capital Amortization

Project Capital Amortization			
Year	Wind Power		Total Amortization
2010	\$0	\$0	\$0
2011	\$0	\$0	\$0
2012	\$15,177,340	\$0	\$15,177,340
2013	\$15,177,340	\$9,585,688	\$24,763,028
2014	\$15,177,340	\$9,585,688	\$24,763,028
2015	\$15,177,340	\$9,585,688	\$24,763,028

Table 6.4.15: Waste to energy Project Capital Amortization

Project Capital Amortization			
Year	Waste to Energy		Total Amortization
2010	\$0	\$0	\$0
2011	\$0	\$0	\$0
2012	\$0	\$0	\$0
2013	\$3,834,275	\$0	\$3,834,275
2014	\$3,834,275	\$2,556,184	\$6,390,459
2015	\$3,834,275	\$2,556,184	\$6,390,459

A summary of the generation infrastructure capital amortization is presented in table 6.4.16. It can be shown that by 2015 the capital amortized for all projects accumulates to be approximately \$ 387 million.

Table 6.4.16: Generation Infrastructure Total Amortizations

Generation Infrastructure Total Amortizations	
2010	\$0
2011	\$13,079,962
2012	\$81,186,524
2013	\$126,888,243
2014	\$258,365,576
2015	\$387,286,726

6.4.2.2. Transmission Investments

Investments in the Transmission infrastructure are summarized in table 6.4.17. These data will be used to calculate the yearly debt over the given life time for each project. The following tables shows the capital amortization for each project over all phases of payments

Table 6.4.17: Transmission Investment data

Project	Life time	Financed By	Percent Invest.	Interest Rate
Completing the 220 kV loop at Mansourieh	10	GoL	100%	5%
Complete the Infrastructure at Ksara Substation	20	Int'l Loan	100%	10%
Completing LENCC	20	Int'l Loan	100%	10%
Regional Substation/Transmission System	30	GoL	100%	5%
Transmission System Expansion	30	Int'l Loan	100%	10%

Table 6.4.18: 220 kV loop Project Capital Amortization

Year	Project Capital Amortization	
	Completing the 220 kV loop at Mansourieh	Total Amortization
2010	\$0	\$0
2011	\$129,505	\$129,505
2012	\$129,505	\$129,505
2013	\$129,505	\$129,505
2014	\$129,505	\$129,505
2015	\$129,505	\$129,505

Table 6.4.19: Ksara Substation Project Capital Amortization

Year	Project Capital Amortization		
	Complete the Infrastructure at Ksara Substation		Total Amortization
2010	\$0	\$0	\$0
2011	\$1,409,515	\$0	\$1,409,515
2012	\$1,409,515	\$1,526,975	\$2,936,491
2013	\$1,409,515	\$1,526,975	\$2,936,491
2014	\$1,409,515	\$1,526,975	\$2,936,491
2015	\$1,409,515	\$1,526,975	\$2,936,491

Table 6.4.20: LENCC Project Capital Amortization

Year	Project Capital Amortization		
	Completing LENCC		Total Amortization
2010	\$0	\$0	\$0
2011	\$1,174,596	\$0	\$1,174,596
2012	\$1,174,596	\$1,174,596	\$2,349,192
2013	\$1,174,596	\$1,174,596	\$2,349,192
2014	\$1,174,596	\$1,174,596	\$2,349,192
2015	\$1,174,596	\$1,174,596	\$2,349,192

Table 6.4.21: Regional Substation and transmission lines Projects Capital Amortization

Year	Project Capital Amortization			Total Amortization
	Regional Substation/Transmission System			
2010	\$0	\$0	\$0	\$0
2011	\$1,626,286	\$0	\$0	\$1,626,286
2012	\$1,626,286	\$1,626,286	\$0	\$3,252,572
2013	\$1,626,286	\$1,626,286	\$13,010,287	\$16,262,859
2014	\$1,626,286	\$1,626,286	\$13,010,287	\$16,262,859
2015	\$1,626,286	\$1,626,286	\$13,010,287	\$16,262,859

Table 6.4.22: Transmission expansion Project Capital Amortization

Year	Project Capital Amortization			Total Amortization
	Transmission System Expansion			
2010	\$0	\$0	\$0	\$0
2011	\$0	\$0	\$0	\$0
2012	\$0	\$0	\$0	\$0
2013	\$10,607,925	\$0	\$0	\$10,607,925
2014	\$10,607,925	\$10,607,925	\$0	\$21,215,850
2015	\$10,607,925	\$10,607,925	\$21,215,850	\$42,431,699

A summary of the Transmission infrastructure capital amortization is presented in table 6.4.23. It can be shown that by 2015 the capital amortized for all projects accumulates to be \$ 58.6 million.

Table 6.4.23: Transmission Infrastructure Total Amortizations

Transmission Infrastructure Total Amortizations	
2010	\$0
2011	\$1,626,286
2012	\$3,252,572
2013	\$26,870,784
2014	\$37,478,708
2015	\$58,694,558

6.4.2.3. Distribution Investments

Investments in the Distribution infrastructure are summarized in table 6.4.24. These data will be used to calculate the yearly debt over the given life time for each project. The following tables shows the capital amortization for each project over all phases of payments

Table 6.4.24: Distribution Investment data

Project	Life time	Financed By	Percent Invest.	Interest Rate
Bidding Process	0	GoL	100%	5%
Distribution Network Facilities / AMR / Billing	20	Private Sector	100%	15%
Upgrade / Rehabilitate Distribution System	10	Private Sector	100%	15%
Program Management	10	GoL	100%	5%
Monitoring Center	20	Private Sector	100%	15%
Distribution Management Center	20	Int'l Loan	100%	10%

Table 6.4.25: Distribution Improvement Project Capital Amortization

Project Capital Amortization		
Year	Improve the Distribution	Total Amortization
2010	\$ -	\$ -
2011	\$ 1,000,000.00	\$ 1,000,000.00
2012	\$ -	\$ -
2013	\$ -	\$ -
2014	\$ -	\$ -
2015	\$ -	\$ -

Table 6.4.26: Distribution Network facilities Project Capital Amortization

Project Capital Amortization				
Year	Distribution Network Facilities / AMR / Billing			Total Amortization
2010	\$ -	\$ -	\$ -	\$ -
2011	\$ -	\$ -	\$ -	\$ -
2012	\$ 15,976,147.04	\$ -	\$ -	\$ 15,976,147.04
2013	\$ 15,976,147.04	\$ 15,976,147.04	\$ -	\$ 31,952,294.08
2014	\$ 15,976,147.04	\$ 15,976,147.04	\$ 15,976,147.04	\$ 47,928,441.12
2015	\$ 15,976,147.04	\$ 15,976,147.04	\$ 15,976,147.04	\$ 47,928,441.12

Table 6.4.27: Rehabilitate of Distribution System Project Capital Amortization

Project Capital Amortization				
Year	Upgrade / Rehabilitate Distribution System			Total Amortization
2010	\$ -	\$ -	\$ -	\$ -
2011	\$ -	\$ -	\$ -	\$ -
2012	\$ 1,992,520.63	\$ -	\$ -	\$ 1,992,520.63
2013	\$ 1,992,520.63	\$ 3,985,041.25	\$ -	\$ 5,977,561.88
2014	\$ 1,992,520.63	\$ 3,985,041.25	\$ 3,985,041.25	\$ 9,962,603.13
2015	\$ 1,992,520.63	\$ 3,985,041.25	\$ 3,985,041.25	\$ 9,962,603.13

Table 6.4.28: Program management Project Capital Amortization

Project Capital Amortization				
Year	Program Management			Total Amortization
2010	\$ -	\$ -		\$ -
2011	\$ -	\$ -		\$ -
2012	\$ -	\$ -		\$ -
2013	\$ 647,522.87	\$ -		\$ 647,522.87
2014	\$ 647,522.87	\$ 647,522.87		\$ 1,295,045.75
2015	\$ 647,522.87	\$ 647,522.87		\$ 1,295,045.75

Table 6.4.29: Monitoring Centre Project Capital Amortization

Project Capital Amortization				
Year	Monitoring Center			Total Amortization
2010	\$ -	\$ -		\$ -
2011	\$ -	\$ -		\$ -
2012	\$ -	\$ -		\$ -
2013	\$ 1,597,614.70	\$ -		\$ 1,597,614.70
2014	\$ 1,597,614.70	\$ 3,195,229.41		\$ 4,792,844.11
2015	\$ 1,597,614.70	\$ 3,195,229.41		\$ 4,792,844.11

Table 6.4.30: DMS Project Capital Amortization

Project Capital Amortization				
Year	Distribution Management Center			Total Amortization
2010	\$ -	\$ -		\$ -
2011	\$ -	\$ -		\$ -
2012	\$ -	\$ -		\$ -
2013	\$ 1,174,596.25	\$ -		\$ 1,174,596.25
2014	\$ 1,174,596.25	\$ 1,761,894.37		\$ 2,936,490.62
2015	\$ 1,174,596.25	\$ 1,761,894.37		\$ 2,936,490.62

A summary of the Distribution infrastructure capital amortization is presented in table 6.4.31. It can be shown that by 2015 the capital amortized for all projects accumulates to be approximately \$ 66.9 million.

Table 6.4.31: Distribution Infrastructure Total Amortizations

Distribution Infrastructure Total Amortizations	
2010	\$0
2011	\$1,000,000
2012	\$17,968,668
2013	\$41,349,590
2014	\$66,915,425
2015	\$66,915,425

6.4.2.4. Supply and Demand Investments

Investments in the Supply and Demand strategic area are summarized in table 6.4.32. These data will be used to calculate the yearly debt over the given life time for each project. The following tables shows the capital amortization for each project over all phases of payments

Table 6.4.32: Supply & Investment data

Project	Life time	Financed By	Percent Invest.	Interest Rate
LNG terminal	20	GoL	10%	5%
		Private Sector	90%	15%
Gas Pipeline	30	GoL	10%	5%
		Private Sector	90%	15%
LCEC / CFL / SWH / Public Lighting	10	GoL	100%	5%

Table 6.4.33: LNG terminal Project Capital Amortization

Year	Project Capital Amortization			
	LNG terminal			Total Amortization
2010	\$ -	\$ -	\$ -	\$ -
2011	\$ 10,626,670.75	\$ -	\$ -	\$ 10,626,670.75
2012	\$ 10,626,670.75	\$ 18,217,149.85	\$ -	\$ 28,843,820.60
2013	\$ 10,626,670.75	\$ 18,217,149.85	\$ 18,217,149.85	\$ 47,060,970.45
2014	\$ 10,626,670.75	\$ 18,217,149.85	\$ 18,217,149.85	\$ 47,060,970.45
2015	\$ 10,626,670.75	\$ 18,217,149.85	\$ 18,217,149.85	\$ 47,060,970.45

Table 6.4.34: Gas Pipeline Project Capital Amortization

Year	Project Capital Amortization			
	Gas Pipeline			Total Amortization
2010	\$ -	\$ -	\$ -	\$ -
2011	\$ 5,743,012.88	\$ -	\$ -	\$ 5,743,012.88
2012	\$ 5,743,012.88	\$ 5,743,012.88	\$ -	\$ 11,486,025.75
2013	\$ 5,743,012.88	\$ 5,743,012.88	\$ 5,743,012.88	\$ 17,229,038.63
2014	\$ 5,743,012.88	\$ 5,743,012.88	\$ 5,743,012.88	\$ 17,229,038.63
2015	\$ 5,743,012.88	\$ 5,743,012.88	\$ 5,743,012.88	\$ 17,229,038.63

Table 6.4.35: LCEC Project Capital Amortization

Year	Project Capital Amortization				Total Amortization
	LCEC / CFL / SWH / Public Lighting				
2010	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
2011	\$906,532.02	\$0.00	\$0.00	\$0.00	\$906,532.02
2012	\$906,532.02	\$1,036,036.60	\$0.00	\$0.00	\$1,942,568.62
2013	\$906,532.02	\$1,036,036.60	\$647,522.87	\$0.00	\$2,590,091.50
2014	\$906,532.02	\$1,036,036.60	\$647,522.87	\$647,522.87	\$3,237,614.37
2015	\$906,532.02	\$1,036,036.60	\$647,522.87	\$647,522.87	\$3,237,614.37

A summary of the supply & demand capital amortization is presented in table 6.4.36. It can be shown that by 2015 the capital amortized for all projects accumulates to be approximately \$ 67.6 million.

Table 6.4.36: supply and demand Total Amortizations

Supply and Demand Total Amortizations	
2010	\$0
2011	\$17,276,216
2012	\$42,272,415
2013	\$66,880,101
2014	\$67,527,623
2015	\$67,527,623

6.4.2.5. Legal Framework Investments

Investments in the Legal Framework strategic area are summarized in table 6.4.37. These data will be used to calculate the yearly debt over the given life time for each project. The following tables shows the capital amortization for each project over all phases of payments

Table 6.4.37: Legal framework Investment data

Project	Life time	Financed By	Percent Invest.	Interest Rate
EDL Human Resources	5	GoL	100%	5%
Corporatization Procedures	10	GoL	100%	5%

Table 6.4.38: EDL HR Project Capital Amortization

Project Capital Amortization			
Year	EDL Human Resources		Total Amortization
2010	\$ 1,154,873.99	\$ -	\$ 1,154,873.99
2011	\$ 1,154,873.99	\$ 2,309,747.98	\$ 3,464,621.97
2012	\$ 1,154,873.99	\$ 2,309,747.98	\$ 3,464,621.97
2013	\$ 1,154,873.99	\$ 2,309,747.98	\$ 3,464,621.97
2014	\$ 1,154,873.99	\$ 2,309,747.98	\$ 3,464,621.97
2015	\$ -	\$ 2,309,747.98	\$ 2,309,747.98

Table 6.4.39: Corporatization Project Capital Amortization

Project Capital Amortization				
Year	Corporatization Procedures			Total Amortization
2010	\$ -	\$ -	\$ -	\$ -
2011	\$ 6,475,228.75	\$ -	\$ -	\$ 6,475,228.75
2012	\$ 6,475,228.75	\$ 6,475,228.75	\$ -	\$ 12,950,457.50
2013	\$ 6,475,228.75	\$ 6,475,228.75	\$ 8,417,797.37	\$ 21,368,254.87
2014	\$ 6,475,228.75	\$ 6,475,228.75	\$ 8,417,797.37	\$ 21,368,254.87
2015	\$ 6,475,228.75	\$ 6,475,228.75	\$ 8,417,797.37	\$ 21,368,254.87

A summary of the legal framework capital amortization is presented in table 6.4.40.

Table 6.4.40: Legal framework Total Amortizations

Legal Framework Total Amortizations	
2010	\$1,154,874
2011	\$9,939,851
2012	\$16,415,079
2013	\$24,832,877
2014	\$24,832,877
2015	\$23,678,003

6.4.2.6. Policy Investment Summary

Tables 6.4.41, 6.4.42 and 6.4.43 summarize the total investment financed by the different parties for the different infrastructure strategic area.

Table 6.4.41: Generation investment (divided by financing parties)

Infrastructure: Generation Investment Summary	
Financed By	Total (up to 2015)
GoL	\$1,050,000,000
Int'l Loan	\$520,000,000
Private Sector	\$1,555,000,000
Total Investment	\$3,125,000,000

Table 6.4.42: Transmission investment (divided by financing parties)

Infrastructure: Transmission Investment Summary	
Financed By	Total (up to 2015)
GoL	\$251,000,000
Int'l Loan	\$445,000,000
Private Sector	\$0
Total Investment	\$696,000,000

Table 6.4.43: Distribution investment (divided by financing parties)

Infrastructure: Distribution Investment Summary	
Financed By	Total (up to 2015)
GoL	\$11,000,000
Int'l Loan	\$25,000,000
Private Sector	\$380,000,000
Total Investment	\$416,000,000

Table 6.4.44 provides a summary of the infrastructure as a whole. It can be noted that the private sector has the biggest share of investment in this strategic area.

Table 6.4.44: total infrastructure investment (divided by financing parties)

Infrastructure Investment Summary	
Financed By	Total (up to 2015)
GoL	\$1,312,000,000
Int'l Loan	\$990,000,000
Private Sector	\$1,935,000,000
Total Investment	\$4,237,000,000

Table 6.4.45 provides a summary of the supply and demand investment in terms of the financing part. It can also be noted here that the private sector has the biggest share of investment in this strategic area.

Table 6.4.45: supply and demand investment (divided by financing parties)

Supply and Demand Investment Summary	
Financed By	Total (up to 2015)
GoL	\$68,000,000
Int'l Loan	\$0
Private Sector	\$387,000,000
Total Investment	\$455,000,000

Table 6.4.46 provides a summary of the legal framework investment in terms of the financing party. This strategic area is cumulatively financed by the GoL.

Table 6.4.46: legal framework investment (divided by financing parties)

Legal Framework Investment Summary	
Financed By	Total (up to 2015)
GoL	\$180,000,000
Int'l Loan	\$0
Private Sector	\$0
Total Investment	\$180,000,000

Tables 6.4.47 and 6.4.48 summarize total policy investment per strategic area and per financing party. It can be concluded that the most capital intensive strategic area is the infrastructure and the financing party with the biggest share is the private sector.

Table 6.4.47: Summary of Energy Program Budget per Strategic Areas

Summary of Energy Program Budget per Strategic Areas	
Strategic Area	Total Budget
Infrastructure	\$4,237,000,000.00
Demand/Supply	\$455,000,000.00
Legal Framework	\$180,000,000.00
Total Investment	\$4,872,000,000.00

Table 6.4.48: Summary of Energy Program Budget per Financing Party

Summary of Energy Program Budget per Financing Party	
Financed By	Total Budget
GoL	\$1,560,000,000.00
Int'l Loan	\$990,000,000.00
Private Sector	\$2,322,000,000.00
Total Investment	\$4,872,000,000.00

Table 6.4.49 shows the total calculated capital amortization for the entire projects of the policy, these amounts will be added to the utility expenses per year during the production costing.

Table 6.4.49: Over all capital amortization for all projects

Capital Amortization over policy period	
Year	Amount
2010	\$ 1,154,873.99
2011	\$ 45,635,930.63
2012	\$ 166,510,445.69
2013	\$ 292,236,781.35
2014	\$ 460,535,397.27
2015	\$ 609,517,522.67

6.4.3. Production Costing After Policy Implementation – Gradual Financial and Economic Improvement

Based on the simulation data obtained in section 6.3.2 production costing is performed on a yearly basis. The total production cost along with the losses/deficits of EdL and the total economic losses are calculated.

Table 6.4.50 shows other important factors corresponding to major initiatives in transmission and distribution that have a direct effect on the production costing. Such effect has to do with reduction of losses that is achieved throughout the years. Full implementation of the reforms at the transmission and the distribution level will reduce the total losses by 24% (given the total losses of the current situation are approximately 40%)

Table 6.4.51 summarizes all the financial figures necessary to financially evaluate the sector after the implementation of the policy. Starting year 2013 LNG will be available for Lebanon and thus will be a major fuel for thermal units. This action will reduce the cost of each kW-hr produced and therefore reduce the losses. On the other hand, due to the new capacity installed, the EENS reduces to reach 32 GW-hr by the end of 2014 and thus reducing the economic losses tremendously resulting from VoLL and self-generation.

It can be concluded that a gradual financial and economic improvement is set in the energy sector after the implementation of the suggested policy. At this level losses are not set to zero yet because the tariff is very low and needs to be fixed (section 6.5)..

Table 6.4.50: Transmission and distribution rehabilitation (reduction in losses)

Transmission & Distribution Rehabilitation (reduction in losses)							
Year		2010	2011	2012	2013	2014	2015
Completing the 220 kV loop at Mansourieh			1.0%				
Complete the Infrastructure at Ksara Substation			No decrease in the losses				
Completing LENCC			No decrease in the losses				
Regional Substation / Transmission System				0.5%	0.5%		
Transmission System Expansion					No decrease in the losses		
Improve the Distribution		0.5%	0.5%				
Distribution Network Facilities / AMR / Billing				3.5%	5.5%	6.0%	5.0%
Upgrade / Rehabilitate Distribution System					0.5%	0.5%	
Program Management				No decrease in the losses			
Monitoring Center				No decrease in the losses			
Distribution Management Center				No decrease in the losses			
Total	Technical Losses Improvement	0.0%	1.0%	0.5%	0.5%	0.0%	0.0%
	Non-Technical Losses Improvement	0.5%	0.5%	3.5%	6.0%	6.5%	5.0%
	Cumulative Network Losses Improvement	0.5%	2.0%	6.0%	12.5%	19.0%	24.0%

Table 6.4.51: Total losses/subsidies on the economy 2010-2015 after policy implementation

Total Losses & Subsidies on the Economy and the Government						
Item	2010	2011	2012	2013	2014	2015
Energy Demanded (GW-hr)	16053	17173	18189.796	19267.347	20828.571	22285.714
EES (GW-hr)	14404.16	13820.38	16361.79	18279.40	20422.67	22253.36
EENS (GW-hr)	1648.85	3352.62	1828.01	987.95	405.90	32.36
Total Production Cost (MM\$)	\$2,013.9	\$1,964.3	\$2,326.69	\$1,656.73	\$1,696.8	\$1,634.2
Technical Losses (GW-hr)	2160.62	1934.85	2208.84	2376.32	2654.95	2892.94
Non-Technical Losses (GW-hr)	2387.49	2258.25	2193.71	1510.79	533.03	580.81
Energy Available for Sale (GW-hr)	12243.53	11885.53	14152.95	15903.08	17767.72	19360.42
Energy Billed (GW-hr)	9856.04	9627.28	11959.24	14392.28	17234.69	18779.61
Not collected Billed Energy(GW-hr)	492.80	481.36	597.96	719.61	861.73	0.00
Collected Billed Energy (GW-hr)	9363.24	9145.92	11361.28	13672.67	16372.96	18779.61
Total Gained Revenues (MM\$)	\$896.9	\$876.17	\$1,088.41	\$1,309.8	\$1,568.5	\$1,799.08
Losses (MM\$)	\$1,116.9	\$1,088.1	\$1,238.28	\$346.8	\$128.3	-\$164.81
Old Capital Amortization (MM\$)	\$381.3	\$381.35	\$381.35	\$381.3	\$381.3	\$381.354
New Policy Project capital (MM\$)	\$1.1	\$45.63	\$166.51	\$292.2	\$460.5	\$609.517
Total Capital Amortization (MM\$)	\$382.5	\$426.99	\$547.86	\$673.5	\$841.8	\$990.871
Deficit/Subsidies (MM\$)	\$1,499.4	\$1,515.17	\$1,786.15	\$1,020.4	\$970.1	\$826.054
Cost of Private Generation (MM\$)	\$612.5	\$1,245.416	\$679.061	\$366.9	\$150.7	\$12.019
Economic Cost VOLL (MM\$)	\$538.5	\$1,094.96	\$597.02	\$322.6	\$132.5	\$10.5
Total Economic Losses (MM\$)	\$1,151.019	\$2,340.38	\$1,276.08	\$689.6	\$283.3	\$22.5
Grand Total Losses/Subsidies(MM\$)	\$2,650.4	\$3,855.55	\$3,062.2	\$1,710.1	\$1,253.5	\$848.64

The energy produced escalates, due to new capacity installment, from approximately 14.5 TW-hr in year 2010 to reach more than 22 TW-hr thus satisfying the needed demand and establishing a reliable 24/24 energy supply. Figure 6.4.2 compares the energy available for sale, the billed energy and the collected energy from year 2010 till 2015. A reduction in the losses is viewed by the end of 2015 after the full implementation the pie chart shown in figure 58 compares the billed energy with other losses.

Figure 6.4.2: Illustration of losses after policy implementation

The total financial burden, including direct EdL losses and economic losses due to VoLL and self-generation are best illustrated using the stacked bar chart shown in figure 6.4.4. The figure shows that by the end of 2015 economic losses vanishes but the deficits account up to \$ 8.4 million. These losses are the major results of a bad tariff structure and the capital amortization of new projects that are not accounted in the tariff.

Figures 6.4.5 and 6.4.6 illustrates the reduction of the economic losses and the total losses after the implementation of the policy.

Figure 6.4.3: losses illustration after the policy implementation using a pie chart

Figure 6.4.4: financial burden after policy implementation

Figure 6.4.5: total economic losses after policy implementation

Figure 6.4.6: grand total losses/deficits after policy implementation

6.5. Tariff Restructure

The tariff needs to be restructured in order to eliminate the remaining financial burden. In the context of this thesis the restructure will be a gradual increase in the average existing tariff to eliminate the financial deficit in the electricity sector and establish a balanced budget for the operating utility EdL, on one hand; and reduce any other financial burden on the end user which is mainly caused by the cost of self-generation on the other hand.

6.5.1. Balancing Financial Impact

As a first step the average tariff will gradually increase starting year 2012, that is whenever the end user starts to feel the improvement in energy supply, until year 2015. In order to achieve a break even scenario the average tariff must be increased by at least 46% as shown in table 6.5.1. The restructure process starts by an increase in year 2012 by 5% followed 8% in year 2013 and 12% in year 2014 and finally by 14.89% in the last year so that the financial impact is balanced. By doing so the final average tariff will be 14 cents billed for each kW-hr produced. Table 6.5.1 illustrates the financial figures impacted by the increase of the tariff.

Table 6.5.1: Tariff Correction to achieve a balanced financial impact

Item	Year					
	2010	2011	2012	2013	2014	2015
% Average of Tariff Increase	0%	0%	5%	8.00%	12.00%	14.89%
Increase of Tariff from 2010	45.9152%					
New Average Tariff in \$/kW-hr	\$0.10	\$0.10	\$0.10	\$0.11	\$0.12	\$0.14
Total Gained Revenues (MM\$)	\$896.9	\$876.1	\$1,142.8	\$1,485.3	\$1,992.1	\$2,625.1
Losses (MM\$)	\$1,116.9	\$1,088.1	\$1,183.8	\$171.3	-\$295.3	-\$990.8
Old Capital Amortization (MM\$)	\$381.3	\$381.3	\$381.3	\$381.3	\$381.3	\$381.3
New Policy Project capital (MM\$)	\$1,154.8	\$45.6	\$166.5	\$292.2	\$460.5	\$609.5
Total Capital Amortization (MM\$)	\$382.5	\$426.9	\$547.8	\$673.5	\$841.8	\$990.8
Deficit/Subsidies (MM\$)	\$1,499.4	\$1,515.1	\$1,731.7	\$844.96	\$546.5	\$0.00
Cost of Private Generation (MM\$)	\$612.5	\$1,245.4	\$679.06	\$366.99	\$150.7	\$12.01
Economic Cost VOLL (MM\$)	\$538.5	\$1,094.9	\$597.027	\$322.66	\$132.5	\$10.5
Total Economic Losses (MM\$)	\$1,151.01	\$2,340.3	\$1,276.08	\$689.66	\$283.3	\$22.5
Grand Total Losses/Subsidies (MM\$)	\$2,650.4	\$3,855.5	\$3,007.8	\$1,534.62	\$829.9	\$22.5

Figure 6.5.1 illustrates graphically the reduction in financial losses while increasing the tariff.

Figure 6.5.1: Tariff increase – Balancing the financial impact

6.5.2. Profitable Financial Impact

The same procedures described in section 6.5.1 are followed also here, but this time to achieve a profitable financial impact. A total profit of \$ 192 million can be achieved if the total average tariff is increased by 56.8%. Table 6.5.2 illustrates the increase in average tariff to achieve a profitable scenario.

Table 6.5.2: Tariff Correction to achieve a profitable financial impact

Item	Year					
	2010	2011	2012	2013	2014	2015
% Average of Tariff Increase	0%	0%	7%	10%	14%	17%
Increase of Tariff from 2010	56.8362%					
New Average Tariff in \$/kW-hr	\$0.10	\$0.10	\$0.10	\$0.11	\$0.13	\$0.15
Total Gained Revenues (MM\$)	\$896.9	\$876.1	\$1,164.59	\$1,541.6	\$2,104.62	\$2,821.61
Losses (MM\$)	\$1,116.9	\$1,088.1	\$1,162.1	\$115.05	-\$407.79	-\$1,187.34
Old Capital Amortization (MM\$)	\$381.3	\$381.3	\$381.35	\$381.35	\$381.35	\$381.35
New Policy Project capital (MM\$)	\$1,154.8	\$45.6	\$166.5	\$292.23	\$460.53	\$609.51
Total Capital Amortization (MM\$)	\$382.5	\$426.9	\$547.86	\$673.59	\$841.88	\$990.87
Deficit/Subsidies (MM\$)	\$1,499.4	\$1,515.1	\$1,709.96	\$788.64	\$434.099	-\$196.477
Cost of Private Generation (MM\$)	\$612.5	\$1,245.4	\$679.06	\$366.99	\$150.78	\$12.019
Economic Cost VOLL (MM\$)	\$538.5	\$1,094.9	\$597.02	\$322.66	\$132.56	\$10.567
Total Economic Losses (MM\$)	\$1,151.01	\$2,340.3	\$1,276.08	\$689.66	\$283.35	\$22.58
Grand Total Losses/Subsidies (MM\$)	\$2,650.4	\$3,855.5	\$2,986.05	\$1,478.305	\$717.45	-\$173.88

Figure 6.5.2 is a graphical illustration of the profitable scenario.

Figure 6.5.2: Tariff Increase - Profitable Financial impact

6.6. Levelized Cost of Generation after Policy Implementation

The Levelized cost of generation (operation cost in \$/kW-hr) for all plants is calculated from year 2010 till 2015 after the implementation of the policy. It must be noted that in the case of policy implementation the issue of Capex must be taken into account.

Two scenarios are considered in the Levelized Cost calculation, the first neglecting the capital expenditure and the second will consider the amount of capital expenditure. In this case the Levelized cost is best illustrated using the following formula:

$$\underline{\underline{LC(\$ / MWh) = Fuel\ Cost(\$ / MWh) + O \& M(\$ / MWh) + Capex(\$ / MWh)}} \quad (1.14)$$

The Levelized Cost specify the cost for producing each kW-hr in thermal units, this calculated figure is then compared with the tariff in order to decide whether the cost of production is above or below the value of the tariff, and can even compared with other Levelized Cost corresponding to different generating units.

Figure 6.6.2 till figure 6.6.9 illustrates the Levelized Cost for thermal units, with capex and without, for the years of policy implementation and is compared with the tariff.

The figure below compares the total cost of production during the policy implementation compared to the average tariff. Upon the arrival of LNG in year 2013, the sector abandons the operation on fuel oil and switches to NG. Therefore a drop in total cost of production can be seen accompanied with the increase in the average tariff to abolish the deficits.

Figure 6.6.1: Total production Costing compared to the tariff

Figures 6.6.10 and 6.6.11 compare the Levelized Cost for each thermal unit with the tariff using one figure and considering the two scenarios, with Capex and without Capex.

Figure 6.6.12 is a chart that summarizes the whole policy in terms of the cost of operation for each unit.

Figure 6.6.2: Zaharani Levelized Cost after policy implementation

Figure 6.6.3: Deir Ammar Levelized Cost after policy implementation

Figure 6.6.4: Sour Levelized Cost after policy implementation

Figure 6.6.5: Baalbeck Levelized Cost after policy implementation

Figure 6.6.6: Jieh Levelized Cost after policy implementation

Figure 6.6.7: Zouk Levelized Cost after policy implementation

Figure 6.6.8: New PP1 Levelized Cost after policy implementation

Figure 6.6.9: New PP2 Levelized Cost after policy implementation

Figure 6.6.10: LC for all thermal units compared to the tariff with no capex – policy implementation

Figure 6.6.11: LC for all thermal units compared to the tariff with capex – policy implementation

Figure 6.6.12: LC (with and w/o capex) compared to the tariff with policy implementation

7. Sensitivity Analysis

The suggested policy in Chapter 6 was justified to rescue the LEPS from the technical deterioration and the financial burden. There is a great concern that some of the suggested investments are delayed or omitted.

In this section a sensitivity analysis is performed, that is a benefit/loss analysis is conducted for selected projects within the policy. Such an analysis will reconsider the policy with and without the availability of the selected project. The benefit/loss analysis is performed on the technical and financial level. Obtained results will indicate how sensitive the performance of the entire sector to a project in the policy. The sensitivity analysis will consider projects of different level of importance.

The performed sensitivity analysis will give an answer to a universal question that might be asked, “What will happen if one of the projects in the policy is not implemented?”

7.1. Scenario 1: Full Policy Implementation with No Rental Power (barges)

The first case Scenario takes into account full policy implementation without the use of Rental Power. A benefit/loss analysis is conducted, that is the policy will be re-simulated without the capacity of the barges and will be compared to the base case (full policy implementation).

Figure 7.1.1 shows that if rental power is not adopted in the first four years, there will be an increase in the EENS in years 2010, 2011, 2012 and 2013. Such an increase in EENS will lead to a higher economic losses accounted in the addition of \$ 1.6 billion by year 2011 as shown in figure 7.1.2. The only benefit of not adopting the rental power is that the total losses/subsidies are reduced by at most \$ 215 million by year 2011, this is true since the price of each kW-hr produced by the rental power is approximately 15 cents/kW-hr which above the average tariff, on the other hand a portion of the energy produced from rental units are not billed and are lost.

Figure 7.1.1: net benefit/loss in EENS for the case of no rental power

Figure 7.1.2: financial net benefit/loss for the case of no rental power

A general conclusion for this scenario is that the adoption of rental power is a correct decision, since it reduces the EENS by at least 2000 GW-hr in the years of their availability thus reducing the total economic losses by at least \$ 1 billion, and on the other hand will substitute for the offline rehabilitation units.

Rental power is not considered a critical or a strategic project since it is a temporary power used as an emergency stop gap for three or four years until new capacity is being installed. And such project has no effect at all on the long run and will not affect the reliability indices obtained in year 2015.

7.2. Scenario 2: Full Policy Implementation with No LNG

Another scenario takes a strategic project into account, which is the availability of LNG to Lebanon. It is important to note that LNG is the backbone of the fuel sourcing strategy adopted in the suggested policy, and upon the unavailability of LNG, the current electric sector will continue to use expensive fuel oil for operation at low efficiency. Therefore the cost of each kW-hr produced is further increased and is controlled by future oil prices.

Figure 7.2.1: net benefit/loss in EENS for the case of no LNG

At the technical level, if LNG is not available the thermal units will operate at either HFO or diesel at very high prices and very low efficiencies thus reducing the total EES and increasing the EENS as shown in figure 7.2.1.

The catastrophic impact of such scenario lies in the total cost of production. Figure 7.2.2 illustrates the financial losses, it can be seen that an added loss of more than \$ 1 billion is accounted in year 2014. The availability of LNG is important for low cost of production.

Figure 7.2.2: financial net benefit/loss for the case of no LNG

7.3. Scenario 3: Full Policy Implementation with No Rehabilitation of Zouk and Jieh

Rehabilitation of two existing old plants, Zouk & Jieh, is a difficult decision. These two plants are old enough that they need to be decommissioned as soon as possible. The rehabilitation process needs to improve the efficiency as well as prolong the lifetime of the plants. It can be seen that such project is not

economically justified. In Jieh for example the cost of each kW-hr produced including the capex is 77 cents after rehabilitation which is a huge cost and is way above the tariff (see figure 6.6.12).

The loss/benefit analysis of the rehabilitation process is varying, in the short term (2010-2013) the rehabilitation process considers shutting down the units for the rehabilitation process to take place, therefore capacity is lost. But on the medium term (2014-2015) units come back in sequence with more capacity better efficiency and longer life but still operate at high cost.

Figure 7.3.1 shows the net benefit loss of the unavailability of the rehabilitation project in terms of the EENS when compared to full policy implementation. The figure shows that at the short term EENS is reduce by at least 400 GW-hr since the units is not off for rehabilitation. On the long run the EENS is more compared to the full policy implementation, since in the rehabilitation process two units of Jieh are decommissioned and capacity is reduced.

Figure 7.3.1: net benefit/loss in EENS for the case of no Zouk & Jieh rehabilitation

In terms of deficits the availability and unavailability of the rehabilitation project has no big effect. Economically speaking, at the sort term the economic losses are reduce by at least \$ 500 million so the

EENS is reduced. In the medium term the case is opposite, the EENS will increase and thus increasing the economic losses.

Figure 7.3.2 illustrates the financial benefit/loss analysis in the case of no rehabilitation of Zouk and Jieh when compared to the full policy implementation.

Figure 7.3.2: Financial net benefit/loss for the case of no Zouk & Jieh rehabilitation

8. Thesis Summary and Conclusion

This research work utilizes the state of the art of reliability worth assessment to assess the adequacy of an existing generating capacity. The concept of Load Modification Technique along with the extended concept of reliability evaluation in energy limited generating capacity is employed to develop an energy model which is the operating engine of this thesis. The energy model is a reliability based model used to assess the existing generating capacity and perform production costing to financially evaluate the electric sector.

The basis of this thesis is extended from the devolving fact of the LEPS and the decision to develop a strategic plan that is based mainly on a generation expansion program. This strategic plan is a comprehensive policy tackling all the operating levels in the electric sector, from technical to financial and even administrative.

This thesis starts by introducing the concept and the evaluation techniques of power system reliability which is the basic concept that will be used throughout the research work on the LEPS. Followed, is a brief description of the current situation of the LEPS describing mainly the deteriorated generating capacity that falls way behind the demand, and the financial burden imposed by the high operating cost and the large EENS. In the same context, such situation talks about itself in demanding an immediate strategic plan to rescue the LEPS before it reach to the point of catastrophic failure.

Chapter 2 of this thesis addresses the technique of LMT and the concept of reliability evaluation in energy limited generating capacity. The capacity modification concept is illustrated using a simple numerical example, where it is extended to illustrate the concept of energy limitation which is sometimes referred to as the peak shaving technique. Energy limitation will be considered an important technique since most of the generating capacities in the LEPS will be dealt with as energy limited units. This approach is also further illustrated using the RBTS as a full system example.

A new approach was developed in this thesis which is the Off-Peak capacity modification, in the hereby context, the off peak capacity modification assumes that a generating unit is fully available with no limitation in only one season which is away from the peaking season. Such an approach is used to resemble the power imported throughout regional interconnection, since such countries will suffer from power shortages during the peaking season and is not capable of exporting power.

Chapter 3 illustrates the procedures of building a Load Duration Curve. It starts by explaining the concept of the LDC and how it is used as a load model that model the demanded power at different slots of time. In the same Chapter the RBTS load model is explained which will be tuned around to be a suggested load model for the LEPS. This is done because there is a difficulty in obtaining a load profile for the LEPS due to lots of load shedding and other self and private generation. The tuning procedure was based on editing the existing RBTS load model such that it achieves the energy demanded (area under the LDC) by the LEPS and the appropriate Load Factor.

Chapter 4 of this thesis is a first step in the evaluation technique before a strategic plan is suggested. This Chapter opens by giving a background data about the LEPS and its current deteriorating situation. Since the type of fuel is the master controller of the financial deficit of the LEPS, Chapter 4 briefly address the types of fuel being used in Lebanon for thermal generation, their prices, future expected prices, and how they are linked to the international price of the CO barrel. Furthermore this Chapter describes the technical details of the existing generating infrastructure which is then used in the adequacy reliability evaluation of this capacity. Assuming the available data corresponds to year 2009, which is held as a base case, the existing generating capacity is simulated to obtain the reliability and other risk indices that illustrates the deteriorating fact of the LEPS.

Evolving from the obtained data of the simulation performed using the energy model production costing is performed to obtain the appropriate financial figures that illustrate the huge financial and economic burden of the existing system. Production costing is then addressed in details where the Levelized cost is calculated for all units and is compared to the existing average tariff to recognize that all available generating units (except hydro) are operating at a cost way above the average tariff.

Chapter 5 holds the discussed base case in the previous Chapter and performs a forecast for the future years up to 2015. Such forecast assumes that the year 2009 is a base case and for each year in the future system technically deteriorate, the fuel prices increase and no investment is performed. In such procedure each year is simulated separately where the obtained reliability and financial figures are worse than the previous year. By 2015 a catastrophic situation is reached maybe to the point of total failure.

Chapter 6 is the core concept of this research. The Chapter accelerates from the deteriorating condition of the LEPS and suggests a comprehensive policy for the management, development and radical rehabilitation of the LEPS. The Chapter opens by giving an executive summary of the policy, briefly

describing the three strategic areas and the 10 major initiatives of the policy. The policy is then organized in the appropriate technical and financial time line for the ease of implementation and simulation.

Based on the technical initiatives and the new capacity additions suggested by the policy, each year will be treated exclusively and simulated independent of the previous year. Towards the end of 2015 (end of policy implementation) a reliable system is achieved with the appropriate reliability figures obtained that describes the tremendous improvement achieved after the policy implementation and in particular the generation expansion.

Before performing production costing, the new investments in the sector at all the three strategic levels are discussed and the capital amortization resulting from the new investments are calculated and are aggregated at the end to develop a cash flow summarizing the total investments resulting from the implementation of the policy which will be added to the expenses of EDL. Based on the energy data obtained from the policy simulation, production costing is performed where a gradual financial and economical improvements is justified. Towards the end of the policy life deficits decrease and economic losses vanishes (very low EENS). Production costing is then addressed in details where the Levelized cost is calculated for all units and is compared to the existing average tariff to recognize that after year 2013 most of the available generating units are operating at a cost below the average tariff.

In order to totally eliminate the deficits and operate a profitable utility, the structure and the average value of the tariff must be reconsidered. In this research work the existing average tariff is restructured in two ways, the first is a breakeven case which will achieve balanced financial impact, and the second is a profitable case which will achieve a profitable financial impact.

Chapter 7 performs a sensitivity analysis on the suggested policy. Such an analysis considers three different projects in the policy at different level of importance. Sensitivity to the policy considers the unavailability of the project. In other words a project is selected and removed from the policy, the whole policy will be re-simulated with the new editing's and compared to the full policy implementation scenario in the context of loss/benefit analysis. Such analysis address the technical and financial loss/benefit of the project removed.

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A. Annex 1: RBTS Simulation Results

RBTS Simulation Results

The modified LDC after the addition of unit 1 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 993830.15 MW-hr. The EENS after the addition of Unit # 1 is 651378.95 MW-hr. The EES of Unit # 1 is 342451.20 MW-hr.

Figure A.1: Modified RBTS load model after the addition of unit #1

The modified LDC after the addition of unit 2 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 651378.95 MW-hr. The EENS after the addition of Unit # 1 is 479279.75 MW-hr. The EES of Unit # 1 is 172099.20 MW-hr.

Figure A.2: Modified RBTS load model after the addition of unit #2

The modified LDC after the addition of unit 3 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 479279.75 MW-hr. The EENS after the addition of Unit # 1 is 311300.25 MW-hr. The EES of Unit # 1 is 167979.50 MW-hr.

Figure A.3: Modified RBTS load model after the addition of unit #3

The modified LDC after the addition of unit 4 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 311300.25 MW-hr. The EENS after the addition of Unit # 1 is 174391.59 MW-hr. The EES of Unit # 1 is 136908.66 MW-hr.

Figure A.4: Modified RBTS load model after the addition of unit #4

The modified LDC after the addition of unit 5 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 174391.59 MW-hr. The EENS after the addition of Unit # 1 is 79829.95 MW-hr. The EES of Unit # 1 is 94561.64 MW-hr.

Figure A.5: Modified RBTS load model after the addition of unit #5

The modified LDC after the addition of unit 6 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 79829.95 MW-hr. The EENS after the addition of Unit # 1 is 62668.96 MW-hr. The EES of Unit # 1 is 17160.99 MW-hr.

Figure A.6: Modified RBTS load model after the addition of unit #6

The modified LDC after the addition of unit 7 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 62668.96 MW-hr. The EENS after the addition of Unit # 1 is 48197.70 MW-hr. The EES of Unit # 1 is 14471.26 MW-hr.

Figure A.7: Modified RBTS load model after the addition of unit #7

The modified LDC after the addition of unit 8 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 48197.70 MW-hr. The EENS after the addition of Unit # 1 is 3035.05 MW-hr. The EES of Unit # 1 is 45162.65 MW-hr.

Figure A.8: Modified RBTS load model after the addition of unit #8

The modified LDC after the addition of unit 9 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 3035.05 MW-hr. The EENS after the addition of Unit # 1 is 153.60 MW-hr. The EES of Unit # 1 is 2881.45 MW-hr.

Figure A.9: Modified RBTS load model after the addition of unit #9

The modified LDC after the addition of unit 10 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 153.60 MW-hr. The EENS after the addition of Unit # 1 is 26.58 MW-hr. The EES of Unit # 1 is 127.03 MW-hr.

Figure A.10: Modified RBTS load model after the addition of unit #10

The modified LDC after the addition of unit 11 is shown in the figure below. The modified LDC will be treated as the equivalent LDC for the remaining units. The EENS before adding Unit # 1 is 26.58 MW-hr. The EENS after the addition of Unit # 1 is 9.48 MW-hr. The EES of Unit # 1 is 17.10 MW-hr.

Figure A.11: Modified RBTS load model after the addition of unit #11

The figure below shows the LDC after the addition of the generating model of the RBTS system.

Figure A.12: Equivalent LDC after the addition of all units

B. Annex 2: Simulation Results for the Current Situation of the LEPS

Zouk-1 (Energy Limited Unit)

Table B.1: LMT Data for Zouk-1 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Zouk-1	Energy Limited with Limited Storage	Capacity & Energy Modification	20	100	4

Table B.2: Energy Distribution for Zouk-1 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
510	1
535	0.3

Figure B.1: Equivalent LDC after adding Zouk 1

EES: 515.201 GW-hr

Duty Cycle: 0.7352

Zouk-2 (Energy Limited Unit)

Table B.3: LMT Data for Zouk-2 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Zouk-2	Energy Limited with Limited Storage	Capacity & Energy Modification	20	100	5

Table B.4: Energy Distribution for Zouk-2 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
510	1
535	0.3

Figure B.2: Equivalent LDC after adding Zouk 2

EES: 519.866 GW-hr

Duty Cycle: 0.7418

Zouk-3 (Energy Limited Unit)

Table B.5: LMT Data for Zouk-3 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Zouk-3	Energy Limited with Limited Storage	Capacity & Energy Modification	20	100	6

Table B.6: Energy Distribution for Zouk-3 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
510	1
535	0.3

Figure B.3: Equivalent LDC after adding Zouk 3

EES: 515.22 GW-hr

Duty Cycle: 0.7356

Zouk-4 (Energy Limited Unit)

Table B.7: LMT Data for Zouk-4 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Zouk-4	Energy Limited with Limited Storage	Capacity & Energy Modification	20	120	7

Table B.8: Energy Distribution for Zouk-4 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
545	1
565	0.3

Figure B.4: Equivalent LDC after adding Zouk 4

EES: 547.22 GW-hr

Duty Cycle: 0.6507

Jieh-1 (Unlimited Energy Unit)

Table B.9: LMT Data for Jieh-1 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Jieh-1	Unlimited Energy	Capacity Modification	35	25	8

Figure B.5: Equivalent LDC after adding Jieh 1

EES: 142.35 GW-hr

Duty Cycle: 1.00

Jieh-2 (Unlimited Energy Unit)

Table B.10: LMT Data for Jieh-2 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Jieh-2	Unlimited Energy	Capacity Modification	35	25	9

Figure B.6: Equivalent LDC after adding Jieh 2

EES: 142.35 GW-hr

Duty Cycle: 1.00

Jieh-3 (Unlimited Energy Unit)

Table B.11: LMT Data for Jieh-3 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Jieh-3	Unlimited Energy	Capacity Modification	35	50	10

Figure B.7: Equivalent LDC after adding Jieh 3

EES: 284.7 GW-hr

Duty Cycle: 1.00

Jieh-4 (Unlimited Energy Unit)

Table B.12: LMT Data for Jieh-4 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Jieh-4	Unlimited Energy	Capacity Modification	35	50	11

Figure B.8: Equivalent LDC after adding Jieh 4

EES: 284.7 GW-hr

Duty Cycle: 1.00

Jieh-5 (Unlimited Energy Unit)

Table B.13: LMT Data for Jieh-5 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Jieh-5	Unlimited Energy	Capacity Modification	35	61	12

Figure B.9: Equivalent LDC after adding Jieh 5

EES: 347.344 GW-hr

Duty Cycle: 1.00

DieAm-1 (Unlimited Energy Unit)

Table B.14: LMT Data for DieAm-1 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
DieAm-1	Unlimited Energy	Capacity Modification	18	120	13

Figure B.10: Equivalent LDC after adding DieAm 1

EES: 914.544 GW-hr

Duty Cycle: 1.00

DieAm-2 (Unlimited Energy Unit)

Table B.15: LMT Data for DieAm-2 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
DieAm-2	Unlimited Energy	Capacity Modification	18	120	14

Figure B.11: Equivalent LDC after adding DieAm 2

EES: 914.544 GW-hr

Duty Cycle: 1.00

DieAm-3 (Unlimited Energy Unit)

Table B.16: LMT Data for DieAm-3 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
DieAm-3	Unlimited Energy	Capacity Modification	18	120	15

Figure B.12: Equivalent LDC after adding DieAm 3 (HRSG)

EES: 914.544 GW-hr

Duty Cycle: 1.00

Zahra-1 (Unlimited Energy Unit)

Table B.17: LMT Data for Zahra-1 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Zahra-1	Unlimited Energy	Capacity Modification	18	120	16

Figure B.13: Equivalent LDC after adding Zahra 1

EES: 914.544 GW-hr

Duty Cycle: 1.00

Zahra-2 (Unlimited Energy Unit)

Table B.18: LMT Data for Zahra-2 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Zahra-2	Unlimited Energy	Capacity Modification	18	120	17

Figure B.14: Equivalent LDC after adding Zahra 2

EES: 914.544 GW-hr

Duty Cycle: 1.00

Zahra-3 (Unlimited Energy Unit)

Table B.19: LMT Data for Zahra-3 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Zahra-3	Unlimited Energy	Capacity Modification	18	120	18

Figure B.15: Equivalent LDC after adding Zahra 3 (HRSG)

EES: 912.549 GW-hr

Duty Cycle: 0.9978

Sour-1 (Energy Limited Unit)

Table B.20: LMT Data for Sour-1 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Sour-1	Energy Limited with Limited Storage	Capacity & Energy Modification	10	35	19

Table B.21: Energy Distribution for Sour-1 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
150	1
155	0.3

Figure B.16: Equivalent LDC after adding Sour 1

EES: 151.503 GW-hr

Duty Cycle: 0.5490

Sour-2 (Energy Limited Unit)

Table B.22: LMT Data for Sour-2 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
Sour-2	Energy Limited with Limited Storage	Capacity & Energy Modification	10	35	20

Table B.23: Energy Distribution for Sour-2 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
150	1
155	0.3

Figure B.17: Equivalent LDC after adding Sour 2

EES: 151.543 GW-hr

Duty Cycle: 0.5492

BBK-1 (Energy Limited Unit)

Table B.24: LMT Data for BBK-1 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
BBK-1	Energy Limited with Limited Storage	Capacity & Energy Modification	10	35	21

Table B.25: Energy Distribution for BBK-1 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
150	1
155	0.3

Figure B.18: Equivalent LDC after adding BBK1

EES: 151.497 GW-hr

Duty Cycle: 0.549

BBK-2 (Energy Limited Unit)

Table B.26: LMT Data for BBK-2 PP

Power Plant	Category	Type of LMT	FOR (%)	Capacity (MW)	Priority
BBK-2	Energy Limited with Limited Storage	Capacity & Energy Modification	10	35	22

Table B.27: Energy Distribution for BBK-2 PP

Energy Distribution for all Hydro Units	
Energy Available (GW-hr)	Cumulative Probability
150	1
155	0.3

Figure B.19: Equivalent LDC after adding BBK2

EES: 151.488 GW-hr

Duty Cycle: 0.549

C. Annex 3: 2010– 2015 Technical Data (No Action Taken)

Year 2010

The LMT data for all units are summarized in the tables below. Following the tables, the equivalent LDC figures for each unit are presented.

Table C.1: Hydro Plants LMT data year 2010- no policy

Hydro Plants									
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Plant Utilization	Energy distribution		Priority level
							Energy (GWh)	Cumulative probability	
Nahr Ibrahim	Energy Limited with Limited Storage	Capacity & Energy Modification	8	190	1000.34	0.65	900	1	1
Nahr el Bared									
Litani							1000	0.78	
Kadisha									

Table C.2: Power Imports LMT data year 2010- no policy

Imported Power							
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Load Factor	Priority level
Syria	Unlimited Energy	Capacity Modification	1	108	588.96	0.63	2
Egypt			1	123	525.00	0.49	3

Table C.3: Thermal Plants LMT data year 2010- no policy

Thermal Plants											
Power Plant	Unit	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Duty Cycle	Plant Utilization	Energy distribution		Priority level
									Energy (GWh)	Cumulative probability	
Zouk	Zouk1	Energy Limited with Limited Storage	Capacity & Energy Modification	20	98	506.71	0.74	0.7	499.8	1.0	4
							524.3		0.3		
	Zouk2			20	98	508.71	0.74		499.8	1.0	5
							524.3		0.3		
	Zouk3			20	98	504.11	0.73		499.8	1.0	6
							524.3		0.3		
	Zouk4			20	118	537.04	0.65		534.1	1.0	7
							553.7		0.3		
Jieh	Jieh1	Unlimited Energy	Capacity Modification	36	25	140.16	1.00	1.0	No Energy Limitation		8
	Jieh2			36	25	140.16	1.00				9
	Jieh3			36	49	274.71	1.00				10
	Jieh4			36	49	274.71	1.00				11
	Jieh5			36	60	336.38	1.00				12
	Deir Ammar			DieAm1	Unlimited Energy	Capacity Modification	13				118
DieAm2		13	118	899.30			1.00	14			
DieAm3		13	118	899.30			1.00	15			
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	13	118	899.30	1.00	1.0	No Energy Limitation		16
	Zahra2			13	118	899.30	1.00				17
	Zahra3			13	118	898.65	1.00				18
Sour	Sour1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.20	34.30	148.51	0.55	0.6	147.0	1.0	19
							151.9		0.3		
	Sour2			10.20	34.30	148.50	0.55		147.0	1.0	20
							151.9		0.3		
Baalbeck	BBK1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.20	34.30	148.48	0.55	0.6	147.0	1.0	21
							151.9		0.3		
	BBK2			10	34	148.52	0.55		147.0	1.0	22
							151.9		0.3

Figure C.1: equivalent LDC figures year 2010 – no policy (a)

Figure C.2: equivalent LDC figures year 2010 – no policy (b)

Figure C.3: equivalent LDC figures year 2010 – no policy (c)

Year 2011

The LMT data for all units are summarized in the tables below. Following the tables, the equivalent LDC figures for each unit are presented.

Table C.4: Hydro Plants LMT data year 2011 - no policy

Hydro Plants									
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Plant Utilization	Energy distribution		Priority level
							Energy (GWh)	Cumulative probability	
Nahr Ibrahim	Energy Limited with Limited Storage	Capacity & Energy Modification	8	190	1000.34	0.65	900	1	1
Nahr el Bared									
Litani									
Kadisha							1000	0.78	

Table C.5: Power Imports LMT data year 2011 - no policy

Imported Power							
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Load Factor	Priority level
Syria	Unlimited Energy	Capacity Modification	1	108	588.96	0.63	2
Egypt			1	123	525.00	0.49	3

Table C.6: Thermal Plants LMT data year 2011- no policy

Thermal Plants											
Power Plant	Unit	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Duty Cycle	Plant Utilization	Energy distribution		Priority level
									Energy (GWh)	Cumulative probability	
Zouk	Zouk1	Energy Limited with Limited Storage	Capacity & Energy Modification	20.8	96.0	498.20	0.75	0.7	489.8	1.0	4
									513.8	0.3	
	Zouk2			20.8	96.0	492.72	0.74		489.8	1.0	5
									513.8	0.3	
	Zouk3			20.8	96.0	497.95	0.75		489.8	1.0	6
									513.8	0.3	
	Zouk4			20.8	115.2	529.48	0.67		523.4	1.0	7
									542.6	0.3	
Jieh	Jieh1	Unlimited Energy	Capacity Modification	36.4	24.0	134.55	1.00	1.0	No Energy Limitation		8
	Jieh2			36.4	24.0	134.55	1.00				9
	Jieh3			36.4	48.0	269.11	1.00				10
	Jieh4			36.4	48.0	269.11	1.00				11
	Jieh5			36.4	58.6	330.78	1.00				12
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	13.5	115.2	866.36	1.00	1.0	No Energy Limitation		13
	DieAm2			13.5	115.2	866.36	1.00				14
	DieAm3			13.5	115.2	866.36	1.00				15
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	13.5	115.2	866.36	1.00	1.0	No Energy Limitation		16
	Zahra2			13.5	115.2	866.36	1.00				17
	Zahra3			13.5	115.2	866.36	1.00				18
Sour	Sour1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.4	33.6	145.51	0.54	0.6	144.1	1.0	19
									148.9	0.3	
	Sour2			10.4	33.6	145.50	0.54		144.1	1.0	20
									148.9	0.3	
Baalbeck	BBK1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.4	33.6	145.47	0.54	0.6	144.1	1.0	21
									148.9	0.3	
	BBK2			10.4	33.6	145.49	0.54		144.1	1.0	22
									148.9	0.3

Figure C.4: equivalent LDC figures year 2011 – no policy (a)

Figure C.5: equivalent LDC figures year 2011 – no policy (b)

Figure C.6: equivalent LDC figures year 2011 – no policy (c)

Year 2012

The LMT data for all units are summarized in the tables below. Following the tables, the equivalent LDC figures for each unit are presented.

Table C.7: Hydro Plants LMT data year 2012 - no policy

Hydro Plants									
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Plant Utilization	Energy distribution		Priority level
							Energy (GWh)	Cumulative probability	
Nahr Ibrahim	Energy Limited with Limited Storage	Capacity & Energy Modification	8	190	1000.34	0.65	900	1	1
Nahr el Bared									
Litani									
Kadisha							1000	0.78	

Table C.8: Power Imports LMT data year 2012 - no policy

Imported Power							
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Load Factor	Priority level
Syria	Unlimited Energy	Capacity Modification	1	108	588.96	0.63	2
Egypt			1	123	525.00	0.49	3

Table C.9: Thermal Plants LMT data year 2012- no policy

Thermal Plants											
Power Plant	Unit	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Duty Cycle	Plant Utilization	Energy distribution		Priority level
									Energy (GWh)	Cumulative probability	
Zouk	Zouk1	Energy Limited with Limited Storage	Capacity & Energy Modification	21.2	94.1	490.30	0.78	0.7	480.0	1.0	4
									503.5	0.3	
	Zouk2			21.2	94.1	482.70	0.77		480.0	1.0	5
									503.5	0.3	
	Zouk3			21.2	94.1	487.31	0.78		480.0	1.0	6
									503.5	0.3	
	Zouk4			21.2	112.9	520.82	0.69		512.9	1.0	7
									531.8	0.3	
Jieh	Jieh1	Unlimited Energy	Capacity Modification	37.1	23.5	132.45	1.00	1.0	No Energy Limitation		8
	Jieh2			37.1	23.5	132.45	1.00				9
	Jieh3			37.1	47.1	259.38	1.00				10
	Jieh4			37.1	47.1	259.38	1.00				11
	Jieh5			37.1	57.4	314.57	1.00				12
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	13.8	112.9	851.30	1.00	1.0	No Energy Limitation		13
	DieAm2			13.8	112.9	851.30	1.00				14
	DieAm3			13.8	112.9	851.30	1.00				15
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	13.8	112.9	851.30	1.00	1.0	No Energy Limitation		16
	Zahra2			13.8	112.9	851.30	1.00				17
	Zahra3			13.8	112.9	851.30	1.00				18
Sour	Sour1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.6	32.9	142.50	0.55	0.6	141.2	1.0	19
									145.9	0.3	
	Sour2			10.6	32.9	142.50	0.55		141.2	1.0	20
									145.9	0.3	
Baalbeck	BBK1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.6	32.9	142.51	0.55	0.6	141.2	1.0	21
									145.9	0.3	
	BBK2			10.6	32.9	142.54	0.55		141.2	1.0	22
									145.9	0.3

Figure C.7: equivalent LDC figures year 2012 – no policy (a)

Figure C.8: equivalent LDC figures year 2012 – no policy (b)

Figure C.9: equivalent LDC figures year 2012 – no policy (c)

Year 2013

The LMT data for all units are summarized in the tables below. Following the tables, the equivalent LDC figures for each unit are presented.

Table C.10: Hydro Plants LMT data year 2013 - no policy

Hydro Plants									
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Plant Utilization	Energy distribution		Priority level
							Energy (GWh)	Cumulative probability	
Nahr Ibrahim	Energy Limited with Limited Storage	Capacity & Energy Modification	8	190	1000.34	0.65	900	1	1
Nahr el Bared									
Litani									
Kadisha							1000	0.78	

Table C.11: Power Imports LMT data year 2013 - no policy

Imported Power							
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Load Factor	Priority level
Syria	Unlimited Energy	Capacity Modification	1	108	588.96	0.63	2
Egypt			1	123	525.00	0.49	3

Table C.12: Thermal Plants LMT data year 2013- no policy

Thermal Plants											
Power Plant	Unit	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Duty Cycle	Plant Utilization	Energy distribution		Priority level
									Energy (GWh)	Cumulative probability	
Zouk	Zouk1	Energy Limited with Limited Storage	Capacity & Energy Modification	21.6	92.2	464.93	0.74	0.7	470.4	1.0	4
									493.5	0.3	
	Zouk2			21.6	92.2	475.17	0.76		470.4	1.0	5
									493.5	0.3	
	Zouk3			21.6	92.2	473.24	0.75		470.4	1.0	6
									493.5	0.3	
	Zouk4			21.6	110.6	508.23	0.67		502.7	1.0	7
									521.1	0.3	
Jieh	Jieh1	Unlimited Energy	Capacity Modification	37.9	23.1	124.92	1.00	1.0	No Energy Limitation		8
	Jieh2			37.9	23.1	124.92	1.00				9
	Jieh3			37.9	46.1	249.84	1.00				10
	Jieh4			37.9	46.1	249.84	1.00				11
	Jieh5			37.9	56.3	304.15	1.00				12
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	14.1	110.7	836.23	1.00	1.0	No Energy Limitation		13
	DieAm2			14.1	110.7	836.23	1.00				14
	DieAm3			14.1	110.7	836.23	1.00				15
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	14.1	110.7	836.23	1.00	1.0	No Energy Limitation		16
	Zahra2			14.1	110.7	836.23	1.00				17
	Zahra3			14.1	110.7	836.23	1.00				18
Sour	Sour1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.8	32.3	139.50	0.56	0.6	138.4	1.0	19
									143.0	0.3	
	Sour2			10.8	32.3	139.51	0.56		138.4	1.0	20
									143.0	0.3	
Baalbeck	BBK1	Energy Limited with Limited Storage	Capacity & Energy Modification	10.8	32.3	139.49	0.56	0.6	138.4	1.0	21
									143.0	0.3	
	BBK2			10.8	32.3	139.49	0.56		138.4	1.0	22
									143.0	0.3

Figure C.10: equivalent LDC figures year 2013 – no policy (a)

Figure C.11: equivalent LDC figures year 2013 – no policy (b)

Figure C.12: equivalent LDC figures year 2013 – no policy (c)

Year 2014

The LMT data for all units are summarized in the tables below. Following the tables, the equivalent LDC figures for each unit are presented.

Table C.13: Hydro Plants LMT data year 2014 - no policy

Hydro Plants									
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Plant Utilization	Energy distribution		Priority level
							Energy (GWh)	Cumulative probability	
Nahr Ibrahim	Energy Limited with Limited Storage	Capacity & Energy Modification	8	190	1000.34	0.65	900	1	1
Nahr el Bared									
Litani									
Kadisha							1000	0.78	

Table C.14: Power Imports LMT data year 2014 - no policy

Imported Power							
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Load Factor	Priority level
Syria	Unlimited Energy	Capacity Modification	1	108	588.96	0.63	2
Egypt			1	123	525.00	0.49	3

Table C.15: Thermal Plants LMT data year 2014- no policy

Thermal Plants											
Power Plant	Unit	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Duty Cycle	Plant Utilization	Energy distribution		Priority level
									Energy (GWh)	Cumulative probability	
Zouk	Zouk1	Energy Limited with Limited Storage	Capacity & Energy Modification	22.1	90.4	458.66	0.75	0.7	461.0	1.0	4
							483.6		0.3		
	Zouk2			22.1	90.4	469.91	0.76		461.0	1.0	5
							483.6		0.3		
	Zouk3			22.1	90.4	470.28	0.76		461.0	1.0	6
							483.6		0.3		
	Zouk4			22.1	108.4	498.20	0.68		492.6	1.0	7
							510.7		0.3		
Jieh	Jieh1	Unlimited Energy	Capacity Modification	38.6	22.6	132.28	1.00	1.0	No Energy Limitation		8
	Jieh2			38.6	22.6	132.28	1.00				9
	Jieh3			38.6	45.2	240.24	1.00				10
	Jieh4			38.6	45.2	240.24	1.00				11
	Jieh5			38.6	55.1	293.63	1.00				12
	Deir Ammar			DieAm1	Unlimited Energy	Capacity Modification	14.4				108.5
DieAm2		14.4	108.5	812.88			1.00	14			
DieAm3		14.4	108.5	812.88			1.00	15			
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	14.4	108.5	812.88	1.00	1.0	No Energy Limitation		16
	Zahra2			14.4	108.5	812.88	1.00				17
	Zahra3			14.4	108.5	812.88	1.00				18
Sour	Sour1	Energy Limited with Limited Storage	Capacity & Energy Modification	11.0	31.6	137.21	0.55	0.6	135.6	1.0	19
							140.1		0.3		
	Sour2			11.0	31.6	137.20	0.55		135.6	1.0	20
							140.1		0.3		
Baalbeck	BBK1	Energy Limited with Limited Storage	Capacity & Energy Modification	11.0	31.6	137.21	0.55	0.6	135.6	1.0	21
							140.1		0.3		
	BBK2			11.0	31.6	137.22	0.55		135.6	1.0	22
							140.1		0.3

Figure C.13: equivalent LDC figures year 2014 – no policy (a)

Figure C.14: equivalent LDC figures year 2014 – no policy (b)

Figure C.15: equivalent LDC figures year 2014 – no policy (c)

Year 2015

The LMT data for all units are summarized in the tables below. Following the tables, the equivalent LDC figures for each unit are presented.

Table C.16: Hydro Plants LMT data year 2015 - no policy

Hydro Plants									
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Plant Utilization	Energy distribution		Priority level
							Energy (GWh)	Cumulative probability	
Nahr Ibrahim	Energy Limited with Limited Storage	Capacity & Energy Modification	8	190	1000.34	0.65	900	1	1
Nahr el Bared									
Litani									
Kadisha							1000	0.78	

Table C.17: Power Imports LMT data year 2015 - no policy

Imported Power							
Power Plant	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Load Factor	Priority level
Syria	Unlimited Energy	Capacity Modification	1	108	588.96	0.63	2
Egypt			1	123	525.00	0.49	3

Table C.18: Thermal Plants LMT data year 2015- no policy

Thermal Plants											
Power Plant	Unit	Category	Type of modification	FOR (%)	Capacity (MW)	EES (GWh)	Duty Cycle	Plant Utilization	Energy distribution		Priority level
									Energy (GWh)	cumulative probability	
Zouk	Zouk1	Energy Limited with Limited Storage	Capacity & Energy Modification	22.5	88.6	458.94	0.76	0.7	451.8	1.0	4
									473.9	0.3	
	Zouk2			22.5	88.5	457.06	0.76		451.8	1.0	5
									473.9	0.3	
	Zouk3			22.5	88.5	459.31	0.77		451.8	1.0	6
									473.9	0.3	
	Zouk4			22.5	106.3	489.50	0.68		482.8	1.0	7
									500.5	0.3	
Jieh	Jieh1	Unlimited Energy	Capacity Modification	39.4	22.1	117.56	1.00	1.0	No Energy Limitation		8
	Jieh2			39.4	22.1	117.56	1.00				9
	Jieh3			39.4	44.3	235.12	1.00				10
	Jieh4			39.4	44.3	235.12	1.00				11
	Jieh5			39.4	54.0	288.55	1.00				12
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	14.6	106.3	789.28	1.00	1.0	No Energy Limitation		13
	DieAm2			14.6	106.3	789.28	1.00				14
	DieAm3			14.6	106.3	789.28	1.00				15
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	14.6	106.3	789.28	1.00	1.0	No Energy Limitation		16
	Zahra2			14.6	106.3	789.28	1.00				17
	Zahra3			14.6	106.3	789.28	1.00				18
Sour	Sour1	Energy Limited with Limited Storage	Capacity & Energy Modification	11.3	31.0	134.20	0.56	0.6	132.9	1.0	19
									137.3	0.3	
	Sour2			11.3	31.0	134.21	0.56		132.9	1.0	20
									137.3	0.3	
Baalbeck	BBK1	Energy Limited with Limited Storage	Capacity & Energy Modification	11.3	31.0	134.20	0.56	0.6	132.9	1.0	21
									137.3	0.3	
	BBK2			11.3	31.0	134.22	0.56		132.9	1.0	22
									137.3	0.3

Figure C.16: equivalent LDC figures year 2015 – no policy (a)

Figure C.17: equivalent LDC figures year 2015 – no policy (b)

Figure C.18: equivalent LDC figures year 2015 – no policy (c)

D. Annex 4: 2010-2015 Production Costing (No Action Taken)

2010 Production costing details

Table D.1: Imports cost 2010 - no policy

Imports					
Country	EES (GWh)	Price (¢/kWh)	Price (\$/GWh)	Total Cost	Total Import's Cost
Syria	588.96	14.14	\$ 141,443.72	\$ 83,304,551.89	\$ 146,144,147.58
Egypt	525.00	11.97	\$ 119,694.24	\$62,839,595.69	

Table D.2: Hydro cost year 2010 - no policy

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GW-hr)	Total Cost
ALL-Hydro	1000.34	61	\$40,666.67	\$40,680,330.67

Table D.3: NG units cost year 2010 - no policy

Unit operating on NG										
Power Plant	Unit Name	Fuel Type	EES (GWh)	Heat Rate (kJ/kWh)	Fuel Price (\$/GJ)	Cost (\$/GWh)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost of O&M (MM \$)	Total Unit Cost (MM \$)
Deir Ammar	DieAm2	NG	899.30	11426.04	5.51	62,994.16	56.65	21.00	18.89	75.54

Table D.4: 2010 Production costing for units operating on fuel oil

Thermal Units													
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Total Consumption (K tons)	Fuel Price (\$/ton)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost O&M (MM \$)	Transp (\$/ton)	Cost of Transp (MM \$)	Total Unit Cost (MM \$)	Total Plant Cost (MM \$)
Zouk	Zouk1	HFO	506.71	263.16	133.34	428.22	57.10	28.00	14.19	0.00	0.00	71.29	287.10
	Zouk2	HFO	508.71	269.28	136.99	428.22	58.66	28.00	14.24	0.00	0.00	72.90	
	Zouk3	HFO	504.11	267.24	134.72	428.22	57.69	28.00	14.12	0.00	0.00	71.80	
	Zouk3	HFO	537.04	243.78	130.92	428.22	56.06	28.00	15.04	0.00	0.00	71.10	
Jieh	Jieh1	HFO	140.16	321.42	45.05	428.22	19.29	12.00	1.68	0.00	0.00	20.97	164.84
	Jieh2	HFO	140.16	326.63	45.78	428.22	19.60	12.00	1.68	0.00	0.00	21.29	
	Jieh3	HFO	274.71	295.24	81.11	428.22	34.73	12.00	3.30	0.00	0.00	38.03	
	Jieh4	HFO	274.71	303.28	83.31	428.22	35.68	12.00	3.30	0.00	0.00	38.97	
	Jieh5	HFO	336.38	288.38	97.00	428.22	41.54	12.00	4.04	0.00	0.00	45.58	
Deir Ammar	DieAm1	Diesel	899.30	280.50	252.25	832.26	209.94	21.00	18.89	0.00	0.00	228.83	323.25
	DieAm3	HRS	899.30	0.00	0.00	0.00	0.00	21.00	18.89	0.00	0.00	18.89	
Zahrani	Zahra1	Diesel	899.30	286.62	257.76	832.26	214.52	8.00	7.19	0.00	0.00	221.72	448.33
	Zahra2	Diesel	899.30	283.56	255.01	832.26	212.23	8.00	7.19	0.00	0.00	219.43	
	Zahra3	HRS	899.30	0.00	0.00	0.00	0.00	8.00	7.19	0.00	0.00	7.19	
Tyre	Tyre1	Diesel	898.65	302.94	44.99	832.26	37.44	2.00	0.30	12.00	0.54	38.28	77.32
	Tyre2	Diesel	148.51	309.06	45.90	832.26	38.20	2.00	0.30	12.00	0.55	39.05	
Baalbeck	BBK1	Diesel	148.50	309.06	45.89	832.26	38.19	6.00	0.89	4.00	0.18	39.27	77.91
	BBK2	Diesel	148.48	303.96	45.14	832.26	37.57	6.00	0.89	4.00	0.18	38.64	

2011 Production costing details

Table D.5: Imports cost 2011 - no policy

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost	Total Import's Cost
Syria	588.96	14.14	\$141,443.72	\$83,304,551.89	\$146,144,147.58
Egypt	525.00	11.97	\$119,694.24	\$62,839,595.69	

Table D.6: Hydro cost year 2011 - no policy

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GW-hr)	Total Cost
ALL-Hydro	1000.34	61	\$40,666.67	\$40,680,330.67

Table D.7: NG units cost year 2011 - no policy

Unit operating on NG										
Power Plant	Unit Name	Fuel Type	EES (GWh)	Heat Rate (kJ/kWh)	Fuel Price (\$/GJ)	Cost (\$/GWh)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost of O&M (MM\$)	Total Unit Cost (MM\$)
Deir Ammar	DieAm2	NG	866.36	11654.56	5.68	66,181.67	57.34	21.00	18.19	75.53

Table D.8: 2011 Production costing for units operating on fuel oil

Thermal Units													
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Total Consumption (K tons)	Fuel Price (\$/ton)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost O&M (MM \$)	Transp (\$/ton)	Cost of Transp (MM \$)	Total Unit Cost (MM \$)	Total Plant Cost (MM \$)
Zouk	Zouk1	HFO	498.20	268.42	133.73	440.09	58.85	28.00	13.95	0.00	0.00	72.80	292.60
	Zouk2	HFO	492.72	274.67	135.33	440.09	59.56	28.00	13.80	0.00	0.00	73.36	
	Zouk3	HFO	497.95	272.58	135.73	440.09	59.73	28.00	13.94	0.00	0.00	73.68	
	Zouk3	HFO	529.48	248.66	131.66	440.09	57.94	28.00	14.83	0.00	0.00	72.77	
Jieh	Jieh1	HFO	134.55	327.85	44.11	440.09	19.41	12.00	1.61	0.00	0.00	21.03	167.92
	Jieh2	HFO	134.55	333.17	44.83	440.09	19.73	12.00	1.61	0.00	0.00	21.34	
	Jieh3	HFO	269.11	301.15	81.04	440.09	35.67	12.00	3.23	0.00	0.00	38.89	
	Jieh4	HFO	269.11	309.35	83.25	440.09	36.64	12.00	3.23	0.00	0.00	39.87	
	Jieh5	HFO	330.78	294.14	97.30	440.09	42.82	12.00	3.97	0.00	0.00	46.79	
Deir Ammar	DieAm1	Diesel	866.36	286.11	247.88	855.31	212.01	21.00	18.19	0.00	0.00	230.21	323.93
	DieAm3	HRS	866.36	0.00	0.00	0.00	0.00	21.00	18.19	0.00	0.00	18.19	
Zahrani	Zahra1	Diesel	866.36	292.35	253.28	855.31	216.64	8.00	6.93	0.00	0.00	223.57	451.75
	Zahra2	Diesel	866.36	289.23	250.58	855.31	214.32	8.00	6.93	0.00	0.00	221.26	
	Zahra3	HRS	866.36	0.00	0.00	0.00	0.00	8.00	6.93	0.00	0.00	6.93	
Tyre	Tyre1	Diesel	145.51	309.00	44.96	855.31	38.46	2.00	0.29	12.00	0.54	39.29	79.36
	Tyre2	Diesel	145.50	315.24	45.87	855.31	39.23	2.00	0.29	12.00	0.55	40.07	
Baalbeck	BBK1	Diesel	145.47	315.24	45.86	855.31	39.22	6.00	0.87	4.00	0.18	40.28	79.91
	BBK2	Diesel	145.49	310.04	45.11	855.31	38.58	6.00	0.87	4.00	0.18	39.63	

2012 Production costing details

Table D.9: Imports cost 2012 - no policy

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost	Total Import's Cost
Syria	588.96	15.01	150057.64	\$ 88,377,799.10	\$ 155,044,326.17
Egypt	525.00	12.70	126983.62	\$ 66,666,527.07	

Table D.10: Hydro cost year 2012 - no policy

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GW-hr)	Total Cost
ALL-Hydro	1000.34	61	\$40,666.67	\$40,680,330.67

Table D.11: NG units cost year 2012 - no policy

Unit operating on NG										
Power Plant	Unit Name	Fuel Type	EES (GWh)	Heat Rate (kJ/kWh)	Fuel Price (\$/GJ)	Cost (\$/GWh)	Unit Production Cost (MM \$)	O&M (\$/MWh)	Unit Cost of O&M (MM \$)	Total Unit Cost (MM \$)
Deir Ammar	DieAm2	NG	851.30	11887.65	5.85	69,530.4	59.19	21.00	17.88	77.07

Table D.12: 2012 Production costing for units operating on fuel oil

Thermal Units													
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Total Consumption (K tons)	Fuel Price (\$/ton)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost O&M (MM \$)	Transp (\$/ton)	Cost of Transp (MM \$)	Total Unit Cost (MM\$)	Total Plant Cost (MM \$)
Zouk	Zouk1	HFO	490.30	273.79	134.24	452.32	60.72	28.00	13.73	0.00	0.00	74.45	298.39
	Zouk2	HFO	482.70	280.16	135.23	452.32	61.17	28.00	13.52	0.00	0.00	74.68	
	Zouk3	HFO	487.31	278.04	135.49	452.32	61.28	28.00	13.64	0.00	0.00	74.93	
	Zouk3	HFO	520.82	253.63	132.09	452.32	59.75	28.00	14.58	0.00	0.00	74.33	
Jieh	Jieh1	HFO	132.45	334.41	44.29	452.32	20.03	12.00	1.59	0.00	0.00	21.62	169.32
	Jieh2	HFO	132.45	339.83	45.01	452.32	20.36	12.00	1.59	0.00	0.00	21.95	
	Jieh3	HFO	259.38	307.17	79.67	452.32	36.04	12.00	3.11	0.00	0.00	39.15	
	Jieh4	HFO	259.38	315.53	81.84	452.32	37.02	12.00	3.11	0.00	0.00	40.13	
	Jieh5	HFO	314.57	300.03	94.38	452.32	42.69	12.00	3.77	0.00	0.00	46.46	
Deir Ammar	DieAm1	Diesel	851.30	291.83	248.44	879.06	218.39	21.00	17.88	0.00	0.00	236.27	331.21
	DieAm3	HRSG	851.30	0.00	0.00	0.00	0.00	21.00	17.88	0.00	0.00	17.88	
Zahrani	DieAm4	HRSG	851.30	298.20	253.86	879.06	223.15	8.00	6.81	0.00	0.00	229.96	464.36
	DieAm5	HRSG	851.30	295.02	251.15	879.06	220.77	8.00	6.81	0.00	0.00	227.58	
	DieAm6	HRSG	851.30	0.00	0.00	0.00	0.00	8.00	6.81	0.00	0.00	6.81	
Tyre	DieAm7	HRSG	142.50	315.18	44.91	879.06	39.48	2.00	0.29	12.00	0.54	40.31	81.42
	DieAm8	HRSG	142.50	321.55	45.82	879.06	40.28	2.00	0.28	12.00	0.55	41.11	
Baalbeck	DieAm9	HRSG	142.51	321.55	45.82	879.06	40.28	6.00	0.86	4.00	0.18	41.32	81.98
	DieAm10	HRSG	142.54	316.24	45.08	879.06	39.62	6.00	0.86	4.00	0.18	40.66	

2013 Production costing details

Table D.13: Imports cost 2013 - no policy

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost	Total Import's Cost
Syria	588.96	15.46	154559.37	\$ 91,029,133.07	\$ 159,695,655.95
Egypt	525.00	13.08	130793.13	\$ 68,666,522.88	

Table D.14: Hydro cost year 2013 - no policy

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GW-hr)	Total Cost
ALL-Hydro	1000.34	61	\$40,666.67	\$40,680,330.67

Table D.15: NG units cost year 2013 - no policy

Unit operating on NG										
Power Plant	Unit Name	Fuel Type	EES (GWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Cost (\$/GWh)	Unit Production Cost (MM \$)	O&M (\$/MWh)	Unit Cost of O&M (MM \$)	Total Unit Cost (MM \$)
Deir Ammar	DieAm2	NG	836.23	12125.41	6.02	73,048.70	61.09	21.00	17.56	78.65

Table D.16: 2013 Production costing for units operating on fuel oil

Thermal Units													
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Total Consumption (K tons)	Fuel Price (\$/ton)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost O&M (MM \$)	Transp (\$/ton)	Cost of Transp (MM \$)	Total Unit Cost (MM\$)	Total Plant Cost (MM\$)
Zouk	Zouk1	HFO	464.93	279.27	129.84	464.91	60.36	28.00	13.02	0.00	0.00	73.38	300.82
	Zouk2	HFO	475.17	285.76	135.79	464.91	63.13	28.00	13.30	0.00	0.00	76.43	
	Zouk3	HFO	473.24	283.60	134.21	464.91	62.40	28.00	13.25	0.00	0.00	75.65	
	Zouk3	HFO	508.23	258.70	131.48	464.91	61.13	28.00	14.23	0.00	0.00	75.36	
Jieh	Jieh1	HFO	124.92	341.09	42.61	464.91	19.81	12.00	1.50	0.00	0.00	21.31	169.63
	Jieh2	HFO	124.92	346.63	43.30	464.91	20.13	12.00	1.50	0.00	0.00	21.63	
	Jieh3	HFO	249.84	313.31	78.28	464.91	36.39	12.00	3.00	0.00	0.00	39.39	
	Jieh4	HFO	249.84	321.84	80.41	464.91	37.38	12.00	3.00	0.00	0.00	40.38	
	Jieh5	HFO	304.15	306.03	93.08	464.91	43.27	12.00	3.65	0.00	0.00	46.92	
Deir Ammar	DieAm1	Diesel	836.23	297.67	248.92	903.51	224.90	21.00	17.56	0.00	0.00	242.46	338.67
	DieAm3	HRSg	836.23	0.00	0.00	0.00	0.00	21.00	17.56	0.00	0.00	17.56	
Zahrani	Zahra1	Diesel	836.23	304.16	254.35	903.51	229.81	8.00	6.69	0.00	0.00	236.50	477.23
	Zahra2	Diesel	836.23	300.92	251.63	903.51	227.35	8.00	6.69	0.00	0.00	234.04	
	Zahra3	HRSg	836.23	0.00	0.00	0.00	0.00	8.00	6.69	0.00	0.00	6.69	
Tyre	Tyre1	Diesel	139.50	321.48	44.85	903.51	40.52	2.00	0.28	12.00	0.54	41.34	83.50
	Tyre2	Diesel	139.51	327.98	45.76	903.51	41.34	2.00	0.28	12.00	0.55	42.17	
Baalbeck	BBK1	Diesel	139.49	327.98	45.75	903.51	41.34	6.00	0.84	4.00	0.18	42.36	84.03
	BBK2	Diesel	139.49	322.56	44.99	903.51	40.65	6.00	0.84	4.00	0.18	41.67	

2014 Production costing details

Table D.17: Imports cost 2014 - no policy

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost	Total Import's Cost
Syria	588.96	15.92	159196.15	\$ 93,760,007.06	\$ 164,486,525.63
Egypt	525.00	13.47	134716.92	\$ 70,726,518.57	

Table D.18: Hydro cost year 2014 - no policy

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GW-hr)	Total Cost
ALL-Hydro	1000.34	61	\$40,666.67	\$40,680,330.67

Table D.19: NG units cost year 2014 - no policy

Unit operating on NG										
Power Plant	Unit Name	Fuel Type	EES (GWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Cost (\$/GWh)	Unit Production Cost (MM \$)	O&M (\$/MWh)	Unit Cost of O&M (MM \$)	Total Unit Cost (MM\$)
Deir Ammar	DieAm2	NG	812.88	12367.91	6.21	76,744.97	62.38	21.00	17.07	79.46

Table D.20: 2014 Production costing for units operating on fuel oil

Thermal Units													
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Total Consumption (K tons)	Fuel Price (\$/ton)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost O&M (MM \$)	Transp (\$/ton)	Cost of Transp (MM\$)	Total Unit Cost (MM\$)	Total Plant Cost (MM\$)
Zouk	Zouk1	HFO	458.66	284.85	130.65	477.88	62.44	28.00	12.84	0.00	0.00	75.28	308.84
	Zouk2	HFO	469.91	291.48	136.97	477.88	65.45	28.00	13.16	0.00	0.00	78.61	
	Zouk3	HFO	470.28	289.27	136.04	477.88	65.01	28.00	13.17	0.00	0.00	78.18	
	Zouk3	HFO	498.20	263.88	131.46	477.88	62.82	28.00	13.95	0.00	0.00	76.77	
Jieh	Jieh1	HFO	132.28	347.92	46.02	477.88	21.99	12.00	1.59	0.00	0.00	23.58	174.99
	Jieh2	HFO	132.28	353.56	46.77	477.88	22.35	12.00	1.59	0.00	0.00	23.94	
	Jieh3	HFO	240.24	319.58	76.78	477.88	36.69	12.00	2.88	0.00	0.00	39.57	
	Jieh4	HFO	240.24	328.28	78.87	477.88	37.69	12.00	2.88	0.00	0.00	40.57	
	Jieh5	HFO	293.63	312.15	91.65	477.88	43.80	12.00	3.52	0.00	0.00	47.32	
Deir Ammar	DieAm1	Diesel	812.88	303.62	246.81	928.70	229.21	21.00	17.07	0.00	0.00	246.28	342.81
	DieAm3	HRS	812.88	0.00	0.00	0.00	0.00	21.00	17.07	0.00	0.00	17.07	
Zahrani	Zahra1	Diesel	812.88	310.25	252.19	928.70	234.21	8.00	6.50	0.00	0.00	240.72	485.43
	Zahra2	Diesel	812.88	306.93	249.50	928.70	231.71	8.00	6.50	0.00	0.00	238.22	
	Zahra3	HRS	812.88	0.00	0.00	0.00	0.00	8.00	6.50	0.00	0.00	6.50	
Tyre	Tyre1	Diesel	137.21	327.91	44.99	928.70	41.78	2.00	0.27	12.00	0.54	42.60	86.05
	Tyre2	Diesel	137.20	334.54	45.90	928.70	42.63	2.00	0.27	12.00	0.55	43.45	
Baalbeck	BBK1	Diesel	137.21	334.54	45.90	928.70	42.63	6.00	0.82	4.00	0.18	43.64	86.57
	BBK2	Diesel	137.22	329.02	45.15	928.70	41.93	6.00	0.82	4.00	0.18	42.93	

2015 Production costing details

Table D.21: Imports cost 2015 - no policy

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost	Total Import's Cost
Syria	588.96	16.40	163972.04	\$ 96,572,807.27	\$ 169,421,121.40
Egypt	525.00	13.88	138758.43	\$ 72,848,314.13	

Table D.22: Hydro cost year 2015 - no policy

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GW-hr)	Total Cost
ALL-Hydro	1000.34	61	\$ 40,666.67	\$40,680,330.67

Table D.23: NG units cost year 2015 - no policy

Unit operating on NG										
Power Plant	Unit Name	Fuel Type	EES (GWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Cost (\$/GWh)	Unit Production Cost (MM \$)	O&M (\$/MWh)	Unit Cost of O&M (MM \$)	Total Unit Cost (MM\$)
Deir Ammar	DieAm2	NG	789.28	12615.27	6.39	80,628.26	63.64	21.00	16.57	80.21

Table D.24: 2015 Production costing for units operating on fuel oil

Thermal Units													
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Total Consumption (K tons)	Fuel Price (\$/ton)	Unit Production Cost (MM\$)	O&M (\$/MWh)	Unit Cost O&M (MM \$)	Transp (\$/ton)	Cost of Transp (MM \$)	Total Unit Cost (MM\$)	Total Plant Cost (MM\$)
Zouk	Zouk1	HFO	458.94	290.55	133.35	491.25	65.51	28.00	12.85	0.00	0.00	78.36	315.77
	Zouk2	HFO	457.06	297.31	135.89	491.25	66.75	28.00	12.80	0.00	0.00	79.55	
	Zouk3	HFO	459.31	295.05	135.52	491.25	66.57	28.00	12.86	0.00	0.00	79.44	
	Zouk3	HFO	489.50	269.15	131.75	491.25	64.72	28.00	13.71	0.00	0.00	78.43	
Jieh	Jieh1	HFO	117.56	354.87	41.72	491.25	20.49	12.00	1.41	0.00	0.00	21.90	174.70
	Jieh2	HFO	117.56	360.63	42.40	491.25	20.83	12.00	1.41	0.00	0.00	22.24	
	Jieh3	HFO	235.12	325.97	76.64	491.25	37.65	12.00	2.82	0.00	0.00	40.47	
	Jieh4	HFO	235.12	334.85	78.73	491.25	38.67	12.00	2.82	0.00	0.00	41.50	
	Jieh5	HFO	288.55	318.39	91.87	491.25	45.13	12.00	3.46	0.00	0.00	48.59	
Deir Ammar	DieAm1	Diesel	789.28	309.69	244.43	954.64	233.35	21.00	16.57	0.00	0.00	249.92	346.71
	DieAm3	HRSG	789.28	0.00	0.00	0.00	0.00	21.00	16.57	0.00	0.00	16.57	
Zahrani	Zahra1	Diesel	789.28	316.45	249.77	954.64	238.44	8.00	6.31	0.00	0.00	244.75	493.28
	Zahra2	Diesel	789.28	313.07	247.10	954.64	235.89	8.00	6.31	0.00	0.00	242.21	
	Zahra3	HRSG	789.28	0.00	0.00	0.00	0.00	8.00	6.31	0.00	0.00	6.31	
Tyre	Tyre1	Diesel	134.20	334.47	44.89	954.64	42.85	2.00	0.27	12.00	0.54	43.66	88.20
	Tyre2	Diesel	134.21	341.23	45.80	954.64	43.72	2.00	0.27	12.00	0.55	44.54	
Baalbeck	BBK1	Diesel	134.20	341.23	45.79	954.64	43.72	6.00	0.81	4.00	0.18	44.70	88.69
	BBK2	Diesel	134.22	335.60	45.05	954.64	43.00	6.00	0.81	4.00	0.18	43.99	

E. Annex 5: 2010-2015 Policy Simulation Results (Energy Data)

Year 2010 (LMT Data)

Table E.1: Production costing data for thermal units – year 2010 (a)

Thermal Plants Data - 1						
Power Plant	Unit Name	Category	Type Of Modification	Commissioning Year	Retirement Year	Type & Fuel
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	1998	2022	CCGT - NG
	DieAm2			1998	2022	CCGT - Diesel
	DieAm3			2002	2026	HRS
Zouk	Zouk1	Energy Limited Unit with Limited Storage	Capacity & Energy Modification	1984	2015	Steam - HFO
	Zouk2			1985	2016	
	Zouk3			1986	2018	
	Zouk4			1986	2018	
Jieh	Jieh1	Unlimited Energy	Capacity Modification	1970	2010	Steam - HFO
	Jieh2			1970	2010	
	Jieh3			1980	2012	
	Jieh4			1981	2013	
	Jieh5			1981	2014	
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	1998	2022	CCGT - Diesel
	Zahra2			1998	2022	
	Zahra3			2001	2025	HRS
Tyre	Tyre1	Energy Limited Unit with Limited Storage	Capacity & Energy Modification	1996	2022	OCGT - Diesel
	Tyre2			1996	2022	
Baalbeck	BBK1	Energy Limited Unit with Limited Storage	Capacity & Energy Modification	1996	2022	OCGT - Diesel
	BBK2			1996	2022	

Table E.2: Production costing data for thermal units – year 2010 (b)

Thermal Plants Data - 2									
Power Plant	FOR (%)	Maximum Generation (MW)	Energy (GW-hr) per unit simulated results	Duty Cycle	Energy (GWh) Simulated Results	Plant Duty Cycle	Energy Distribution		Priority
							Energy (GWh)	Cumulative Probability	
Deir Ammar	13	118	899.301	1.000	2697.903	1.0	No Energy Limitation		6
	13	118	899.301	1.000					7
	13	118	899.301	1.000					8
Zouk	20	98	506.833	0.738	2060.93	0.72	500	1.0	9
							524	0.3	
	20	98	507.208	0.738			500	1.0	10
							524	0.3	
	20	98	506.781	0.737			500	1.0	11
							524	0.3	
	20	118	540.108	0.653			534	1.0	12
							554	0.3	
Jieh	36	25	140.16	1.000	1165.61	1.00	No Energy Limitation		13
	36	25	140.16	1.000					14
	36	49	274.713	1.000					15
	36	49	274.651	0.999					16
	36	60	335.926	0.998					17
Zahrani	13	118	892.949	0.992	2535.522	0.946	No Energy Limitation		18
	13	118	873.016	0.970					19
	13	118	769.557	0.855					20
Tyre	10	34	148.507	0.554	296.987	0.550	147	1.0	21
							152	0.3	
	10	34	148.48	0.553			147	1.0	22
							152	0.3	
Baalbeck	10	34	148.514	0.554	296.963	0.550	147	1.0	23
							152	0.3	
	10	34	148.449	0.553			147	1.0	24
							152	0.3	

Year 2010 (Simulation Figures)

Figure E.1: Policy Simulation LDC figures – 2010 (a)

Figure E.2: Policy Simulation LDC figures – 2010 (b)

Figure E.3: Policy Simulation LDC figures – 2010 (c)

Figure E.4: Policy Simulation LDC figures – 2010 (d)

Year 2011 (LMT Data)

Table E.3: Production costing data for thermal units – year 2011 (a)

Thermal Plants - 1						
Power Plant	Unit Name	Category	Type Of Modification	Commissioning Year	Retirement Year	Type & Fuel
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	1998	2025	CCGT - NG
	DieAm2			1998	2025	CCGT - Diesel
	DieAm3			2002	2025	HRSG
Zouk	Zouk1	Unit is Temporary OFF due to Rehabilitation				
	Zouk2	Energy Limited Unit - Limited Storage	Capacity & Energy Modification	1985	2016	Steam - HFO
	Zouk3		Capacity & Energy Modification	1986	2018	
	Zouk4		Capacity & Energy Modification	1986	2018	
Jieh	Jieh1	Unlimited Energy	Capacity Modification	1970	2010	Steam - HFO
	Jieh2			1970	2010	
	Jieh3	Unit is Temporary OFF due to Rehabilitation				
	Jieh4	Unlimited Energy	Capacity Modification	1981	2013	Steam - HFO
	Jieh5			1981	2014	
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	1998	2025	CCGT - Diesel
	Zahra2			1998	2025	
	Zahra3			2001	2025	HRSG
Tyre	Tyre1	Energy Limited Unit - Limited Storage	Capacity & Energy Modification	1996	2022	CCGT - Diesel
	Tyre2			1996	2022	
	Tyre3			2011	2041	HRSG
Baalbeck	BBK1	Energy Limited Unit - Limited Storage	Capacity & Energy Modification	1996	2022	CCGT - Diesel
	BBK2			1996	2022	

Table E.4: Production costing data for thermal units – year 2011 (b)

Thermal Plants - 2						
Power Plant	FOR (%)	Maximum Generation (MW)	Energy (GW-hr) per unit simulated results	Duty Cycle	Energy (GW-hr) Simulated Results	Plant Duty Cycle
Deir Ammar	14	119	896.498	1.0000	2689.494	1.0
	14	119	896.498	1.0000		
	14	119	896.498	1.0000		
Zouk	Rehabilitation				1522.955	0.71
	21	96	496.812	0.7478		
	21	96	497.349	0.7486		
	21	115	528.794	0.6644		
Jieh	36	24	134.553	1.0000	868.99	1.0
	36	24	134.553	1.0000		
	Rehabilitation					
	36	48	269.107	1.0000		
	36	59	330.777	1.0000		
Zahrani	14	119	896.011	0.9995	2661.199	0.98
	14	119	890.951	0.9938		
	14	119	874.237	0.9752		
Tyre	10	34	145.503	0.5428	436.513	0.552
	10	34	145.506	0.5428		
	10	34	145.504	0.5428		
Baalbeck	10	34	145.51	0.5428	290.993	0.551
	10	34	145.483	0.5427		

Year 2011 (Simulation Figures)

Figure E.5: Policy Simulation LDC figures – 2011 (a)

Figure E.6: Policy Simulation LDC figures – 2011 (b)

Figure E.7: Policy Simulation LDC figures – 2011 (c)

Figure E.8: Policy Simulation LDC figures – 2011 (d)

Year 2012 (LMT Data)

Table E.5: Production costing data for thermal units – year 2012 (a)

Thermal Plants - 1						
Power Plant	Unit Name	Category	Type Of Modification	Commissioning Year	Retirement Year	Type & Fuel
New PP 1	RE1	Unlimited Energy	Capacity Modification	2012	2037	RE - HFO
	GT1			2012	2042	GT - HFO
	GT2			2012	2042	
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	1998	2028	CCGT - NG
	DieAm2			1998	2028	CCGT - Diesel
	DieAm3			2002	2028	HRSG
Zouk	Zouk1	Unlimited Energy	Capacity Modification	1984	2035	Steam - HFO
	Zouk2	Unit is Temporary OFF due to Rehabilitation				
	Zouk3	Energy Limited Unit	Capacity & Energy Modification	1986	2018	Steam - HFO
	Zouk4		Capacity & Energy Modification	1986	2018	
Jieh	Jieh1	Decomissioned Unit				
	Jieh2	Decomissioned Unit				
	Jieh3	Unlimited Energy	Capacity Modification	1980	2022	Steam - HFO
	Jieh4	Unit is Temporary OFF due to Rehabilitation				
	Jieh5	Unlimited Energy	Capacity Modification	1981	2014	Steam - HFO
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	1998	2028	CCGT - Diesel
	Zahra2			1998	2028	
	Zahra3			2001	2028	HRSG
Tyre	Tyre1	Energy Limited Unit	Capacity & Energy Modification	1996	2022	CCGT - Diesel
	Tyre2			1996	2022	
	Tyre3			2011	2041	HRSG
Baalbeck	BBK1	Energy Limited Unit	Capacity & Energy Modification	1996	2022	CCGT - Diesel
	BBK2			1996	2022	
	BBK3			2011	2041	HRSG

Table E.6: Production costing data for thermal units – year 2012 (b)

Thermal Plants - 2									
Power Plant	FOR (%)	Maximum Generation (MW)	Energy (GW-hr) per unit simulated results	Duty Cycle	Energy (GWh) Simulated Results	Plant Duty Cycle	Energy Distribution		Priority
							Energy (GWh)	Cumulative Probability	
New PP 1	4	100	840.96	1.000	3074.76	0.98966	No Energy Limitation		6
	15	150	1116.9	1.000					7
	15	150	1116.9	1.000					8
Deir Ammar	14	121	911.565	1.0000	2734.25	1.0	No Energy Limitation		9
	14	121	911.565	1.0000					10
	14	121	911.12	0.9997					11
Zouk	10	118	925.146	0.9995	1931.09	0.8225	No Energy Limitation		12
	Rehabilitation						Rehabilitation		13
	21	94	487.205	0.7490			480	1	
							504	0.3	
	21	113	518.739	0.6633			513	1	14
							532	0.3	
Jieh	Rehabilitation								
	Rehabilitation								
	18	54	382.111	0.9851	688.792	0.97	No Energy Limitation		15
	Rehabilitation						Rehabilitation		16
	37	57	306.681	0.9749			No Energy Limitation		
Zahrani	14	121	868.668	0.9529	2431.212	0.888	No Energy Limitation		17
	14	121	826.69	0.9069					18
	14	121	735.854	0.8072					19
Tyre	11	33	142.521	0.5540	427.535	0.552	141	1.0	20
							146	0.3	
	11	33	142.49	0.5538			141	1.0	21
							146	0.3	
	11	33	142.524	0.5540			141	1.0	22
				146	0.3				
Baalbeck	11	33	142.574	0.5542	427.577	0.553	141	1	23
							146	0	
	11	33	142.549	0.5541			141	1	24
							146	0	
	11	33	142.454	0.5537			141	1.0	25
				146	0.3				

2012 (Simulation Figures)

Figure E.9: Policy Simulation LDC figures – 2012 (a)

Figure E.10: Policy Simulation LDC figures – 2012 (b)

Figure E.11: Policy Simulation LDC figures – 2012 (c)

Figure E.12: Policy Simulation LDC figures – 2012 (d)

Year 2013 (LMT Data)

Table E.7: Production costing data for thermal units – year 2013 (a)

Thermal Plants - 1						
Power Plant	Unit Name	Category	Type Of Modification	Commissioning Year	Retirement Year	Type & Fuel
New PP 1	RE1	Unlimited Energy	Capacity Modification	2012	2037	RE - LNG
	RE2			2013	2038	
	GT1			2012	2042	CCGT - LNG
	GT2			2012	2042	
	GT3			2013	2043	HRS
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	1998	2031	CCGT - LNG
	Zahra2			1998	2031	
	Zahra3			2001	2031	HRS
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	1998	2031	CCGT - LNG
	DieAm2			1998	2031	
	DieAm3			2002	2031	HRS
Tyre	Tyre1	Energy Limited Unit - Limited Storage	Capacity & Energy Modification	1996	2022	CCGT - LNG
	Tyre2			1996	2022	
	Tyre3			2011	2041	HRS
Baalbeck	BBK1	Energy Limited Unit - Limited Storage	Capacity & Energy Modification	1996	2022	CCGT - LNG
	BBK2			1996	2022	
	BBK3			2011	2041	HRS
Zouk	Zouk1	Unlimited Energy	Capacity Modification	1984	2035	Steam - HFO
	Zouk2			1984	2036	
	Zouk3	Unit is Temporary OFF due to Rehabilitation				
	Zouk4	Energy Limited Unit	Capacity & Energy Modification	1986	2018	Steam - HFO
Jieh	Jieh1	Decomissioned Unit				
	Jieh2	Decomissioned Unit				
	Jieh3	Unlimited Energy	Capacity Modification	1980	2022	Steam - HFO
	Jieh4			1981	2023	
	Jieh5	Unit is Temporary OFF due to Rehabilitation				

Table E.8: Production costing data for thermal units – year 2013 (b)

Thermal Plants - 2											
Power Plant	FOR (%)	Maximum Generation (MW)	Energy (GW-hr) per unit simulated results	Duty Cycle	Energy (GW-hr) Simulated Results	Plant Duty Cycle	Energy Distribution		Priority		
							Energy (GW-hr)	Cumulative Probability			
New PP 1	4	98	824.14	1.000	5296.468	1.00	No Energy Limitation		7		
	4	100	840.96	1.000					8		
	6	147	1210.456	1.000					9		
	6	147	1210.456	1.000					10		
	6	147	1210.456	1.000					11		
Zahrani	11	122	951.16	1.0000	2838.367	1.0	No Energy Limitation		12		
	11	122	949.024	0.9978					13		
	11	122	938.183	0.9864					14		
Dier Ammar	11	122	911.386	0.9582	2589.687	0.90	No Energy Limitation		15		
	11	122	867.492	0.9120					16		
	11	122	810.809	0.8524					17		
Tyre	11	32	200.116	0.8021	575.734	0.76	No Energy Limitation		18		
	11	32	191.814	0.7688					19		
	11	32	183.804	0.7367					20		
Baalbeck	11	32	177.945	0.7133	516.436	0.68	No Energy Limitation		21		
	11	32	172.386	0.6910					22		
	11	32	166.105	0.6658					23		
Zouk	10	116	557.203	0.609	1382.191	0.54	No Energy Limitation		24		
	10	116	482.197	0.527					25		
	Rehabilitation						1382.191		0.54	Rehabilitation	
	22	111	342.791	0.4520			503	1			
							521	0.3			
Jieh	Decomissioned Unit										
	Decomissioned Unit										
	18	53	156.559	0.411	301.793	0.4	No Energy Limitation		27		
	18	53	145.234	0.382					28		
	Rehabilitation									Rehabilitation	

2013 (Simulation Figures)

Figure E.13: Policy Simulation LDC figures – 2013 (a)

Figure E.14: Policy Simulation LDC figures – 2013 (b)

Figure E.15: Policy Simulation LDC figures – 2013 (c)

Figure E.16: Policy Simulation LDC figures – 2013 (d)

Year 2014 (LMT Data)

Table E.9: Production costing data for thermal units – year 2014 (a)

Thermal Plants						
Power Plant	Unit Name	Category	Type Of Modification	Commissioning Year	Retirement Year	Type & Fuel
New PP 2	GT-1	Unlimited Energy	Capacity Modification	2014	2044	GT - LNG
	GT-2			2014	2044	
	GT-3			2014	2044	
	GT-4			2014	2044	
	GT-5			2014	2044	
	GT-6			2014	2044	
New PP 1	RE1	Unlimited Energy	Capacity Modification	2012	2037	RE - LNG
	RE2			2013	2038	
	GT1			2012	2042	CCGT - LNG
	GT2			2012	2042	
	HRSB			2013	2043	HRSB
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	1998	2031	CCGT - LNG
	Zahra2			1998	2031	
	Zahra3			2001	2031	HRSB
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	1998	2031	CCGT - NG
	DieAm2			1998	2031	
	DieAm3			2002	2031	HRSB
Tyre	Tyre1	Unlimited Energy	Capacity Modification	1996	2022	CCGT - LNG
	Tyre2			1996	2022	
	Tyre3			2011	2041	HRSB
Baalbeck	BBK1	Unlimited Energy	Capacity Modification	1996	2022	CCGT - LNG
	BBK2			1996	2022	
	BBK3			2011	2041	HRSB
Zouk	Zouk1	Unlimited Energy	Capacity Modification	1984	2035	Steam - HFO
	Zouk2			1984	2036	
	Zouk3			1984	2037	
	Zouk4	Unit is Temporary OFF due to Rehabilitation				
Jieh	Jieh1	Decomissioned Unit				
	Jieh2	Decomissioned Uni				
	Jieh3	Unlimited Energy	Capacity Modification	1980	2022	Steam - HFO
	Jieh4			1981	2023	
	Jieh5			1981	2024	

Table E.10: Production costing data for thermal units – year 2014 (b)

Thermal Plants										
Power Plant	FOR (%)	Maximum Generation (MW)	Energy (GW-hr) per unit simulated results	Duty Cycle	Energy (GW-hr) Simulated Results	Plant Duty Cycle	Energy Distribution		Priority	
							Energy (GW-hr)	Cumulative Probability		
New PP-2	6	125	1029.3	1.00	6175.8	1.00	No Energy Limitation		6	
	6	125	1029.3	1.00					7	
	6	125	1029.3	1.00					8	
	6	125	1029.3	1.00					9	
	6	125	1029.3	1.00					10	
	6	125	1029.3	1.00					11	
New PP-1	4	96	807.321	1.0000	5202.459	1.00	No Energy Limitation		12	
	4	98	824.14	1.0000					13	
	6	144	1185.753	0.9994					14	
	6	144	1185.001	0.9994					15	
	6	144	1200.244	0.9916					16	
Zahrani	11	120	906.213	0.9686	2602.014	0.93	No Energy Limitation		17	
	11	120	871.102	0.9311					18	
	11	120	824.699	0.8815					19	
Deir Ammar	11	120	756.271	0.8084	1973.64	0.71	No Energy Limitation		20	
	11	120	652.608	0.6976					21	
	11	120	564.761	0.6037					22	
Tyre	11	32	138.789	0.5563	401.505	0.54	No Energy Limitation		23	
	11	32	133.952	0.5369					24	
	11	32	128.764	0.5161					25	
Baalbeck	11	32	123.158	0.4937	355.001	0.72	No Energy Limitation		26	
	11	32	118.068	0.4733					27	
	11	32	113.775	0.4560					28	
Zouk	11	113	363.889	0.413	929.642	0.35	No Energy Limitation		29	
	11	114	310.927	0.3498					30	
	11	114	254.826	0.2867					31	
	Rehabilitation							Rehabilitation		
Jieh	Decommissioned Unit									
	Decommissioned Unit									
	19	52	90.332	0.2448	257.742	0.22	No Energy Limitation		32	
	19	52	81.453	0.2208					33	
	19	62	85.957	0.1954					34	

2014 (Simulation Figures)

Figure E.17: Policy Simulation LDC figures – 2014 (a)

Figure E.18: Policy Simulation LDC figures – 2014 (b)

Figure E.19: Policy Simulation LDC figures – 2014 (c)

Figure E.20: Policy Simulation LDC figures – 2014 (d)

Figure E.21: Policy Simulation LDC figures – 2014 (e)

Year 2015 (LMT Data)

Table E.11: Production costing data for thermal units – year 2015 (a)

Thermal Plants						
Power Plant	Unit Name	Category	Type Of Modification	Commissioning Year	Retirement Year	Type & Fuel
New PP-2	GT-1	Unlimited Energy	Capacity Modification	2014	2044	CCGT - LNG
	GT-2			2014	2044	
	HRSB-1			2014	2044	HRSB
	GT-3			2014	2044	CCGT - LNG
	GT-4			2014	2044	
	HRSB-2			2014	2044	HRSB
	GT-5			2015	2045	CCGT - LNG
	GT-6			2015	2045	
	HRSB-3			2015	2045	HRSB
	GT-7			2015	2045	CCGT - LNG
	GT-8			2015	2045	
	HRSB-4			2015	2045	HRSB
New PP-1	RE1	Unlimited Energy	Capacity Modification	2012	2037	RE - LNG
	RE2			2013	2038	
	GT1			2012	2042	CCGT - LNG
	GT2			2012	2042	
	HRSB			2013	2043	HRSB
Zahrani	Zahra1	Unlimited Energy	Capacity Modification	1998	2031	CCGT - LNG
	Zahra2			1998	2031	
	Zahra3			2001	2031	HRSB
Deir Ammar	DieAm1	Unlimited Energy	Capacity Modification	1998	2031	CCGT - NG
	DieAm2			1998	2031	
	DieAm3			2002	2031	HRSB
Tyre	Tyre1	Energy Limited Unit - Limited Storage	Capacity & Energy Modification	1996	2022	CCGT - LNG
	Tyre2			1996	2022	
	Tyre3			2011	2041	HRSB
Baalbeck	BBK1	Energy Limited Unit - Limited Storage	Capacity & Energy Modification	1996	2022	CCGT - LNG
	BBK2			1996	2022	
	BBK3			2011	2041	HRSB
Zouk	Zouk1	Unlimited Energy	Capacity Modification	1984	2035	Steam - HFO
	Zouk2			1984	2036	
	Zouk3			1984	2037	
	Zouk4			1984	2038	
Jieh	Jieh1	Decomissioned Unit				
	Jieh2	Decomissioned Unit				
	Jieh3	Unlimited Energy	Capacity Modification	1980	2022	Steam - HFO
	Jieh4			1981	2023	
	Jieh5			1981	2024	

Table E.12: Production costing data for thermal units – year 2015 (b)

Thermal Plants								
Power Plant	FOR (%)	Maximum Generation (MW)	Energy (GW-hr) per unit simulated results		Duty Cycle	Energy (GWh) Simulated Results	Plant Duty Cycle	Priority
New PP-2	6	123	1012.831		1.000	12193.681	1.00	6
	6	123	1012.831		1.000			7
	6	123	1012.831		1.000			8
	6	123	1012.831		1.000			9
	6	123	1012.831		1.000			10
	6	123	1012.831		1.000			11
	6	123	1012.831		1.000			12
	6	123	1012.831		1.000			13
	6	123	1012.831		1.000			14
	6	125	1029.3		1.000			15
	6	125	1028.053		0.998			16
	6	125	1020.849		0.991			17
New PP-1	4	94	771.776		0.976	4416.124	0.87	18
	4	96	768.635		0.952			19
	6	141	1053.344		0.907			20
	6	141	977.079		0.841			21
	6	141	845.29		0.712			22
Zahrani	12	118	546.988		0.601	1448.751	0.53	23
	12	118	482.913		0.530			24
	12	118	418.85		0.460			25
Dier Ammar	12	118	363.364		0.399	924.05	0.34	26
	12	118	308.036		0.338			27
	12	118	252.65		0.277			28
Tyre	11	31	58.855		0.243	165.921	0.23	29
	11	31	55.191		0.228			30
	11	31	51.875		0.214			31
Baalbeck	11	31	48.52		0.200	135.451	0.19	32
	11	31	45.114		0.186			33
	11	31	41.817		0.173			34
Zouk	11	111	123.412		0.142	316.007	0.09	35
	11	111	88.819		0.102			36
	11	112	60.459		0.069			37
	11	136	43.317		0.040			38
Jieh	Decomissioned Unit							
	Decomissioned Unit							
	19	51	9.56	0.0264	23.652	0.020	39	
	19	51	7.464	0.0206			40	
	19	61	6.628	0.0153			41	

2015 (Simulation Figures)

Figure E.22: Policy Simulation LDC figures – 2015 (a)

Figure E.23: Policy Simulation LDC figures – 2015 (b)

Figure E.24: Policy Simulation LDC figures – 2015 (c)

Figure E.25: Policy Simulation LDC figures – 2015 (d)

Figure E.26: Policy Simulation LDC figures – 2015 (e)

F. Annex 6: Production Costing Data of Policy Implementation

Production Costing: Year 2010

Table F.1: Thermal Units Basic Data after policy implementation – year 2010

Thermal Units: Basic Data									
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Fuel Price (\$/ton)	O&M (\$/MWh)	Transp. (\$/ton)
Zouk	Zouk1	HFO	506.83	263.16	-	\$0.00	\$428.22	\$28.00	\$0.00
	Zouk2	HFO	507.21	269.28	-	\$0.00	\$428.22	\$28.00	\$0.00
	Zouk3	HFO	506.78	267.24	-	\$0.00	\$428.22	\$28.00	\$0.00
	Zouk4	HFO	540.11	243.78	-	\$0.00	\$428.22	\$28.00	\$0.00
Jieh	Jieh1	HFO	140.16	321.42	-	\$0.00	\$428.22	\$12.00	\$0.00
	Jieh2	HFO	140.16	326.63	-	\$0.00	\$428.22	\$12.00	\$0.00
	Jieh3	HFO	274.71	295.24	-	\$0.00	\$428.22	\$12.00	\$0.00
	Jieh4	HFO	274.65	303.28	-	\$0.00	\$428.22	\$12.00	\$0.00
	Jieh5	HFO	335.93	288.38	-	\$0.00	\$428.22	\$12.00	\$0.00
Dier Ammar	DieAm1	Diesel	899.30	280.50	-	\$0.00	\$832.26	\$21.00	\$0.00
	DieAm2	NG	899.30	282.54	10612.42	\$5.82	\$0.00	\$21.00	\$0.00
	DieAm3	HRSB	899.30	0.00	-	\$0.00	\$0.00	\$21.00	\$0.00
Zahrani	Zahra1	Diesel	892.95	286.62	-	\$0.00	\$832.26	\$8.00	\$0.00
	Zahra2	Diesel	873.02	283.56	-	\$0.00	\$832.26	\$8.00	\$0.00
	Zahra3	HRSB	769.56	0.00	-	\$0.00	\$0.00	\$8.00	\$0.00
Tyre	Tyre1	Diesel	148.51	302.94	-	\$0.00	\$832.26	\$2.00	\$12.00
	Tyre2	Diesel	148.48	309.06	-	\$0.00	\$832.26	\$2.00	\$12.00
Baalbeck	BBK1	Diesel	148.51	309.06	-	\$0.00	\$832.26	\$6.00	\$4.00
	BBK2	Diesel	148.45	303.96	-	\$0.00	\$832.26	\$6.00	\$4.00

Table F.2: Production Costing for Thermal Units after policy implementation – year 2010

Thermal Units: Total Production Cost							
Power Plant	Unit Name	Total FO Consumption (K tons)	Total Fuel Cost (MM\$)	Unit Cost of O&M	Unit Cost of Transportation (MM\$)	Total Unit Production Cost (MM\$)	Total Plant Production Cost (MM\$)
Zouk	Zouk1	133.38	\$57.11	\$14.19	\$0.00	\$71.31	\$287.68
	Zouk2	136.58	\$58.49	\$14.20	\$0.00	\$72.69	
	Zouk3	135.43	\$57.99	\$14.19	\$0.00	\$72.18	
	Zouk4	131.67	\$56.38	\$15.12	\$0.00	\$71.51	
Jieh	Jieh1	45.05	\$19.29	\$1.68	\$0.00	\$20.97	\$164.77
	Jieh2	45.78	\$19.60	\$1.68	\$0.00	\$21.29	
	Jieh3	81.11	\$34.73	\$3.30	\$0.00	\$38.03	
	Jieh4	83.30	\$35.67	\$3.30	\$0.00	\$38.96	
	Jieh5	96.87	\$41.48	\$4.03	\$0.00	\$45.51	
Deir Ammar	DieAm1	252.25	\$209.94	\$18.89	\$0.00	\$228.83	\$322.14
	DieAm2	254.09	\$55.54	\$18.89	\$0.00	\$74.43	
	DieAm3	0.00	\$0.00	\$18.89	\$0.00	\$18.89	
Zahrani	Zahra1	255.94	\$213.01	\$7.14	\$0.00	\$220.15	\$439.32
	Zahra2	247.55	\$206.03	\$6.98	\$0.00	\$213.01	
	Zahra3	0.00	\$0.00	\$6.16	\$0.00	\$6.16	
Tyre	Tyre1	44.99	\$37.44	\$0.30	\$0.54	\$38.28	\$77.32
	Tyre2	45.89	\$38.19	\$0.30	\$0.55	\$39.04	
Baalbek	BBK1	45.90	\$38.20	\$0.89	\$0.18	\$39.28	\$77.90
	BBK2	45.12	\$37.55	\$0.89	\$0.18	\$38.63	

Table F.3: Imports Costing after policy implementation – year 2010

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost (MM\$)	Total Import's Cost (MM\$)
Syria	588.96	14.14	\$141,443.72	\$83.30	\$251.50
Egypt	525.00	11.97	\$119,694.24	\$62.84	
Turkey	832.20	12.66	\$126,600.00	\$105.36	

Table F.4: Rental Power Costing after policy implementation – year 2010

Rental Power							
Units	EES (GWh)	Energy Conversion Cost (¢/KWh)	Fuel Type	SFOC (gr/KWh) Oil	Total Consumption (K tons)	Fuel Price (\$/ton)	Total Rental Power Cost (MM\$)
Barges	2403.744	\$4.82	HFO	230	552.86112	\$428.22	\$352.61

Table F.5: Hydro Units Costing after policy implementation – year 2010

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GWh)	Total Cost (MM\$)
ALL-Hydro	1000.34	61.00	\$40,666.67	\$40.68

Production Costing: Year 2011

Table F.6: Thermal Units Basic Data after policy implementation – year 2011

Thermal Units: Basic Data									
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Fuel Price (\$/ton)	O&M (\$/MWh)	Transp. (\$/ton)
Zouk	Unit is Temporary OFF due to Rehabilitation								
	Zouk2	HFO	496.81	274.67	-	\$0.00	\$440.09	\$28.00	\$0.00
	Zouk3	HFO	497.35	272.58	-	\$0.00	\$440.09	\$28.00	\$0.00
	Zouk4	HFO	528.79	248.66	-	\$0.00	\$440.09	\$28.00	\$0.00
Jieh	Jieh1	HFO	134.55	327.85	-	\$0.00	\$440.09	\$12.00	\$0.00
	Jieh2	HFO	134.55	333.17	-	\$0.00	\$440.09	\$12.00	\$0.00
	Unit is Temporary OFF due to Rehabilitation								
	Jieh4	HFO	269.11	309.35	-	\$0.00	\$440.09	\$12.00	\$0.00
	Jieh5	HFO	330.78	294.14	-	\$0.00	\$440.09	\$12.00	\$0.00
Deir Ammar	DieAm1	Diesel	896.50	281.11	-	\$0.00	\$855.31	\$21.00	\$0.00
	DieAm2	NG	896.50	283.19	10824.67	\$5.99	\$0.00	\$21.00	\$0.00
	DieAm3	HRS	896.50	0.00	-	\$0.00	\$0.00	\$21.00	\$0.00
Zahrani	Zahra1	Diesel	896.01	287.35	-	\$0.00	\$855.31	\$8.00	\$0.00
	Zahra2	Diesel	890.95	284.23	-	\$0.00	\$855.31	\$8.00	\$0.00
	Zahra3	HRS	874.24	0.00	-	\$0.00	\$0.00	\$8.00	\$0.00
Tyre	Tyre1	Diesel	145.50	309.00	-	\$0.00	\$855.31	\$2.00	\$12.00
	Tyre2	Diesel	145.51	315.24	-	\$0.00	\$855.31	\$2.00	\$12.00
	Tyre3		145.50	0.00	-	\$0.00	\$0.00	\$2.00	\$0.00
Baalbeck	BBK1	Diesel	145.51	315.24	-	\$0.00	\$855.31	\$6.00	\$4.00
	BBK2	Diesel	145.48	310.04	-	\$0.00	\$855.31	\$6.00	\$4.00

Table F.7: Production Costing for Thermal Units after policy implementation – year 2011

Thermal Units: Total Production Cost							
Power Plant	Unit Name	Total FO Consumption (K tons)	Total Fuel Cost	Unit Cost of O&M (MM\$)	Unit Cost of Transportation (MM\$)	Total Unit Production Cost (MM\$)	Total Plant Production Cost (MM\$)
Zouk	Unit is Temporary OFF due to Rehabilitation						\$220.23
	Zouk2	136.46	\$60.05	\$13.91	\$0.00	\$73.96	
	Zouk3	135.57	\$59.66	\$13.93	\$0.00	\$73.59	
	Zouk4	131.49	\$57.87	\$14.81	\$0.00	\$72.67	
Jieh	Jieh1	44.11	\$19.41	\$1.61	\$0.00	\$21.03	\$129.02
	Jieh2	44.83	\$19.73	\$1.61	\$0.00	\$21.34	
	Unit is Temporary OFF due to Rehabilitation						
	Jieh4	83.25	\$36.64	\$3.23	\$0.00	\$39.87	
	Jieh5	97.30	\$42.82	\$3.97	\$0.00	\$46.79	
Deir Ammar	DieAm1	252.01	\$215.55	\$18.83	\$0.00	\$234.38	\$330.20
	DieAm2	253.88	\$58.17	\$18.83	\$0.00	\$76.99	
	DieAm3	0.00	\$0.00	\$18.83	\$0.00	\$18.83	
Zahrani	Zahra1	257.47	\$220.22	\$7.17	\$0.00	\$227.39	\$458.10
	Zahra2	253.24	\$216.60	\$7.13	\$0.00	\$223.72	
	Zahra3	0.00	\$0.00	\$6.99	\$0.00	\$6.99	
Tyre	Tyre1	44.96	\$38.46	\$0.29	\$0.54	\$39.29	\$79.65
	Tyre2	45.87	\$39.23	\$0.29	\$0.55	\$40.07	
	Tyre3	0.00	\$0.00	\$0.29	\$0.00	\$0.29	
Baalbeck	BBK1	45.87	\$39.23	\$0.87	\$0.18	\$40.29	\$79.92
	BBK2	45.11	\$38.58	\$0.87	\$0.18	\$39.63	

Table F.8: Imports Costing after policy implementation – year 2011

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost (MM\$)	Total Import's Cost (MM\$)
Syria	588.96	14.57	\$145,687.03	\$85.80	\$259.05
Egypt	525.00	12.33	\$123,285.07	\$64.72	
Turkey	832.20	13.04	\$130,398.00	\$108.52	

Table F.9: Rental Power Costing after policy implementation – year 2011

Rental Power							
Units	EES (GWh)	Energy Conversion Cost (¢/KWh)	Fuel Type	SFOC (gr/KWh) Oil	Total Consumption (K tons)	Fuel Price (\$/ton)	Total Rental Power Cost (MM\$)
Barges	2403.744	\$4.96	HFO	234.6	563.92	\$440.09	\$367.51

Table F.10: Hydro Units Costing after policy implementation – year 2011

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GWh)	Total Cost (MM\$)
ALL-Hydro	1000.34	61.00	\$40,666.67	\$40.68

Production Costing: Year 2012

Table F.11: Thermal Units Basic Data after policy implementation – year 2012

Thermal Units: Basic Data									
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Fuel Price (\$/ton)	O&M (\$/MWh)	Transp. (\$/ton)
New PP1	RE1	HFO	840.96	170	11178.00	\$0.00	\$452.32	\$10.00	\$0.00
	GT1	HFO	1116.9	270	11442.32	\$0.00	\$452.32	\$30.00	\$0.00
	GT2	HFO	1116.9	270	11442.32	\$0.00	\$452.32	\$30.00	\$0.00
Zouk	Zouk1	HFO	925.15	228.16	-	\$0.00	\$452.32	\$28.00	\$0.00
	Unit is Temporary OFF due to Rehabilitation								
	Zouk3	HFO	487.21	278.0365	-	\$0.00	\$452.32	\$28.00	\$0.00
	Zouk4	HFO	518.74	253.6287	-	\$0.00	\$452.32	\$28.00	\$0.00
Jieh	Decommissioned Unit								
	Decommissioned Unit								
	Jieh3	HFO	382.11	270.2426	-	0.00	\$452.32	\$12.00	\$0.00
	Unit is Temporary OFF due to Rehabilitation								
	Jieh5	HFO	306.68	300.0255	-	\$0.00	\$452.32	\$12.00	\$0.00
Deir Ammar	DieAm1	Diesel	911.57	286.8322	-	\$0.00	\$879.06	\$21.00	\$0.00
	DieAm2	NG	911.57	288.9546	11041.16	\$6.17	\$0.00	\$21.00	\$0.00
	DieAm3	HRS	911.12	0	-	\$0.00	\$0.00	\$21.00	\$0.00
Zahrani	Zahra1	Diesel	868.67	293.1994	-	\$0.00	\$879.06	\$8.00	\$0.00
	Zahra2	Diesel	826.69	290.0158	-	\$0.00	\$879.06	\$8.00	\$0.00
	Zahra3	HRS	735.85	0	-	\$0.00	\$0.00	\$8.00	\$0.00
Tyre	Tyre1	Diesel	142.52	315.1788	-	\$0.00	\$879.06	\$2.00	\$12.00
	Tyre2	Diesel	142.49	321.546	-	\$0.00	\$879.06	\$2.00	\$12.00
	Tyre3	HRS	142.52	0	-	\$0.00	\$0.00	\$2.00	\$0.00
Baalbeck	BBK1	Diesel	142.57	321.546	-	\$0.00	\$879.06	\$6.00	\$4.00
	BBK2	Diesel	142.55	316.24	-	\$0.00	\$879.06	\$6.00	\$4.00
	BBK3	HRS	142.45	0	-	\$0.00	\$0.00	\$6.00	\$0.00

Table F.12: Production Costing for Thermal Units after policy implementation – year 2012

Thermal Units: Total Production Cost							
Power Plant	Unit Name	Total FO Consumption (K tons)	Total Fuel Cost	Unit Cost of O&M (MM\$)	Unit Cost of Transportation (MM\$)	Total Unit Production Cost (MM\$)	Total Plant Production Cost (MM\$)
New PP1	RE1	142.96	\$64.66	\$8.41	\$0.00	\$73.07	\$412.89
	GT1	301.56	\$136.40	\$33.51	\$0.00	\$169.91	
	GT2	301.56	\$136.40	\$33.51	\$0.00	\$169.91	
Zouk	Zouk1	211.08	\$95.48	\$25.90	\$0.00	\$121.38	\$270.33
	Unit is Temporary OFF due to Rehabilitation						
	Zouk3	135.46	\$61.27	\$13.64	\$0.00	\$74.91	
	Zouk4	131.57	\$59.51	\$14.52	\$0.00	\$74.03	
Jieh	Decommissioned Unit						\$96.59
	Decommissioned Unit						
	Jieh3	103.26	46.71	4.59	0.00	\$51.29	
	Unit is Temporary OFF due to Rehabilitation						
	Jieh5	92.01	\$41.62	\$3.68	\$0.00	\$45.30	
Deir Ammar	DieAm1	261.47	\$229.84	\$19.14	\$0.00	\$248.99	\$349.40
	DieAm2	263.40	\$62.14	\$19.14	\$0.00	\$81.28	
	DieAm3	0.00	\$0.00	\$19.13	\$0.00	\$19.13	
Zahrani	Zahra1	254.69	\$223.89	\$6.95	\$0.00	\$230.84	\$454.10
	Zahra2	239.75	\$210.76	\$6.61	\$0.00	\$217.37	
	Zahra3	0.00	\$0.00	\$5.89	\$0.00	\$5.89	
Tyre	Tyre1	44.92	\$39.49	\$0.29	\$0.54	\$40.31	\$81.71
	Tyre2	45.82	\$40.28	\$0.28	\$0.55	\$41.11	
	Tyre3	0.00	\$0.00	\$0.29	\$0.00	\$0.29	
Baalbeck	BBK1	45.84	\$40.30	\$0.86	\$0.18	\$41.34	\$82.86
	BBK2	45.08	\$39.63	\$0.86	\$0.18	\$40.66	
	BBK3	0.00	\$0.00	\$0.85	\$0.00	\$0.85	

Table F.13: Imports Costing after policy implementation – year 2012

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost (MM\$)	Total Import's Cost (MM\$)
Syria	588.96	15.01	\$150,057.64	\$88.38	\$155.04
Egypt	525.00	12.70	\$126,983.62	\$66.67	

Table F.14: Rental Power Costing after policy implementation – year 2012

Rental Power							
Units	EES (GWh)	Energy Conversion Cost (¢/KWh)	Fuel Type	SFOC (gr/KWh) Oil	Total Consumption (K tons)	Fuel Price (\$/ton)	Total Rental Power Cost (MM\$)
Barges	2403.744	\$5.11	HFO	239.292	575.20	\$452.32	\$383.09

Table F.15: Hydro Units Costing after policy implementation – year 2012

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GWh)	Total Cost (MM\$)
ALL-Hydro	1000.34	61.00	\$40,666.67	\$40.68

Table F.16: Wind Power Costing after policy implementation – year 2012

Wind Power				
Unit	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost
Wind Power	128.532	0.012	\$ 120	\$ 15,423.84

Production Costing: Year 2013

Table F.17: Thermal Units Basic Data after policy implementation – year 2013

Thermal Units: Basic Data									
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Fuel Price (\$/ton)	O&M (\$/MWh)	Transp. (\$/ton)
New PP1	RE1	LNG	824.14	170	11178	\$7.50	\$372.41	\$10.00	\$0.00
	RE2	LNG	840.96	170	11178	\$7.50	\$372.41	\$10.00	\$0.00
	GT1	LNG	1210.46	170	10612.42105	\$7.50	\$372.41	\$10.00	\$0.00
	GT2	LNG	1210.46	170	10612.42105	\$7.50	\$372.41	\$10.00	\$0.00
	HRSg	HRSg	1210.46	0	0	\$0.00	\$0.00	\$10.00	\$0.00
Zouk	Zouk1	HFO	557.20	232.72	-	\$0.00	\$464.91	\$28.00	\$0.00
	Zouk2	HFO	482.20	239.67	-	\$0.00	\$464.91	\$28.00	\$0.00
	Unit is Temporary OFF due to Rehabilitation								
	Zouk4	HFO	342.79	258.70	-	\$0.00	\$464.91	\$28.00	\$0.00
Jieh	Decommissioned Unit								
	Decommissioned Unit								
	Jieh3	HFO	156.56	275.65	-	\$0.00	\$464.91	\$12.00	\$0.00
	Jieh4	HFO	145.23	284.35	-	\$0.00	\$464.91	\$12.00	\$0.00
	Unit is Temporary OFF due to Rehabilitation								
Deir Ammar	DieAm1	NG	911.39	292.67	10612.42	\$6.36	\$0.00	\$21.00	\$0.00
	DieAm2	NG	867.49	294.83	11261.99	\$6.36	\$0.00	\$21.00	\$0.00
	DieAm3	HRSg	810.81	0.00	0.00	\$0.00	\$0.00	\$21.00	\$0.00
Zahrani	Zahra1	LNG	951.16	299.16	10612.42	\$7.50	\$0.00	\$10.00	\$0.00
	Zahra2	LNG	949.02	295.92	11178.00	\$7.50	\$0.00	\$10.00	\$0.00
	Zahra3	HRSg	938.18	0.00	0.00	\$0.00	\$0.00	\$10.00	\$0.00
Tyre	Tyre1	LNG	200.12	321.48	10612.42	\$7.50	\$0.00	\$20.00	\$0.00
	Tyre2	LNG	191.81	327.98	10612.42	\$7.50	\$0.00	\$20.00	\$0.00
	Tyre3	HRSg	183.80	0.00	0.00	\$0.00	\$0.00	\$20.00	\$0.00
Baalbeck	BBK1	LNG	177.95	327.98	10612.42	\$7.50	\$0.00	\$22.00	\$0.00
	BBK2	LNG	172.39	322.56	10612.42	\$7.50	\$0.00	\$22.00	\$0.00
	BBK3	HRSg	166.11	0.00	0.00	\$0.00	\$0.00	\$22.00	\$0.00

Table F.18: Production Costing for Thermal Units after policy implementation – year 2013

Thermal Units: Total Production Cost							
Power Plant	Unit Name	Total FO Consumption (K tons)	Total Fuel Cost	Unit Cost of O&M (MM\$)	Unit Cost of Transportation (MM\$)	Total Unit Production Cost (MM\$)	Total Plant Production Cost (MM\$)
New PP1	RE1	0	\$69.09	\$8.24	\$0.00	\$77.33	\$385.25
	RE2	0	\$70.50	\$8.41	\$0.00	\$78.91	
	GT1	0	\$96.34	\$12.10	\$0.00	\$108.45	
	GT2	0	\$96.34	\$12.10	\$0.00	\$108.45	
	HRSG	0	\$0.00	\$12.10	\$0.00	\$12.10	
Zouk	Zouk1	129.67	\$60.29	\$15.60	\$0.00	\$75.89	\$193.94
	Zouk2	115.57	\$53.73	\$13.50	\$0.00	\$67.23	
	Unit is Temporary OFF due to Rehabilitation						
	Zouk4	88.68	\$41.23	\$9.60	\$0.00	\$50.83	
Jieh	Decommissioned Unit						\$42.88
	Decommissioned Unit						
	Jieh3	43.16	\$20.06	\$1.88	\$0.00	\$21.94	
	Jieh4	41.30	\$19.20	\$1.74	\$0.00	\$20.94	
	Unit is Temporary OFF due to Rehabilitation						
Deir Ammar	DieAm1	0	\$61.51	\$19.14	\$0.00	\$80.64	\$178.02
	DieAm2	0	\$62.13	\$18.22	\$0.00	\$80.34	
	DieAm3	0	\$0.00	\$17.03	\$0.00	\$17.03	
Zahrani	Zahra1	0	\$75.71	\$9.51	\$0.00	\$85.22	\$183.65
	Zahra2	0	\$79.56	\$9.49	\$0.00	\$89.05	
	Zahra3	0	\$0.00	\$9.38	\$0.00	\$9.38	
Tyre	Tyre1	0	\$15.93	\$4.00	\$0.00	\$19.93	\$42.71
	Tyre2	0	\$15.27	\$3.84	\$0.00	\$19.10	
	Tyre3	0	\$0.00	\$3.68	\$0.00	\$3.68	
Baalbeck	BBK1	0	\$14.16	\$3.91	\$0.00	\$18.08	\$39.25
	BBK2	0	\$13.72	\$3.79	\$0.00	\$17.51	
	BBK3	0	\$0.00	\$3.65	\$0.00	\$3.65	

Table F.19: Imports Costing after policy implementation – year 2013

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost	Total Import's Cost (MM\$)
Syria	588.96	15.01	\$150,057.64	\$88.38	\$155.04
Egypt	525.00	12.70	\$126,983.62	\$66.67	

Table F.20: Rental Power Costing after policy implementation – year 2013

Rental Power							
Units	EES (GWh)	Energy Conversion Cost (¢/KWh)	Fuel Type	SFOC (gr/KWh) Oil	Total Consumption (K tons)	Fuel Price (\$/ton)	Total Rental Power Cost (MM\$)
Barges	2403.744	\$5.11	HFO	239.292	575.20	\$452.32	\$383.09

Table F.21: Hydro Units Costing after policy implementation – year 2013

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GWh)	Total Cost (MM\$)
ALL-Hydro	1000.34	61.00	\$40,666.67	\$40.68

Table F.22: Wind Power Costing after policy implementation – year 2013

Wind Power				
Unit	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost
Wind Power	128.532	0.012	\$ 120	\$ 15,423.84

Production Costing: Year 2014

Table F.23: Thermal Units Basic Data after policy implementation – year 2014

Thermal Units: Basic Data									
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Fuel Price (\$/ton)	O&M (\$/MWh)	Transp. (\$/ton)
New PP2	GT1	LNG	1029.3	160	10612.42	\$7.73	\$383.59	\$10.00	\$0.00
	GT2	LNG	1029.3	160	10612.42	\$7.73	\$383.59	\$10.00	\$0.00
	GT3	LNG	1029.3	160	10612.42	\$7.73	\$383.59	\$10.00	\$0.00
	GT4	LNG	1029.3	160	10612.42	\$7.73	\$383.59	\$10.00	\$0.00
	GT5	LNG	1029.3	160	10612.42	\$7.73	\$383.59	\$10.00	\$0.00
	GT6	LNG	1029.3	160	10612.42	\$7.73	\$383.59	\$10.00	\$0.00
New PP1	RE1	LNG	807.32	173.4	10801.48	\$7.73	\$383.59	\$10.00	\$0.00
	RE2	LNG	824.14	173.4	10801.48	\$7.73	\$383.59	\$10.00	\$0.00
	GT1	LNG	1185.8	173.4	10254.95	\$7.73	\$383.59	\$10.00	\$0.00
	GT2	LNG	1185	173.4	10254.95	\$7.73	\$383.59	\$10.00	\$0.00
	HRSG	HRSG	1200.2	0	0.00	\$0.00	\$0.00	\$10.00	\$0.00
Zouk	Zouk1	HFO	363.89	237.38	-	\$0.00	\$477.88	\$28.00	\$0.00
	Zouk2	HFO	310.93	244.46	-	\$0.00	\$477.88	\$28.00	\$0.00
	Zouk3	HFO	254.83	243.04	-	\$0.00	\$477.88	\$28.00	\$0.00
	Unit is Temporary OFF due to Rehabilitation								
Jieh	Decommissioned Unit								
	Decommissioned Unit								
	Jieh3	HFO	90.33	281.16	-	\$0.00	\$477.88	\$12.00	\$0.00
	Jieh4	HFO	81.45	290.03	-	\$0.00	\$477.88	\$12.00	\$0.00
	Jieh5	HFO	85.96	275.03	-	\$0.00	\$477.88	\$12.00	\$0.00
Deir Ammar	DieAm1	NG	756.27	303.62	10824.67	\$6.55	\$0.00	\$21.00	\$0.00
	DieAm2	NG	652.61	305.83	11487.23	\$6.55	\$0.00	\$21.00	\$0.00
	DieAm3	HRSG	564.76	0.00	0.00	\$0.00	\$0.00	\$21.00	\$0.00
Zahrani	Zahra1	LNG	906.21	310.25	10612.42	\$7.73	\$383.59	\$10.00	\$0.00
	Zahra2	LNG	871.10	306.93	11178.00	\$7.73	\$383.59	\$10.00	\$0.00
	Zahra3	HRSG	824.70	0.00	0.00	\$0.00	\$0.00	\$10.00	\$0.00
Tyre	Tyre1	LNG	138.79	327.91	10824.67	\$7.73	\$383.59	\$20.00	\$0.00
	Tyre2	LNG	133.95	334.54	10824.67	\$7.73	\$383.59	\$20.00	\$0.00
	Tyre3	HRSG	128.76	0.00	0.00	\$0.00	\$0.00	\$20.00	\$0.00
Baalbeck	BBK1	LNG	123.16	334.54	10824.67	\$7.73	\$383.59	\$22.00	\$0.00
	BBK2	LNG	118.07	329.02	10824.67	\$7.73	\$383.59	\$22.00	\$0.00
	BBK3	HRSG	113.78	0.00	0.00	\$0.00	\$0.00	\$22.00	\$0.00

Table F.24: Production Costing for Thermal Units after policy implementation – year 2014

Thermal Units: Total Production Cost							
Power Plant	Unit Name	Total FO Consumption (K tons)	Total Fuel Cost	Unit Cost of O&M	Unit Cost of Transportation (MM\$)	Total Unit Production Cost (MM\$)	Total Plant Production Cost (MM\$)
New PP2	GT1	0	\$84.38	\$10.29	\$0.00	\$94.68	\$568.06
	GT2	0	\$84.38	\$10.29	\$0.00	\$94.68	
	GT3	0	\$84.38	\$10.29	\$0.00	\$94.68	
	GT4	0	\$84.38	\$10.29	\$0.00	\$94.68	
	GT5	0	\$84.38	\$10.29	\$0.00	\$94.68	
	GT6	0	\$84.38	\$10.29	\$0.00	\$94.68	
New PP1	RE1	0	\$67.36	\$8.07	\$0.00	\$75.44	\$375.97
	RE2	0	\$68.77	\$8.24	\$0.00	\$77.01	
	GT1	0	\$93.93	\$11.86	\$0.00	\$105.79	
	GT2	0	\$93.88	\$11.85	\$0.00	\$105.73	
	HRSB	0	\$0.00	\$12.00	\$0.00	\$12.00	
Zouk	Zouk1	86.38	\$41.28	\$10.19	\$0.00	\$51.47	\$133.23
	Zouk2	76.01	\$36.32	\$8.71	\$0.00	\$45.03	
	Zouk3	61.93	\$29.60	\$7.14	\$0.00	\$36.73	
	Unit is Temporary OFF due to Rehabilitation						
Jieh	Decommissioned Unit						\$37.82
	Decommissioned Unit						
	Jieh3	25.40	\$12.14	\$1.08	\$0.00	\$13.22	
	Jieh4	23.62	\$11.29	\$0.98	\$0.00	\$12.27	
	Jieh5	23.64	\$11.30	\$1.03	\$0.00	\$12.33	
Deir Ammar	DieAm1	0	\$53.62	\$15.88	\$0.00	\$69.50	\$144.17
	DieAm2	0	\$49.10	\$13.70	\$0.00	\$62.81	
	DieAm3	0	\$0.00	\$11.86	\$0.00	\$11.86	
Zahrani	Zahra1	0	\$74.29	\$9.06	\$0.00	\$83.35	\$175.53
	Zahra2	0	\$75.22	\$8.71	\$0.00	\$83.93	
	Zahra3	0	\$0.00	\$8.25	\$0.00	\$8.25	
Tyre	Tyre1	0	\$11.61	\$2.78	\$0.00	\$14.38	\$30.84
	Tyre2	0	\$11.20	\$2.68	\$0.00	\$13.88	
	Tyre3	0	\$0.00	\$2.58	\$0.00	\$2.58	
Baalbeck	BBK1	0	\$10.30	\$2.71	\$0.00	\$13.01	\$27.98
	BBK2	0	\$9.87	\$2.60	\$0.00	\$12.47	
	BBK3	0	\$0.00	\$2.50	\$0.00	\$2.50	

Table F.25: Imports Costing after policy implementation – year 2014

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost (MM\$)	Total Import's Cost (MM\$)
Syria	588.96	15.92	\$159,196.15	\$93.76	\$164.49
Egypt	525.00	13.47	\$134,716.92	\$70.73	

Table F.26: Hydro Units Costing after policy implementation – year 2014

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GWh)	Total Cost (MM\$)
ALL-Hydro	1000.34	61.00	\$40,666.67	\$40.68

Table F.27: Wind Power Costing after policy implementation – year 2014

Wind Power				
Unit	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost
Wind Power	128.532	0.012	\$ 120	\$ 15,423.84

Table F.28: Waste Power Costing after policy implementation – year 2014

Waste Power				
Units	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Waste Power Cost
Waste Power	63.24	0.01	\$ 100	\$ 6,324.10

Production Costing: Year 2015

Table F.29: Thermal Units Basic Data after policy implementation – year 2015

Thermal Units: Basic Data									
Power Plant	Unit Name	Fuel Type	EES (GWh)	SFOC (gr/KWh)	Heat Rate (mmBtu/GWh)	Fuel Price (\$/mmBtu)	Fuel Price (\$/ton)	O&M (\$/MWh)	Transp. (\$/ton)
New PP2	GT1	LNG	1012.83	163.2	10824.67	7.96	\$395.09	\$10.00	\$0.00
	GT2	LNG	1012.83	163.2	10824.67	7.96	\$395.09	\$10.00	\$0.00
	HRSG1	HRSG	1012.83	0	0.00	0.00	\$0.00	\$10.00	\$0.00
	GT3	LNG	1012.83	163.2	10824.67	7.96	\$395.09	\$10.00	\$0.00
	GT4	LNG	1012.83	163.2	10824.67	7.96	\$395.09	\$10.00	\$0.00
	HRSG2	HRSG	1012.83	0	0.00	0.00	\$0.00	\$10.00	\$0.00
	GT5	LNG	1012.83	163.2	10824.67	7.96	\$395.09	\$10.00	\$0.00
	GT6	LNG	1012.83	163.2	10824.67	7.96	\$395.09	\$10.00	\$0.00
	HRSG3	HRSG	1012.83	0	0.00	0.00	\$0.00	\$10.00	\$0.00
	GT7	LNG	1029.3	160	10612.42	7.96	\$395.09	\$10.00	\$0.00
	GT8	LNG	1028.05	160	10612.42	7.96	\$395.09	\$10.00	\$0.00
	HRSG4	HRSG	1020.85	0	0.00	0.00	\$0.00	\$10.00	\$0.00
New PP1	RE1	LNG	771.776	176.868	11017.51	7.96	\$395.09	\$10.00	\$0.00
	RE2	LNG	768.635	176.868	11017.51	7.96	\$395.09	\$10.00	\$0.00
	GT1	LNG	1053.34	176.868	10460.05	7.96	\$395.09	\$10.00	\$0.00
	GT2	LNG	977.079	176.868	10460.05	7.96	\$395.09	\$10.00	\$0.00
	HRSG	HRSG	845.29	0	0.00	0.00	\$395.09	\$10.00	\$0.00
Zouk	Zouk1	HFO	123.41	242.13	-	-	\$491.25	\$28.00	\$0.00
	Zouk2	HFO	88.82	249.35	-	-	\$491.25	\$28.00	\$0.00
	Zouk3	HFO	60.46	247.90	-	-	\$491.25	\$28.00	\$0.00
	Zouk4	HFO	43.32	223.70	-	-	\$491.25	\$28.00	\$0.00
Jieh	Decommissioned Unit								
	Decommissioned Unit								
	Jieh3	HFO	9.56	286.78	-	-	\$491.25	\$12.00	\$0.00
	Jieh4	HFO	7.46	295.83	-	-	\$491.25	\$12.00	\$0.00
	Jieh5	HFO	6.63	280.53	-	-	\$491.25	\$12.00	\$0.00
Dier Ammar	DieAm1	NG	363.36	309.69	11041.16	6.75	-	\$21.00	\$0.00
	DieAm2	NG	308.04	311.95	11716.97	6.75	-	\$21.00	\$0.00
	DieAm3	HRSG	252.65	0.00	0.00	-	-	\$21.00	\$0.00
Zahrani	Zahra1	LNG	546.99	311.45	10824.67	7.96	\$395.09	\$10.00	\$0.00
	Zahra2	LNG	482.91	308.07	11401.56	7.96	\$395.09	\$10.00	\$0.00
	Zahra3	HRSG	418.85	0.00	0.00	0.00	\$0.00	\$10.00	\$0.00
Tyre	Tyre1	LNG	58.86	334.47	11041.16	7.96	\$395.09	\$20.00	\$0.00
	Tyre2	LNG	55.19	341.23	11041.16	7.96	\$395.09	\$20.00	\$0.00
	Tyre3	HRSG	51.88	0.00	0.00	0.00	\$0.00	\$20.00	\$0.00
Baalbeck	BBK1	LNG	48.52	341.23	11041.16	7.96	\$395.09	\$22.00	\$0.00
	BBK2	LNG	45.11	335.60	11041.16	7.96	\$395.09	\$22.00	\$0.00
	BBK3	HRSG	41.82	0.00	0.00	0.00	\$0.00	\$22.00	\$0.00

Table F.30: Production Costing for Thermal Units after policy implementation – year 2015

Thermal Units: Total Production Cost							
Power Plant	Unit Name	Total FO Consumption (K tons)	Total Fuel Cost	Unit Cost of O&M	Unit Cost of Transportation (MM\$)	Total Unit Production Cost (MM\$)	Total Plant Production Cost (MM\$)
New PP2	GT1	0	\$87.23	\$10.13	\$0.00	\$97.36	\$819.07
	GT2	0	\$87.23	\$10.13	\$0.00	\$97.36	
	HRS G1	0	\$0.00	\$10.13	\$0.00	\$10.13	
	GT3	0	\$87.23	\$10.13	\$0.00	\$97.36	
	GT4	0	\$87.23	\$10.13	\$0.00	\$97.36	
	HRS G2	0	\$0.00	\$10.13	\$0.00	\$10.13	
	GT5	0	\$87.23	\$10.13	\$0.00	\$97.36	
	GT6	0	\$87.23	\$10.13	\$0.00	\$97.36	
	HRS G3	0	\$0.00	\$10.13	\$0.00	\$10.13	
	GT7	0	\$86.91	\$10.29	\$0.00	\$97.21	
	GT8	0	\$86.81	\$10.28	\$0.00	\$97.09	
	HRS G4	0	\$0.00	\$10.21	\$0.00	\$10.21	
New PP1	RE1	0	\$67.66	\$7.72	\$0.00	\$75.37	\$348.19
	RE2	0	\$67.38	\$7.69	\$0.00	\$75.07	
	GT1	0	\$87.67	\$10.53	\$0.00	\$98.20	
	GT2	0	\$81.32	\$9.77	\$0.00	\$91.09	
	HRS G	0	\$0.00	\$8.45	\$0.00	\$8.45	
Zouk	Zouk1	29.88	\$14.68	\$3.46	\$0.00	\$18.13	\$46.53
	Zouk2	22.15	\$10.88	\$2.49	\$0.00	\$13.37	
	Zouk3	14.99	\$7.36	\$1.69	\$0.00	\$9.06	
	Zouk4	9.69	\$4.76	\$1.21	\$0.00	\$5.97	
Jieh	Decommissioned Unit						\$3.63
	Decommissioned Unit						
	Jieh3	2.74	\$1.35	\$0.11	\$0.00	\$1.46	
	Jieh4	2.21	\$1.08	\$0.09	\$0.00	\$1.17	
	Jieh5	1.86	\$0.91	\$0.08	\$0.00	\$0.99	
Dier Ammar	DieAm1	0	\$27.07	\$7.63	\$0.00	\$34.70	\$70.82
	DieAm2	0	\$24.35	\$6.47	\$0.00	\$30.82	
	DieAm3	0	\$0.00	\$5.31	\$0.00	\$5.31	
Zahrani	Zahra1	0	\$47.11	\$5.47	\$0.00	\$52.58	\$105.41
	Zahra2	0	\$43.81	\$4.83	\$0.00	\$48.64	
	Zahra3	0	\$0.00	\$4.19	\$0.00	\$4.19	
Tyre	Tyre1	0	\$5.17	\$1.18	\$0.00	\$6.35	\$13.34
	Tyre2	0	\$4.85	\$1.10	\$0.00	\$5.95	
	Tyre3	0	\$0.00	\$1.04	\$0.00	\$1.04	
Baalbeck	BBK1	0	\$4.26	\$1.07	\$0.00	\$5.33	\$11.21
	BBK2	0	\$3.96	\$0.99	\$0.00	\$4.96	
	BBK3	0	\$0.00	\$0.92	\$0.00	\$0.92	

Table F.31: Imports Costing after policy implementation – year 2015

Imports					
Country	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost	Total Import's Cost (MM\$)
Syria	588.96	16.40	\$163,972.04	\$96.57	\$169.42
Egypt	525.00	13.88	\$138,758.43	\$72.85	

Table F.32: Hydro Units Costing after policy implementation – year 2015

Hydro Plants				
Units	EES (GWh)	Cost (LL/kWh)	Cost (\$/GWh)	Total Cost (MM\$)
ALL-Hydro	1000.34	61.00	\$40,666.67	\$40.68

Table F.33: Wind Power Costing after policy implementation – year 2015

Wind Power				
Unit	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Cost
Wind Power	128.532	0.012	\$120	\$15,423.84

Table F.34: Waste Power Costing after policy implementation – year 2015

Waste Power				
Units	EES (GWh)	Price (¢/KWh)	Price (\$/GWh)	Total Waste Power Cost
Waste Power	63.24	0.01	\$100	\$ 6,324.10

G. Annex 7: Levelized Cost Data after Policy Implementation

Table G.1: Levelized Cost data for Thermal units year 2010 (policy implementation)

2010				
Power Plant	Fuel Cost (\$/MW-hr)	O&M or ECA (\$/MW-hr)	Total Energy (MW-hr/yr)	Total Capital
Barges (Rental)	\$98.49	\$48.20	2403744	\$0.00
New PP2	-	-	-	\$0.00
New PP1	-	-	-	\$0.00
Zahrani	\$165.27	\$8.00	2535522	\$0.00
Deir Ammar	\$98.40	\$21.00	2697903	\$0.00
Sour	\$254.67	\$2.00	296987	\$0.00
Baalbeck	\$255.10	\$6.00	296963	\$0.00
Zouk	\$111.59	\$28.00	2060930	\$0.00
Jieh	\$129.36	\$12.00	1165610	\$0.00

Table G.2: Levelized Cost data for Thermal units year 2011 (policy implementation)

2011				
Power Plant	Fuel Cost (\$/MW-hr)	O&M or ECA (\$/MW-hr)	Total Energy (MW-hr/yr)	Total Capital
Barges (Rental)	\$103.24	\$49.65	2403744	\$0.00
New PP2	-	-	-	\$0.00
New PP1	-	-	-	\$0.00
Zahrani	\$164.14	\$8.00	2661199	\$2,331,082.35
Deir Ammar	\$101.77	\$21.00	2689494	\$2,331,082.35
Sour	\$177.97	\$2.00	436513	\$8,417,797.37
Baalbeck	\$267.41	\$6.00	290993	\$0.00
Zouk	\$116.60	\$28.00	1522955	\$0.00
Jieh	\$136.48	\$12.00	868990	\$0.00

Table G.3: Levelized Cost data for Thermal units year 2012 (policy implementation)

2012				
Power Plant	Fuel Cost (\$/MW-hr)	O&M or ECA (\$/MW-hr)	Total Energy (MW-hr/yr)	Total Capital
Barges (Rental)	\$108.24	\$51.14	2403744	\$0.00
New PP2	-	-	-	\$0.00
New PP1	\$109.75	\$23.33	3074760	\$32,525,717.54
Zahrani	\$178.78	\$8.00	2431212	\$4,662,164.70
Deir Ammar	\$106.79	\$21.00	2734250	\$4,662,164.70
Sour	\$186.56	\$2.00	427535	\$8,417,797.37
Baalbeck	\$186.93	\$6.00	427577	\$8,417,797.37
Zouk	\$111.99	\$28.00	1931090	\$3,661,771.38
Jieh	\$128.23	\$12.00	688792	\$3,661,771.38

Table G.4: Levelized Cost data for Thermal units year 2013 (policy implementation)

2013				
Power Plant	Fuel Cost (\$/MW-hr)	O&M or ECA (\$/MW-hr)	Total Energy (MW-hr/yr.)	Total Capital
Barges (Rental)	\$113.47	\$52.67	2403744	\$0.00
New PP2	-	-	-	\$0.00
New PP1	\$65.37	\$10.00	5296468	\$52,821,765.29
Zahrani	\$54.48	\$10.00	2838367	\$6,993,247.05
Deir Ammar	\$46.37	\$21.00	2589687	\$6,993,247.05
Sour	\$53.06	\$12.00	575734	\$8,417,797.37
Baalbeck	\$53.06	\$14.00	516436	\$8,417,797.37
Zouk	\$112.32	\$28.00	1382191	\$7,323,542.77
Jieh	\$130.10	\$12.00	301793	\$7,323,542.77

Table G.5: Levelized Cost data for Thermal units year 2014 (policy implementation)

2014				
Power Plant	Fuel Cost (\$/MW-hr)	O&M or ECA (\$/MW-hr)	Total Energy (MW-hr/yr)	Total Capital
Barges (Rental)	\$0.00	\$0.00	0	\$0.00
New PP2	\$81.98	\$10.00	6175800	\$107,292,006.15
New PP1	\$65.06	\$10.00	5202459	\$52,821,765.29
Zahrani	\$56.11	\$10.00	2602014	\$6,993,247.05
Deir Ammar	\$48.71	\$21.00	1973640	\$6,993,247.05
Sour	\$55.75	\$12.00	401505	\$8,417,797.37
Baalbeck	\$55.75	\$14.00	355001	\$8,417,797.37
Zouk	\$115.31	\$28.00	929642	\$10,985,314.15
Jieh	\$134.72	\$12.00	257742	\$10,985,314.15

Table G.6: Levelized Cost data for Thermal units year 2015 (policy implementation)

2015				
Power Plant	Fuel Cost (\$/MW-hr)	O&M or ECA (\$/MW-hr)	Total Energy (MW-hr/yr)	Total Capital
Barges (Rental)	\$0.00	\$0.00	0	\$0.00
New PP2	\$57.14	\$10.00	12193681	\$214,584,012.31
New PP1	\$68.36	\$10.00	4416124	\$52,821,765.29
Zahrani	\$58.95	\$10.00	1448751	\$6,993,247.05
Deir Ammar	\$51.18	\$21.00	924050	\$6,993,247.05
Sour	\$58.57	\$12.00	165921	\$8,417,797.37
Baalbeck	\$58.57	\$14.00	135451	\$8,417,797.37
Zouk	\$119.24	\$28.00	316007	\$14,647,085.54
Jieh	\$141.42	\$12.00	23652	\$14,647,085.54

Table G.7: Levelized Cost of Thermal Units after Policy Implementation

Power Plant	Item	Year					
		2010	2011	2012	2013	2014	2015
		\$/MW-hr					
Barges (Rental)	W/O Capital	\$146.69	\$152.89	\$159.37	\$166.14	\$0.00	\$0.00
	With Capital	\$146.69	\$152.89	\$159.37	\$166.14	\$0.00	\$0.00
New PP2	W/O Capital	\$0.00	\$0.00	\$0.00	\$0.00	\$91.98	\$67.14
	With Capital	\$0.00	\$0.00	\$0.00	\$0.00	\$109.35	\$84.74
New PP1	W/O Capital	\$0.00	\$0.00	\$133.09	\$75.37	\$75.06	\$78.36
	With Capital	\$0.00	\$0.00	\$143.67	\$85.34	\$85.22	\$90.32
Zahrani	W/O Capital	\$173.27	\$172.14	\$186.78	\$64.48	\$66.11	\$68.95
	With Capital	\$173.27	\$173.02	\$188.70	\$66.94	\$68.80	\$73.78
Deir Ammar	W/O Capital	\$119.40	\$122.77	\$127.79	\$67.37	\$69.71	\$72.18
	With Capital	\$119.40	\$123.64	\$129.49	\$70.07	\$73.26	\$79.75
Sour	W/O Capital	\$256.67	\$179.97	\$188.56	\$65.06	\$67.75	\$70.57
	With Capital	\$256.67	\$199.26	\$208.25	\$79.68	\$88.71	\$121.30
Baalbeck	W/O Capital	\$261.10	\$273.41	\$192.93	\$67.06	\$69.75	\$72.57
	With Capital	\$261.10	\$273.41	\$212.62	\$83.36	\$93.46	\$134.71
Zouk	W/O Capital	\$139.59	\$144.60	\$139.99	\$140.32	\$143.31	\$147.24
	With Capital	\$139.59	\$144.60	\$141.88	\$145.62	\$155.13	\$193.59
Jieh	W/O Capital	\$141.36	\$148.48	\$140.23	\$142.10	\$146.72	\$153.42
	With Capital	\$141.36	\$148.48	\$145.55	\$166.36	\$189.35	\$772.70
Tariff (\$/MW-hr)		\$95.80	\$95.80	\$100.59	\$108.64	\$121.67	\$139.79