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Potential of Energy Integration in Mashreq and Neighboring Countries

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ABBREVIATIONS AND ACRONYMS

AERF	Arab Electricity Regulators' Forum
AC	Alternating current
AFPC	Al Furat Petroleum Oil Company
AGP	Arab Gas Pipeline
AUPTDE	Arab Union of Producers, Transporters and Distributors of Electricity
bbl	Barrel
bcm	Billion cubic meters
bcma	Billion cubic meters per annum
BOO	Build-own-operate
BOT	Build-own-transfer
BOTAS	Oil and Gas Pipeline Corporation (Turkey)
BOOT	Build-own-operate-transfer
BTE	Azeri-Turkish Baku-Tbilisi-Erzerum
BTU	British thermal unit
CCGT	Combined cycle gas turbine
CEGCO	Central Electricity Generating Company
CFB	Circulating fluidized bed
CNG	Compressed natural gas
DC	Direct current
EAMGCC	Euro-Arab Mashreq Gas Co-operation Centre
ECA	Energy conversion agreement
ECSEE	Energy Community of South East Europe
EDC	Electricity Distribution Company
EdL	Electricité du Libon
EE	Energy efficiency
EEHC	Egyptian Electricity Holding Company
EGAS	Egyptian Natural Gas Holding Company
EGPC	Egyptian General Petroleum Corporation
EIA	Energy Information Administration (US); environmental impact assessment
EIB	European Development Bank
EIJLST	Egypt-Iraq-Jordan-Lebanon-Syria-Turkey
ELTAM	Egypt-Libya-Turkey-Algeria-Morocco
EMRA	Electricity Market Regulatory Authority
EPC	Engineering, procurement and construction (contract)
ERC	Electricity Regulatory Commission
EU	European Union
EUAS	Electricity Generation Company of Turkey
GCC	Gulf Cooperation Council
GE	General Electric
GSA	Gas sales agreement
GPC	General Petroleum Corporation (WBG)
GWh	Gigawatt hour
HFO	Heavy fuel oil
HVDC	High-voltage direct current
IDB	Islamic Development Bank
IEA	International Energy Agency
IGAT	Iranian Gas Trunkline
INOGATE	Interstate Oil and Gas Transport to Europe
IOC	International Oil Company
IPP	Independent power producer
JEPCO	Jordan Electric Power Company

kV	Kilovolt
kWh	Kilowatt hour
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
LTAM	Libya-Tunisia-Algeria-Morocco
mbl	Million barrels
mcm	Million cubic meters
MEDELEC	Euro-Mediterranean Electricity Cooperation (European)
MED-EMIP	Euro-Mediterranean Energy Market Integration Project
MED-REG	Mediterranean Working Group on Electricity and Natural Gas
MEMR	Ministry of Energy and Mineral Resources (Jordan)
MEW	Ministry of Energy and Water
MMBTU	1 million British thermal units
mmscm	Million standard cubic meters
MTOE	Million tons of oil equivalent
MVA	Megavoltampere
MW	Megawatt
NEPCO	National Electric Power Company (Jordan)
NERC	National Energy Research Center
NGL	Natural gas liquids
NIGC	National Iranian Gas Company
NIOC	National Iranian Oil Company
O&M	Operations and maintenance
PA	Palestinian Authority
p.a.	Per annum
PEA	Palestinian Energy and natural Resources Authority
PERC	Palestinian Energy Regulatory Commission
PETL	Palestinian Energy Transmission Company
PNA	Palestinian National Authority
PEEDEE	Public Establishment for Distribution and Exploitation of Electric Energy
PEEGT	Public Establishment for Electricity Generation and Transmission (Syria)
RCREEE	Regional Centre for Renewable Energy and Energy Efficiency
RE	Renewable energy
SCADA/EMS	Supervisory Control and Data Acquisition/ Energy Management System
SGC	Syrian Gas Company
SGDC	Syrian Gas Distribution Company
SIGIR	Special Inspector General for Iraq Reconstruction
TA	Technical assistance
tcm	Trillion cubic meters
TGI	Turkey-Greece-Italy
TEIAS	Turkish Electricity Transmission Company
TEN	Trans-European Network
TETAS	Turkish Electricity Trading and Contracting Company
TPS	Thermal power station
TSO	Transmission system operation
TWh	Terawatt hour (= 1 billion kWh)
UAE	United Arab Emirates
UCTE	Union for the Co-ordination of Transmission of Electricity
WBG	West Bank & Gaza
YTL	Turkish Lira and New Turkish Liras

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EXECUTIVE SUMMARY

E.1 The Context

A sustained and high economic growth in the Mashreq countries including Egypt, Iraq, Jordan, Syria, Lebanon and the West Bank & Gaza has triggered a rapid increase in energy demand, particularly electricity consumption. Although part of this growing demand may be curbed through more effective energy conservation policies and technologies, there is a clear need to expand electricity generating capacity in all countries of the region. Indeed, most countries have been facing power disruptions which impose a heavy burden on economic activities. In order to ensure a reliable electricity service, each country would need to maintain reserve margins (difference between installed generating capacity and peak demand) typically of the order of 15%. The reserve margin in the Mashreq countries has declined from 50% in 1990 to – 6 % in 2008[1] resulting in frequent power outages.

One of the most significant bottlenecks in developing new power generating capacity is the supply of the required fuel. The region depended in the older days on oil for power generation. This dependence was substantially reduced (from 54% in 1990 to 43% in 2008) as gas became a desirable substitute owing to its economic and environmental attributes. The share of gas in power generation increased significantly from 25% to 48% during 1990 to 2008. However, in recent years gas availability has turned into a serious issue as countries like Syria, Jordan, Saudi Arabia, Kuwait, UAE, etc, have realized that their domestic gas production is not sufficient to meet the needs of their power sectors. This has triggered a search for sources of imported gas and/or electricity.

Unlike oil that is normally traded in a fluid and free market, gas and electricity trade require construction of cross-border infrastructure facilities which in turn require well structured regional integration schemes. Regional integration of gas and electricity systems enables the connected countries to trade energy. However, the interconnected networks, particularly power grids, impart other benefits such as increased reliability, reduced reserves, and economies of scale in construction of larger plants.

Despite their benefits, cross-border projects face numerous technical, institutional and implementation challenges. A distinct feature of regional integration projects is the length of preparation time. Most of these projects have taken many years (or several decades) to prepare. Each project has been structured and restructured a number of times. It is sometimes the deficiency in the initial formulation that results in further revisions. It is also the difficulty of working out the cross-border issues, and coordinating solutions amongst the participating countries. This is indeed an area that the World Bank and its partners have a unique comparative advantage and can help the countries foresee and resolve cross-border issues before they paralyze the progress of the project.

[1] The reserve figures for both 1990 and 2008 are somewhat overstated as available generation was likely lower.

E.2 Objective of the Study

The objective of this study is to carry out a country-by-country analysis of the power and gas sector demand and supply picture in order to assess opportunities for regional energy integration in the Mashreq and neighboring countries, and to identify specific interconnection projects that may require support from the World Bank and other international financiers. The study is conducted in the context of the World Bank Arab World Initiative. Although the present study focuses on Mashreq countries, issues of regional integration are intertwined among various MENA sub-regions, and Turkey with eventual integration with Europe, so Mashreq is not considered in isolation.

There are two other parallel efforts to examine the energy integration potential in the Maghreb and the GCC countries. In addition, the World Bank and its partners are implementing a major Solar Power Initiative with support from the Clean Technology Fund (CTF) to assist the MENA countries with development of large scale concentrated solar power (CSP) electricity generation capabilities for their own use or for export to other countries. Large scale development of solar power is expected to support and facilitate regional integration among MENA countries and with Europe as well.

Economic and energy statistics for the Mashreq countries and key countries in the surrounding area including Libya, Turkey and Iran are provided in Exhibit ES-1.

Exhibit ES-1: Key Statistics of Mashreq Countries and Surrounding Area

	Egypt	*Iraq*	*Jordan*	*Syria*	*Lebanon*	*WBG*	*Libya*	*Turkey*	*Iran*
Population (millions)	81.5	26.1	5.9	21.2	4.1	3.8	6.3	73.9	72.0
GDP (US$ Billions)*	441.6	105.8	31.2	94.2	47.9	12.6	96.7	1028.9	839.4
	Electricity								
Generation Capacity (MW)	21,944	6,128	2,260	7,700	1,976	140	5400	40,830	47,896
Consumption (GWh)	125,129	66,839	12,770	40,273	10,152	4521	25,514	191,240	196,041
Reserve Margin (%)	11	-(44)	12	15	-(14)	-(11)	-(3)	39	--
Average Tariff (US cents/kWh)	3.1	1.2	7.1	5.0	6.1	14.1	2.3	12.7	1.9
	Gas								
Production (bcm)	54.0	4.3	0.2	6.3	0	0	28.0	0.9	111.9
Consumption (bcm)	37.6	4.3	3.5	6.3	0	0	15.0	36.5	113.0

Notes: 1) Population and GDP data based on World Bank Statistics for 2008. GDP data is based on purchasing power parity.

2) Data reflect 2008 values unless unavailable, in which case the most recent data available are shown.

3) Reserve margin is based on installed capacity, but could be much lower depending generation and fuel availability.

E.3 Power Sector Issues and Options

Electricity demand has grown significantly in the Mashreq countries in recent years. Peak electricity demand increased 145% from 1990 to 2008, growing from 17,446 MW in 1990 to 42,732 MW in 2008. From 2008 through 2030, peak demand is forecast to increase by almost 62,000 MW representing an average annual growth rate of about 4.1 % (see Exhibit ES-2).

Exhibit ES-2: Historical and Forecast Demand in Mashreq Countries[2]

Country	1990	2000	2008	2010	2020	2030
Peak Demand (MW)						
Egypt	6902	11,736	19,738	22,587	42,263	56,716
Iraq	5162	4865	10,900	11,910	16,006	21,510
Jordan	624	1206	2260	2539	4547	6110
Syria	3258	5990	6715	7518	10,448	14,041
Lebanon	1220	1681	2309	2403	3059	3875
WBG	280	495	810	885	1393	2401
Mashreq Total	**17,446**	**25,973**	**42,732**	**47,842**	**77,716**	**104,653**

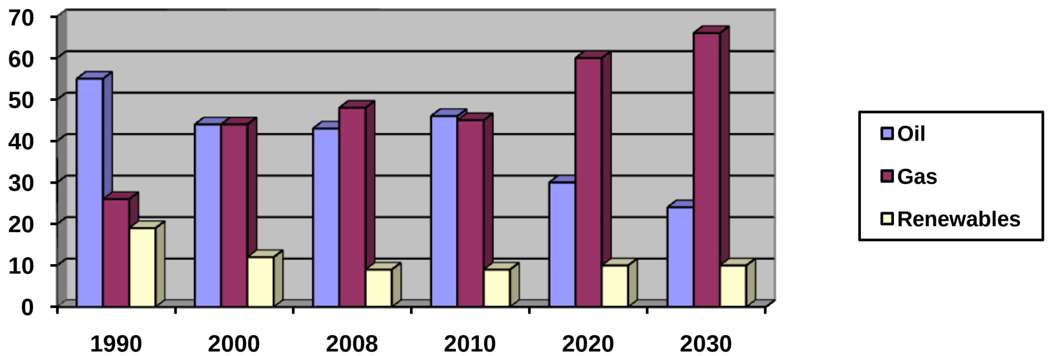
The total investment that will be needed for the expansion of generation, transmission and distribution in the Mashreq countries is enormous, estimated at US$131 billion by 2020, and an additional US$108 billion by 2030[3]. Mobilizing such levels of investment will require substantial changes in energy policy to increase electricity prices, improve the financial performance of the power sector and attract private sector investors.

A further pre-requisite for expanding power generating capacity is an adequate supply of natural gas. Exhibit ES-3 shows Mashreq electricity generation by fuel type. Total gas use in power generation is projected to increase from 32.9 bcm in 2008 to 102 bcm in 2030. Adequate supply of natural gas may prove most challenging in all Mashreq countries.

[2] The Mashreq total peak demand is a simple sum of the individual country demands. It does not take into account load diversity among the countries which is not currently known

[3] Based on estimates for Egypt's expansion plan of approximately US$101 billion to meet 150,000 GWh of demand growth, with approximately 82% allocated for generation, 13% for transmission, and 5% for distribution (October 10, 2008 World-Bank-sponsored report, *Energy Cost of Supply and Pricing Report).*

Exhibit ES-3: Mashreq Generation Production by Fuel Type (%)



E.4 Gas Sector Issues and Options

Historically, gas demand in the Mashreq countries has been driven by the availability of gas supplies. Through the 1990s, Jordan, Syria and Egypt utilized all of their gas production for domestic use. Jordan and Syria continue to use their gas production domestically and seek to further expand development of domestic gas fields and production facilities[4], while Egypt began exporting gas in the early 2000s. Lebanon has no domestic gas, but has been planning unsuccessfully, until recently[5], to use imported gas. The West Bank & Gaza has no gas infrastructure and no gas demand, but does have an undeveloped gas field lying off-shore. Iraq has significant gas reserves, but owing to the prevailing conflict, limited gas infrastructure and other reasons, has historically consumed only limited quantities of gas. Nevertheless, gas consumption in the Mashreq countries has grown significantly in recent years and is forecast to more than triple to 169 bcm by 2030 (see Exhibit ES-4).

Exhibit ES-4: Historical and Forecast Gas Consumption in Mashreq Countries (bcm)

Country	**1990**	**2000**	**2007**	**2020**	**2030**
Egypt	8.24	21.78	37.60	51.70	63.80
Iraq	1.98	3.15	4.28	46.63	62.00
Jordan	0.12	0.26	3.53	7.09	8.55
Syria	1.69	6.10	6.25	19.35	27.53
Lebanon	0	0	0	2.69	3.98
WBG	0	0	0	1.8	2.8
Total	12.03	31.29	51.66	129.26	168.66

The Mashreq region has large gas reserves, but 94% of these reserves are in two countries - Iraq and Egypt accounting for 55% and 39%, respectively. Gas production in Mashreq countries was only 14 bcm in 1990, but increased to 65 bcm by 2007 representing a total expansion of over

[4] Jordan for example signed in October 2009 a deal with BP to explore for natural gas reserves in the Risheh field near the border with Iraq, an investment that could reach billions of dollars.
[5] Egypt and Lebanon reached an agreement in September 2009 to supply natural gas to Lebanon's Beddawi power plant. Partial delivery of gas started mid October 2009, enough to power operation of one turbine at the Beddawi power plant.

360%. The current plans indicate an increase of over 200% in gas production between 2007 and 2030. Almost all the increase in gas production is expected to come from Egypt (growing from 54 bcm to 92 bcm) and Iraq (growing from 4 bcm to 95 bcm). However, both Egypt and Iraq face significant constraints in expanding their gas production capacity to the extent envisaged in current plans. For Egypt the constraint is the size of its gas reserves, and for Iraq the constraint is its implementation capacity.

Egypt's gas program has been very successful. Since the early 1990s, gas reserves and production have approximately quadrupled. Domestic consumption has been rapidly expanded, LNG export terminals have been constructed and Egypt has become the main source of gas imports for Jordan, Lebanon, Syria, and Israel. In 2007, Egypt's gas production was 54 bcm, of which 15.9 bcm, or 30%, was exported internationally. However, the rapid internal and external demand for Egyptian gas has triggered political sensitivities to further exports and a technical need to revisit gas allocation.

The government of Iraq has prepared an ambitious gas utilization plan in order to utilize its gas fields in the south (which are the largest reserves and mostly associated with oil production) for domestic use and for export to Kuwait. It would also develop the gas reserves in the north and west for export to Syria and Turkey, and eventually Europe. The plan aims at producing about 60 bcm/year of gas by 2015 of which about half would be exported. Unfortunately the Iraqi plans have not moved forward in recent years because of difficulties in implementation. In retrospect these plans have turned out to be unrealistic. The Government is now preparing a consolidated energy strategy. It is hoped that through this plan the Government will develop a comprehensive and realistic gas production policy with clear guidelines for gas allocation to domestic versus exports.

Considering the risks in the long-term supply of gas, the gas importing countries of the Region are considering the LNG option. Several studies have been undertaken into the potential for LNG supply to Lebanon indicating the economic viability of such an option to Lebanon. Jordan and Syria may also consider the LNG option in the future.

E.5 Existing Regional Energy Networks

The Electricity Network

There is a regional electricity network and a regional gas pipeline in place in the Mashreq region. The electricity network is part of the Arab power system which was initiated in 1988 by a five-country agreement between Jordan, Syria, Egypt, Turkey and Iraq. Each country undertook to upgrade its electricity system to a regional standard. The project was extended to eight countries with the addition of Lebanon, Libya and the West Bank & Gaza (West Bank & Gaza was officially included in the project in 2008). There are presently a number of high-voltage interconnections between the national power systems of Egypt, Iraq, Jordan, Lebanon, Syria, West Bank & Gaza, Libya, Turkey and Iran. A list of interconnections between the Mashreq countries, and with neighboring Turkey, Iran and Libya is provided in Exhibit ES-5.

Exhibit ES-5: Mashreq International Interconnections

Countries	Circuits/Voltage	Capacity	Year of Operation
Turkey – Syria	1 x 400 kV	1135 MVA	2007
Syria – Jordan	1 x 230 kV	55 MVA	1977
Syria – Jordan	1 x 230 kV	267 MVA	1980
Syria – Jordan	1 x 400 kV	1135 MVA	2000
Syria – Lebanon	2 x 66 kV	110 MVA	1972
Syria – Lebanon	1 x 230 kV	267 MVA	1977
Syria – Lebanon	1 x 400 kV	1135 MVA	April 2010
Syria – Iraq	1 x 230 kV	267 MVA	2000
Jordan – Egypt	1 x 400 kV	550 MVA	1997
Jordan – West Bank	2 x 132 kV (operated at 33 kV)	20 MW	2007
Egypt – Libya	1 x 220 kV	120 MVA	1998
Egypt - Gaza	1 x 22 kV	17 MW	2006
Iraq – Turkey	1 x 400 kV (operated at 154 kV)	200 MW	2002
Iraq – Iran	1 x 400 kV	325 MW	From April 2009

Although the Mashreq countries appear to be strongly interconnected, there are numerous transmission constraints in the national systems that limit transfers between countries. More generally, the exchange of power among these countries has been much less than the available interconnection capacity. There are a number of reasons for the limited electricity trade the most important of which is the lack of surplus generating capacity in the interconnected countries.

The Regional Gas Network

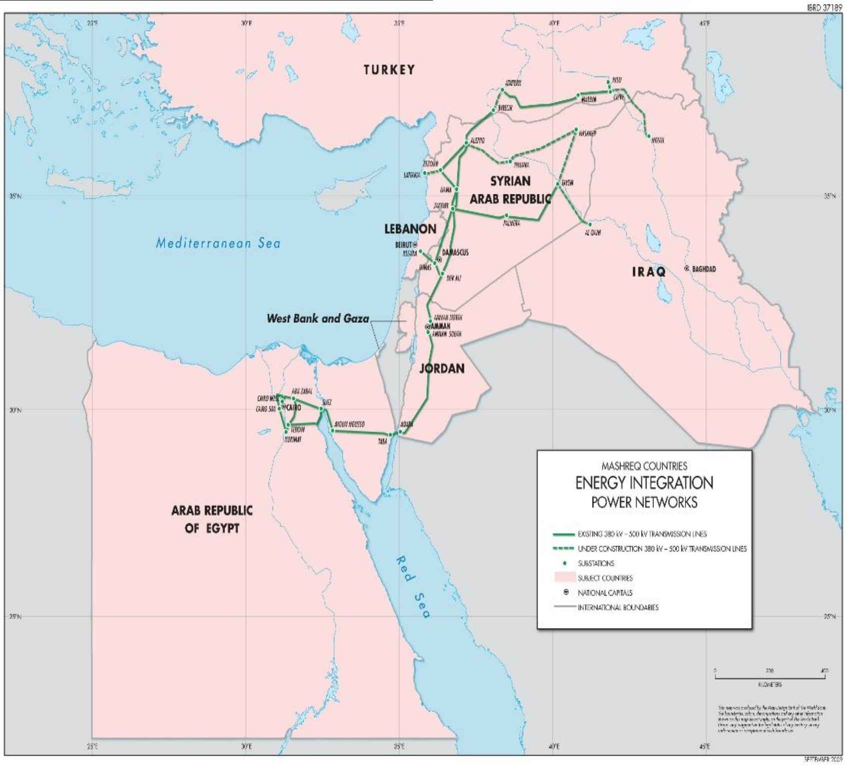
The only cross-border gas pipeline system in the Mashreq region is the Arab Gas Pipeline (AGP). It was conceived as an international gas infrastructure project from Egypt to Turkey, via Jordan and Syria, with the ultimate objective of enabling Egyptian gas to reach the European markets. To date, the sections in Egypt, the crossing of the Gulf of Aqaba and through Jordan have been constructed, as has the section in Syria from the Jordanian border to Al Rayan (the hub of the Syrian gas network). The link to Tripoli in Lebanon was also completed in 2004 though has remained idle until recently due to the lack of gas supply.

The final phase of the pipeline includes two segments within Syria (186 km from Furglus to Aleppo, and 60 km from Aleppo to Kilis at the Turkish border) and a short segment (45 km) within Turkey from Kilis to Gaziantep to connect to the Turkish gas network. The plans for construction of these segments have continually been postponed due to uncertainty in the availability of additional gas from Egypt. Indeed, Syria is now seeking an arrangement with Turkey to construct the latter portions of the pipeline in order to import gas from Turkey which could be supplied by Iran or Caspian countries. This may be a transitional arrangement, with the direction of gas flow reversed if Egypt decides to increase gas exports, or when Iraq begins delivering gas to Syria.

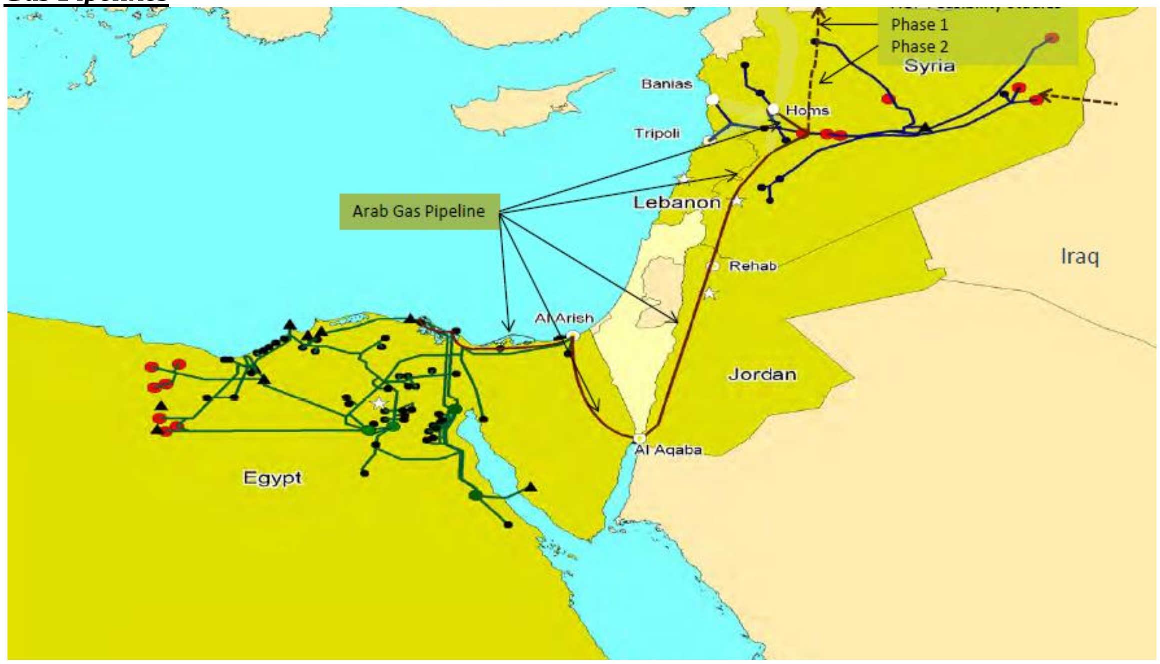
To date, trade on the AGP has been limited, far below its design capacity of 10 bcm/year. Until recently, the only firm sales on the AGP have been made between Egypt and Jordan. In 2008, Egypt started exporting gas to Syria, but has been slow ramping supply up to its export commitment owing to infrastructure constraints in Egypt. Further, Egypt has only recently started exporting gas to Lebanon. In 2009, Egypt exported 3.3 bcm to Jordan, 0.9 bcm to Syria and 0.3 bcm to Lebanon, representing about 45% of the AGP design capacity. By 2013, it is expected that Egypt's gas exports through the AGP will increase to 4.2 bcm to Jordan, 2.2 bcm to Syria and 0.6 bcm to Lebanon, representing 70% of the AGP design capacity. Regional energy networks are shown in Exhibit ES-6.

Exhibit ES-6: Regional Energy Networks

Electric Interconnection – Existing and Planned



Gas Pipelines



E.6 Main Bottlenecks to Regional Integration of Energy Systems

There are a number of institutional, regulatory and technical constraints to the expansion of electricity and gas trade in the Mashreq countries. However, the overarching bottleneck is the unavailability of gas or electricity to sell which is in turn influenced by the lack of economic/financial incentive to develop export capacity. Gas/electricity trades impart significant benefit to the importing countries. For example for most countries in the region the import of gas yields a benefit of more than US$ 10/MMBTU, yet their expectation is to pay a substantially lower price for the imported gas. The reason is that electricity and gas trade have traditionally been viewed as a means of utilizing idle capacity or idle resources. However, the nature of the business has changed; sellers need to develop additional capacity for export purposes and will not undertake the required investments unless they are confident of an attractive return on their investment.

Gas Pricing

The Mashreq countries have been planning and operating under the assumption that natural gas is abundant and cheap. They are now forced to transit to a business environment in which gas has become the fuel of choice, with scarce availability and a high premium. Many policymakers and even planners have been surprised by the sudden shift of view about gas availability. Nevertheless, there is a need for much stronger economic incentives if suppliers of gas and electricity are to invest in capacity expansion aimed at energy exports.

There is not yet a generally accepted international price for gas, so cross-border transactions are based on negotiated prices. There is often a wide range for price negotiation from the seller's cost of supply, typically ranging from US$ 1- 3[6]/MMBTU, to the buyer's benefit from using gas, potentially exceeding US$ 11/MMBTU. This wide range creates a problem of differing expectations between sellers and buyers. The LNG market has helped in narrowing the range of price negotiation even though the LNG market accounts for only a small portion of the World's natural gas demand (about 7.5% in 2008). Despite its small share of the gas trade, LNG is linking the gas prices in the markets of Asia, Europe and the US to the expectation of gas prices in the local markets around the world. Since any significant gas exporter has the option of selling its gas in the form of LNG, it expects at least the same net yield from selling piped gas.

It is not the intention of this study to play a role in gas price negotiations. However, the study provides a framework for such negotiations. Exhibit ES-7 includes the main benchmarks to consider in the discussion of gas prices. The estimated values are assumed based on Egyptian gas information. The framework follows Egypt's decision chain in determining:

(i) the amount of gas to be produced at each given time;
(ii) the amount to be allocated for domestic use;
(iii) the amount to be allocated to exports in the form of LNG; and
(iv) the amount to be allocated to exports in the form of piped gas to Mashreq countries.

[6] Excluding depletion premium

Exhibit ES-7: Estimated Price for Egyptian Gas (US $ /MMBTU in 2009 Prices)

Estimated Price	Explanation
Benchmarked on Egypt's Cost of Gas Supply	
LRMC - $1.5 to $2.6 Depletion premium - $1.4 to $3.6 Economic cost - $2.90 to $6.2	Cost of gas development and production in Egypt's new gas fields is expected to be much higher than in the past.[7] Based on the projected gas production profile and current reserves Egypt would need to switch to alternative fuels as gas supply becomes a constraint resulting in a depletion premium of $1.4 in 2010, increasing to $3.6 by 2020.
Benchmarked on Egypt's Opportunity Cost	
Benefit from Domestic Use: Avoided cost in power - $7.50 to $12.50 Avoided cost in residential and commercial sectors - $11	The power sector serves as the first vehicle for shifting in and out of gas consumption. The avoided cost (or netback value) in power constitutes an important measure of gas use in the domestic market estimated on the basis of a steam plant fired with heavy fuel oil compared with gas use in a steam plant (lower netback), or a combined cycle plant (higher netback). The avoided cost in the residential/commercial sector is based on the alternative of using diesel oil and LPG.
Benefit from LNG Export Henry Hub gas price - $ 6.50 (-) Re-gasification cost - $ 0.35 (-) Shipping cost - $ 1.00 (-) Liquefaction cost - $1.10 (-) Pipeline cost - $0.25 (=) $3.80	LNG prices are normally linked to a basket of energy products but are increasingly correlated with the US gas prices. The benchmark Henry Hub price is a long-term projection provided by the US EIA. Average levelized cost of re-gasifying LNG at the receiving terminal. Average shipping cost of LNG to the US Henry Hub market. Average levelized cost of liquefaction based on data for the LNG plants built in Egypt. Average levelized cost of pipeline transportation of gas to LNG plant.
Benchmarked on the Benefit of Gas Use in Receiving Countries	
Netback value (avoided cost) estimated for: Jordan - $8.00 Syria - $7.60 Lebanon - $8.30 to $10.00 Turkey - $8.00	The alternative plant built in the absence of gas is steam plant fired with heavy fuel oil. Jordan, Lebanon and Turkey import fuel oil while Syria uses mostly domestic oil. Netback values are reduced by the cost of transmission to the destination country.
Expected Price for Egyptian Gas	
At the Egyptian border: $4.00 to $6.00 Transport to Jordan - $0.50 Transport to Syria - $0.65 Transport to Lebanon - $0.70	Estimating a fair price is not an exact science; however, Egypt should receive a price that would encourage gas exploration and development, and allocation of gas to pipeline exports rather than LNG. Based on an average levelized cost of transportation from Egypt to each of destination countries.

[7] LRMC is estimated at $1.5 to $2.6. Financially, Egypt buys gas from producers at about $3 while receiving some of the gas in return according to a production sharing contract. The average cost is about $1.6.

The results suggest that domestic gas use imparts the highest economic benefit to Egypt even though the financial return may be low due to the prevailing energy price subsidies. Egypt should therefore consider assigning the highest priority to meeting the (present and future) gas requirements of its own economy. Should there be additional gas to allocate to exports, Egypt is likely to give priority to LNG rather than piped gas to other Mashreq countries because of higher commercial return on LNG exports (based on historical experience).

The essence of the recommendation here is that Jordan, Syria and Lebanon should provide a commercial incentive to encourage Egypt to supply the Mashreq market via the AGP prior to any further allocation to LNG. While the relevant price levels are subject to research and negotiation, the emerging gas price is likely to be higher than the underlying prices of previous contracts between Egypt, Jordan and Syria. Higher gas prices would provide a strong commercial incentive for exploration and development of Egypt's large estimated yet-to-find gas reserves. It is also noted that the emerging gas network interconections through Turkey are creating market signals that are eventually linked to the European market conditions.

Electricity Pricing

Electricity trade generally falls under two categories: short-term power exchanges and longer-term power trades. Short-term power exchanges usually occur when there are surpluses and deficits owing to daily or seasonal load variation or significant equipment outages, and diversity in the marginal cost of supply between participating countries. These exchanges are normally small in volume but very effective in sharing the reserve capacity. Longer-term power trades on the other hand refer to significant volumes of energy transferred from one country to another on a regular and more sustained basis.

Short-term exchanges are often based on idle capacity and are feasible as long as the price covers variable costs including fuel and operation and maintenance. For example, there may be an economic basis for short-term exchanges of electricity between Egypt and Syria because their peak demand occurs at different times of the day. Longer-term trades generally occur when a country has a cost comparative advantage over another country, or has excess generating capacity forecast for an extended period of time. Currently, the more likely scenario is for Egypt to export electricity to other Mashreq countries. The indicative costs for short and long-term export of electricity from Egypt are summarized in Exhibit ES-8. Under the current conditions the cost of electricity generated in Egypt for short-term power exchanges during the peak period when it has oil plant on the margin would be 10.0 US cents/kWh. However, the cost of electricity generation could be much lower (4.1 to 6.1 US cents/kWh) in the future if Egypt has gas plants on the margin. Similarly, the longer-term electricity trade could be based on a cost of generation ranging from3.9 to 5.1 US cents/kWh. Short-term exchanges and longer-term trades of Egyptian electricity would only make sense if the importing countries were willing to pay prices in excess of these levels plus the cost of transmission. A further implication is that Egypt may want to weigh the potential returns from the export of electricity versus the export of gas. It appears that electricity export to a market like Turkey where wholesale prices are quite high, close to 11 US cents/kWh average in recent years, may prove more profitable than gas exports to the same market.

Exhibit ES-8: Estimated Price for Egyptian Power (US cents/kWh in 2009 Prices)

Expected Price (US cents/kWh)	**Explanation**
Short-term Exchange-Oil Fuel cost: 9.3 Variable O&M cost: 0.7 Generation cost: 10.0	In Egypt's present configuration peaking and some intermediate units run on HFO. The fuel cost is calculated as the levelized value of HFO based on World Bank forecasts of international oil prices.
Short-term Exchange-Gas Fuel cost: 3.9 to 5.9 Variable O&M cost: 0.2 Generation cost: 4.1 to 6.1	Egypt may have gas-fired open-cycle turbine generation available for sale at certain times of the day and year. The fuel cost is calculated as the levelized value of gas at US$ 4 to 6/MMBTU.
Long-term Trade Capital cost: 1.0 Fuel cost: 2.5 to 3.7 O&M cost: 0.4 Generation cost: 3.9 to 5.1	The long-term trade is based on a large volume electricity export over an extended period of time in which case Egypt would invest in gas-based combined cycle generation. Fuel cost is based on a natural gas price of US$ 4.00 to 6.00 per MMBTU.
Market Price in Turkey Wholesale: 10.8	Average wholesale price in Turkey's balancing market from August 2006 to April 2009 (73.88 Euros/MWh converted at exchange rate of 1 US$ = 0.6822 Euros)
Transmission Costs To Jordan: 0.03 To WBG: 0.03 To Syria: 0.21 To Lebanon: 0.26 To Turkey: 0.36	

Policy, Legal and Regulatory Constraints

Aside from providing sufficient economic incentive through the pricing policy, regional integration of electricity and gas systems would require a proper policy, legal and regulatory framework. In particular, the policy, legal and regulatory regimes should facilitate energy trade through:

- The removal of exclusive rights to supply;
- Unbundling of supply and transmission;
- The introduction of third party access to the transmission system; and
- The establishment of an independent and informed regulatory agency to oversee the market and regulate the monopoly transmission and distribution services including tariffs.

These steps are fundamental to the successful operation of a regional market. While the Mashreq countries are at different stages of electricity market development, none of the countries meets the basic requirements outlined above. Most importantly, all Mashreq countries face a serious challenge of addressing the unwillingness, and in many cases, the inability of segments of the population to pay prices that reflect the economic cost of supply.

E.7 The Relevance of the Neighboring Countries

Although the present study focuses on energy networks in the Mashreq countries, there are some significant current or potential inter-linkages with some neighboring countries.. The linkages to non-Arab neighboring countries were also studied here. In particular, the cases of Turkey, European Union (EU) and Iran were reviewed to identify the relevant aspects to Mashreq energy integration.

Mashreq countries have had an aspiration to connect their power grids to the EU system. This is often envisaged to take place through Turkey. At the same time Turkey has pursued a vision of becoming an energy hub and has restructured its gas and electricity sectors in line with the EU practices and according to the standards that facilitate cross-border energy trade. Therefore study of Turkey's case provides very useful insights for integration of the Mashreq energy systems.

First, Turkey is an excellent destination for electricity exports with attractive prices and market structures and market players. Second, Turkey has been rather successful in establishing a market structure and regulation conducive to energy trade. The Electricity Market Law of 2001 obliges the transmission and distribution companies to allow open, guaranteed and non-discriminatory access to the network by third parties to facilitate competition in the electricity market. Similarly, the arrangements to facilitate cross-border gas trade have been also very concrete and impressive. Till 2001 the state owned Oil and Gas Pipeline Corporation (BOTAS) was the monopoly responsible for imports, transmission, wholesale operations, storage and distribution of natural gas. The Natural Gas Market Law of 2001 reorganized the structure of the market to enable private sector entry and competition on the lines of the EU gas directives. Under this law BOTAS was not allowed to sign new import contracts till its market share fell to 20%, was obliged to transfer 80% of the existing contracts or the volumes of supply under them to new entrants by 2009, was not allowed to carry on distribution activity anymore and was obliged to privatize its distribution subsidiaries. Private sector investments were allowed in imports, exports, gas trading, storage and distribution. Only transmission was envisaged to be in the public sector.

Similar lessons emerge from studying the EU energy systems. The liberalization of the European electricity markets has encouraged more integrated dispatch based on economic grounds across larger and larger regions. Several reform measures have been undertaken in the EU through various directives with the objective of promoting competition in the internal electricity market and enabling cross-border transactions. The first package of directives, issued in 1996, enabled the largest consumers to choose their suppliers and also provided for open access. A second package of directives were issued in 2003 that required a step-wise opening of the retail market with the target of full opening by July 2007. Still, there was a view that electricity markets largely remained national in scope and had high levels of market concentration. This led to issue of the third package of directives in June 2009 which aimed at full retail market liberalization and a level of effective unbundling that would promote development of cross border transfer capacity and cross-border competition.

Iran is another non-Arab country in the Middle East that in many areas complements the Mashreq energy networks while at the same time has the potential to compete with some in exporting electricity and gas to some common destinations particularly Turkey and Europe. The study of the case of Iran is useful in separating real prospects from numerous ideas for cross-border energy trade. Substantial gas reserves of Iran give it a comparative advantage in electricity exports to Turkey and also possibly via Turkey to the European systems. Iran will also be a key transit country for the electricity exports from Turkmenistan to Turkey and beyond. In the short term a 180 km submarine HVDC link between Iran and UAE is imminent. The link will have a transfer capacity of 1,500 MW and will connect Iran to the GCC Grid. However, in view of the high growth in domestic electricity and gas demand and also the steeply growing gas reinjection needs of the oil wells, the ability of Iran to increase dramatically its volume of gas or electricity exports in the near future is considered doubtful by many, especially in the context of international sanctions and a limited ability to attract foreign investment needed to increase gas production.

E.8 The Impact of Renewable Energy Development on the Regional Integration Agenda

Regional integration efforts are becoming somewhat intertwined with the development of renewable energy (RE). The impact is four folds. First, most RE sites (wind farms and solar fields) are far from the power grids and would require dedicated transmission lines to evacuate power to the grid; this affects the overall transmission capacity and the possibility of electricity trade. Second, RE power supply is expected to grow substantially and provide a source of electricity export. For example, Egypt alone is planning to add more than 7000 MW of wind energy over the next 10 years. Third, regional integration of power networks results in larger and more diversified power generation capacity than in isolated national markets, and thereby provides a better opportunity for the development of RE and possibly stronger commercial incentives for the development of a local industry in the manufacturing of the RE equipment. Fourth, there is a substantial international financial support for RE development which could be tapped into by the public and private entities in order to expand RE generating capacity while strengthening cross-border interconnections that offer synergy between RE and regional integration.

The impact of RE on the regional integration agenda has been explicitly addressed in various solar initiatives. In particular, the Middle East and North Africa (MENA) Concentrated Solar Power (CSP) Initiative is formulated to promote the application of CSP in the MENA region which receives some of the most intensive solar radiation in the world and has some of the best markets for solar energy within the region. The Initiative has received approval from the Clean Technology Fund (CTF) for $750 million concessional financing in support of a proposed investment plan with a total cost of $6 billion. It is also worth noting that the development of RE in Mashreq (and more broadly MENA) will be further strengthened by the financial incentives for export of clean energy to Europe. These exports will in turn require capacity reinforcement of major transmission corridors within Mashreq countries (e.g. Egypt-Jordan-Syria transmission corridor) as well as expansion of the transmission interconnection between Syria and Turkey. Therefore, the completion of the synchronization of Turkey's transmission network with the EU grid and prospect of long term integration of the electricity networks of Turkey and the Mashreq will provide a massive transformation opportunity to the entire Mediterranean Basin for enhancing security of energy supply and in particular development of solar power in the MENA region and green electricity exports to Europe.

E.9 Potential Projects for Regional Integration

The existing electricity interconnections are probably sufficient for the present short-term exchanges though some improvement in the local systems would smoothen such transactions. Energy trade, on the other hand, which refers to significant volumes of energy transferred from one to another country on a regular basis would require substantially expanded and strengthened cross-border gas and electricity systems.

A number of potential projects are identified to strengthen and expand the regional electricity and gas networks. Projects with a greater potential for implementation follow.

1. Upgrade the interconnection between Iraq and Syria which includes a single circuit 400 kV overhead transmission line of about 165 km between Tayem substation in Syria and Qa'im substation in Iraq. The primary benefits of the project are that it would help address Iraq's electricity shortage, improve energy security for the Mashreq region, strengthen economic cooperation between Syria and Iraq and facilitate development of the proposed regional electricity market initially including Syria, Iraq, Iran and Turkey. The added benefit of this project is that it could be combined with development of the Akass gas field (described below) for the potential swap of surplus Iraqi gas into electricity which it has in deficit. The investment cost is estimated at US$ 115-125 million. The Syrian segment of the project is under construction. The Iraqi segment is at the design stage and would require significant implementation support.

2. Expand and strengthen the transmission corridor from Egypt to Syria. This project would have a number of components within each national grid which are currently insufficient for large volume electricity transmission. Costs would range from US$ 400 to 735 million. The project could include reinforcement of interconnections with neighboring countries. The justification and size of investments would depend on the availability of electricity for transmission through the system.

3. Complete the Arab Gas Pipeline (AGP) through construction of two segments within Syria and one segment in Turkey. The investment costs of these three segments are estimated at: $350 million for Furglus-Aleppo within Syria; $80 million for Aleppo – Kilis within Syria; and $67 million for Kilis - Goziantep within Turkey. The construction of the first segment is not likely without a firm commitment from Egypt to supply gas. However, construction of the other two segments is under serious consideration to enable Syria to import gas via Turkey.

4. Construct Iraq-Syria gas pipeline which could be of small or large scale. The small scale pipeline is intended to transport gas from the Akkas gas field in Iraq's western desert to Syria. This would be a 50 km pipeline with an estimated cost of US$ 75 million. It has significant mutual benefits for Iraq and Syria. Iraq would not need to build a gas processing plant at Akkas; Syria has the capacity to process the gas in its own plants. The gas could be utilized for power generation in Syria with part of the power exported back to Iraq. This would be highly beneficial to Iraq with a generation gap of about 50% and fast growing demand. Iraq's efforts to install new capacity have progressed very slowly.

The larger scale gas pipeline between Iraq and Syria would be of a completely different nature, including an 800 km pipeline at a cost of about US$ 1.2 billion. This project would represent a major source of gas input to the AGP and a major gas outlet from Iraq. It could potentially be an avenue for selling Iraqi gas to Turkey and beyond. This pipeline and the potential pipeline projects from Iraq to Jordan (Item 5) and from Iraq to Turkey (Item 6) are likely to compete, so only one might proceed to implementation.

5. Construct Iraq-Jordan gas pipeline which would import gas from Iraq's northern and/or southern gas fields to the AGP via Jordan's Risha gas field. It would include an 800 km pipeline with an estimated cost of US$ 1.2 billion. It would enable regional gas trade, an additional export route for Iraq, and second option for gas imports for Syria, Lebanon and Jordan.

6. Construct Iraq-Turkey gas pipeline which would include two distinct (and not mutually exclusive) alternatives for exporting gas from Iraq to Turkey and on to Europe. The first option focuses on delivering gas from Iraq's Kurdistan region to Turkey. Investment is under way to develop the gas fields in Kurdistan for domestic use. Private firms involved in the development of these fields are now negotiating gas sales to Turkey and others through the Nabucco pipeline system that is expected to transport gas from the Caspian countries to Europe. The second option for exporting Iraqi gas to Turkey is based on the gas resources of Iraq's northern and/or southern fields and possibly its Akass field in the western desert, for export to Turkey via the AGP, either through Syria or Jordan. This latter alternative has been addressed above.

7. Construct new generation capacity in Syria or Jordan for the benefit of the host country, Iraq, Lebanon and the West Bank & Gaza. The first phase could cost $300 million for a 500 MW gas-based plant. Iraq has had significant difficulty building much needed generation capacity and costs are very high owing to conflict, limited private sector involvement, economies of scale, and other factors. Lebanon and the West Bank & Gaza have problems of their own, although not on the same scale. Construction of generation in either Jordan or Syria for the benefit of the host country, Iraq, Lebanon and the West Bank & Gaza would significantly improve energy integration, particularly if tied to gas exports from Iraq.

8. Construct new interconnection from Jordan to West Bank: A feasibility study on a new Jordan – West Bank interconnection recommends further cooperation with Jordan, with the first step including construction of a new 2 x 400 kV interconnection developed in conjunction with a 132 kV transmission system in the West Bank. The favored interconnection alternative would originate at the Samra Thermal Power Plant north of Amman in Jordan, and connect to a new 400 kV substation in the Jerusalem area in the West Bank. The length of the interconnection is estimated to be 101 km with a cost of US$ 99.2 million (in 2008 Dollars). This estimate includes the cost of the interconnection and substation investments in both Jordan and the West Bank.

9. Establish a regional coordination center to serve all Mashreq countries[8]. A consultant study estimates the investment cost of the regional coordination center at US$ 16- 22 million. A regional coordination center would result in significant savings in the form of more optimal generation planning (from a regional rather than national perspective), reduced cost of settlement (one central system rather than five or more separate national settlement systems), and reduced cost of load interruptions.

Finally, it is noted that in order to increase gas exports from Egypt there is a need to de-bottleneck certain segments of Egyptian gas pipeline system which could constitute a relevant project. Furthermore, there may be some potential interest from private sector to build power plants that could target partly domestic supply and partly export to other countries. It would be useful to explore these potential prospects in the form of developing private-public ventures that would also serve cross-border energy trade.

E.10 Next Steps

Regional projects by their very nature are more complex than single country projects. To move forward the preparation and implementation of gas and electricity integration in the Mashreq region one should pursue two parallel tracks. The first track relates to the harmonization of: (i) technical codes and standards for the national energy systems; (ii) regulation in the national energy sectors; (iii) goals and milestones for energy sector reform relating to, in particular, open access and consistent and fair pricing of transport; (iv) energy pricing and taxation; and (v) identifying an independent process and procedure for resolving disputes relating to regional energy transactions. The second track relates to help in cross-border transactions. This is an area with significant gaps in terms of realistic information, preparatory steps and structuring such transactions.

The World Bank plans to continue its support in both the above tracks. In the area of harmonization, the Arab League and the World Bank have agreed to carry out a joint study on the institutional and regulatory framework for electricity trade. The study will assist Arab countries to develop and set up a harmonized legislative structure and electricity cross border codes necessary for promoting electricity trade among Arab countries and with targeted neighbouring regions including the EU market. There will be a comprehensive mechanism for coordination and joint work among the stakeholders. A Steering Committee composed of technical/policy representations from the member countries, the Arab League, the World Bank and the Arab Fund for Economic and Social Development will provide strategic direction and country input while also assessing the practical relevance of the study results. A Technical Committee consisting of technical staff from the power utilities, or Ministries of Electricity, of individual member countries, will also work directly with the study team to provide technical details, and to convey the outcomes of various stages of the study to the Steering Committee, and their own management and technical staff. The study will draw upon the work of various

[8] The Regional Control Center could be expanded to serve countries outside Mashreq as well. In fact, the consultant study considered the economics of serving the ELJIST and ELTAM countries including Egypt, Iraq, Jordan, Syria, Lebanon, Turkey, Libya, Tunisia, Algeria and Morocco, 10 countries in all.

initiatives and forums[9] that have in the past attempted to address the institutional and policy issues relating to the integration of the energy markets in the region.

In regard to the second track, i.e., formulating transactions, the World Bank has planned an operational activity to pursue with the participating countries the possibility of implementing each of the projects identified in this study. These activities have varying time-frames and degrees of uncertainty that would need to be clarified among the relevant stakeholders through a systematic consultation process. The World Bank and its partners can assist Mashreq countries in this particular area by:

- Playing the role of convener and facilitator by bringing together the stakeholders: governments, regional entities, private sector, financiers and donors, NGOs, etc.
- Proposing specific schemes to the relevant sub-sets of stakeholders;
- Supporting project implementation by providing finance from its own funds, and mobilizing resources from other donors and the private sector, and
- Coordinating project implementation, which is often the biggest challenge in regional integration projects.

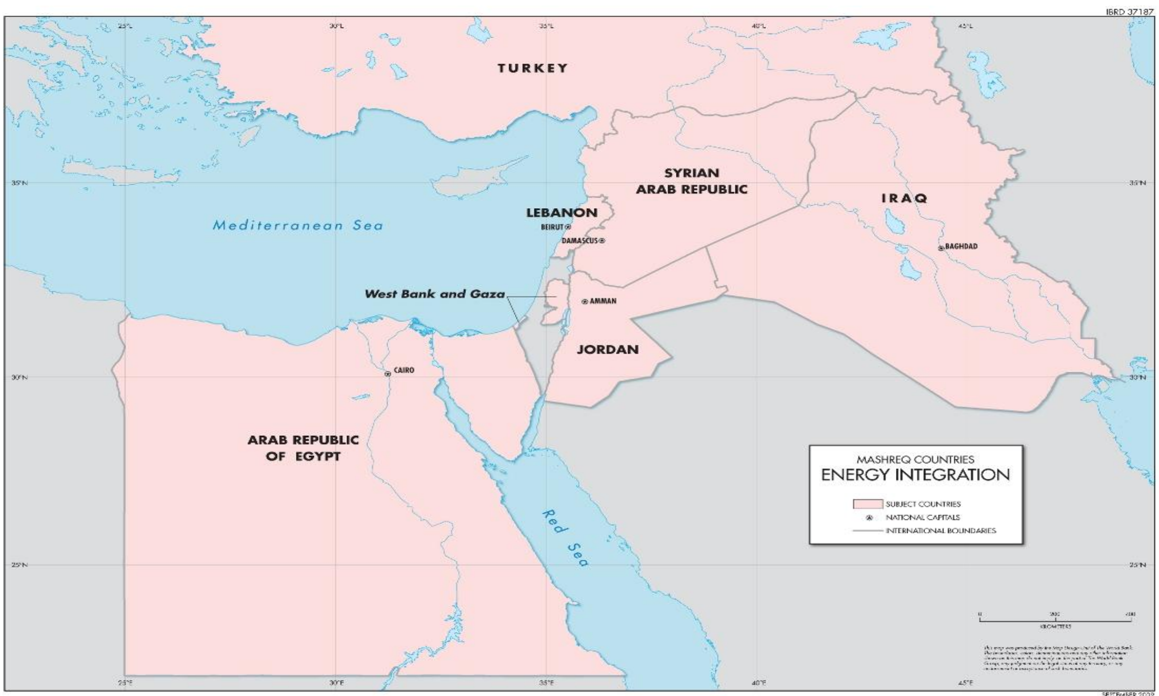
[9] There have been a number of initiatives including: Euro-Arab Mashreq Gas Market Project; Euro-Mediterranean Energy Market Integration Project; Mediterranean Working Group on Electricity and Natural Gas; Energy Efficiency in Construction; MENA Regulatory Forum; and Regional Center for Renewable Energy and Energy Efficiency. Substantial work is also being done by various regional forums such as the Arab League; Arab Union of Electricity (AUE); the Arab Electricity Regulators' Forum (AERF); the Energy Charter Treaty; Mediterranean Ring; and the Mediterranean Solar Plan.

Chapter 1. **INTRODUCTION AND BACKGROUND**

The Mashreq ("East") region of the Middle East and North Africa region (MENA) comprises Egypt, Iraq, Jordan, Lebanon, Syria and the West Bank & Gaza (figure 1.1). This region is experiencing significant increases in energy demand. In spite of recent additions of generating capacity, demand growth has often exceeded supply, leading to widespread power interruptions in some countries, taking a significant toll on the economies. Key statistics of the Mashreq countries and surrounding area are provided in table 1.1.

Significant expansion of electricity generation, transmission, and distribution capacity as well as primary fuel supply infrastructure are necessary if the capacity of the power sectors of the Mashreq countries are to come back into balance with a reserve margin to ensure adequate reliability. There are adequate reserves of gas in the region to serve as the primary fuel for power generation. Nevertheless, development of the reserves and expansion of the delivery infrastructure necessary to transport the fuel to the load centers, particularly the generating stations, is lacking. Financing the huge investments necessary in gas and electricity infrastructure will be challenging to say the least, particularly when there is no clear picture of the magnitude and sources of energy supply.

Figure 1. 1: Mashreq Region



The development of the energy supply industries in the Mashreq countries would benefit from the ability to access fuel resources and electricity generation available in other countries in the MENA region. However, integration of the electricity and gas systems of the Mashreq countries has been limited to only a few, relatively minor sales over existing cross-border interconnections. Several Mashreq countries have expressed interest in exploring the potential and benefits of expanding regional cross-border transactions and energy trade between themselves, and with neighboring regions. However, a systematic assessment of existing energy resources, consumption, and opportunities for regional gas and electricity trade is lacking. Such an assessment is necessary to provide a quantitative basis for any following detailed study of necessary investment in regional energy projects and cross-border interconnections, as well as for the development of a framework to encourage sustained regional energy trade in the future.

Table 1. 1: Key Statistics of Mashreq Countries and Surrounding Area

	Egypt	*Iraq*	*Jordan*	*Syria*	*Lebanon*	*WBG*	*Libya*	*Turkey*	*Iran*
Population (millions)	81.5	26.1	5.9	21.2	4.1	3.8	6.3	73.9	72.0
GDP (US$ Billions)*	441.6	105.8	31.2	94.2	47.9	12.6	96.7	1028.9	839.4
	Electricity								
Generation Capacity (MW)	21,944	6,128	2,260	7,700	1,976	140	5400	40,830	47,896
Consumption (GWh)	125,129	66,839	12,770	40,273	10,152	4521	25,514	191,240	196,041
Reserve Margin (%)	11	-(44)	12	15	-(14)	-(11)	-(3)	39	--
Average Tariff (US cents/kWh)	3.1	1.2	7.1	5.0	6.1	14.1	2.3	12.7	1.9
	Gas								
Production (bcm)	54.0	4.3	0.2	6.3	0	0	28.0	0.9	111.9
Consumption (bcm)	37.6	4.3	3.5	6.3	0	0	15.0	36.5	113.0

Notes: 1) Population and GDP data based on World Bank Statistics for 2008. GDP data is based on purchasing power parity.

2) Data reflect 2008 values unless unavailable, in which case the most recent data available are shown.

3) Reserve margin is based on installed capacity, but could be much lower depending generation and fuel availability.

As such, the objective of this study is to analyze the power and gas sectors in each country to assess opportunities for regional energy integration in the Mashreq and neighboring countries, and to identify specific integration projects that may require support from the World Bank and other international financiers. This project is conducted in the context of the World Bank Arab World Initiative, and is co-financed by ESMAP and the World Bank Arab World Initiative. There are two other parallel efforts to examine the energy integration potential in Maghreb and GCC countries. The study teams are working together to ensure consistency and efficiency in the conduct of the three initiatives.

This report is organized in 11 chapters:

Chapter 1	Introduction and background
Chapters 2–7	Country chapters describing the energy context in Egypt, Iraq, Jordan, Lebanon, Syria and West Bank & Gaza
Chapter 8	Description of energy context in neighboring jurisdictions including EU, Iran, Libya, and Turkey
Chapter 9	Analysis of regional power interconnections
Chapter 10	Analysis of regional gas interconnections
Chapter 11	Energy integration projects with greater potential for implementation and the impact of renewable energy development
Chapter 12	Conclusions including electricity and gas tariffs, electricity and gas export pricing, institutional constraints and next steps.

Chapter 2. **EGYPT PROSPECTS FOR ENERGY INTEGRATION**

2.1. Overview

Egypt is a significant energy producer. It is anticipated that in coming years energy will continue to play an important role in Egypt's economy. Since the early 1990s, gas reserves and production have approximately quadrupled, while electric generating capacity has doubled. Egypt has gas reserves and successful gas exploration activities, a liquefied natural gas (LNG) export terminal, the Arab Gas Pipeline (AGP), and electrical interconnections west through Libya and north to the other Mashreq countries. Although its exports of oil-based products have declined in recent years, higher world oil prices and exports of LNG have increased the country's hydrocarbon revenues.

Energy is poised to remain a significant contributor to Egypt's economy for years to come. However, it will require successful expansion of energy production and delivery systems. Currently, Egypt's electricity sector is in balance, with generation capacity in amounts necessary to reliably meet the country's demand, but levels of unsupplied energy have been increasing in recent years. The electricity sector is heavily dependent on the use of natural gas to fuel its generators. Electricity demand is forecast to grow at more than 6 percent annually in the coming years placing considerable stress on electricity supply and gas infrastructure.

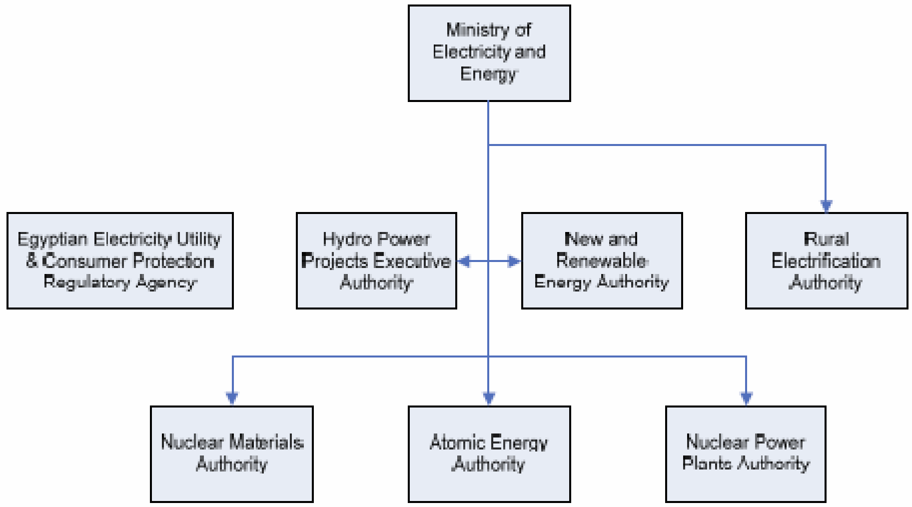
The cost of the expansion plan to meet the country's future electricity requirement is enormous, estimated at 570 billion EGP by 2022–23 (approximately US$101 billion). Financing this aggressive expansion plan will be challenging because Egypt heavily subsidizes the domestic prices for all forms of energy. Electricity prices would have to more than double in real terms to fund the expansion plan. For example, if subsidies were to be removed at the class level, residential tariffs would need to be increased by 83 percent. Assuming a five-year transition period to bring tariffs up to the cost of supply, the residential class would require nominal tariff increases of 47 percent in each year of the five-year transition period. Enormous political will is necessary to address the subsidy issue, but appears to be the only means available if energy is to remain a significant contributor to Egypt's economy.

2.2. Power Sector Structures

The Ministry of Electricity and Energy is responsible for the electricity sector including policy formation and implementation of Government decrees. The structure of the electricity sector is shown in figure 2.1.

The Egyptian Electricity Utility and Consumer Protection Regulatory Agency has regulatory oversight responsibility for the electricity sector. The agency's role is to optimize the technical, operational, financial, and procedural systems of the electricity business. However, noticeably absent is the responsibility to regulate tariffs, which lies with Government. Not surprisingly, tariffs are far below the cost of supply, and there are significant cross-subsidies among customer classes. Residential customers in particular are heavily subsidized.

Figure 2. 1: Electricity Sector Structure



Source: Ministry of Electricity

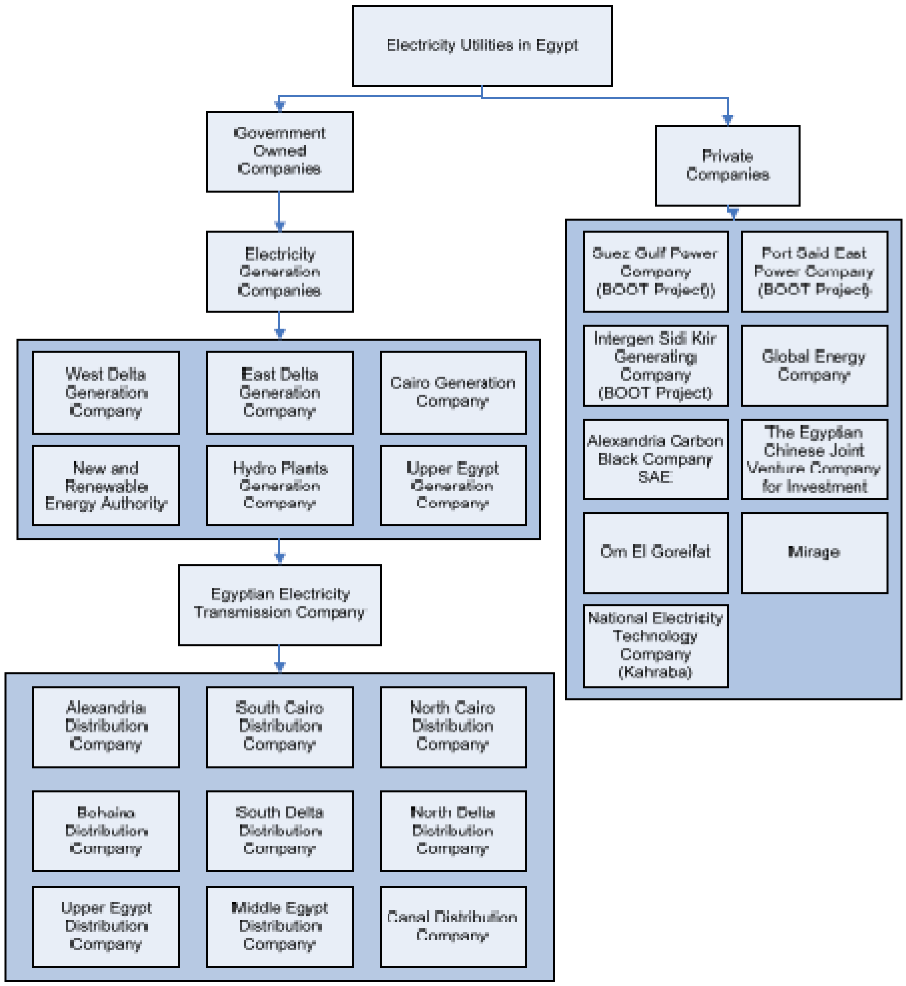
Reporting to the Ministry of Electricity and Energy are a number of Executive Authorities with responsibility for specific components of the electricity sector. These authorities are the Hydropower Projects Executive Authority, New and Renewable Energy Authority[10], Rural Electrification Authority, Nuclear Materials Authority, Atomic Energy Authority, and Nuclear Power Plants Authority.

The Egyptian Electricity Holding Company (EEHC) and its affiliates are responsible for the day-to-day operation of the electricity industry including generation, transmission, and distribution. The EEHC is a joint stock-holding company. In the generation sector, there are 6 Government-owned companies, 3 private build-own-operate-transfer companies (BOOTs), and 6 IPPs. The Government-owned generating companies include hydro plants, new and renewables, and four companies divided by geographic area, including Cairo, East Delta, West Delta, and Upper Egypt. The three BOOT companies are Suez Gulf Power Company, Port Said East Power Company, and Globeleq Sidi Krir Power Generating Company. The six IPPs are the National Electricity Technology Company, Mirage, Global Energy Company, Alexandria Carbon Black Company, the Egyptian Chinese Joint Venture Company for Investment and On El Goreifat Company. A schematic of EEHC and its affiliates is shown in figure 2.2.

The state-owned Electricity Transmission Company carries out all transmission activities and acts as the single buyer of all generation. The transmission company, in turn, sells all power to the nine state-owned distribution companies that are split geographically: Cairo North, Cairo South, Alexandria, Canal, El Bahara, North Delta, South Delta, Middle Egypt, and Upper Egypt.

[10] The New and Renewable Energy Authority acts as the national focal point for expanding development of renewable energy technologies in Egypt on a commercial scale, thus reducing fossil fuel use and protecting the environment.

Figure 2. 2: Organization of Egypt's Electric Utilities



Source: Ministry of Electricity

As noted, Egypt's retail electricity prices are far below levels reflecting the economic cost of supply. In a February 2009 World Bank report entitled *Tapping a Hidden Resource – Energy Efficiency on the Middle East and North Africa*, it is reported that a residential customer in Egypt consuming 700 kWh per month pays only 17 percent of a benchmark tariff based on an average of the tariffs of France, Greece, Italy, Spain, Portugal and Turkey. These countries were chosen as the benchmark because their tariffs reflect the cost of supply, and as such, provide a reasonable approximation of the opportunity cost of electricity. Further, Egypt's tariffs are even far below the average tariff paid by other countries in the Middle East and Africa (MENA). A residential customer in Egypt consuming 700 kWh per month pays only 43 percent of the MENA average. Egypt's retail tariff for its industrial customers is likewise far below the benchmark, and only 44 percent of the MENA average.

2.3. Electricity Demand and Supply

2.3.1 Demand

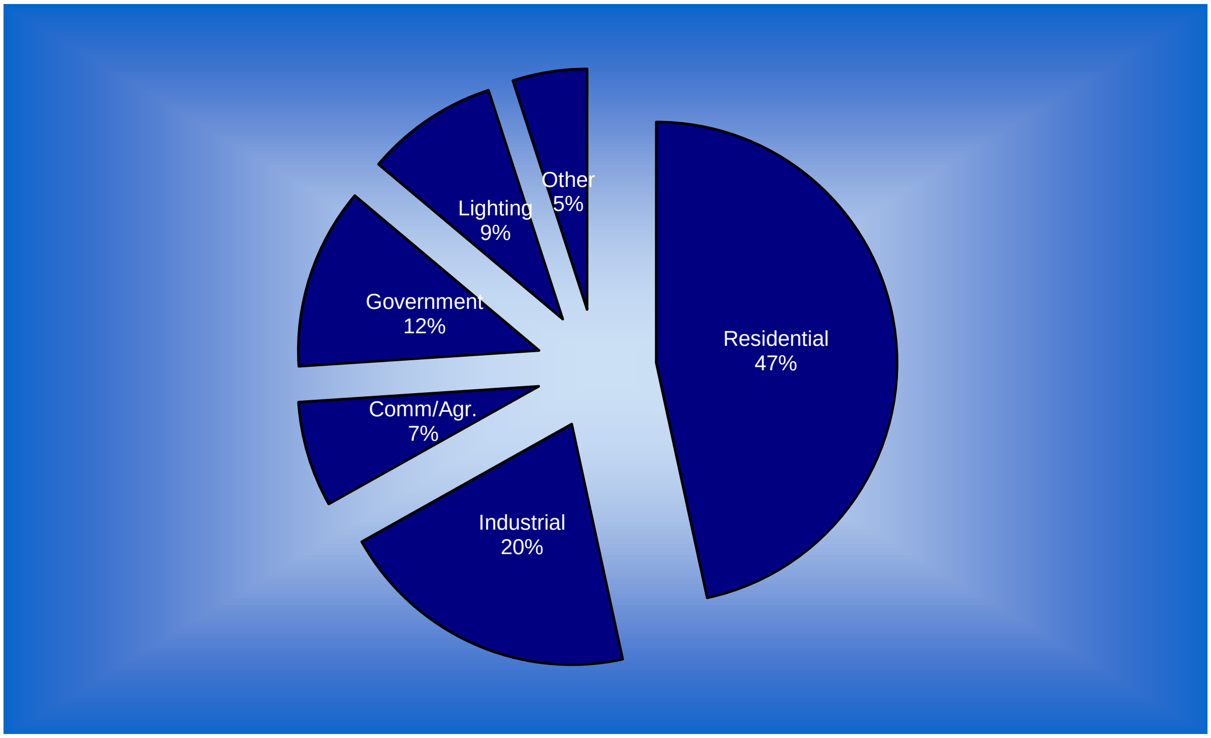
Electricity demand has grown significantly in recent years. From 1990 to 2008, peak electricity demand increased 186 %, growing from 6902 MW in 1990 to 19,738 MW in 2008. Between 2000 and 2008, peak demand increased by 68 percent. This has required substantial new additions in generating capacity. Historical electricity demand is shown in table 2.1.

Table 2. 1 Historical Demand

Year	1990	2000	2008
Peak demand (MW)	6902	11,736	19,738
Energy demand (GWh)	41,410	71,660	125,129

The breakdown of electricity consumption in Egypt by customer class is shown in figure 2.3. As can be seen, the residential class is the largest, consuming 47 percent of the total. The industrial class accounts for 20 percent, while Government, public lighting, agriculture and commercial account for 12 percent, 9 percent, 4 percent, and 3 percent, respectively.

Figure 2. 3: Electricity Sales by Sector



Electricity demand is forecast to continue growing at very high levels in the future (table 2.2). In 2020 EEHC forecasts demand to be 42,263 MW, a 114 percent increase over 2008 levels, representing annual growth of approximately 6.5 percent.

Table 2. 2 Forecast Demand

Year	2008	2010	2020	2030
Peak demand (MW)	19,738	22,587	42,263	56,716
Energy demand (GWh)	125,129	128,424	240,300	322,943

A breakdown of the demand forecast by customer class is shown in table 2.3.

Table 2. 3 Breakdown of Demand Forecast by Customer Class ***(GWh***)

Year	*Industry*	*Agriculture*	*Public Utilities*	*Commercial*	*Residential*	*Government*	*Total*
2007/08	37,349	4220	12,249	7242	38,443	5684	105,187
2008/09	39,949	4489	13,095	7806	41,045	6081	112,465
2009/10	42,774	4772	13,997	8402	43,768	6502	120,215
2010/11	45,814	5067	14,950	9031	46,618	6944	128,424
2011/12	49,071	5375	15,961	9693	49,599	7412	137,111
2012/13	52,555	5699	17,036	10,388	52,717	7902	146,297
2013/14	56,272	6035	18,168	11,118	55,978	8418	155,989
2014/15	60,224	6388	19,371	11,863	59,375	8960	166,181
2015/16	64,441	6756	20,640	12,647	62,929	9528	176,941
2016/17	68,932	7140	21,986	13,470	66,646	10,124	188,298
2017/18	73,717	7540	23,406	14,336	70,533	10,748	200,280
2018/19	78,811	7958	24,907	15,245	74,597	11,403	212,921
2019/20	84,230	8382	26,501	16,199	78,848	12,084	226,244
2020/21	90,002	8822	28,183	17,202	83,293	12,798	240,300
2021/22	96,144	9281	29,963	18,254	87,941	13,544	255,127

2.3.2 Supply

Egypt’s electricity generating capacity is meeting demand with adequate levels of reliability, growing steadily to 22,583 MW in 2008. Egypt’s installed generating capacity is composed of 63 percent steam turbines, 8 percent gas turbines, 14 percent combined cycle, and 15 percent hydro. A list of power plants is provided in table 2.4. Recent generation additions have been met with private sector investment, including three private build-own-operate-transfer companies (BOOTs) and six IPPs (see names above). Combined, these generating companies produced approximately 13,800 GWh in 2007–08, representing approximately 11 percent of the generation production in the country.

Table 2. 4 Egypt's Power Stations

Comp	Station		No. of Units	Installed Capac. (MW)	Fuel	Commissioning Date
Cairo	Shoubra El-kheima	(ST)	4×315	1260	N.G-H.F.O	84 - 85 - 1988
	Cairo West	(ST)	4× 87.5	350	N.G-H.F.O	66-1979
	Cairo West Ext.	(ST)	2× 330	660	N.G-H.F.O	1995
	Cairo South 1	(CC)	3×110+4×60	570	N.G-H.F.O	57-65-1989
	Cairo South II	(CC)	1×165	165	N.G	1995
	Cairo North	(CC)	4×250+2×250	1500	N.G-L.F.O	2005-2008
	Wadi Hof	(G)	3×33.3	100	N.G-L.F.O	1985
East Delta	Damietta	(CC)	6×132+3×136	1200	N.G-L.F.O	1989 – 1993
	Ataka	(ST)	2×150+2×300	900	N.G-H.F.O	85-86-1987
	Abu Sultan	(ST)	4×150	600	N.G-H.F.O	83-84-1986
	Shabab	(G)	3×33.5	100	N.G-L.F.O	1982
	Port Said	(G)	2×23.96+1×24.6	73	N.G-L.F.O	77-1984
	Arish	(ST)	2×33	66	H.F.O	2000
	Oyoun Mousa	(ST)	2×320	640	N.G-H.F.O	2000
	Sharm El-Sheikh	(G)	2×23.7 + 4×24.27 +4×5.8 + 2×5	178	L.F.O	-
	Hurghada	(G)	3×23.5 + 3×24.3	143	L.F.O	-
	Zafarana(wind)(1)		100×0.6+127×0.66 +190×0.85	305	Wind	2000-2003-2004 2006-2007-2008
	Boot					
	Suez Gulf	(ST)	2×341.25	682.5	N.G-H.F.O	2002
	Port Said East	(ST)	2×341.25	682.5	N.G-H.F.O	2003
Middle Delta	Talkha	(CC)	8×24.72+2×45.95	290	N.G-L.F.O	79-80-1989
	Talkha 210	(ST)	2×210	420	N.G-H.F.O	93-1995
	Talkha 750*	(CC)	2×250+1×250	750	N.G-L.F.O	2006-2008
	Nubaria*	(CC)	4×250+2×250	1500	N.G-L.F.O	2005-2006
	Mahmoudia	(CC)	8×25+2×58.7	316	N.G-L.F.O	83-1995
	Mahmoudia**	(ST)	1×50+1×25	75	N.G-L.F.O	81-1982
West Delta	Kafr El-Dawar	(ST)	4×110	440	N.G-H.F.O	80-84-1986
	Damanhour Ext	(ST)	1×300	300	N.G-H.F.O	1991
	Damanhour (Old)	(ST)	3×65	195	N.G-H.F.O	68-1969
	Damanhour	(CC)	4×24.62+1×58	156.5	N.G-L.F.O	1985-1995
	El-Seiuf	(G)	6×33.3	200	N.G-L.F.O	81-82-83-1984
	El-Seiuf	(ST)	2×26.6+2×30	113	H.F.O	61-1969
	Karmouz	(G)	1×11.37 + 1×11.68	23.1	L.F.O	1980
	Abu Kir	(ST)	4×150+1×311	911	N.G-H.F.O	83-84-1991
	Abu Kir	(G)	1×24.27	24.3	N.G-L.F.O	1983
	Sidi Krir 1.2	(ST)	2 ×320	640	N.G-H.F.O	99-2000
	Matrouh	(ST)	2×30	60	N.G-H.F.O	1990
	Boot					
	Sidi Krir 3,4	(ST)	2 × 341.25	682.5	N.G-H.F.O	2002
Upper Egypt	Walidia	(ST)	2×312	624	H.F.O	92-1997
	Kuriemat 1	(ST)	2×627	1254	N.G-H.F.O	1998-1999
	Kuriemat 2(2)	(CC)	2*250+1*250	500	N.G-L.F.O	2007
	Assiut	(ST)	3×30	90	H.F.O	1966 - 1967
Hydro Plants	High Dam		12×175	2100	Hydro	1967
	Aswan Dam I		7×46	322	Hydro	1960
	Aswan Dam II		4×67.5	270	Hydro	85-1986
	Esna		6×14.28	86	Hydro	1993
	New Naga Hamadi(3)		4×16	64	Hydro	2008

Notes:

1) Wind farm had entered with 80 MW
2) Steam component is not yet in operation
3) Naga Hamadi includes 5.4 MW retired in 9/2007 and four new units added in 3/2008.
4) Source: EEHC 2008 Annual Report

Egypt has electrical interconnections with Gaza, with the other Mashreq countries through Jordan and with North African countries through Libya. The interconnection with Jordan is a 400 kV submarine cable across the Gulf of Aqaba. The link to Libya is a 220 kV line, and the link with Gaza is a 22 kV line. In 2008 Egypt purchased 251 GWH over its interconnections, while selling 814 GWh (net exports of 563 GWh). This level of exports represents about 0.5 percent of Egypt's total production.

As noted, EEHC is forecasting very high levels of demand growth of approximately 6.5 percent annually through 2020. Such levels will require an aggressive generation expansion program if future demand is to be met with adequate levels of supply reliability. The projected investment plan includes construction of new plants to meet growing demand and allow for retirement of older plants that are no longer economical to operate. Furthermore, significant investment in transmission and distribution is necessary to transmit the new generating capacity to the load centers.

Table 2.5 shows net capacity additions of each generation technology for each year through 2022–23. The table allows for retirements of 1344 MW, including 941 MW of open cycle gas turbines, 398 MW of steam turbines, and 5 MW of hydro.

Table 2. 5 Egypt's Proposed Generation Expansion Plan, 2007–23

Year	RES	Hydro	CCGT	OCGT	Steam	Nuclear	TOTAL
2007/8	120	64	500	0	0	0	**684**
2008/9	120	0	1,750	0	0	0	**1,870**
2009/10	400	0	1,500	0	1,190	0	**3,090**
2010/11	500	0	0	0	350	0	**850**
2011/12	500	0	375	0	1,300	0	**2,175**
2012/13	580	0	1,000	0	1,950	0	**3,530**
2013/14	600	0	1,375	0	0	0	**1,975**
2014/15	600	32	750	0	1,300	0	**2,682**
2015/16	600	0	750	0	1,300	0	**2,650**
2016/17	600	0	750	0	1,300	0	**2,650**
2017/18	600	0	1,250	0	0	1,000	**2,850**
2018/19	600	0	1,000	0	1,300	0	**2,900**
2019/20	600	0	750	0	1,950	0	**3,300**
2020/21	600	0	1,250	0	0	1,000	**2,850**
2021/22	600	0	1,000	0	1,950	0	**3,550**
2022/23	600	0	1,000	0	1,950	0	**3,550**
TOTAL	**8,220**	**96**	**15,000**	**0**	**15,840**	**2,000**	**41,156**

Source: EEHC

Net expected capacity additions by 2022–23 exceed 41,000 MW. The majority of generation capacity investment (74 percent) will be steam turbines and combined-cycle gas turbines, but a significant portion (20 percent, or 8220 MW by 2022–23) will be met with renewable forms of generation including wind turbines and one solar-thermal power plant. Open cycle gas turbine technology used for peaking is expected to remain at current levels, that is, no net additions. Rounding out the generation capacity additions are 2 new nuclear plants of 1000 MW each in

2017–18 and 2020–21. It is understood that Egypt signed an agreement with Russia in March 2008 to provide investment and technology assistance for the first nuclear project.

Table 2.6 shows total annual capacity additions and retirements for 2008–09 through 2022–23.

Table 2. 6 Total Plant Capacity Additions, 2008–23 ***(MW)***

Year	**Opening capacity**	**Capacity additions**	**Capacity retirements**	**Closing capacity**
2008–09	22,628	1870	163	24,335
2009–10	24,335	3090	48	27,376
2010–11	27,376	850	344	27,882
2011–12	27,882	2175	50	30,007
2012–13	30,007	3530	205	33,332
2013–14	33,332	1975	33	35,274
2014–15	35,274	2682	91	37,865
2015–16	37,865	2650	124	40,391
2016–17	40,391	2650	30	43,011
2017–18	43,011	2850	60	45,801
2018–19	45,801	2900	130	48,571
2019–20	48,571	3300	65	51,806
2020–21	51,806	2850	0	54,656
2021–22	54,656	3550	0	58,206
2022–23	58,206	3550	0	61,756

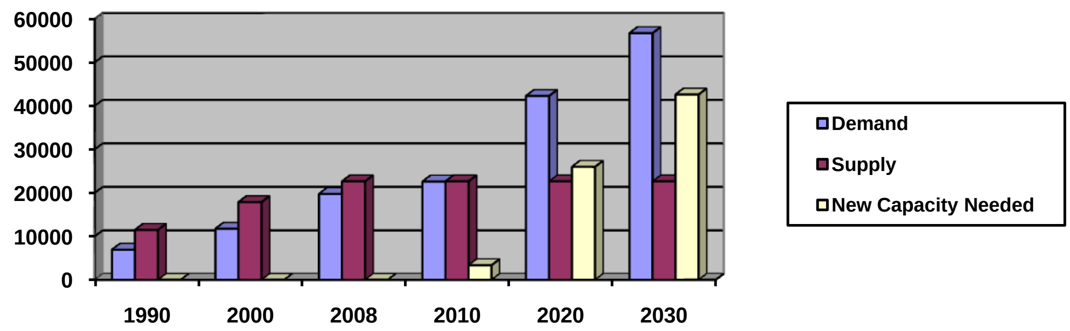
Source: EEHC.

The total cost of the expansion plan for generation, transmission, and distribution is enormous, estimated at 570 billion EGP by 2022–23 (approximately US$101 billion based on an exchange rate of US$1 = 5.62 EGP). Electricity prices will have to more than double in real terms to fund the expansion plan. If subsidies were to be removed at the class level, using the residential class as an example, tariffs would need to be increased by 83 percent. Assuming a 5-year transition period to bring tariffs up to the cost of supply, the residential class would require nominal annual tariff increases of 47 percent.[11]

Egypt's electricity demand/supply picture is summarized in Figure 2.4. The blue bar shows historical and forecast demand. The purple bar shows historical generation capacity, and existing capacity (2008) going forward. The yellow bar shows the amount of new capacity needed to meet growing demand with adequate levels of reliability (a 15% reserve margin is assumed for Egypt consistent with its expansion plan). This new generating capacity is needed to supplement existing generation capacity, but does not account for new investment needed to replace retired plant. Egypt will need about 42,600 MW of capacity additions by 2030, almost double current levels of capacity (88 %), if it is to supply increasing demand at adequate levels of reliability.

[11] Information in this paragraph is from "Energy Cost of Supply and Pricing Report," October 10, 2008, by Kantor Management Consultants and Environmental Quality International, sponsored by the World Bank.

Figure 2. 4: Egypt's Demand/Supply Context, 1990–2030 ***(MW)***



Source: Various – see Appendix A

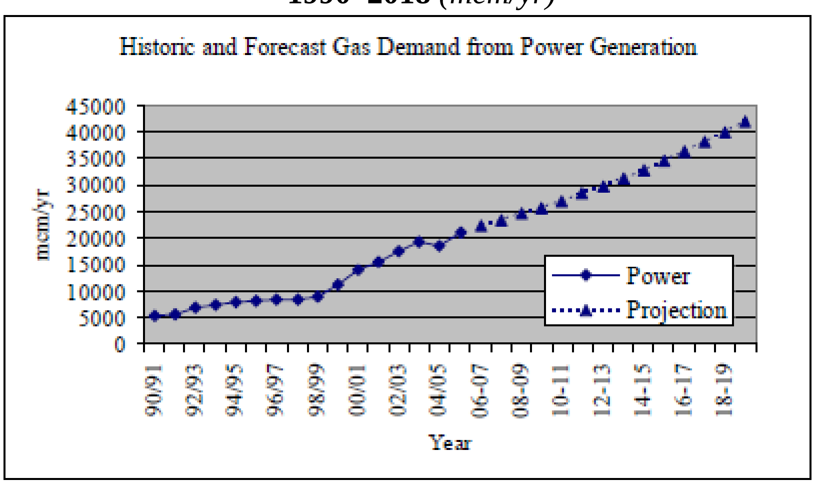
2.3.3 Power Sector Fuel Requirements

Gas demand for electricity generation has grown rapidly, increasing from 5 bcm in 1990 to almost 23 bcm in 2008—or close to 9 percent annually. According to the Ministry of Electricity and Energy Annual Report, 8 percent of electricity generation was produced from oil products, 81 percent from natural gas, 10 percent from hydro, and the remaining 1 percent from wind in 2007.

Gas demand by power generators is expected to continue to increase as numerous new gas-fired power stations come on line. Future growth in gas consumption will be closely tied to growth in electricity demand. Historic and forecast gas demand for power generation is shown in figure 2.5. The forecast shows that, by 2020, gas consumption for power generation will be about 80 percent greater than levels experienced in 2007–08.

Figure 2. 5: Historic and Forecast Growth in Gas Demand for Power Generation,

1990–2018 *(mcm/yr)*



Source: EGAS

Currently, fuel oil is used for peaking generation and as a backup fuel, and is expected to continue to be used in this manner in the future. The quantities of primary fuel forecast for the Egyptian power sector are shown in table 2.7. Use of fuel oil for power generation is likewise forecast to double by 2020. By 2030, it is forecast that the power sector will consume 60 bcm of natural gas annually.

Table 2. 7 Forecast Fuel Consumption in Power Sector, 2007–2022

Year	Natural Gas (bcm)	Fuel Oil (MTOE)	Uranium (Metric Tons)
2008–09	22.8	5.02	0
2009–10	24.3	5.45	0
2010–11	25.8	5.78	0
2011–12	27.6	6.20	0
2012–13	29.5	6.69	0
2013–14	31.0	7.13	0
2014–15	33.0	7.62	0
2015–16	35.1	8.14	0
2016–17	37.3	8.68	0
2017–18	38.1	8.94	382.2
2018–19	40.5	9.55	384.6
2019–20	43.3	10.21	384.4
2020–21	44.4	10.57	770.8
2021–22	47.5	11.31	770.5

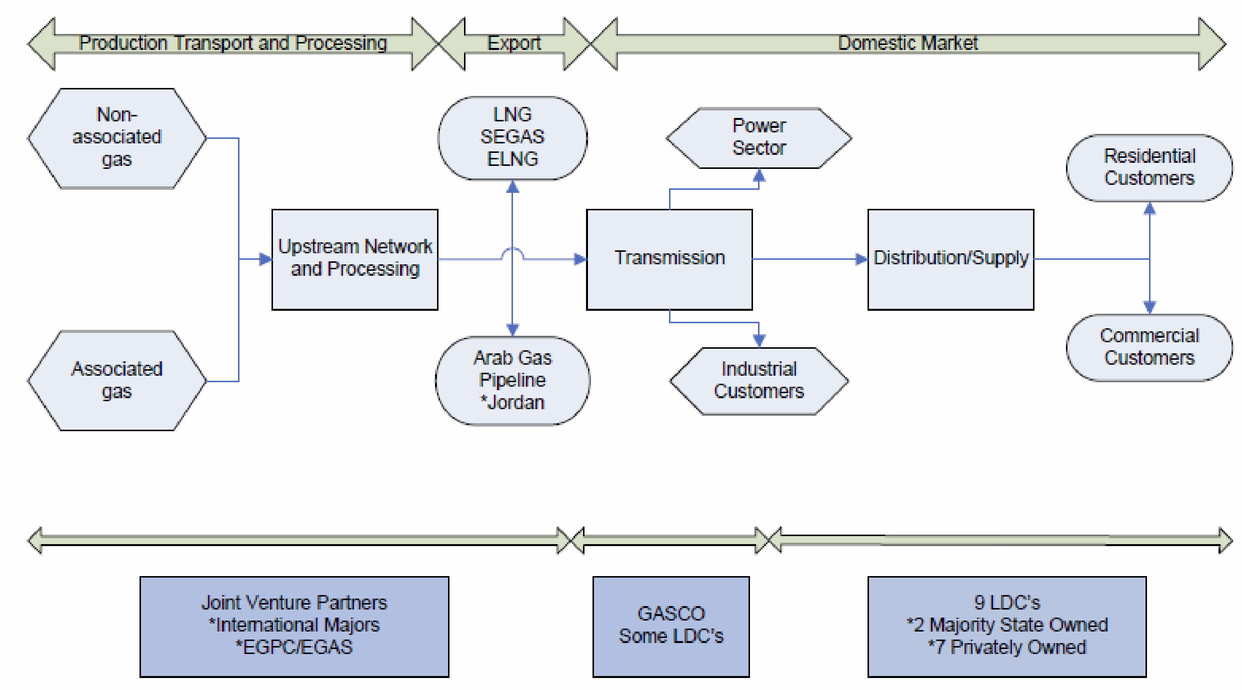
Source: EEHC.

2.4. Gas Sector Structure

The Ministry of Petroleum oversees the oil and gas sectors and is responsible for development and maximization of oil, gas, and mineral reserves. The Government of Egypt has a gas reserve depletion policy that one-third of reserves are to be monetized through export projects, one-third are to be consumed domestically, and one-third are to be set aside for future generations.

The Egyptian Natural Gas Holding Company (EGAS) dominates natural gas activities in the country, participating in upstream joint ventures and export schemes. EGAS is the single buyer and seller of all gas in the domestic market. The upstream sector is open to participation by the private sector through conventional Production Sharing Contracts (PSCs). GASCO is a 100 percent owned affiliate of EGAS responsible for transportation system operation and planning. There are also 7 privately owned and 2 publicly owned local distribution companies responsible for gas distribution services. The organization of the gas sector is shown in figure 2.6.

Figure 2. 6: Organization of Egypt's Gas Sector



Source: World Bank, IPA Energy + Water Consulting

Egypt has no specific gas law. The policy and regulatory roles are not clearly defined and separated, and third party access to transmission networks and independent regulation of gas prices are not currently in place. Egypt does have a functionally separate transmission system operator (GASCO). The Ministry of Petroleum is aware of the shortcomings of the gas market and is in the process of making changes, including plans to establish an independent gas regulator.

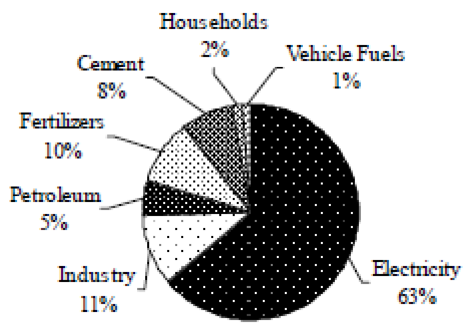
A number of policy decisions have led to the prominent rise in domestic gas consumption in Egypt. In the early 1990s, attractive fiscal and gas pricing terms were introduced on the supply side, creating the incentives necessary for upstream producers to develop existing reserves and explore new gas reserves. However, domestic gas tariffs remain heavily subsidized, funded through the State's share of the natural gas rents. World Bank estimates indicate that natural gas subsidies range from 32 percent–85 percent depending on the customer class, with the greatest subsidies (85 percent) provided to the residential sector. It is understood that the Government intends to phase out subsidies over time, while establishing other social protection measures that target the truly needy. Such actions will dampen the rate of growth in domestic gas demand.

2.5. Gas Sector Demand and Supply

2.5.1 Demand

The Government of Egypt has aggressively pursued the use of gas since the early 1990s, not only in power stations but also in industry. The electricity sector is the dominant gas consumer, accounting for 56 percent of the total gas demand in the country in 2007–08. Figure 2.7 provides a breakdown of gas consumption by consumer category.

Figure 2. 7: Gas Consumption by Consumer Category



Source: EGAS

Industry consumes approximately 11 percent of total gas consumption in Egypt and grew by 9.5 percent annually from the early 1990s through 2004–05. Egypt's fertilizer and cement industries are also large consumers of gas, accounting for 10 percent and 8 percent, respectively, of total gas demand. Gas demand by the petroleum sector has grown rapidly as a result of increasing oil-related activity in Egypt. The petroleum sector uses gas for gas lift, own use, and re-injection; accounting for 5 percent of total gas consumption. Gas is delivered to the domestic sector through low-pressure pipeline distribution systems and in liquid petroleum gas (LPG) cylinders supplied by retailers. Combined, they account for 2 percent of Egypt's total gas demand. Gas consumption in the domestic sector has been growing rapidly at approximately 15 percent annually. Finally, compressed natural gas (CNG) use in vehicles accounts for less than 2 percent of total gas consumed in Egypt, but all taxis in the Cairo area must now run on CNG. Approximately 60,000 of Egypt's vehicles have been converted to run on CNG, and Egypt now has the eighth largest CNG fleet in the World.

The Government of Egypt is committed to increase domestic gas consumption in the future. Domestic gas demand is forecast to increase to 38.8 bcma by 2010 and 51.7 bcma by 2020. Annual growth in domestic gas consumption is forecast at approximately 3 percent through 2020.

2.5.2 Reserves

From 1999 to 2007, Egypt's production of natural gas increased by over 30 percent. In 2006 Egypt produced 53.8 bcm of natural gas, consumed 36.8 bcm, and made the difference available for export. According to the *Oil and Gas Journal*, Egypt's proven gas reserves are 2.2 tcm, representing roughly 1 percent of the World reserves. Undiscovered reserves are estimated to be 3.4 tcm, meaning that with successful exploration and appraisal, Egypt will continue to export natural gas.

2.5.3 Exploration and Production

The majority of Egypt's current exploration and production is in the Nile Delta area and the Western Desert. Major non-associated fields include Abu Madi, Badreddin, and Abu Qir in the Nile Delta, which, combined, account for approximately 50 percent of Egypt's current gas production. Other offshore developments include Port Fuad, South Temsah, Wakah, Rosetta, the Scarab/Saffron fields, and the newly discovered Satis and Enil fields. EGAS expects gas production to evolve in line with gas demand. A significant portion of demand will have to be met from fields under development or with new resources.

2.5.4 Exports

The Arab Gas Pipeline (AGP) connects Egypt to Jordan and other Mashreq countries. Farther extensions of the AGP will connect Mashreq to the Turkish grid. The Arish-Ashkelon gas pipeline to Israel became operational in 2008 and began transferring what is expected to be 1.7 bcm per year.

Egypt has 3 LNG trains that in 2006 processed an estimated 15 bcm of LNG including 3.65 bcm that was shipped to the United States. Union Fenosa, a Spanish firm, built a single train liquefaction facility at Damietta which started production of 6.8 bcm per year in late 2004. In June 2006, a consortium including Union Fenosa signed a framework agreement to expand the plant and production with a second train planned to begin operation in 2010–11. However, this agreement may be put on hold owing to the Government of Egypt's June 2008 announcement that all export contracts are on hold until 2010. Exports are facing pressure in Parliament as they were signed when prices were significantly lower than they are today. A second LNG export project referred to as Egyptian LNG at Idku was built by British Gas in partnership with Petronas and has two 4.9-bcm-per-year trains. It is tied to British Gas's Simian/Sienna offshore fields and began production in 2005. British Gas anticipates building a third liquefaction plant for startup in 2011.

2.5.5 Domestic Gas Transmission

The domestic gas transport network is managed, operated, and maintained by GASCO, a majority state-owned company. The Egyptian General Petroleum Corporation (EGPC) owns 70 percent of GASCO, while Petrojet and Egypt Gas each own 15 percent. Development of the gas transport network has followed the development of gas production fields. By 2005 GASCO had expanded the network to 5170 km with a capacity of 142 mmscm/day. By end-2009, natural gas is expected to reach as far south as Aswan. A map of Egypt's gas network and associated infrastructure is shown in figure 2.8.

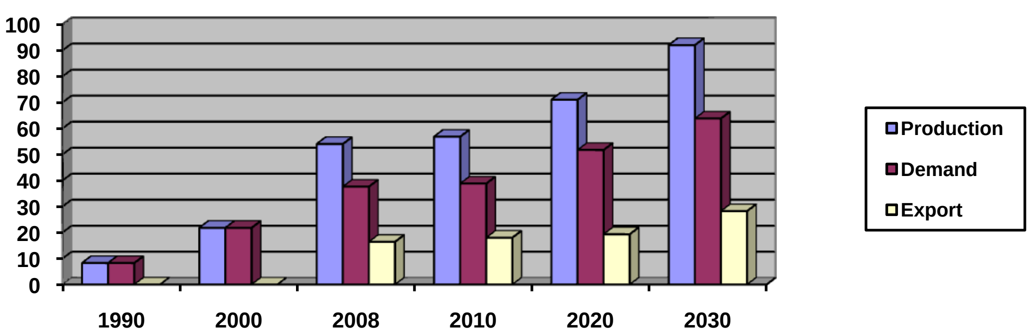
Figure 2. 8: Egypt's Gas Network and Associated Infrastructure

Source: GASCO

2.5.6 Demand/Supply Balance and Export Potential

The gas demand/supply balance is shown in figure 2.10. It shows that Egypt will have 18 bcm for export in 2010**,** increasing to 19 in 2020 and 28 bcm in 2030.

Figure 2. 9: Gas Demand/Supply Balance ***(bcm)***



Source: Various – see Appendix A

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Chapter 3. IRAQ PROSPECTS FOR ENERGY INTEGRATON

3.1. Overview

Iraq's electricity sector is plagued with problems. The country produces enough electricity to supply only approximately half of the estimated demand. Iraq has numerous power plants but most are more than 20 years old and have suffered from years of sanctions and war. Proper maintenance has been sorely lacking and is compounded by a shortage of spare parts. Furthermore, there is a shortage of power sector expertise in the country, and primary fuel supplies have been sporadic at best. From January to August 2008, electricity supply averaged 12 hours per day, but supply to a typical home may have averaged only 6 hours per day.

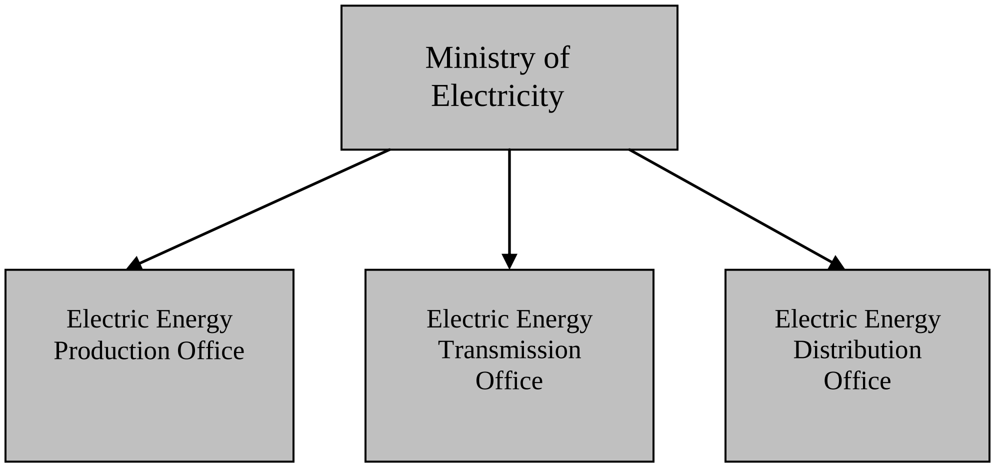
The Ministry of Electricity has an ambitious gas infrastructure program that, if successful, will consume most of the gas production forecast by the Ministry of Oil. However, the program will compete with other initiatives being undertaken by the Government, which are numerous in the unstable political situation. The pressing demands on resources combined with low tariffs, high technical losses, and poor collection rates means that the Ministry will be unable to cover operating costs, let alone raise the required capital from revenues. The electricity sector receives large subsidies from the Ministry of Finance paid for through oil sales. The required investment in electricity generation and primary fuel infrastructure will not take place without alternative sources of funds. An independent power producer (IPP) program is a means to raise private sector capital, but this will require significant tariff increases and the establishment of the necessary legal and regulatory framework. It could take years before investors have enough confidence to proceed with such initiatives in Iraq. This probable delay suggests that Iraq is likely to have surplus gas available for export over the next several years.

The Ministry of Oil forecasts that, by 2015, Iraq will be producing approximately 46 bcma of natural gas, with approximately 20 bcma of this available for export. Some of Iraq's gas supplies are located near the border with Syria close to the Syrian gas network. As yet, no gas pipeline links exist between Iraq and the AGP, but potential exists to develop such pipelines, opening the way for gas exports to the Mashreq countries and farther to Turkey and the EU. Once the security situation has improved, attention will turn to the production and possible export of gas as part of a general reconstruction and to development of Iraq's hydrocarbon industry.

3.2. Power Sector Structure

The Ministry of Electricity, which replaced the Commission of Electricity in 2003, is responsible for generating, transmitting, and distributing electrical energy in Iraq. The Ministry has three departments that report to the Minister: the Electric Energy Production Office, the Electric Energy Transmission Office, and the Electric Energy Distribution Office. Each office has a number of directors general within who cover different geographic areas of the country. The organization of the ministry is shown in figure 3.1.

Figure 3. 1: Energy Sector Structure



Despite the separate divisions for generation, transmission, and distribution under the Ministry, the electricity sector acts as a vertically integrated monopoly without benefit of independent regulation. The Ministry of Electricity is responsible for policy development, regulatory oversight, and planning for the sector.

Retail electricity tariffs are heavily subsidized and woefully inadequate to generate the revenues necessary to expand the power sector. A World Bank report[12] indicates that Iraq's retail electricity price for a residential customer consuming 700 kWh per month is less than 1 percent of a benchmark tariff based on an average of the tariffs of France, Greece, Italy, Portugal, Spain, and Turkey. Furthermore, Iraq's tariffs are even far below the average tariff paid by other countries in MENA. Iraq's tariff for a residential customer consuming 700 kWh per month is less than 2 percent of the MENA average. The country's retail tariff for industrial customers likewise is far below the European benchmark, and only 28 percent of the MENA average.

[12] See February 2009 World Bank report entitled *Tapping a Hidden Resource – Energy Efficiency on the Middle East and North Africa*.

3.3. Electricity Demand and Supply

3.3.1 Demand

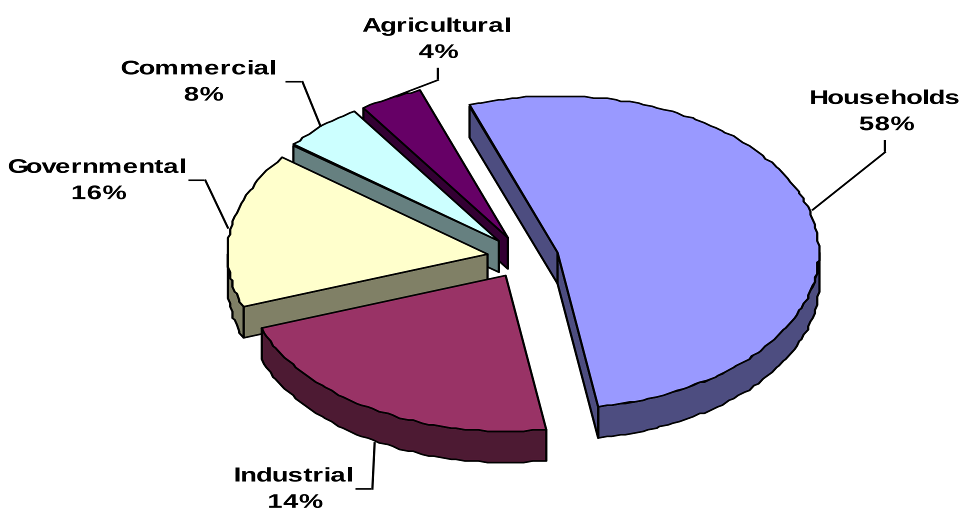
There have been significant supply interruptions in recent years so it is difficult to estimate what demand might have been if supply had not been constrained. As noted, supply interruptions are common; they average up to 12 hours per day. Estimates vary, but it appears that demand could have been 10,900 MW and 66,839 GWh in 2008 if supply had been available. Table 3.1 shows estimated demand in recent years, assuming that supply had not been constrained.

Table 3 1 Historical Demand

Year	**1990**	**2000**	**2008**
Peak demand *(MW)*	5162	4865	10,900
Energy demand *(GWh)*	20,720	30,020	66,839

Iraq's demand breakdown by customer class is shown in figure 3.2. Households make up 58 percent of demand, followed by Government at 16 percent and industry at 14 percent. Commercial and agriculture make up the remainder at 8 percent and 4 percent, respectively.

Figure 3. 2: Demand Breakdown by Customer Class



Source: Ministry of Electricity.

Given that supply is expected to remain constrained for a number of years, forecasts of future demand are equally difficult. Table 3.2 shows that demand is expected to increase to about 16,000 MW and 98,000 GWh by 2020, an increase of 47 percent over 2008 estimates of demand. By 2030, demand is forecast to increase another 34 percent over forecast levels for 2020. These substantial increases in demand will require huge investments in energy infrastructure.

Table 3 2 Forecast Demand

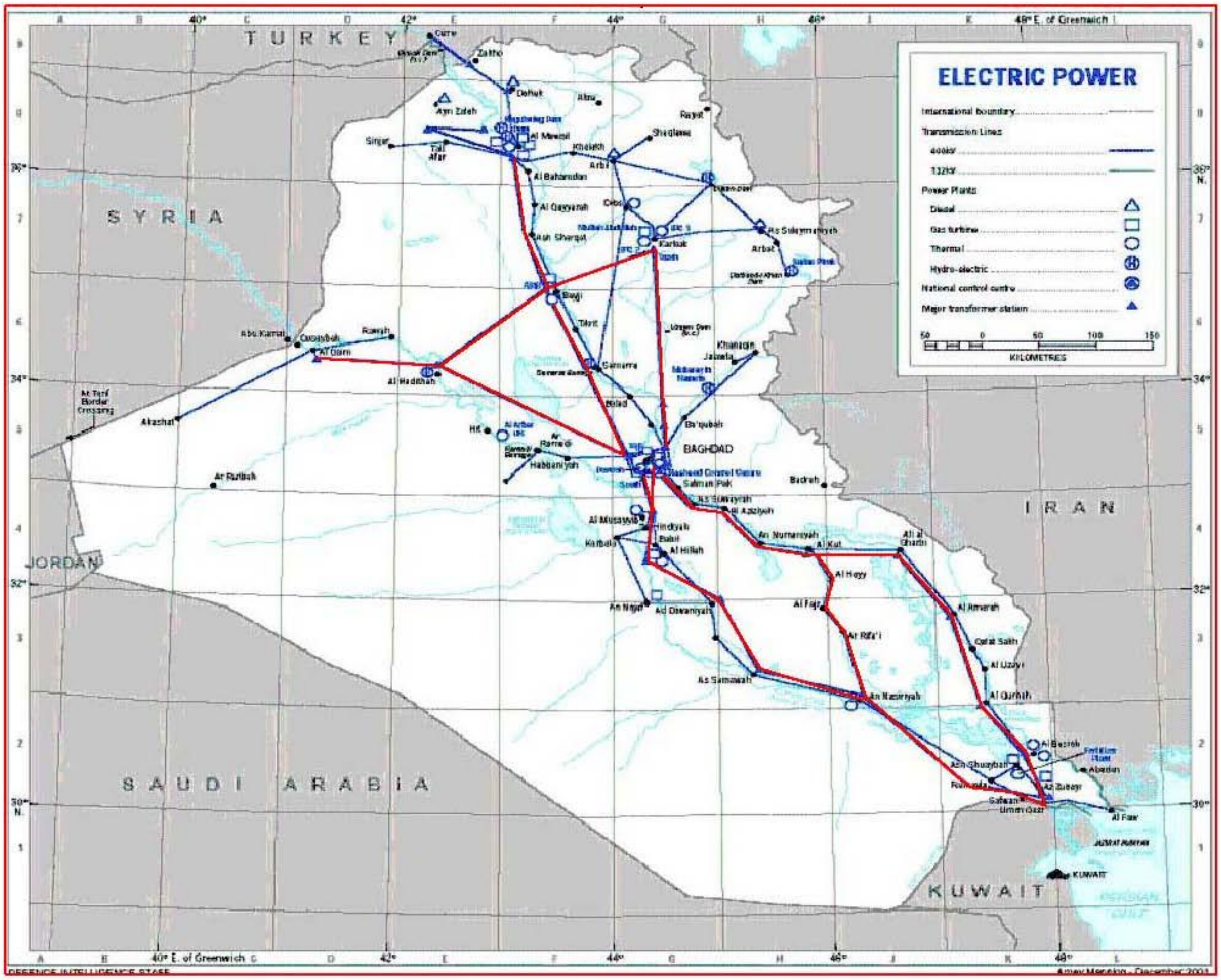
Year	**2008**	**2010**	**2020**	**2030**
Peak demand *(MW)*	10,900	11,910	16,006	21,510
Energy demand *(GWh)*	66,839	73,032	98,150	131,900

3.3.2 Supply

Electricity generating capacity has deteriorated since the war started from 9522 MW in 1990 to an available capacity of only 6128 MW in 2008. Iraq has numerous power plants (figure 3.3), but most are more than 20 years old and have suffered from years of sanctions and war. Proper maintenance has been sorely lacking, compounded by a shortage of spare parts. Furthermore, there is a shortage of power sector expertise in the country, and primary fuel supplies have been sporadic or worse. Despite significant expenditures through the U.S. Iraq Relief and Reconstruction Fund, the estimated power plant available capacity is only approximately 6000 MW. Currently, Iraq produces enough energy to supply only approximately half of the estimated demand. From January to August 2008, electricity supply averaged 12 hours per day in Iraq, but a typical home may have received power for only 6 hours per day.

The Ministry of Electricity reports 8 steam generating plants, 20 gas-powered plants, and 6 hydro plants with an intended capacity of almost 11,000 MW. However, many of these plants are in disrepair. Reportedly, 40 percent of existing infrastructure is thermal (diesel, HFO, or crude), 22 percent is hydro, and 38 percent is gas-fired.

Figure 3. 3: Schematic of Iraq's Power Facilities



Source: Ministry of Electricity.

Recent energy demand and production compared to pre-war levels are shown in table 3.3. Production falls far short of demand and has not returned to pre-war levels. Supply remains significantly constrained. The Government of Iraq is aggressively tackling this problem as discussed below.

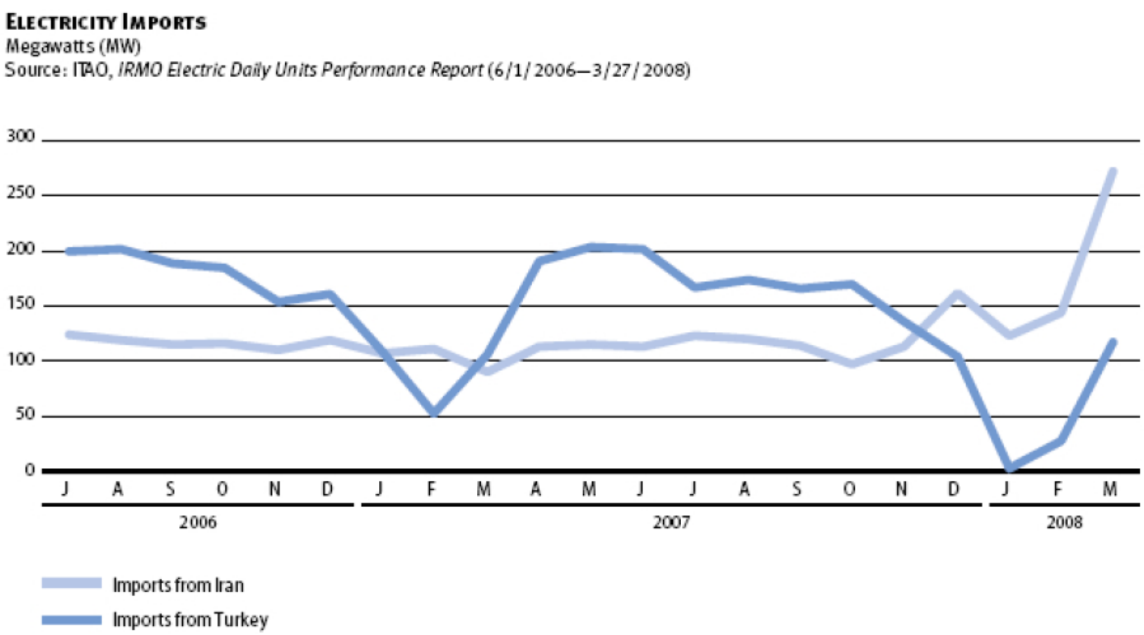
In 2008 approximately 95 percent of electricity production came from oil while hydro accounted for the remaining 5 percent. The reliability and consistency of primary fuel supply, particularly of gas, remains a significant problem.

Table 3 3 Recent Electricity Demand and Production

Electric Power Generation (MW)				
Pre-war	2006			
Average Generation	Average Generation	Peak Generation*	Average Demand	Peak Demand*
4,500	4,063	4,855	7,482	9,299
2007 (Q1)				TBD
Average Generation	Peak Generation**	Average Demand	Peak Demand**	Generation Goal
3,832	4,159	8,533	8,893	6,000
*August 2006				
** February 2007				
Source: SIGIR, Iraq Ministry of Energy, IRMO/ITAO				

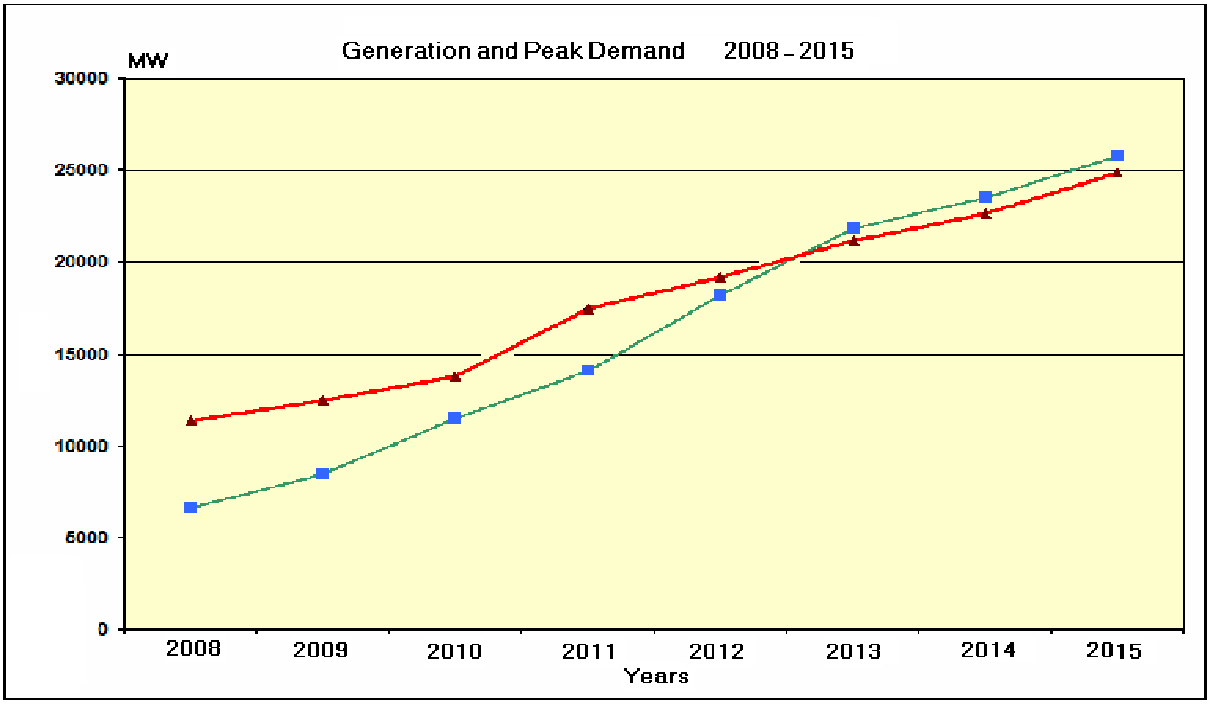
Iraq has electrical interconnections with Syria (227 MW), Iran (125 MW), and Turkey (200 MW). Iraq has deals for significant imports from Iran, which supplies approximately 67 percent of Iraq's imports. Recent import quantities from Iran and Turkey are shown in figure 3.4. In recent years, imports from Syria have been minimal as Syria has had difficulty meeting its own demand.

Figure 3. 4: Recent Imports from Iran and Turkey



It is reported that the Ministry of Electricity expects to add generation capacity in quantities that will bring supply and demand back into balance by 2012 (figure 3.5). Longer term forecasts are not currently available as the Government of Iraq is intent on expanding supply in the near term to levels necessary to meet unconstrained demand in an adequately reliable manner.

Figure 3. 5: Forecast Peak Demand and Generation Capacity



Source: Ministry of Electricity.

Iraq's planned generation expansion plan is shown in table 3.4. It is reported that 6200 MW of new IPP additions are planned by 2015. Of these, 2500 MW will be fueled by natural gas and the remaining 3700 MW by oil. The estimated cost for all new power additions is US$18 billion, equivalent to approximately US$4.5 billion per year. These additions will require an extensive coordination program to expand all infrastructure including primary fuel supply and electrical transmission and distribution as well as funding and construction the power plants themselves.

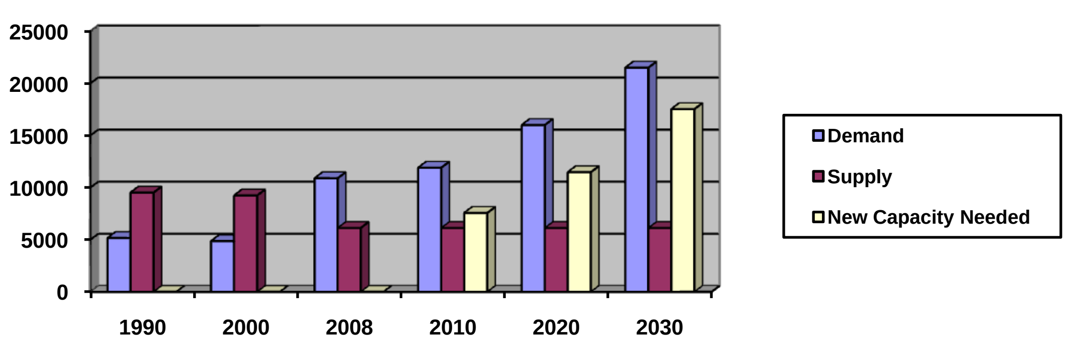
Table 3 4 Planned IPP Additions by 2015

Gas IPP		
Name of Project	**Capacity**	**MW**
Ekazz	2x125	250
Mussayab	4x125	500
Yousifia	4x125	500
Umara	4x125	500
Gharaf	4x125	500
Hartha	2x125	250
Total MW		**2500**
Thermal IPP		
Name of Project	**Capacity**	**MW**
Al Shemal	2x350	700
Salah Al Deen	2x300	600
Alanbar	2x300	600
Khairat	2x300	600
Nassriya	2x300	600
Basra	2x300	600
Total MW		**3700**

Source: Ministry of Electricity

Iraq's electricity demand/supply picture is summarized in figure 3.6. The blue bar shows historical and forecast demand. The purple bar shows historical generation capacity, and existing capacity (2008) going forward. The yellow bar shows the amount of new capacity needed to meet growing demand with adequate levels of reliability (assuming a 10% reserve margin). This new generating capacity is needed to supplement existing generation capacity, but does not account for new investment needed to replace retired plant. Iraq's required investment in new generation capacity is substantial to say the least, posing a significant challenge.

Figure 3. 6: Iraq's Demand/Supply Situation ***(MW)***

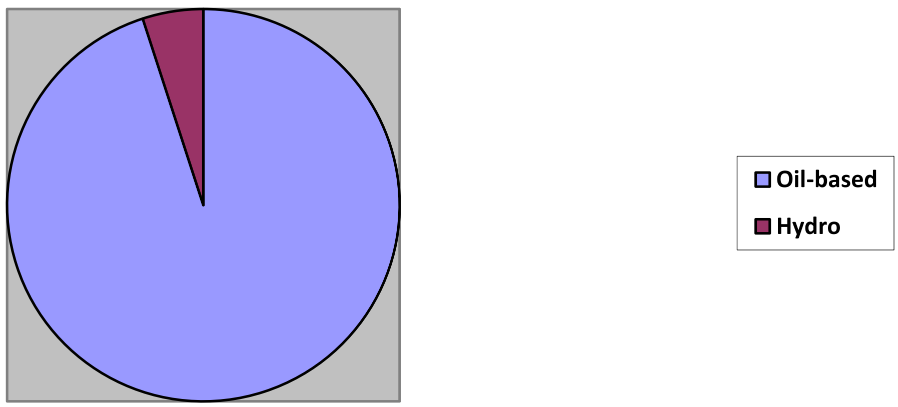


Source: Various – see Appendix A

3.3.3 Power Sector Fuel Requirements

The fuel supply to Iraq's power stations in recent years is shown in figure 3.7. Approximately 95 percent has been met with oil-based fuels (HFO, crude and aviation fuel), while the remaining 5 percent has been met with renewable hydropower generation.

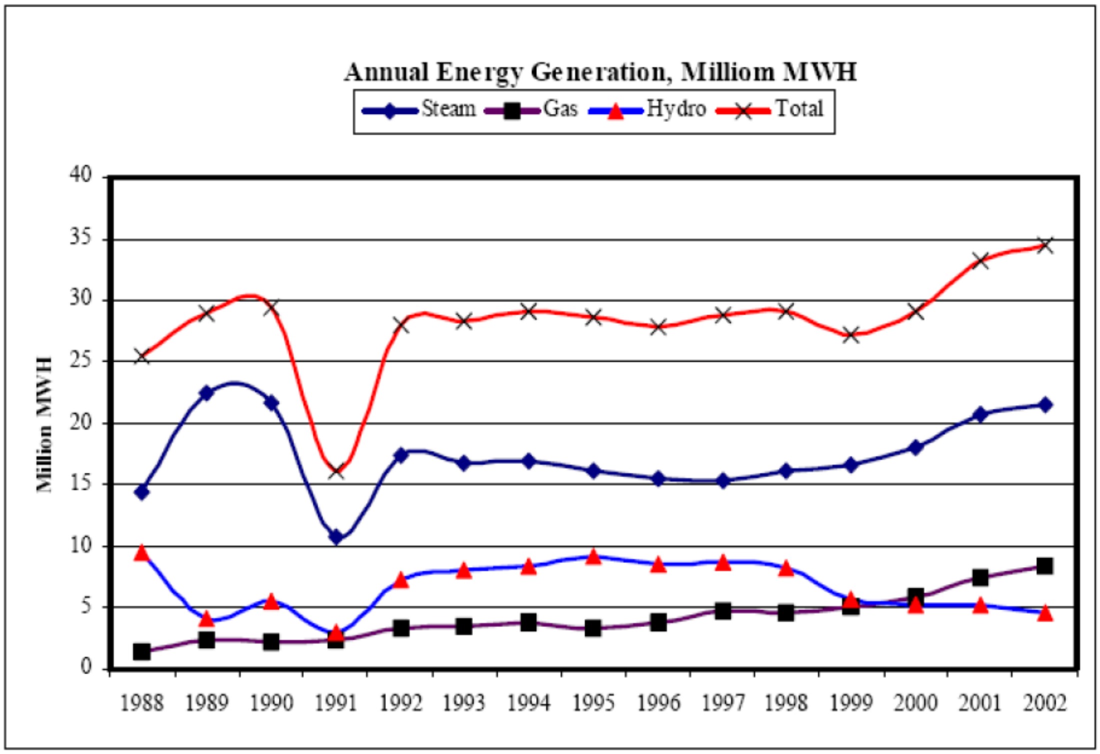
Figure 3. 7: Primary Fuel Supply Mix for Power Stations



Source: Ministry of Electricity.

There are chronic electricity shortages largely as a result of limited generation capacity and fuel supply shortages. The Ministry of Electricity accepts that gas-fired electricity would be both more efficient and environmentally friendly, but the gas gathering and distribution network in Iraq is either inadequate or has been damaged. The Ministry of Oil which is responsible for the gas distribution network has other investment priorities. Gas as a fuel for power stations has been low throughout history (figure 3.8).

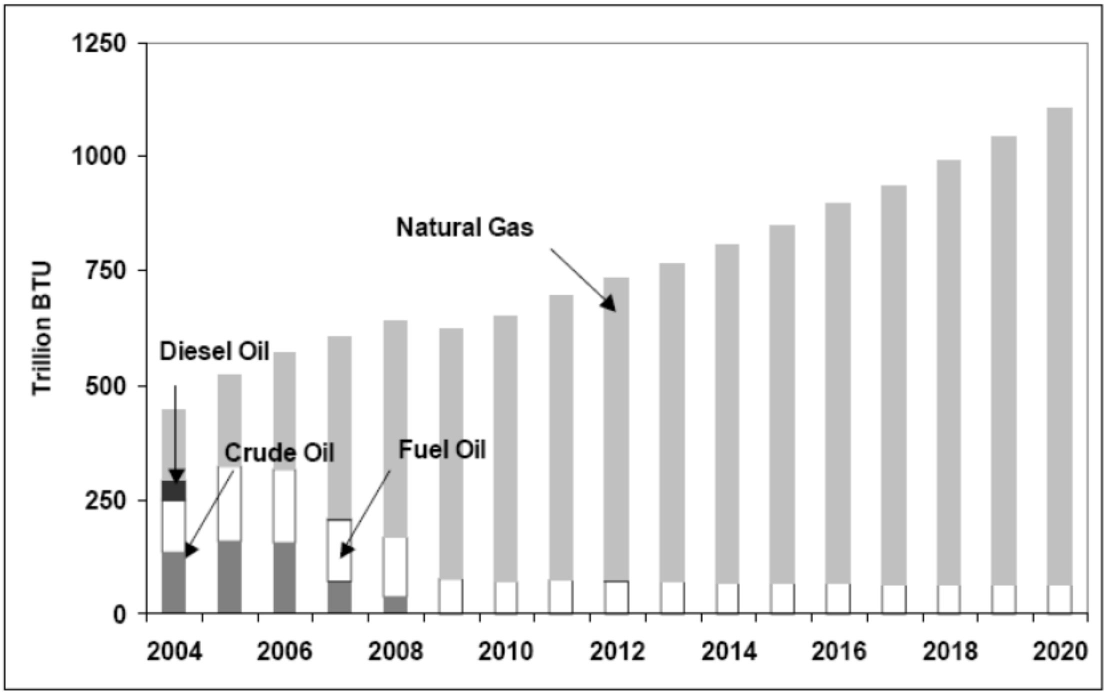
Figure 3. 8: Historical Fuel Supply



Source: Electricity Sector Master Plan, Final Report, July 2004
Figure 7: Fuel usage in Iraqi station, 1988-2002

The Ministry of Electricity has an ambitious gas infrastructure program to supply generating capacity that, if successful, will consume a significant portion of the gas production forecast by the Ministry of Oil. However, the program will have to compete with other Government initiatives, which are numerous in light of the current political situation. There are pressing demands on resources that, when combined with low tariffs, high technical losses, and poor collection rates, mean the Ministry will have difficulty covering operating costs from revenues, let alone have the capital necessary to expand the system. The electricity sector receives large subsidies from the Ministry of Finance through oil sales. The required investment in electricity generation and primary fuel infrastructure will not take place without alternative sources of funds. The IPP program is a means to raise private sector capital. However, success would require significant tariff increases as well as establishing the necessary legal and regulatory framework. It could take years before investors have enough confidence to proceed with such initiatives in Iraq. This probability suggests that Iraq is likely to have surplus gas available for export over the next several years. Forecast fuel requirements are shown in figure 3.9.

Figure 3. 9: Forecast Primary Fuel Requirements for Power Sector



Source: Electricity Sector Master Plan, Final Report, July 2004

3.4. Gas Sector Structure

The Ministry of Oil has overall responsibility for the oil and gas sectors including policy, regulation, and planning (an organizational chart for the Ministry is not available on its website). The Ministry of Electricity and the Ministry of Oil are known to be cooperating closely on fuel matters relating to the power sector.

The gas structure has numerous shortcomings. It does not have a functionally separate transmission system operator, separation of the policy and regulatory roles, third-party access to the transmission network, and independent regulation of gas prices. Domestic gas prices are heavily subsidized.

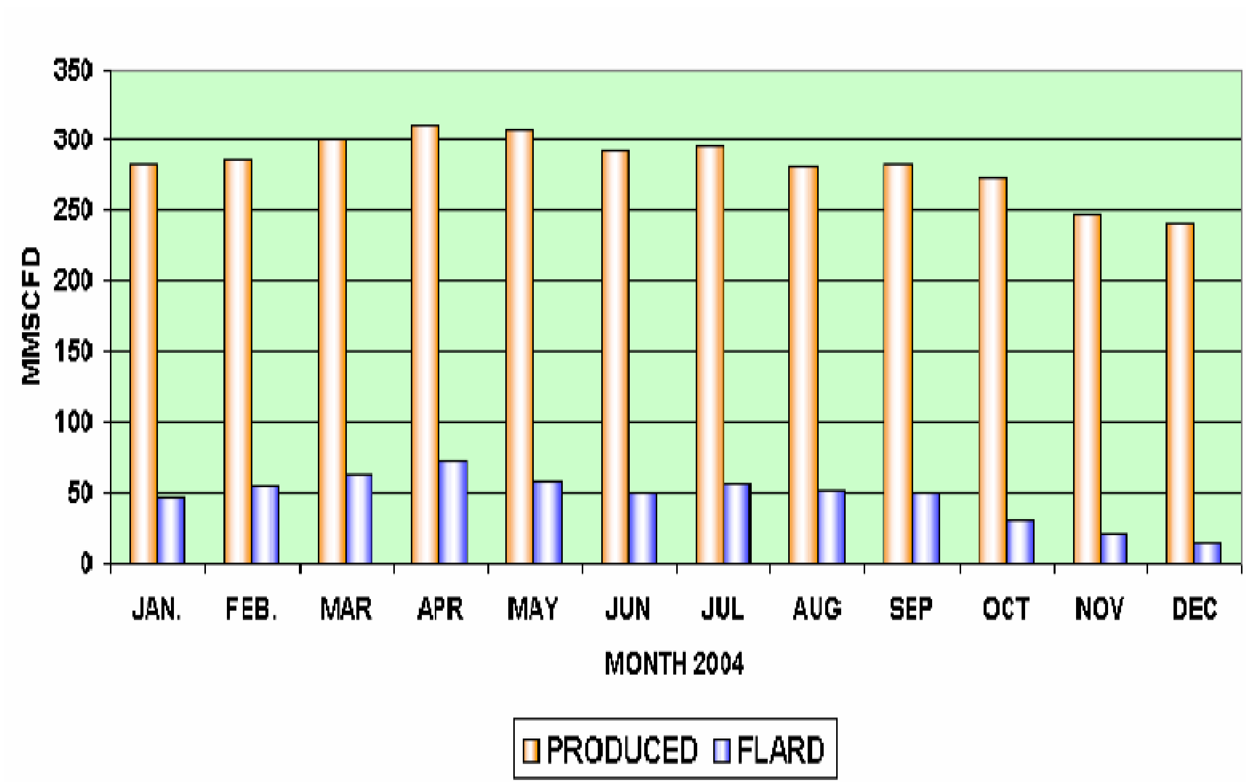
3.5. Gas Demand and Supply

According to the Energy Information Administration's (EIA) International Energy Annual Report, natural gas production in Iraq has declined steadily in recent years. Production declines are attributed to a fall in oil production and deterioration of gas processing facilities. In 2005 dry natural gas production was 2.5 bcm. This compared to 1989 levels of 6 bcm. In 2006 the Ministry of Oil reported that natural gas production averaged 25.5 mcm per day in the south (associated with oil fields) and 13.9 mcm per day in the north (non-associated). The Ministry of Oil also reported that 60 percent of all associated natural gas production was flared owing to insufficient infrastructure necessary for domestic consumption or export. Significant volumes of gas are injected to enhance oil recovery efforts. The January 2007 Special Inspector General for

Iraq Reconstruction (SIGIR) report indicates that the gas flared and injected for oil recovery that year was worth US$4 billion.

Little gas is being used for electricity production. A fertilizer factory and oil facilities are using the majority of gas production that is not being flared. Production of associated gas remains low owing to problems in the oil sector. Figure 3.10 shows associated gas production and amounts flared in 2004.

Figure 3. 10: Associated Gas Produced and Flared in 2004



Source: Ministry of Oil

It is believed that Iraq's oil reserves are second only to Saudi Arabia's. Exploration in Iraq has concentrated on oil, with little attention paid to gas. Iraq's proven natural gas reserves are 3.0 tcm, but probable reserves have been estimated at 7.8–8.5 tcm (*Oil and Gas Journal*). Iraq's proven gas reserves are the tenth largest in the world. Approximately 70 percent of the gas is associated with oil fields, while a little less than 20 percent is non-associated. Approximately 10 percent is estimated to be salt dome gas. Most of the non-associated reserves are in several northern fields.

According to the Ministry of Oil, a number of these non-associated gas fields in the north are slated for development, totaling approximately 285 bcm of reserves. These reserves could produce 25.5–28.3 MMcm/d for export and 11.3 MMcm/d for domestic consumption.

It is reported thata large natural gas field has been discovered near Nineveh, west of Al-Qa'em extending to the Iraqi-Saudi border. The field, known as Ukash, could produce 100,000 bbl per day of gas and condensate. A find of a 60 bcm field of non-associated gas near Akkas in the Western Desert was also reported. It was proposed that this field could be developed for export to Syria through a pipeline from the Akkas field to the Arab Gas Pipeline in Syria.. The Akkas field is 26 km from the Syrian/Iraqi border. It is more than 200 km from the nearest oil field, suggesting that there may be additional gas discoveries in the Western Desert. Gas found in Akkaz field may be more economical to process in Syria, particularly since the Omar and Deir Ezzor gas processing plants in Syria have spare capacity.

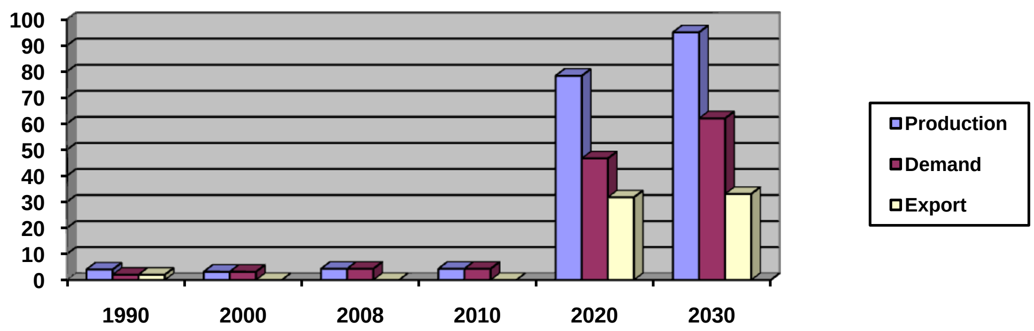
As noted, Iraq's gas processing facilities have deteriorated in recent years. According to reports, prior to the war, the southern infrastructure included 9 gathering stations with a processing capacity of 42.5 mcm/d, all intended for export. The associated dry gas gathered from the North and South Rumaila and Az-Zubair fields was piped to a 16.3 MMcm/d natural gas liquids (NGL) fractionation plant in Az-Zubair and a 2.8 MMcm/d processing plant in Basra. At Khor al-Jubair, there is a 0.5 mcm LPG storage tank farm and loading terminals. Iraq also has a major domestic natural gas pipeline in the south with capacity to deliver 6.8 MMcm/d of associated gas to Baghdad from the West Qurna field. Gas processing facilities in the north gather supply from Kirkuk, Bai Hassan, and Jambur for domestic consumption, including LPG. The EIA indicates that the system is designed to supply LPG to Baghdad and other cities, as well as dry gas and sulfur to power stations and industrial plants.

The main transmission line is a South to North pipeline running from Basra to the Hadithah and Baija refineries north of Baghdad, plus a line from Kirkuk to Baija. Even though significant parts of the gas network are limited for various reasons, it is understood that pipeline capacity is larger than current requirements. The main constraint in the gas supply network is shortage of gas. Major investments in gas infrastructure are needed if gas is to be a significant contributor to Iraq's electricity sector in the future.

The Government of Iraq has prepared an ambitious gas utilization plan for associated and non-associated gas. According to this plan, Iraq would utilize its gas fields in the south (of which most of the largest reserves are associated with oil production) for domestic use and for export to Kuwait. It also would develop the gas reserves in the north and west for export to Syria and Turkey, and eventually to Europe. The plan aims at producing approximately 60 bcm/year of gas by 2015, approximately half of which would be exported. Unfortunately the Iraqi plans have not moved forward in the last few years because of difficulties in implementation. The Government is preparing a consolidated energy strategy with assistance from the World Bank. It is hoped that, through this plan, the Government will develop a comprehensive and realistic gas production policy with clear guidelines for gas allocation to domestic consumption versus exports.

Figure 3.11 illustrates historical and forecast gas production, domestic consumption, and gas available for export. As noted, forecast values will change. However, they indicate that there could be 32 bcma available for export by 2020, and 33 bcma by 2030, even after accounting for increased gas use in power generation. It should be noted that reaching these forecasts will require a return to civil order and considerable investment.

Figure 3. 11: Gas Demand/Supply Balance, 1990–2030 ***(bcm)***



Source: Various – see Appendix A

Chapter 4. **JORDAN PROSPECTS FOR ENERGY INTEGRATION**

4.1. Overview

Demand for both primary energy and electricity is forecast to increase significantly in Jordan, as is the share of natural gas in the primary energy mix. Jordan depends on imports for 95 percent of its primary energy demand. Gas produced domestically supplies less than 10 percent of gas demand, although recent gas exploration activities are promising. Jordan plans to continue replacing oil-fired electricity generation with natural gas, and is well on its way towards its goal of producing 80 percent of its electricity needs from gas. According to Government estimates, the domestic market for gas is expected to grow to 5 bcm per annum by 2015. In the longer term, Jordan hopes to make use of domestic oil shale resources.

With the Arab Gas Pipeline (AGP) and gas supplied from Egypt through a contract with Al Fajr Company, Jordan is well positioned to meet most of its gas requirements through the mid-term. As for the electricity sector, supply has been improved with the commissioning in 2008 of 344 MW of gas turbines, including two at Amman East and one at Samra. In 2009 the gas turbine at Amman East was converted to combined cycle operation with the addition of a steam turbine and in 2010, Samra's second combined cycle plant is scheduled to come into operation with the commissioning of the steam turbine. Furthermore, Jordan is investigating the possibility of using additional wind power and domestic oil shale deposits using circulating fluidized bed (CFB) technology for power generation. The electrical interconnections with Egypt and Syria have provided significant operational benefits to Jordan, particularly with regard to capacity reserve sharing. Use of the interconnections for economy energy exchanges has been limited in spite of potential opportunities brought on by load diversity.

Jordan has proceeded farther down the reform path than other Mashreq countries. A single-buyer market structure is in place in the electricity sector with significant private sector participation. An independent regulatory authority is in place for the electricity sector, but there is currently little regulation of natural gas other than through the contract with Al Fajr Company. It is understood that the Government intends to extend the responsibilities of the electricity regulator to include the oil and gas sectors in the future. Energy tariffs in Jordan are much closer to the economic cost of supply than in other Mashreq countries, and there is less cross-subsidization among customer classes.

4.2. Power Sector Structure

In light of the high levels of demand growth forecast in Jordan and to enable the power sector to operate on a financially self-sustaining basis, in 1999 the National Electric Power Company (NEPCO) was unbundled into three operating companies:

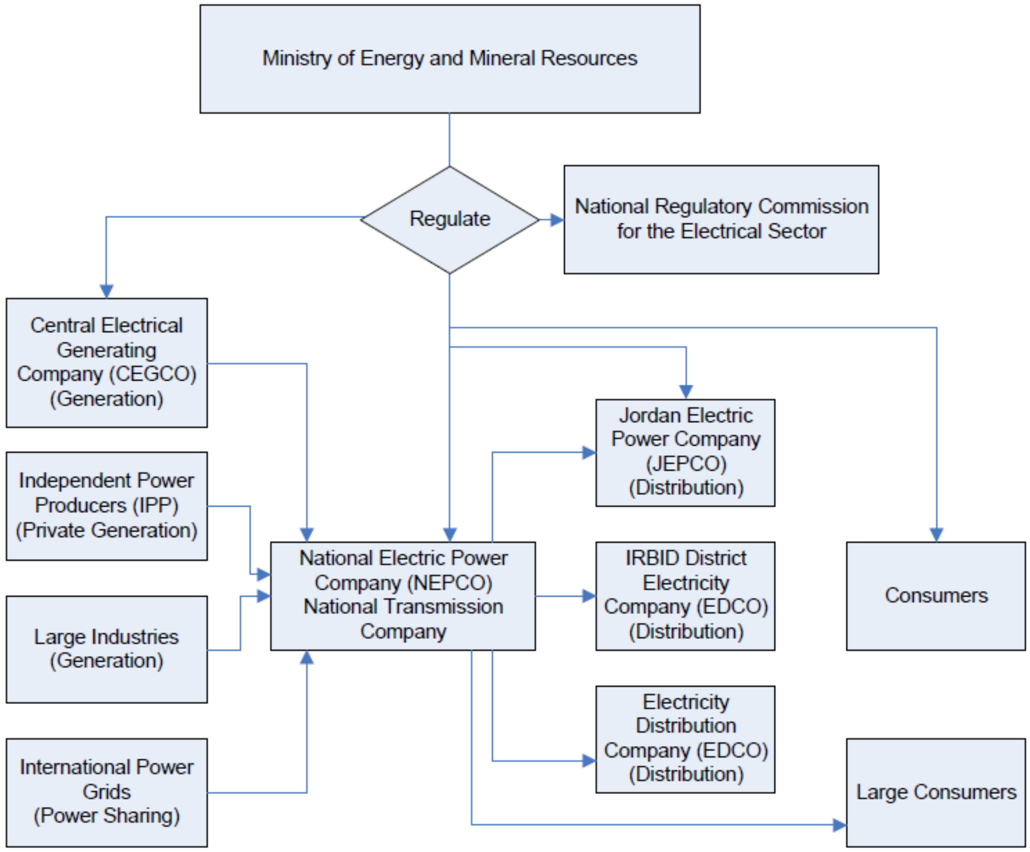
a. Central Electricity Generating Company (CEGCO), which became the generating company
b. Electricity Distribution Company (EDC)
c. NEPCO, which retained responsibility for transmission.

In 2001 the Electricity Regulatory Commission (ERC) was formed to regulate the electricity sector. The ERC is responsible for setting tariffs and issuing licenses for the activities in the sector. The Commission monitors and ensures that entities operate consistently with the obligations documented in their licenses. The ERC exists to ensure that tariffs enable power companies to finance operations and earn a fair return on investment. The ERC improves transparency, even though it resides within the Ministry of Energy and Mineral Resources (MEMR) so is not quite as independent of Government as investors might like (figure 4.1). In the future, the Government intends to extend the ERC's responsibilities to encompass the oil and natural gas sectors.

Jordan has a single-buyer market structure in place. State-owned NEPCO performs the role of single buyer, purchasing all supply from generators and, and in turn, selling all purchased power to the distribution companies and large consumers directly connected to the transmission system. NEPCO is also responsible for transmission asset management, dispatch, demand forecasting, and purchasing natural gas to meet the needs of the power generation companies.

CEGCO is the primary generation company in Jordan. The company was privatized in 2007 and is currently 51 percent privately-owned. It has 1747 MW of generating capacity, which accounted for almost 80 percent of the country's total in 2006. Jordan has a second private power generation company, AES PCS Jordan, and a state-owned generation company known as Samra. Jordan has three private distribution companies including JEPCO, EDCO and IDECO. As a result, the public sector is mainly responsible for generation and distribution while the public sector is responsible for transmission and dispatch, with some limited involvement in generation.

Figure 4. 1: Organization of Jordan's Electricity Sector



Source: MEMR

A World Bank report[13] indicates that a residential customer in Jordan consuming 700 kWh per month pays only about 50 percent of a benchmark tariff based on an average of the tariffs of France, Greece, Italy, Portugal, Spain, and Turkey. Jordan's retail tariff for its industrial customers is likewise well below the benchmark. However, Jordan's retail electricity prices reflect the cost of electricity supply in the country. Jordan has done an excellent job of expanding its electricity supply, relying on low-cost gas imports and on reserve sharing arrangements with Egypt and Syria over its interconnections. Cost-reflective tariffs have enabled Jordan to launch a successful IPP program aided by the elimination of all primary fuel subsidies in 2008.

4.3. Electricity Demand and Supply

4.3.1 Demand

Growth has been strong in recent years (table 4.1), exceeding 9 percent annually from 2000–07.

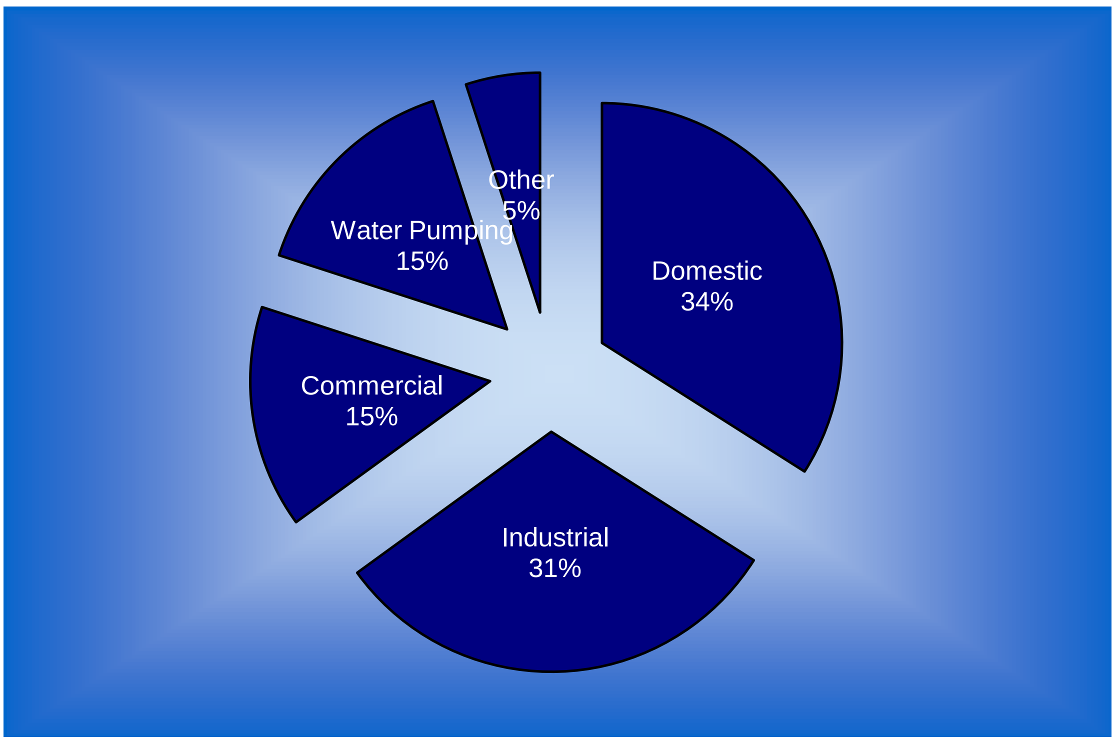
[13] See February 2009 World Bank report entitled *Tapping a Hidden Resource – Energy Efficiency on the Middle East and North Africa*.

Table 4. 1 Historical Demand

Year	**1990**	**2000**	**2008**
Peak demand *(MW)*	624	1206	2260
Energy demand *(GWh)*	2807	5712	12,770

The domestic and industrial customer classes accounted for 34 percent and 31 percent, respectively, of the total energy consumed in Jordan in 2005. The commercial sector and water pumping each accounted for 15 percent of total consumption, while street lighting and "other" customers accounted for the remaining 5 percent. Consumption broken down by consumer group is shown in figure 4.2.

Figure 4. 2: Breakdown of Jordan's Electrical Energy Consumption by Class



Source: NEPCO.

Table 4.2 shows that growth in demand is expected to remain strong, growing at 6 percent annually to 4547 MW and 25,700 GWh by 2020—more than double 2008 demand. By 2030, demand is forecast to increase another 34 percent over the levels forecast for 2020.

Table 4. 2 NEPCO's Demand Forecast

Year	**2008**	**2010**	**2020**	**2030**
Peak demand *(MW)*	2260	2539	4547	6110
Energy Demand *(GWh)*	12,770	14,348	25,695	34,532

4.3.2 Supply

Electricity generating capacity has grown steadily to keep up with supply, more than tripling since 1990 to 2524 MW in 2008 with the commissioning of 2 gas turbines at Amman East and a single gas turbine at Samra (bringing the total to 2 gas turbines at Samra). The Amman East IPP, the first greenfield IPP in the country, came into full CCGT operation in August 2009.

A list of power plants in Jordan is provided in table 4.3. There are six primary power plants: Al Aqaba, a 650 MW gas-fired plant in the south owned by CEGCO; Hussain, a 400 MW oil-fired plant in central Jordan, also owned by CEGCO; Rehab, including a number of gas-fired plants in the north with a total installed capacity of 360 MW; Al Resha with 150 MW of installed capacity burning local natural gas extracted at Resha; Samra, a combined cycle IPP and 2 gas turbines for a total installed capacity of 500 MW burning imported natural gas; and Amman East, a CCGT plant with a total installed capacity of 370 MW. There are also a number of small gas turbines located around the country to supply demand during peak and emergency periods. Jordan has approximately 10.5 MW of renewable generation including wind, biogas, and hydro. Ambient temperatures limit the available generation capacity in Jordan.

Table 4. 3 Jordan's Generating Stations

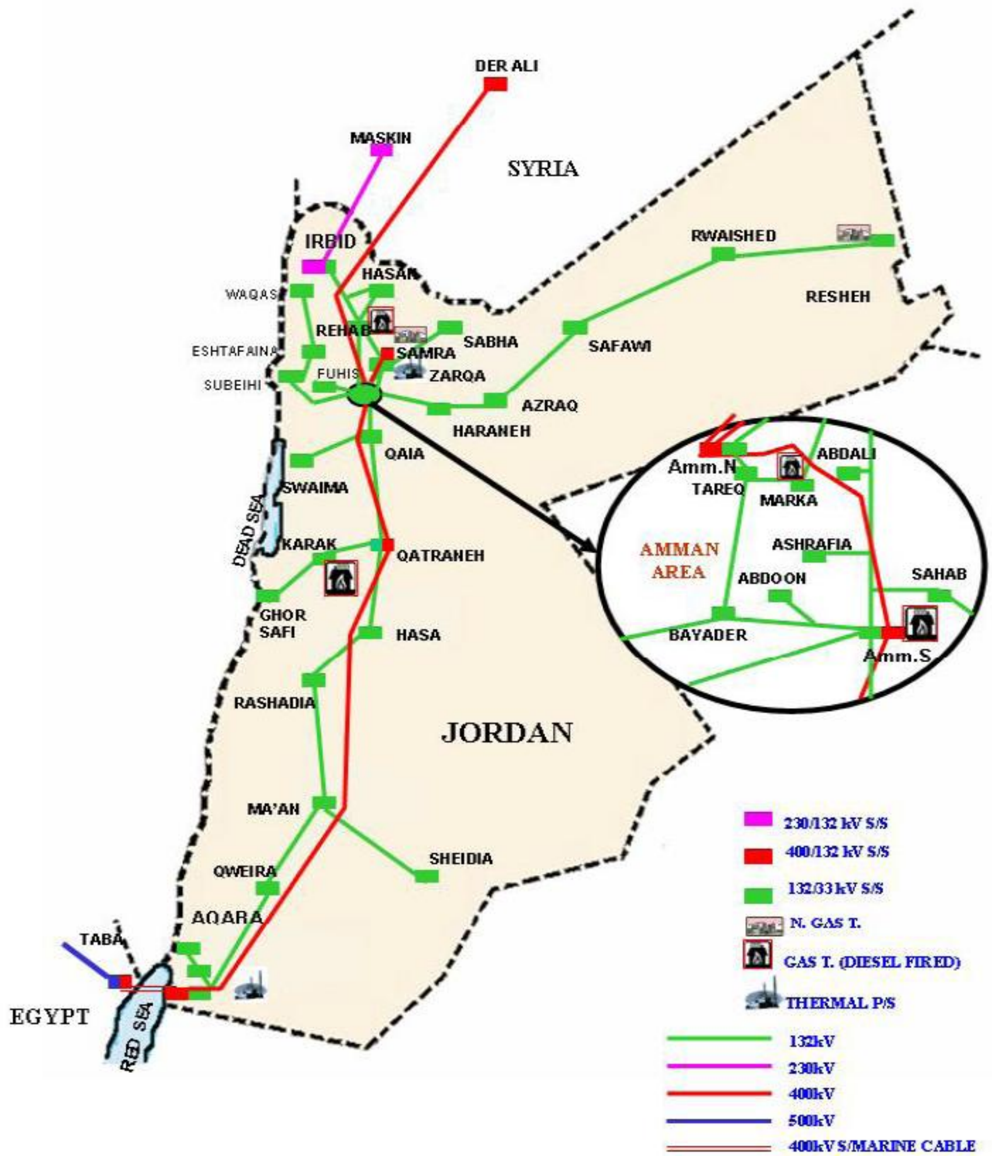
Station name	Type	Installed capacity	Fuel
Al Aqaba TPS[1]	Steam turbine	5 x 130 MW	Imported gas/ Heavy Fuel Oil
Hussein TPS	Steam turbine Steam turbine Gas turbine Gas turbine	3 x 33 MW 4 x 66 MW 1 x 14 MW 1 x 19 MW	Heavy fuel oil Heavy fuel oil Diesel Diesel
Al Resha	Gas turbine	5 x 30 MW	Domestic gas
Rehab	Gas turbine Combined cycle	2 x 30 MW 300 MW	Imported gas Imported gas
Samra[2]	Gas turbine Combined cycle	2 x 98 MW 304 MW	Imported gas Imported gas
Amman East	Combined cycle	2 x 123 MW 1 x 124 MW	Imported gas
Amman South	Gas turbine	2 x 30 MW	Diesel
Marka	Gas turbine	4 x 20 MW	Diesel
Karak	Gas turbine	1 x 20 MW	Diesel
Diesel Units	Diesel	23 MW (combined)	Diesel
Wind and hydro	-	7.5 MW (combined)	Renewable

Source: Update of the 2006 Generation and Transmission Expansion Master Plan, August 15, 2008.
Notes:
1 TPS is thermal power station
2 A steam turbine is scheduled to be added in 2010 to convert the gas turbines at Samra to combined cycle, resulting in a net capacity addition of 108 MW.

The transmission network includes 2200 km of 132 kV circuits that traverse mainly from the north to south of the country. The transmission system is radial without looping, except around Amman. There are also 809 km of 400 kV transmission running through the country from the south near Egypt through the north into Syria (figure 4-3).

The Jordanian grid is connected to Egypt through a 14 km, 400 kV submarine cable across the Gulf of Aqaba. In the north, Jordan is connected to Syria through a 160 km, 400 kV single circuit

Figure 4. 3: Map of Jordan's Power System



Source: MEMR

transmission line. Owing to technical constraints, the maximum power that can be imported to Jordan is 150 MW from Egypt and 100 MW from Syria. Jordan is also interconnected with the West Bank through a 30 km, 2 x 132 kV line that is currently operated at 33 kV to supply the Jericho District in isolated mode.

Jordan normally imports small amounts of energy from Egypt and exports small amounts of energy to Syria and the West Bank. Imports normally take place during the day and exports at night. In 2008 Jordan was a net importer of energy from Egypt and Syria, purchasing 293 GWh, which represented approximately 2.5 percent of domestic production. Jordan exported 140 GWh to the West Bank in 2008. The main benefits of the interconnections to Jordan are operational, reducing the spinning reserve requirement and the pick-up of load during sudden changes in demand or generation.

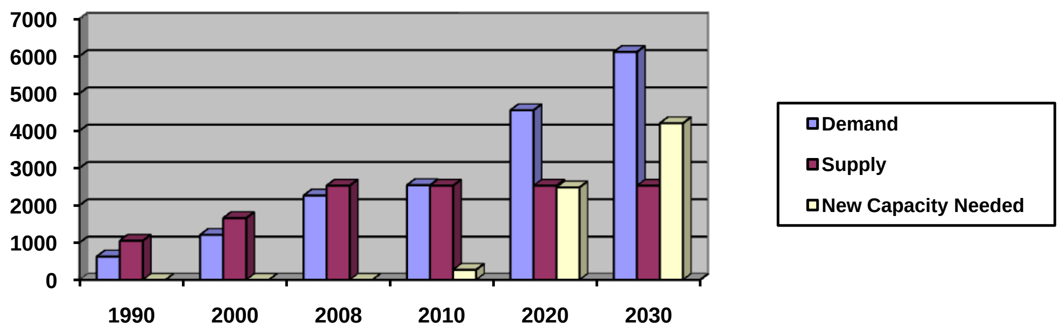
NEPCO's forecast generation expansion plan is as shown in table 4.4. As can be seen, the favored expansion option in the near term is combined cycle fuelled with imported natural gas, along with some gas turbines to meet peaking requirements. In the longer term (2016 and beyond), twelve 300 MW CFB (circulating fluidized bed) oil-shale-fired units are to be added by 2025. Oil shale plants have high capital costs but low fuel costs, making them best suited for base-load operation. Furthermore, to reduce dependence on imported natural gas, Jordan is implementing a program to promote renewable energy development. Finally, the country has significant wind and solar potential. The Government has established a target that 3 percent of total energy requirements be derived from renewable sources by 2015.

Table 4. 4 Favored Generation Expansion Plan

POWER STATION	CAPACITY (MW)	OPERATION DATE
Samra	Steam Turbine 100 MW	2010
Samra 3d Stage	Gas Turbines 200 MW	MID 2010
IPP2	Gas Turbine 248 MW	END 2010
IPP2	Steam Turbine 123 MW	MID 2011
IPP3	Gas Turbine 2X130 MW	MID 2012
IPP3	Steam Turbine 130 MW	MID 2013

Jordan's electricity demand/supply picture is summarized in figure 4.4. The blue bar shows historical and forecast demand. The purple bar shows historical generation capacity, and existing capacity (in 2008) going forward. The yellow bar shows the amount of new capacity needed to meet growing demand with adequate levels of reliability (assuming 10% reserve margin). This new generating capacity is needed to supplement existing generation capacity, but does not account for new investment needed to replace retired plant. Jordan will require an additional 4200 MW of generating capacity by 2030, representing 166 percent of current capacity, if it is to meet growing demand with adequate levels of reliability.

Figure 4. 4: Jordan's Demand/Supply Situation ***(MW)***



Source: Various – see Appendix A

4.3.3 Power Sector Fuel Requirements

Jordan's only domestic natural gas production is from the Al Resha field located in the eastern part of the country close to the Iraqi border. The Al Resha field started production in 1988, and now produces 0.57–0.85 mcm per day, enough to fire 70–85 MW of electric generating capacity. All gas from Al Resha is sold to the Central Electricity Generation Company (CEGCO) at 7 US cents/cm.

The National Electric Power Company (NEPCO) has a 30-year Gas Sales Agreement (GSA) with The Jordanian-Egyptian Fajr Company for natural gas transmission and distribution. NEPCO buys the gas from the Fajr Company and resells the gas to the generation companies which use imported natural gas as the primary fuel. Available gas quantities included in the GSA are shown in table 4.5. Contract re-negotiations resulted in increased deliveries in 2009 and beyond.

Table 4. 5 Contracted Gas Quantities ***(MCM)***

Year	Annual contract quantity
2004	1025
2005	1250
2006	1300
2007	1500
2008	1600
2009	3300
By 2013, gas quantities ramp up to:	4200

Even the additional gas deliveries agreed to as a result of re-negotiations will not be enough gas to supply Jordan's forecast electric power generation needs. Jordan must also import crude oil used to produce HFO for electric power generation. Crude oil is imported through the Aqaba port and transferred by truck to a petroleum refinery in which HFO is refined for power generation. All light oil needed for power production likewise is imported at international prices. High oil prices and limited natural gas make it necessary to scale up efforts to use oil shale as a fuel for power generation. Oil shale deposits are located in different areas of Jordan from Ma'an in the south to Yarmouk River in the north. Total deposits are estimated at approximately 40 billion tons.

Forecast fuel supply requirements for power generation are as shown in table 4.6. As it shows, Jordan hopes to meet all fuel requirements for power generation with gas before 2020.

Table 4. 6 Forecast Fuel Supply Requirements for Power Generation

	2007	**2010**	**2020**	**2030**
Gas *(bcm)*	2.73	3.74	5.68	7.63
Oil *(mbl)*	4.4	3.9	0	0

4.4. Gas Sector Structure

The Ministry of Energy and Mineral Resources (MEMR) is responsible for promotion and development of energy resources and overseeing the performance of the operating companies in the energy sector. Its principal role is to implement national energy policy. It is thus tasked with securing the country's energy requirements from the most appropriate sources consistent with the Government's supply security requirements. The MEMR is implementing a strategy to attract private sector involvement in the energy sector, either in the form of direct investment or through the implementation of projects on a build-own-operate (BOO) or build-own-transfer (BOT) basis.

The Natural Resources Authority (NRA) has a wide range of responsibilities related to developing Jordan's natural resources. These responsibilities include facilitation of exploration and prospecting for mineral resources. The NRA administers laws and regulations relating to mineral resources; and issues permits and licenses for exploration, mining, quarrying, and mineral rights. NRA coordinates investments by international firms to develop natural resources and has recently been involved with development of domestic oil shale deposits.

The contract with Al Fajr Company sets out the obligations of the Governments of Egypt and Jordan for the sale and purchase of gas and construction of required pipelines and other infrastructure. The contract is for 30 years, with the possibility of a 10-year extension. Al Fajr Company constructed the second phase of the AGP on a build-own-operate-transfer (BOOT) basis, with the transfer to take place after 30 years of operation. In return, Al Fajr Company has received exclusivity rights for 18 years. Al Fajr Company is a consortium including the Egypt Gas Holding Company, GASCO, Petrojet, and Enppi. The company is expected to maximize the use of natural gas in Jordan. The license granted Al Fajr by the Government of Jordan gives the company the right to:

- Construct, manage, operate and maintain the part of the AGP in Jordan
- Purchase gas from Egypt and transport and market the gas to Jordanian consumers

- Transport transit gas from the delivery points.

4.5. Gas Demand and Supply

In 2006 gas consumption represented approximately 28 percent of Jordan's total primary energy consumption. Less than 3 percent of Jordan's primary energy requirements are produced in-country, and the percentage has been falling. In 2005 Jordan's total gas consumption was 1.66 bcm, comprising 0.21 bcm produced domestically at the Risha fields and 1.45 bcm imported from Egypt via the AGP. Domestic gas production in recent years is shown in table 4.7. Although domestic gas production has been falling over this period, recent exploration efforts at Risha have been promising.

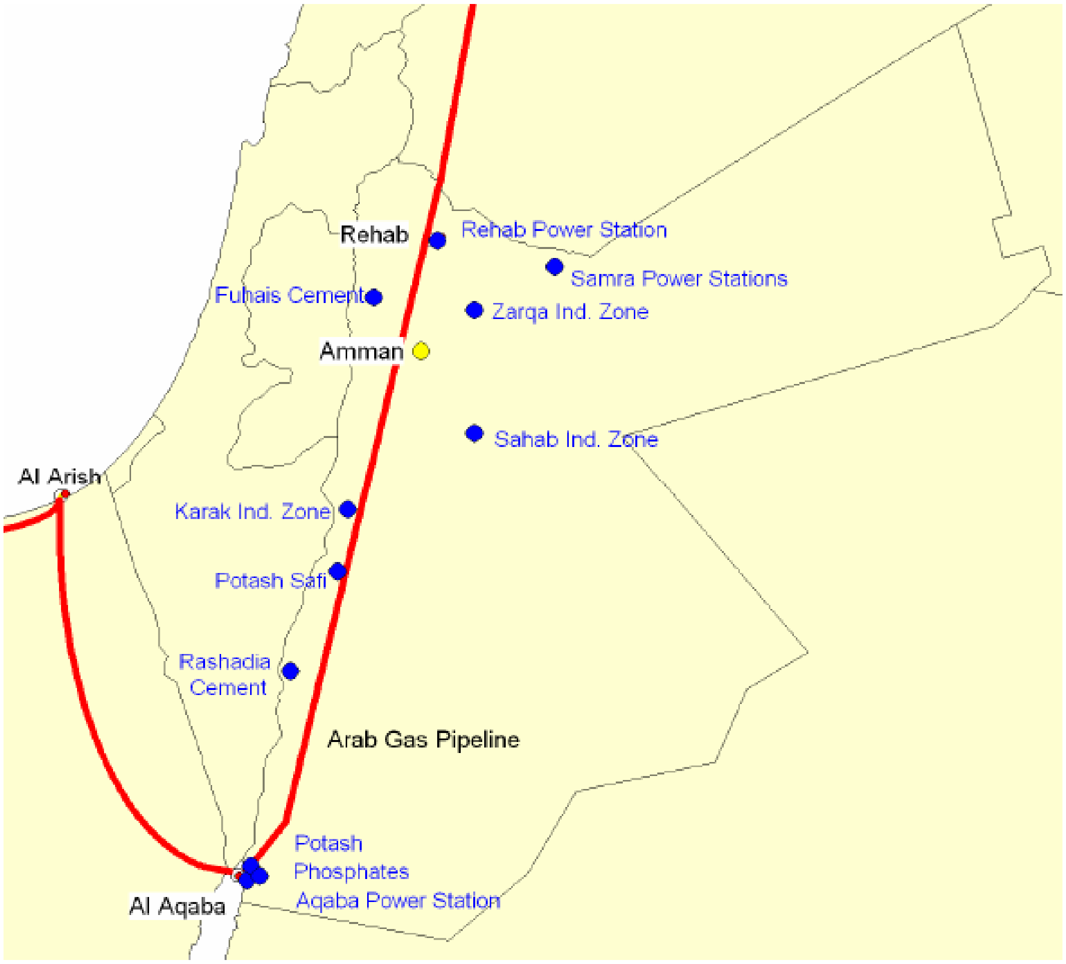
Table 4. 7 Domestic Gas Production

Year	**Gas production** *(mcm)*
1990	124
2000	261
2007	227

Electricity demand is the primary driver of Jordan's natural gas demand. The Government plans to construct additional gas-fired plants, and has established a target to produce 80 percent of electricity from gas by 2010.

A number of new gas consumers are expected to locate near the AGP (figure 4.5). Based on MEMR and NEPCO forecasts, gas demand is expected to continue to grow (table 4.8). The gas forecast is heavily influenced by the electricity demand forecast, cost of competing fuels, and fuel supply security. The overall demand for energy is forecast to remain strong, particularly through the medium term. The share of natural gas in the total energy mix is expected to increase to levels exceeding 40 percent in 2015 and beyond.

Figure 4. 5: Locations of Planned Gas Consumers



Source: IPA Energy

Jordan's domestic gas production met less than 8 percent of domestic gas consumption in 2007. The remainder is imported via the AGP from Egypt, with contracts through the medium term. There appear to be few, if any, sources of gas available that would be more economic than Egypt. Regardless, with secured access to Egyptian gas, Jordan is well placed to continue to expand its use of natural gas. Gas from Iraq or Iran offers another set of options but may not be viable in the short to medium term.

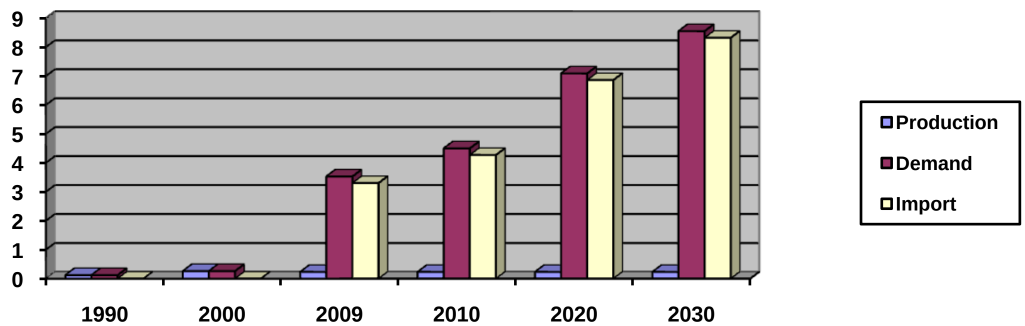
Table 4. 8 Natural Gas Forecast ***(bcm)***

	2007	**2010**	**2020**	**2030**
Gas demand	2.95	4.5	7.1	8.6

Jordan will need to take full advantage of the AGP if it is to meet its future gas requirements. The contract with Al Fajr Company provides exclusivity for 18 years. The exclusivity arrangement was necessary to attract investors.

The gas demand/supply balance is shown in figure 4.6. It shows that Jordan will remain a gas importer with imports increasing from 3.3 bcm in 2009 to 8.3 bcm in 2030, representing a 150 percent increase in gas consumption.

Figure 4. 6: Gas Demand/Supply Balance ***(bcm)***



Source: Various – see Appendix A.

Chapter 5. SYRIA PROSPECTS FOR ENERGY INTEGRATION

5.1. Overview

Syria's power sector had been relatively stable until recent years when a number of challenges arose as a result of rapidly growing electricity demand. High levels of demand growth have eroded capacity reserve margins leading to frequent load shedding, negatively impacting Syria's economy. The financial performance of the electricity sector is deteriorating owing to high technical and non-technical losses and inadequate tariffs. Supply reliability is further hampered by generation fuel security issues owing to inadequate supplies of domestic gas. The power sector requires large Government subsidies. While new electricity generation being brought on will help to alleviate supply shortfalls, increasing electricity demand and plant retirements will continue to put pressure on Syria's electricity infrastructure. Syria is seeking private sector investment in the power sector, but it will be difficult to attract such investment on a sustainable basis without significant changes in energy policy.

Electricity generation is expected to consume the majority of Syria's natural gas. Syria's proven reserves of natural gas could be sufficient to meet a significant portion of domestic needs over the medium term, but inadequate investment to bring new gas reserves into production has lead to greater reliance on other fuels and natural gas imports for electricity generation. Syria has recently started importing gas from Egypt over the AGP, and is giving high priority to the completion of the AGP link to Turkey to gain access to gas purchases from Turkey, Iran and possibly Iraq. If successful, gas could become dominant in the electricity generation mix.

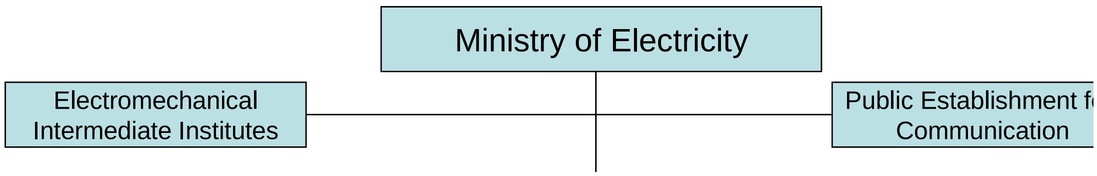
If Syria is to return the electricity sector to financial self-sufficiency while protecting the socially disadvantaged it will need to make significant changes in policy such as industry restructuring, regulation, and retail tariff increases. On the positive side, with improved energy policy, its domestic natural gas resources, and its electricity and gas interconnections, Syria is well positioned to benefit from the integrated regional market. The AGP runs through Syria, and Syria has electricity interconnections with Iraq, Jordan, Lebanon, and Turkey, so Syria is well-positioned as an energy transit country.

5.2. Power Sector Structures

Syria's electricity sector is managed and regulated by the Ministry of Electricity. The Public Establishment for Electricity Generation and Transmission (PEEGT) plans, develops, operates, and maintains the generation and transmission components of the electricity sector.[14] Similarly, the Public Establishment for Distribution and Exploitation of Electric Energy (PEDEEE) and its 14 regional subsidiaries are responsible for the power distribution network.[15] Figure 5.1 shows the organization of Syria's electricity sector.

[14] PEEGT was created in 1994 by Legislation Decree 14.
[15] PEDEE and its 14 establishments were created by Legislation Decrees 13 and 14.

Figure 5. 1: Organization of Syria's Electricity Sector



The Ministry of Electricity is responsible for both policy and regulation. Regulatory decisions have not been made in the best interest of the electricity sector as a whole and free of Government influence as witnessed by the need for large Government subsidies. Although distribution is separate from the generation and transmission components, the electricity sector operates as a vertically integrated, monopolistic structure without competition.

In the summer of 2007, Damascus experienced daily power interruptions lasting as long as five hours. The competitiveness of Syria's industry is being hampered as a result of electricity supply shortages, which numbered 43 days of power outages in 2005. This number compares to 18 days in Egypt and 1 day in Malaysia in the same year. Poor reliability forces Syrian manufacturing firms to install and operate their own high-cost generating equipment that decreases their competitiveness.

Addressing electricity supply shortages is a top priority of Syria's Government. However, Syria's retail electricity prices are far below the levels necessary to recover the economic cost of supply. A report by the World Bank[16] shows that Syria's retail electricity prices for a residential customer consuming 700 kWh per month are only 10 percent of a benchmark tariff based on an average of the tariffs of France, Greece, Italy, Portugal, Spain, and Turkey. Syria's tariffs are even far below the average tariff paid by other countries in the Middle East and Africa (MENA). Syria's tariff for a residential customer consuming 700 kWh per month is only 24 percent of the MENA average, and its retail tariff for industrial customers, although comparable to the MENA average, is likewise far below the European benchmark.

5.3. Electricity Demand and Supply

5.3.1 Demand

Electricity demand has grown substantially in recent years, more than doubling between 1990 and 2008. In 2008 energy demand was over 40 TWh and peak demand was 6,715 MW. Growth in electricity consumption has been 6.8 percent annually since 2000. Table 5.1 shows growth in electricity demand in recent years.

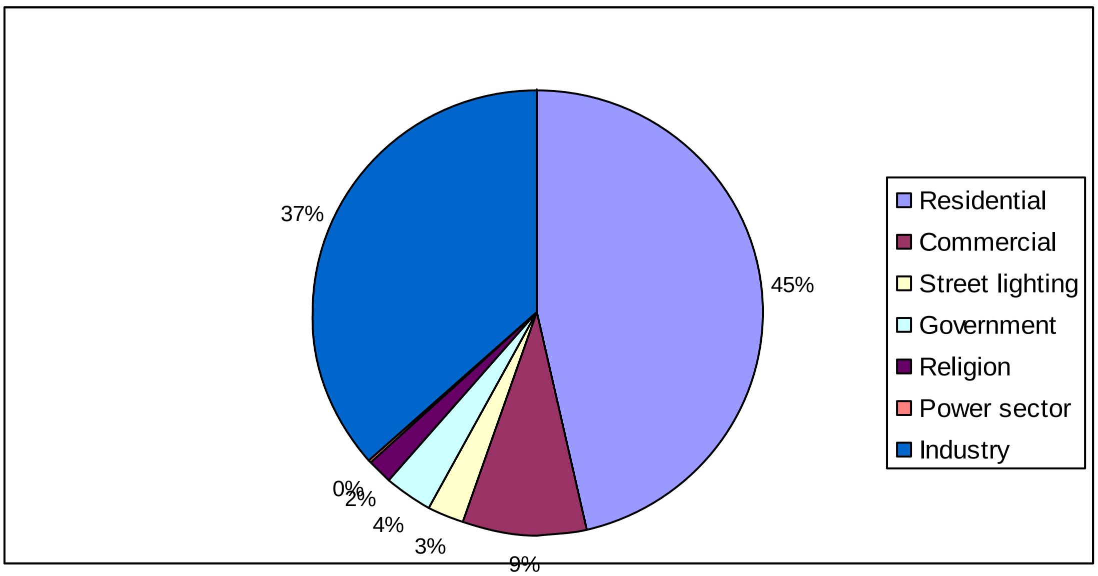
[16] See February 2009 World Bank report entitled *Tapping a Hidden Resource – Energy Efficiency in the Middle East and North Africa*.

Table 5. 1 Historical Demand, 1990–2008

Year	**1990**	**2000**	**2008**
Peak demand *(MW)*	3258	5990	6715
Energy demand *(GWh)*	8310	23,870	40,273

Electricity demand grew rapidly after 2001 owing to an acceleration of the country's industrialization and growth in the commercial and service sectors. The residential sector has experienced increased penetration of appliances and air conditioning as the economy modernizes and the standard of living improves. In recent years, domestic consumption has been growing at approximately 7.5 percent annually. Residential and industrial consumption now account for 45 percent and 37 percent, respectively, of total electricity consumption in the country. The commercial sector accounts for approximately 9 percent. A breakdown of customer class demand is shown in figure 5.2.

Figure 5. 2: Demand Breakdown by Customer Class, 2007



Source: .August 15, 2009 Syrian Arab Republic Electricity Sector Strategy Note, ESMAP, The World Bank.

Technical losses represent approximately 15 percent of the total demand, high by international levels, which typically are 10 percent. Total nontechnical losses also are high. They accounted for 10 percent of the total demand in 2007, far exceeding the 1 percent–2 percent levels accepted by commercially operated power utilities.

Table 5.2 provides a forecast of peak and energy demand from 2008 through 2030. Electricity demand is forecast to grow over 2008–30 at almost 3.7 percent annually. The slowdown in demand growth from historical levels is due to the expected modernization of the Syrian economy, a shift toward less energy-intensive activities, and loss reduction and energy efficiency initiatives. The Government of Syria recently established the National Energy Research Center (NERC) to be responsible for formulating; proposing; and coordinating policies, plans, and programs in renewable energy and energy efficiency. Based on NERC's estimates of the potential for energy efficiency in Syria and on the World Bank's experience in comparable countries in the Region,[17] Syria's electricity demand could be reduced by 3,000 GWh by 2015 (6 percent of total demand), and to 6,000 GWh by 2020 (8.5 percent of total demand). Given the increases expected in low load factor customers, the impact of load management is difficult to evaluate. Nevertheless, it could decrease system peak demand by 160 MW by 2010, 448 MW by 2015, and 866 MW by 2020.

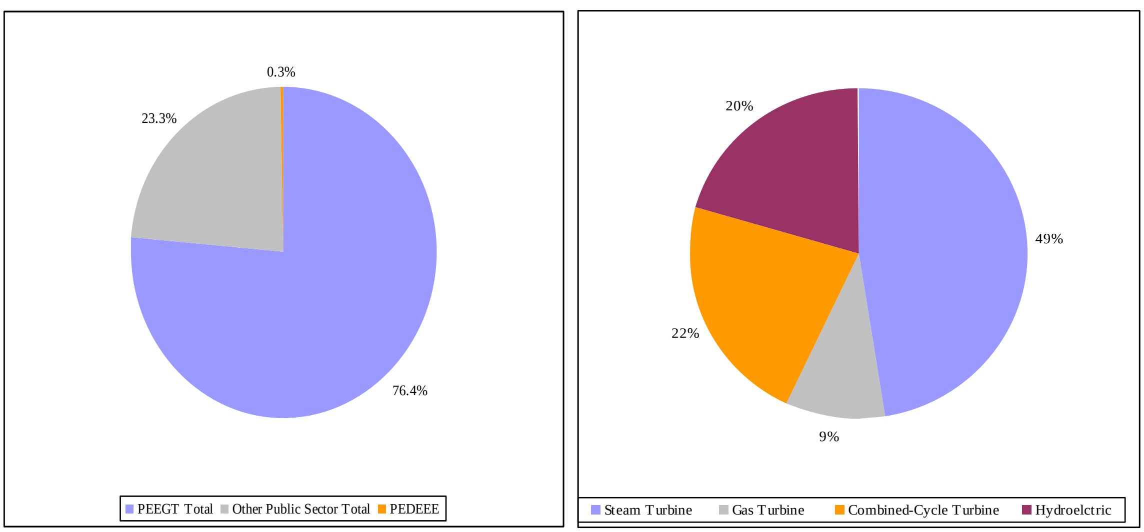
Table 5. 2 Forecast Demand, 2008–30

Year	***2008***	***2010***	***2020***	***2030***
Peak demand *(MW)*	6715	7518	10,448	14,041
Energy demand *(GWh)*	40,273	43,783	62,074	87,000

5.3.2 Supply

Syria's installed generating capacity has more than doubled since 1990, yet has lagged growth in demand. The total installed generation capacity in Syria was 7700 MW in 2008, but as much as 1200 MW were unavailable. In 2007, approximately 76 percent was supplied by PEEGT, 20 percent by the General Establishment of Euphrates Dam (Thawra, Baath, and Tishreen plants), 1.6 percent by Syrian Petroleum Company, 0.9 percent by Homs refinery, 0.6 percent by Banias Refinery, and 0.3 percent by PEDEEE. The generation mix consists of steam (47.6 percent), hydro (20.5 percent), open cycle gas turbines (9.5 percent) and combined-cycle gas turbines (22.5 percent) (figure 5.3).

Figure 5. 3: Power Generation Mix: Ownership and Technology



Source: .August 15, 2009 Syrian Arab Republic Electricity Sector Strategy Note, ESMAP, The World Bank.

A list of Syria's power plants is provided in table 5.3. Steam power plants are used as base load, and gas turbines for peaking. However, the generation deficit has resulted in greater reliance on gas turbines to meet base load requirements.

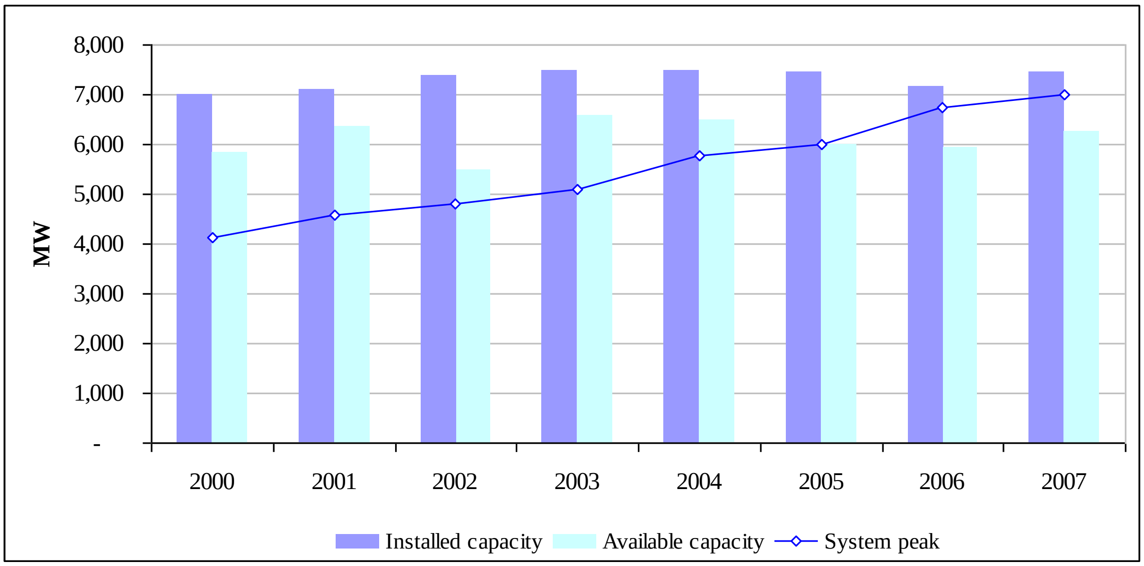
Table 5. 3 Syria's Power Generation Plants

Plant	Organization	Type	No. of units	Capacity *(MW)*		
				Unit	Installed	Available
Banias TPP	PEEGT	Gas turbine	1	30.0	30	0
		Steam turbine	4	170.0	680	340
Mehardeh TPP		Gas turbine	1	30.0	30	0
		Steam turbine	2	165.0	330	290
			2	150.0	300	240
Tishreen TPP		Gas turbine	2	112.5	225	200
		Steam turbine	2	200.0	400	400
Nassrieh CCPP		Gas turbine	3	112.5	337.5	330
		Steam turbine	1	150.0	150	150
Jandar CCPP		Gas turbine	4	118.5	474	440
		Steam turbine	2	114.0	228	200
Zayzoon CCPP		Gas turbine	3	112.5	337.5	330
		Steam turbine	1	150.0	150	150
Aleppo TPP (Halab)		Gas turbine	1	30.0	30	0
		Steam turbine	5	213.0	1065	1,065
Tayyem GTPP		Gas turbine	3	34.0	102	68
Swedieh GTPP		Gas turbine	5	34.0	170	136
Alzara TPP		Steam turbine	3	220.0	660	660
Syrian Petroleum Company	Other public sector	Gas turbine	6	20.0	120	60
Homs Refinery		Steam turbine	2	32.0	64	40
Banias Refinery		Steam turbine	4	12.0	48	0
Thawra Dam		Hydro	8	100.0	800	650
Baath Dam		Hydro	3	25.0	75	51
Tishreen Dam		Hydro	6	105.0	630	450
PEDEEE	PEDEEE	Hydro	2	8.0	16	0
			1	7.0	7	0
System total					7,459	6,250
PEEGT total					5,699	4,999
Other public sector total					1,737	1,251
PEDEEE					23	0
Steam turbine total					3,547	3,035
Gas turbine total					707	464
Combined-cycle turbine total					1677	1600
Hydro turbine total					1,528	1,151

Source: .August 15, 2009 Syrian Arab Republic Electricity Sector Strategy Note, ESMAP, The World Bank.

Figure 5.4 shows that available generating capacity declined by an average of 3.2 percent per year during 2003–06. This rate compares to 8 percent annual growth in peak demand over the same period. Available capacity increased by 5 percent in 2007,[18] but the shortfall in capacity remains high at 757 MW. Even with planned new additions of generation capacity, the shortfall of generating capacity is expected to increase owing to retirement of 2476 MW of older generating plants between 2009 and 2020.

Figure 5. 4: Peak Demand and Installed and Available Generation Capacity, 1997–2006



Source: .August 15, 2009 Syrian Arab Republic Electricity Sector Strategy Note, ESMAP, The World Bank.

As there is no reserve margin to cover off system emergencies such as the forced outage of a major generation facility, the level of unserved demand in GWh reported by PEDEEE (table 5.4) has increased sharply. This issue is particularly critical for industries as poor reliability is negatively impacting their competitiveness.

Table 5. 4 Unserved Demand, 2002–07 ***(GWh)***

	2002	2003	2004	2005	2006	2007
Unserved load	86.3	83.4	103.8	55.0	345.1	427

Source: MOE Reports

No new generating capacity was added to Syria's system from 2001 to 2006. In 2007 conversion of the open cycle gas units at the Nasrieh and Zayzoon plants to combined cycle with the addition of a 150 MW steam unit at each plant was completed. A major new 750 MW combined-

[18] 300 MW of new generation capacity was added in 2007 when Nassrieh and Zayzoon open-cycle power plants were converted to combined-cycle power plants.

cycle power plant at Deir Ali using natural gas as its main fuel became fully operational in 2009. Expansion of the Tashreen power plant by 450 MW and the Banias power plant by 300 MW are expected to be completed in 2010. The new additions are summarized in table 5.5.

Table 5. 5 New Generating Plant Additions

Power plant	**Type**	**Capacity** *(MW)*	**Status**	**Full operation yr** *(est.)*
Tishreen extension	Combined cycle	450	Under construction	2010
Banias extension	Steam	300	Under construction	2010

The transmission system is planned, operated, and maintained by PEEGT. The main transmission network consists of 760 km of 230 kV and 5,080 km of 400kV lines and their associated substations and transformers. The 400 kV south-north transmission interface connects major generating power plants to the transmission grid while the load centers in the country's five regions are integrated and supplied by the major 230kV network. Internal constraints within the 230 kV transmission network exist owing primarily to limited transformer capacity feeding major load centers. PEEGT plans to expand the 400 kV transmission network to reinforce the capacity of the national transmission network.

Syria is a member of the 8-member interconnection consortium that consists of the 400 kV and 500 kV power grid interconnections among the national power systems of Egypt, Iraq, Jordan, Lebanon, Libya, Syria, Turkey, and the West Bank & Gaza (the West Bank & Gaza was officially included in the project in 2008). The Syrian transmission system is strategically located with 9 interconnections to the power systems of Iraq, Jordan, Lebanon, and Turkey at voltage levels ranging from 66 kV to 400 KV (table 5.6).

Table 5. 6 Syria's Electrical Interconnections with Neighboring Countries

Interconnection description	Operational year	Estimated Thermal Limit (MW)[1]	2006 use (% thermal capacity)
Syria-Lebanon, double-circuit, 66kV, 110MVA[2]	1972	94	1.5
Syria-Lebanon, single-circuit, 230kV, 267MVA	1977	227	3.6
Syria-Lebanon, single-circuit, 400kV, 1135MVA	2000	965	15.1
Syria-Lebanon, single-circuit, 400kV, 1135MVA	April 2010	1000	N/A
Syria-Iraq, single-circuit, 230kV, 267MVA	2000	227	3.6
Syria-Jordan, single-circuit, 230kV, 55MVA	1977	47	0.7
Syria- Jordan, single-circuit, 230kV, 267MVA	1980	227	3.6
Syria-Jordan, single-circuit, 400kV, 1135MVA	2000	965	15.1
Syria-Turkey, single-circuit, 400kV, 1135MVA	2007	965	N/A

Notes:

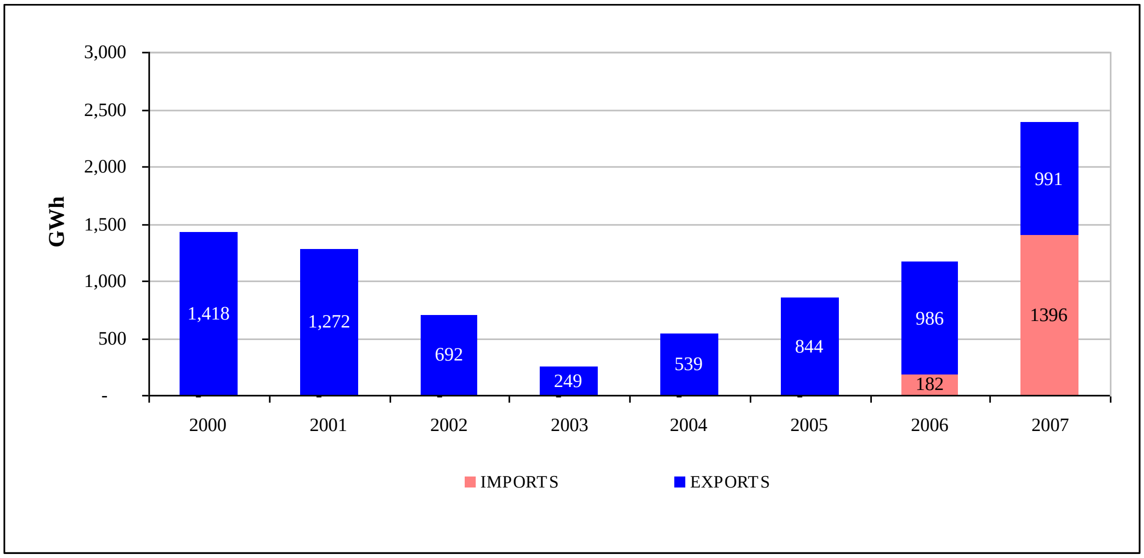
1 Assuming load factor of 0.85.

2. There is no source of the operational status to date for every interconnection. Therefore, imports and exports of energy are an annual lump sum per country.

The 400 kV transmission line between Syria and Turkey (Bireik-Aleppo) links the power systems of the two countries. However, the systems are not synchronized, so the line is used to feed Syria from an isolated power station in Turkey.

Syria cross-border energy imports and exports have evolved through the use of bilateral rather than regional agreements. Bilateral agreements have been the norm because the various electricity networks in the region are not synchronized. Figure 5.5 shows annual electricity imports and exports between Syria and neighboring countries. Existing substation and network capacity constraints in the national power systems and the complexity of bilateral agreements have constrained use of interconnection capacity primarily to the provision of capacity during power emergencies.

Figure 5. 5: Syria's Electricity Imports and Exports, 2000–07



Source: MOE Reports

To meet increased demand, replace retired plant, and restore reserves to 10 percent (there is no reserve capacity), Syria needs close to 7000 MW of additional generating capacity by 2020 (table 5.7).

Table 5. 7 Capacity Needed to Meet Demand 2008–20 ***(MW)***

	2008 (actual)	2010	2015	2020
Capacity demand	7,700	7,518	8,708	10,448
Existing capacity with retirement	7384	7376	5771	4650
Additional capacity with 10 percent reserve		894	3808	6843

Source: World Bank projections.

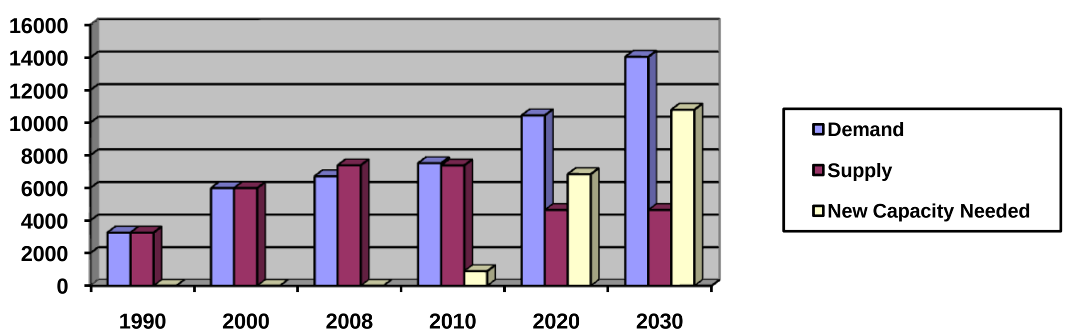
The World Bank estimates that Syria will need to invest US$10.5 billion by 2020 in its electricity sector: US$7 billion for generation capacity and US$3.5 billion for transmission and distribution capacity.

The Government of Syria is considering a number of alternatives to meet the generation deficit, taking into consideration fuel availability and mix, plant technology, and risk profiles. Natural gas, both domestic and imports through pipelines; imported coal; heavy fuel oil; and diesel are all under consideration, as are technologies including simple cycle gas turbines, combined cycle gas turbines, steam, diesel engines, and various renewable technologies.

Depending on availability, natural-gas-fired technologies appear to be the most economic and the most environmentally friendly of the fossil-fuel alternatives. Renewable generation also is expected to make a contribution.

Assuming 10 percent reserve margin, Syria's electricity demand/supply picture through 2030 is shown schematically in figure 5.6. The new generating capacity is needed to supplement existing generation capacity, and accounts for retirements. By 2030, Syria will need over 10,000 MW of new generating capacity.

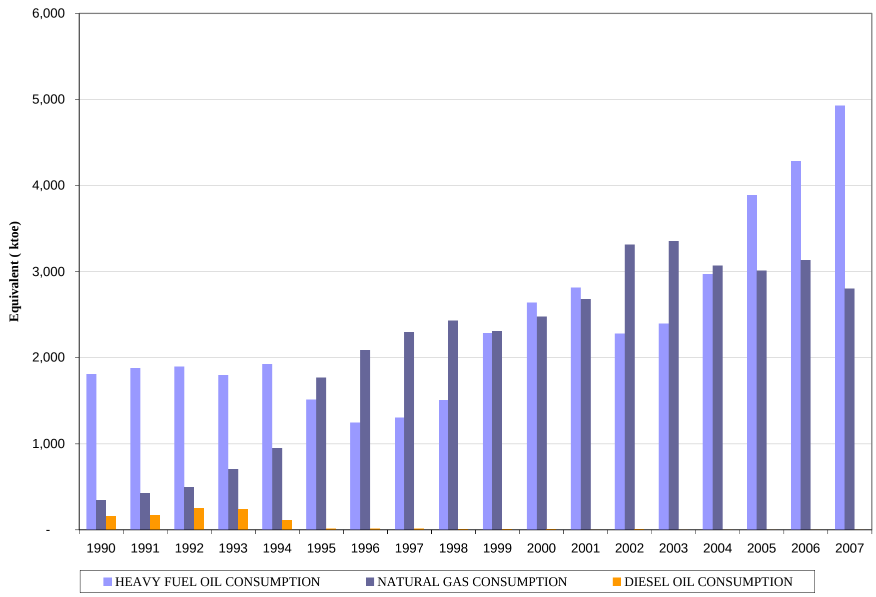
Figure 5. 6: Syria's Demand/Supply Situation, 1990–2030 ***(MW)***



5.3.3 Power Sector Fuel Requirements

PEEGT's power plants burn heavy fuel oil (HFO), natural gas, and a small amount of diesel (figure 5.7). HFO consumption has grown on average by 12 percent per annum since 1996. This rate compares to 4 percent for natural gas. HFO and gas consumption were the same in 2004, but HFO consumption has since exceeded gas consumption due in part to natural gas shortages. Nassrieh and Zayzoon power plants were converted to combined-cycle in 2007, yet natural gas consumption declined 11 percent. The ability to operate dual fuel power plants on natural gas has not been fully exploited owing to the unreliability of the natural gas supply, a critical issue for future generation expansion plans.

Figure 5. 7: Equivalent Fuel Consumption of PEEGT Power Plants, 1990–2007



Source: MOE Reports and World Bank Calculations

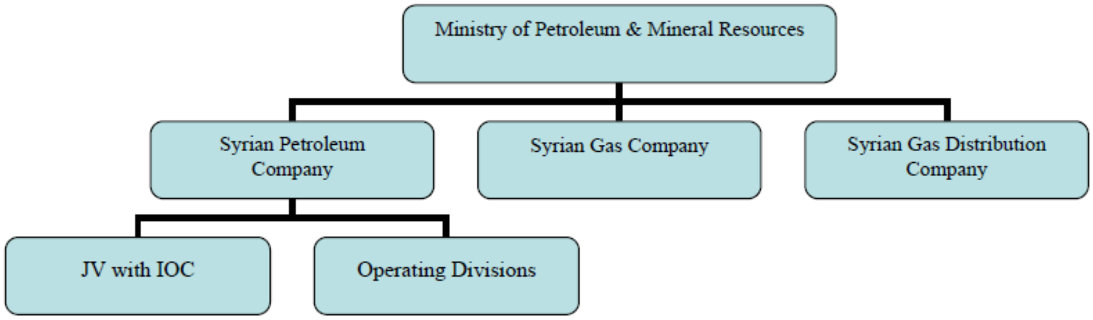
At present, the annual gas consumption of the power sector is approximately 4 bcm. The Syrian Gas Company (SGC) plans to provide the power sector approximately 7 bcm of gas by 2012 and beyond.[19] However, gas imports of at least 1.4 bcm will be required to supply the power sector by 2012 and 9.5 bcm by 2020 if all new generating capacity will be gas fired. Complicating the gas supply picture is the limited gas storage capacity. Production from gas-fired power plants must be adjusted to power demand on a real-time basis. As a result, Syria's power sector is likely to remain dependent on higher cost fuel alternatives to natural gas in the near term, and possibly beyond.

5.4. Gas Sector Structure

The Ministry of Petroleum and Mineral Resources oversees the natural gas sector (figure 5.8). The state-owned Syrian Gas Company (SGC) is responsible for gathering, treating, compressing, and managing natural gas from the various fields. SGC supplies all Syrian gas consumers and owns 3 of the 4 gas processing plants in Syria. Al Furat Petroleum Oil Company (AFPC) operates the fourth. SGC purchases gas from the Syrian Petroleum Company (SPC) and independent producers. Syrian power plants are the primary gas customers, purchasing their gas needs from SGC.[20]

[19] This would be feasible after the completion of 4 new gas production facilities currently under development, which are expected to come into operation during 2009–11. After 2012, production levels of 7 bcm/year will depend on additional investment in new gas fields and production facilities.
[20] It is understood that the Government recently restructured the petroleum sector placing SPC and SGC under a single holding company.

Figure 5. 8: Organization of Syrian Oil and Gas Sector



The Syrian Gas Distribution Company (SGDC) distributes liquid petroleum gas (LPG) to industry and households. LPG is supplied in bottles to domestic consumers and small businesses and delivered by private contractors. There is no natural gas distribution network in Syria.

5.5. Gas Demand and Supply

5.5.1. Gas Demand

Gas to fuel electricity-generating stations is the most significant component of gas demand, and accounted for 99 percent of gas demand in 2007. Industrial demand makes up the remaining component of gas demand. It comprises two refining facilities, a cement plant, and a fertilizer plant at Homs. There is no domestic gas distribution network to supply residential and commercial customers.

SGC gas sales in recent years to the power stations and industrial customers are shown in table 5.8. Gas consumption, although steady, has been constrained by the availability of gas supply.

Table 5. 8 Gas Demand in Syria, 2003–06

Mmcm	2003	2004	2005	2006 H1
Mahardeh PS	45	12	3	0.2
Tayyem PS	134	184	173	88
Tishreen PS	435	367	450	238
Jandar PS	1012	979	1049	496
Nasriah PS	416	429	522	211
Zaizoun PS	431	460	589	262
Zara PS	489	343	100	103
Aleppo PS	543	336	201	204
Swediah PS	0	358	372	187
Total PS	3505	3468	3459	1789
Urea Plant	326	308	289	208
Adra Cement	86	83	88	41
Total	412	391	377	249
Homs Refinery	240	244	229	112
T-3 Station	37	22	22	11

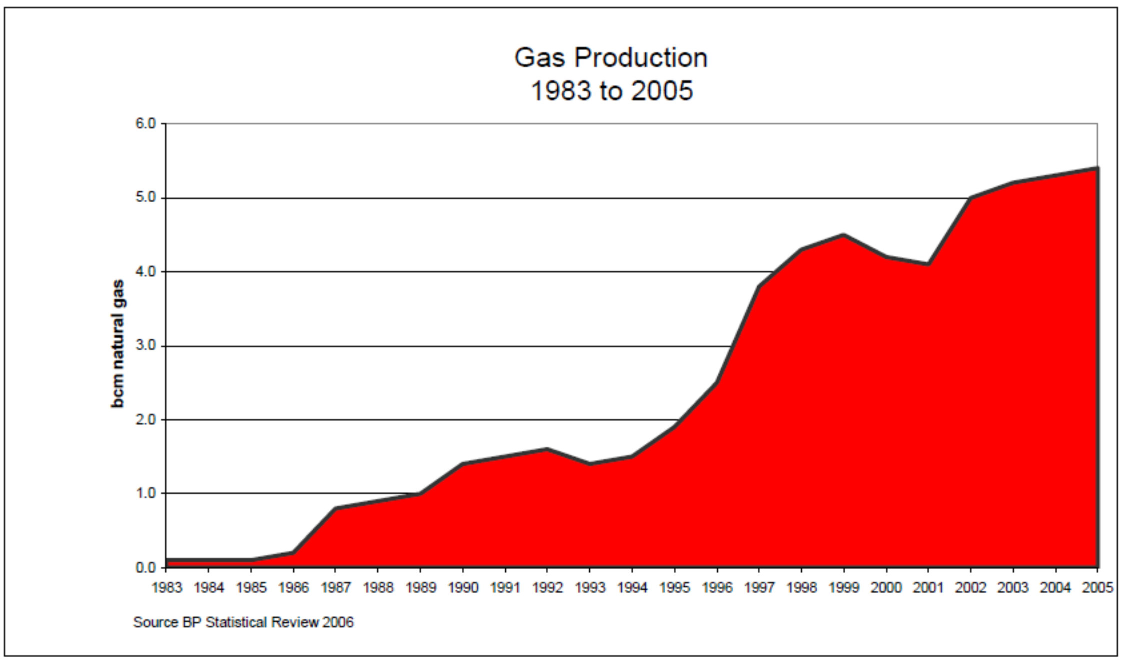
SPC [21]	0	259	258	120
Total	278	526	509	243

Going forward, Syria has plans to develop three industrial cities at Homs, Adra, and Aleppo. There are no plans to develop a local natural gas distribution network that would supply residential and commercial customers. It is assumed that, in the long term, 75 percent of electricity generation will be fueled by natural gas driven by high electricity demand growth and substitution of gas for HFO. On this basis, SGC forecasts annual average increases in gas demand of more than 6.5 percent through 2030.

5.5.2 Gas Supply

Syria's proven gas reserves are estimated at 290 bcm. Gas production in Syria has been dominated by non-associated, or free, gas supplied by the SPC fields in the northeast and associated gas from AFPC. Recently, SPC has developed a number of non-associated gas fields in central Yemen, and additional developments in this region are being planned. Figure 5.9 shows the gas production in recent years through 2005. It has risen with development of new fields.

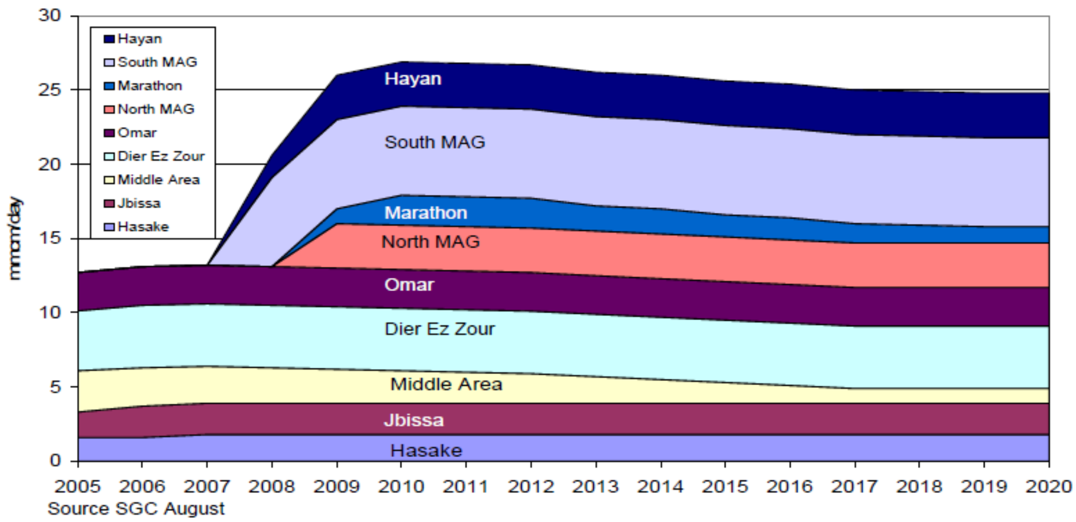
Figure 5. 9: Net Gas Production Trend, 1983–2005



In 2007, total natural gas production was 6.25 bcm. All gas production was consumed domestically. There are 16 gas fields in the central part of Syria that are at various stages of development. Exploration is initiated by the Ministry through the issue of agreements for exploration and development. Contracts for blocks are negotiated between contractors and the Ministry. Only about one-third of Syria has been explored for oil and gas, but gas exploration and development activity have recommenced. International oil companies are bidding for new licenses being offered by the Ministry. SGC's projections of future gas supply are shown in figure 5.10.

[21] Gas supply to SPC gas turbines to support oil recovery at remote sites with associated gas.

Figure 5. 10: SGC Forecast Gas Supply, 2005–20

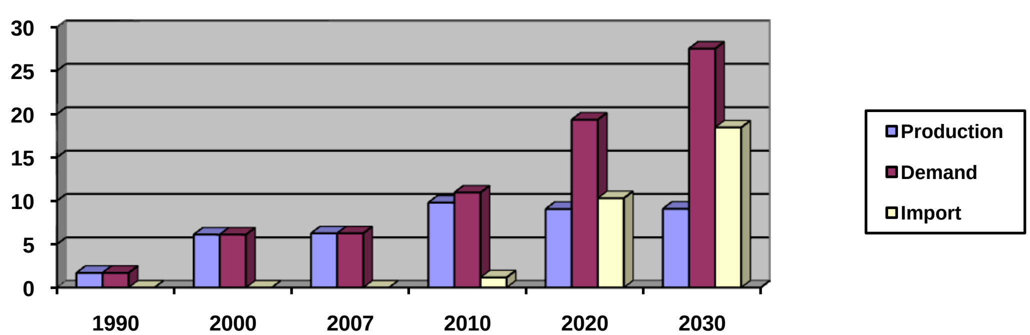


Syria's proven reserves of natural gas estimated at 290 bcm could be sufficient to supply new generation capacity planned for development in the medium-term. However, constrained production capacity and insufficient investment to bring gas reserves into production will make domestic gas supply insufficient to meet future demand of the power sector. As a result, Syria will continue to rely on other types of fuel such as HFO, or will alternatively require greater levels of natural gas imports from the regional market.

Syria has reached an agreement with Egypt to purchase gas to supply the new Deir Ali 750 MW CCGT plant. Under the agreement, Egypt will supply approximately 1 bcm starting in 2009. The completion of the Arab Gas Pipeline and its interconnection with Turkey and the possibility of interconnecting with Iraq in the long term could make several sources of imported gas available in the future.

The historical and forecast gas demand/supply balance is shown in figure 5.11. Syria will have to import 1.2 bcm in 2010, ramping up to 10.3 bcm in 2020 and 18.5 bcm in 2030.

Figure 5. 11: Gas Demand/Supply Balance, 1990–2030 ***(bcm)***



Source: Various – see Appendix A

Chapter 6. **LEBANON PROSPECTS FOR ENERGY INTEGRATION**

6.1. Overview

Significant reform in Lebanon's electricity sector is needed. The reliability and quality of electricity supply is very poor. Supply interruptions are up to 3 hours per day in Beirut, and 12 hours per day in the more remote areas of the country. Electricity supply costs the public considerably in the form of subsidies that go well beyond the levels warranted to assist the poor. Electricity supply unreliability is causing significant spending by industrial and commercial customers on back-up sources of generation estimated to cost the population an additional 25 percent in electricity costs. Furthermore, supply interruptions are estimated to cost industry US$400 million.

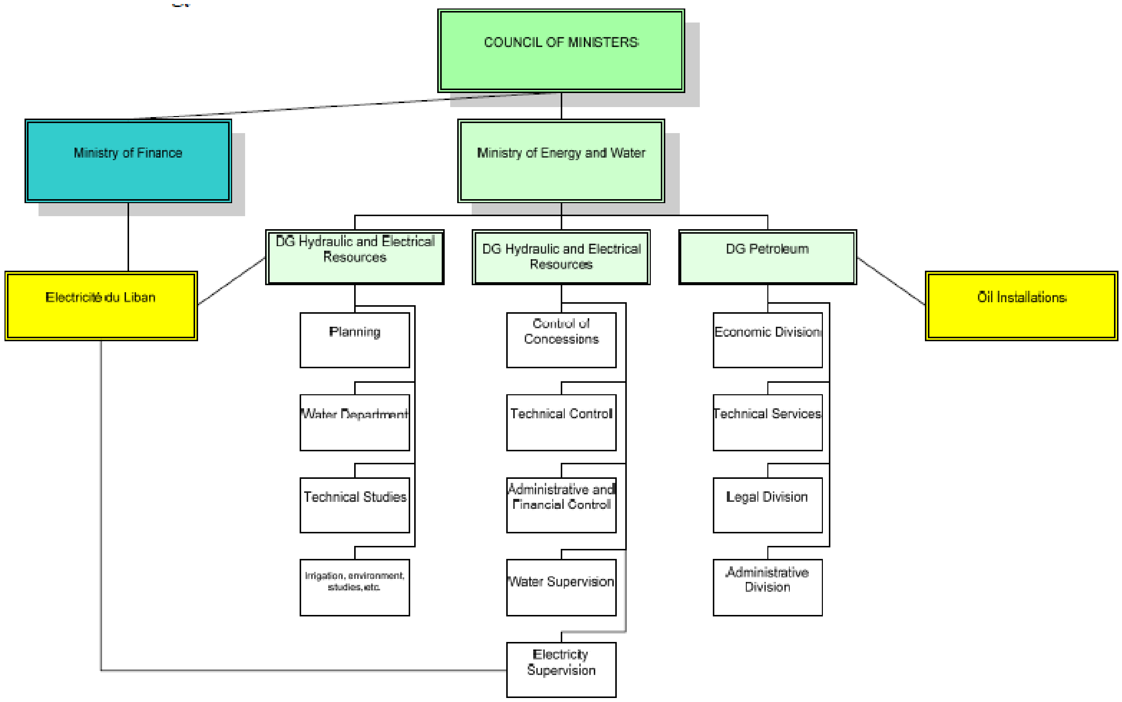
State-owned Electricité du Libon (EdL), the major electric utility in Lebanon, has very high operating costs that are not being recovered in tariffs for four main reasons: the use of high-cost diesel fuel in two major power plants; the use of high-cost gas turbine peaking plants for base load owing to supply shortages; high operation and maintenance (O&M) costs owing to insufficient maintenance and spare parts; and high technical losses. Between 1997 and 2006, subsidies are estimated to have reached 4 percent of GDP, and 39 percent of total Government spending.

It is estimated that electricity demand will grow approximately 60 percent by 2015, resulting in the need for an additional 1500 MW of generating capacity. The availability of natural gas is an integral component of the Government's strategy for the power sector. Lebanon has no gas reserves, and no gas supply infrastructure with the exception of the gas pipeline link from the Beddawi power plant to the AGP in Syria. Lebanon recently started importing gas from Egypt over the AGP, but current imports meet only the requirements of a single turbine at the Beddawi TPS. Gas infrastructure and alternative gas suppliers are badly needed, perhaps from Iraq, Turkey and Iran when the AGP is completed or via an LNG terminal. Lebanon would benefit from electricity imports from Syria and Egypt.

6.2. Power Sector Structure

The Ministry of Energy and Water (MEW) directs Lebanon's energy sector through its policy decisions. EdL is a state-owned, vertically integrated utility with a monopoly over generation, transmission, and distribution of electricity. As noted, EdL incurs significant financial losses owing to high primary fuel costs and low retail tariffs. As a result, the utility receives significant subsidies from Government via the Ministry of Finance. A schematic of Lebanon's energy sector structure is provided in figure 6.1.

Figure 6. 1: Energy Sector Structure



Source: Ministry of Energy and Water.

In addition to policy, MEW is responsible for sector regulation and tariffs. Tariffs must also be approved by the Council of Ministers. The 2002 Energy Sector Law promotes liberalization of the electricity sector through privatization of EdL and establishing an independent regulator. However, implementation has been delayed as a result lack of political agreement on a final reform program for electricity sector restructuring..

EdL has a Board of Directors and a Director-General. Major decisions on operations, investment, and policy are made by the Board of Directors appointed along with the Director-General by the Council of Ministers..

As noted, Lebanon's retail electricity prices are far below the levels necessary to recover the cost of supply. A report by the World Bank[22] shows that Lebanon's retail electricity tariff for a residential customer consuming 700 kWh per month is only 31 percent of the benchmark tariff based on an average of the tariffs of France, Greece, Italy, Portugal, Spain, and Turkey. Lebanon's tariffs even fall below the average tariff paid by other countries in the Middle East and Africa (MENA). Lebanon's tariff for a residential customer consuming 700 kWh per month is 79 percent of the MENA average. Furthermore, although the retail tariff for Lebanon's industrial customers is above the MENA average, the former is far below the European

[22] See February 2009 World Bank report entitled *Tapping a Hidden Resource – Energy Efficiency in the Middle East and North Africa.*

benchmark. The financial impact of Lebanon's retail tariffs is particularly dismal when one considers that the country's cost to supply electricity is well above industry norms.

6.3. Electricity Demand and Supply

6.3.1 Demand

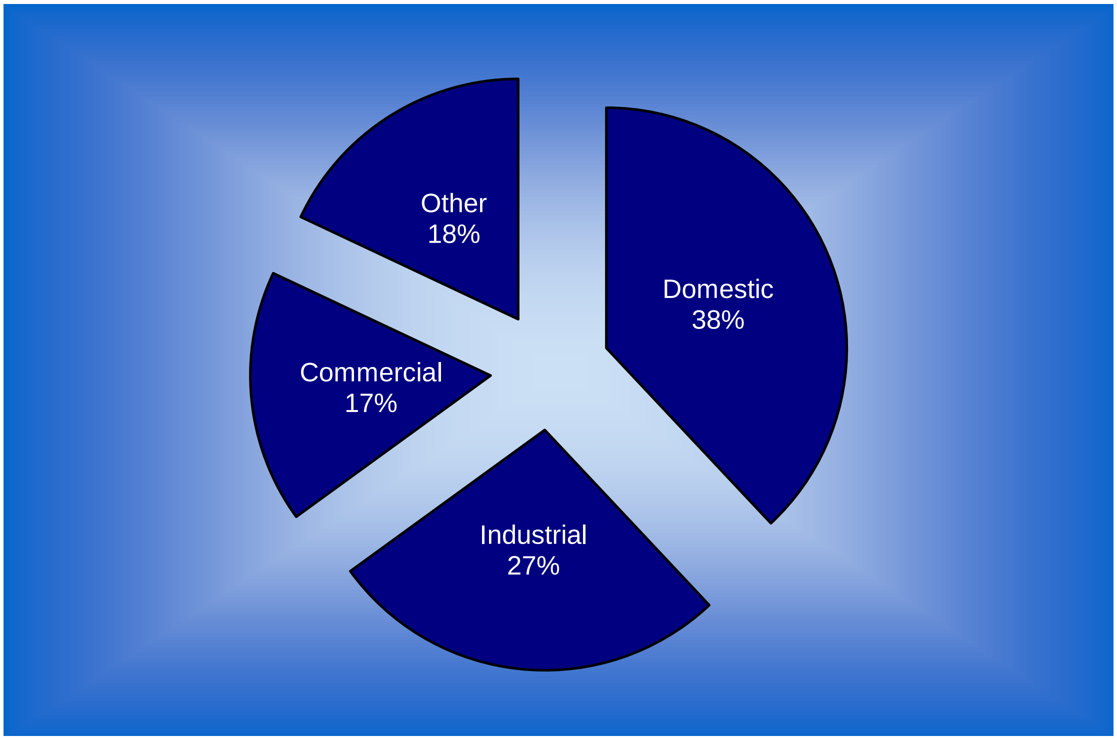
Electricity demand has grown steadily in recent years. It is very difficult to estimate electricity demand in Lebanon owing to the very high levels of unsupplied energy and self-generation. However, from 1990 to 2008, peak electricity demand is judged to have increased 89 percent, growing from 1220 MW in 1990 to 2309 MW in 2008. Historical levels of demand are shown in table 6.1. Lebanon has seasonal peaks in demand in both summer and winter. The daily load curve includes an evening peak and an early morning off-peak period.

Table 6. 1 Historical Demand

Year	***1990***	***2000***	***2008***
Peak demand *(MW)*	1220	1681	2309
Energy demand *(GWh)*	2430	7390	10,152

The industrial and residential sectors account for 27 percent and 38 percent, respectively, of Lebanon's total electricity consumption. The commercial sector accounts for 17 percent, while "other" accounts for 18 percent. Other includes technical losses. The breakdown is shown in figure 6.2.

Figure 6. 2: Electricity Consumption Breakdown ***(%)***



Source: Enerdata 2005.

Under the current situation of regular load shedding (rationing), it is difficult to project demand growth in Lebanon. However, according to the country's May 2008 Generation and Transmission Master Plan, electricity demand is forecast to grow modestly (table 6.2). By 2020, demand is forecast to be 3059 MW, approximately 32 percent greater than 2008 levels. Beyond 2020, demand is forecast to grow at approximately 2.5 percent annually.

Table 6. 2 Forecast Demand

Year	***2008***	***2010***	***2020***	***2030***
Peak demand *(MW)*	2309	2403	3059	3875
Energy demand *(GWh)*	10,152	14,866	18,924	23,972

6.3.2 Supply

Even though Lebanon's generating capacity has increased substantially, from 1220 MW in 1990 to 1976 MW in 2008, capacity has lagged growth in demand. Lebanon has 7 thermal power plants and 5 hydroelectric power stations. Two major thermal power plants, Beddawi and Zahrani, were constructed in the late 1990s. Both plants use combined cycle gas turbine (CCGT) technology, and both have 3 x 145 MW units. A list of the thermal power plants and their output levels is provided in table 6.3.

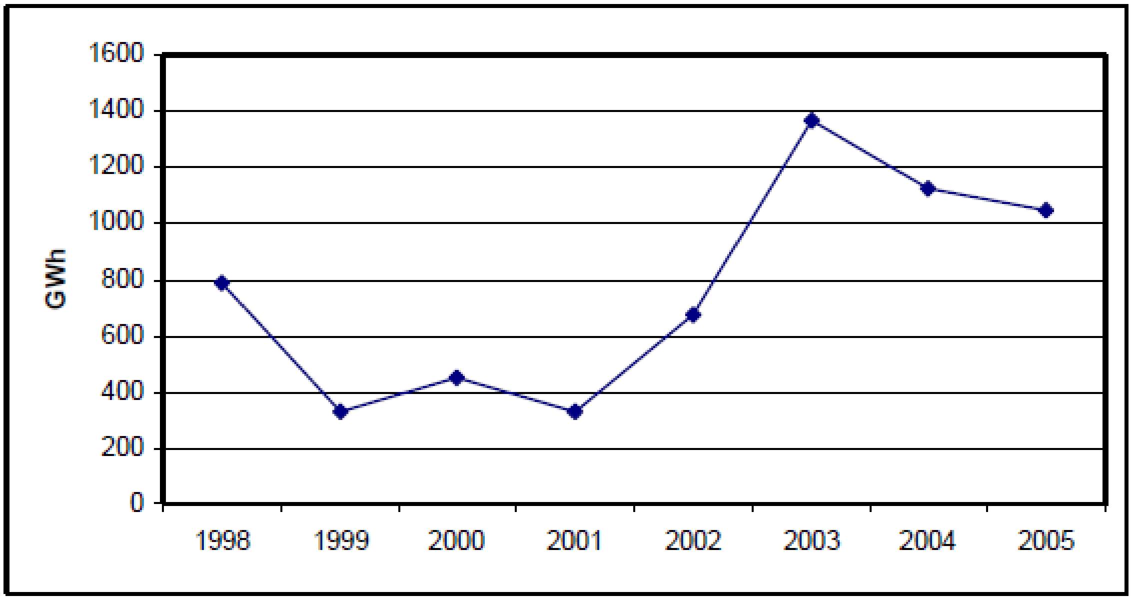
Table 6. 3 Lebanon's Thermal Power Generation Plants

Plant Name	*Installed Capacity (MW)*	*Available Capacity (MW)*	*Plant Type*	*Commissioned*	*Expected Decommissioning*
Zouk	**607**	**520**			**Around 2020**
Unit 1	**145**	**115**	**ST**	**1984**	
Unit 2	**145**	**115**	**ST**	**1985**	
Unit 3	**145**	**130**	**ST**	**1986**	
Unit 4	**172**	**160**	**ST**	**1987**	
Jeih	**346**	**315**			**Before 2015**
Unit 1	**65**	**55**	**ST**	**1970**	
Unit 2	**65**	**40**	**ST**	**1970**	
Unit 3	**72**	**70**	**ST**	**1980**	
Unit 4	**72**	**65**	**ST**	**1981**	
Unit 5	**72**	**65**	**ST**	**1981**	
Hraicheh	**70**	**N/A**	**ST**		**Before 2015**
Zahranni	**435**	**435**			
Unit 1	**145**		**GT**	**1998**	
Unit 2	**145**		**GT**	**1998**	
Unit 3	**145**		**ST1**	**2001**	
Beddawi	**435**	**435**			
Unit 1	**145**		**GT**	**1998**	
Unit 2	**145**		**GT**	**1998**	
Unit 3	**145**		**ST1**	**2001**	
Baalbeck	**70**	**70**	**GT**	**1996**	**Around 2020**
Sour (Tyre)	**70**	**70**	**GT**	**1996**	**Around 2020**
Total Thermal	**2033**	**1770**			

Source: EDL, WB 2004.

Hydroelectric power plants include Litani, Nahr Ibrahim, Bared, Safa, and Kadisha. Litani, Bared, and Kadisha are operated by local state-owned entities while the others are operated through private concessions. Total installed hydro capacity is 280 MW. Of course, hydro output varies with rainfall as shown for the past few years in figure 6.3.

Figure 6. 3: Lebanon's Hydroelectric Output, 1998–2005 *(GWh)*



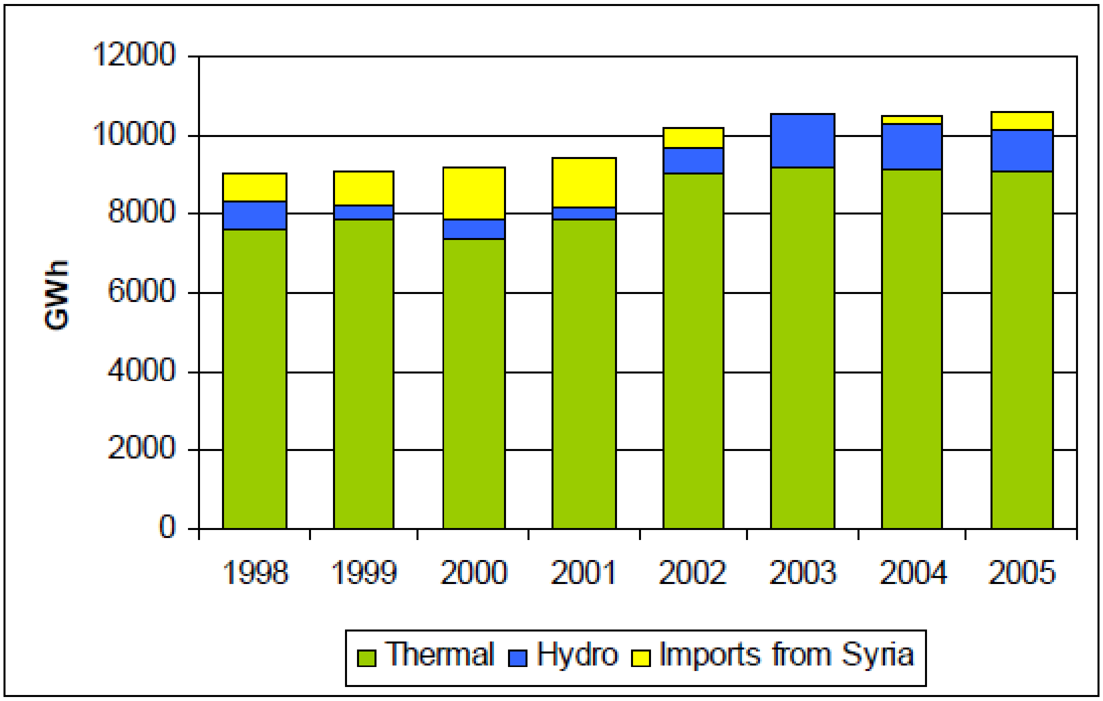
Source: EDL.

Lebanon is electrically interconnected with Syria through a 220 kV Tartous-Deir Nbouh line in the north of Lebanon, a double circuit 66 kV Dimas-Anjar line in the center-east part of the country, and a 400 kV line from Dimas to Kesara. Imports from Syria began in 1995 and have since tripled. However, imports and hydro make only minor contributions to the overall supply mix. Thermal generation provided the majority contribution. The supply mix in recent years is shown in figure 6.4.

The transmission system is made up primarily of 220 kV, 150 kV, and 66 kV lines and sub-stations. The transmission system runs principally from north to south along the coast where most of the country's population resides. There is also a transmission loop through the north-east part of the country. Some components of the transmission system are obsolete and overloaded. Transmission system upgrades have been underway for a number of years Losses are 4 percent, but it is anticipated that, following the rehabilitation plan, losses will be reduced to approximately 3 percent consistent with international standards.

The distribution system includes 12,000 km of overhead and underground 33 kV, 20 kV, 15 kV, 11 kV, and 5 kV lines; and 15,000 transformers. Rehabilitation of the distribution system is ongoing and important to loss-reduction efforts. Technical losses are estimated at 10 percent. Despite significant progress in recent years in commercial loss reduction, they are estimated at 25 percent, which is very high by international standards.

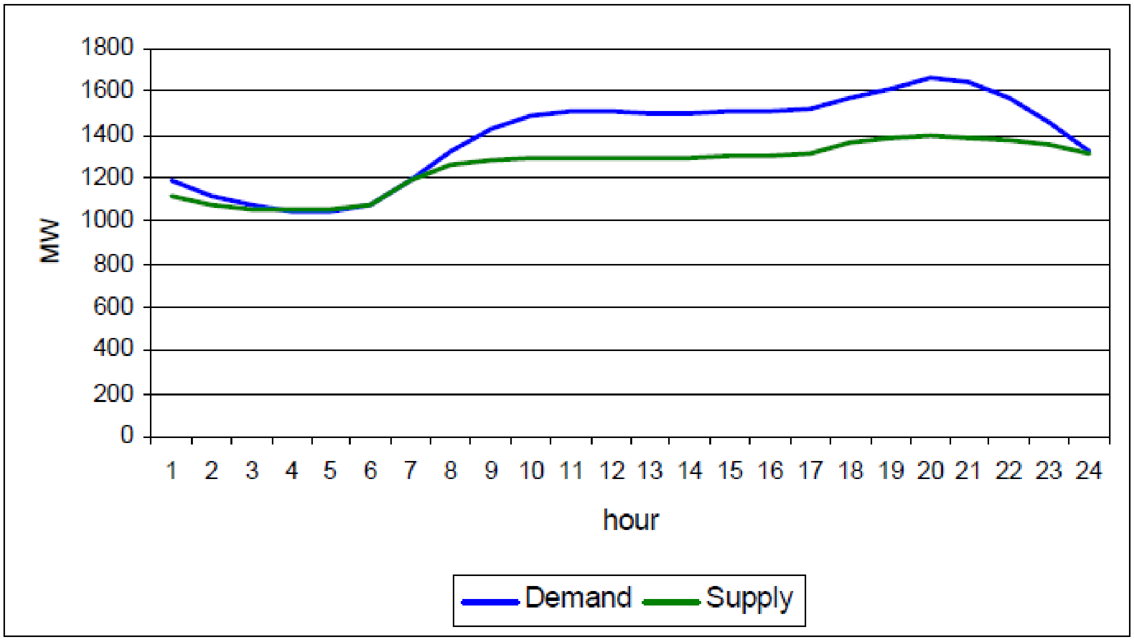
Figure 6. 4: Supply Mix, 1998–2005 ***(GWh)***



Source: EDL.

There is considerable suppressed demand in Lebanon. EdL estimates that 10 percent of demand is not met. Rotating load cuts are imposed in all areas outside Beirut, and, as mentioned, even Beirut experiences interruptions for up to three hours per day. Figure 6.5 compares peak hourly demand to supply in 2005. As can be seen, demand exceeds supply between the hours of 7 am and 2 am (19 of 24 hours), leading to rotating load cuts. As pointed out earlier, the industrial sector has large quantities of back-up generation to supply demand during the rotating load cuts. The World Bank estimates that, in 2002, 1044 GWh was generated by back-up generators, compared to 10,192 GWh supplied by EdL.

Figure 6. 5: Daily Demand/Supply Balance

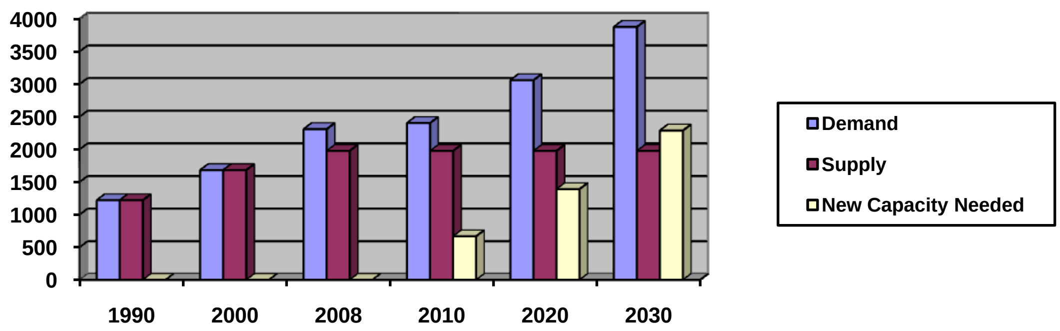


Source: EDL

At this point, there is no firm expansion plan. Studies are ongoing of both expansion and fuel supply to existing generating stations at Beddawi and Zahrani. Lebanon recently started importing natural gas from Egypt via the AGP, and one turbine at Beddawi is currently burning the Egyptian gas. Zahrani might be fueled with liquefied natural gas (LNG), or alternatively, with piped natural gas through the AGP which would require a new pipeline from Beddawi. The issue of security of supply may necessitate further consideration of LNG. LNG would require constructing a terminal to accept LNG deliveries, and pipelines to deliver the LNG to generating stations. In the longer term, gas supplies may be available from other sources such as Iraq.

Lebanon's electricity demand/supply picture is summarized in figure 6.6. The blue bar shows historical and forecast demand. The purple bar shows historical generation capacity and existing capacity (in 2008) going forward. The yellow bar shows the amount of new capacity needed to meet growing demand with adequate levels of reliability (10% reserve margin). This new generating capacity is needed to supplement existing generation capacity, but does not account for new investment needed to replace retired plant. As can be seen, Lebanon will need almost 2300 MW of new capacity by 2030, doubling current levels.

Figure 6. 6: Lebanon's Demand/Supply Situation, 1990–2030 ***(MW)***

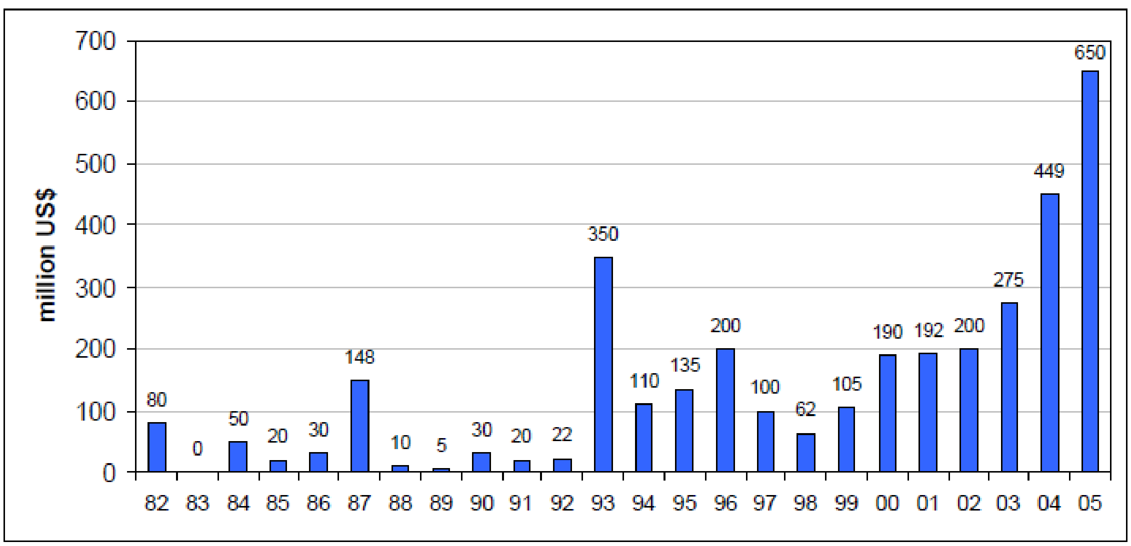


Source: Various – see Appendix A.

6.3.3 Power Sector Fuel Requirements

In 2006, 93 percent of Lebanon's electricity generation was produced by oil products including fuel oil and gas oil. The remaining 7 percent was produced by hydro. The very high cost of primary fuel to generate electricity is a major contributor to EdL's financial woes. It is estimated that the average cost of power in Lebanon in 2006 was 14 US cents/kWh. The average retail electricity tariff is well below this level and has not been increased since 1996. The low retail tariffs and high primary fuel costs have led to significant government subsidization of the power sector. Subsidies in recent years are shown in figure 6.7.

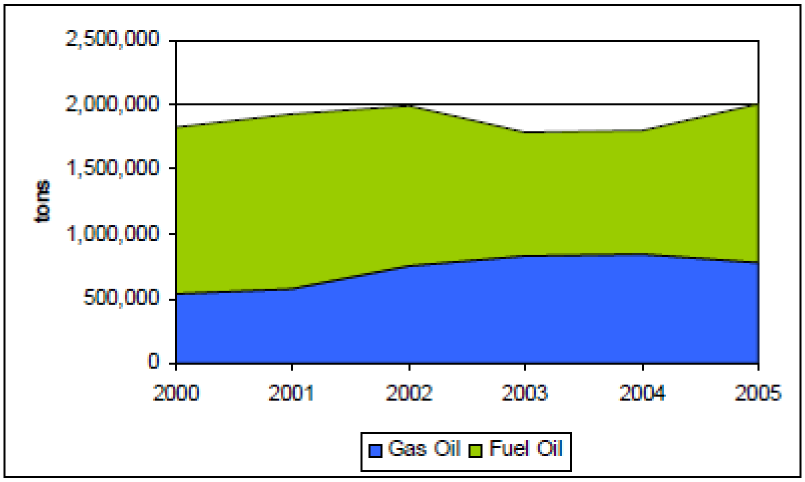
Figure 6. 7: Government Subsidies Conveyed to Power Sector, 1982–2005 ***(US$ mil)***



Source: MEW.

Figure 6.8 shows the amounts of fuel oil and gas oil used in recent years by EdL for electricity generation.

Figure 6. 8: EdL Use of Fuel Oil and Gas Oil, 2000–05 ***(tons)***

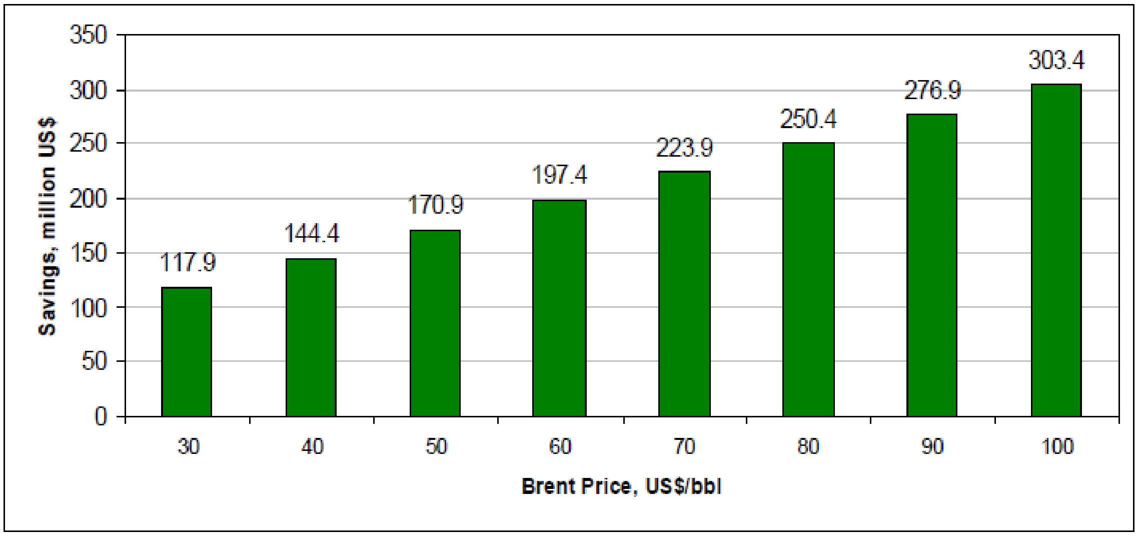


Source: MEW.

Switching from fuel oil and gas oil to natural gas as the primary fuel for generation could lead to significant savings. The Beddawi and Zahrani power plants, which account for almost half of the available thermal capacity in the country, can operate on natural gas. In fact, both plants were designed for natural gas operation. Tyre and Baalbeck can be converted to gas at reasonable cost, and new CCGT capacity would be operated on gas if available. The Ministry of Energy and Water estimates that future electricity sector demand for gas could reach 3 bcm per year. Beddawi and Zahrani alone would require 1.2 bcm per year if operated base load on gas.

Introducing natural gas to the electricity sector is a priority of the Government of Lebanon. Savings would be a function of relative prices of the primary fuels. However, in 2005, MEW estimated that savings from switching to natural gas would range from US$144 million–250 million for crude oil prices ranging from US$40–80/barrel (bbl). Figure 6.9 compares forecast savings. In addition to fuel cost savings, O&M and pollution costs would be reduced.

Figure 6. 9: Forecast Savings from Switching to Natural Gas ***(US$ mil)***



Source: MEW, 2006.

6.4. Gas Sector Structure

Lebanon has no domestic gas supplies and only recently began importing natural gas from Egypt. Further, Lebanon has limited gas infrastructure; the pipeline from the AGP in Syria to the Beddawi TPS is the lone pipeline in the country. As a result, at this time, Lebanon has little need for gas oversight.

However, Lebanon does have two laws that address natural gas. Code Law 549 addresses construction of a terminal for liquefied natural gas (LNG); facilities to store natural gas; and networks to distribute natural gas. Unfortunately, this law does not specify whether it is referring to a gas transmission system and does not address regulation.

Decree Law 5484, 18/05/2001 ratified an understanding between Egypt, Jordan, Lebanon, and Syria concerning natural gas exports from Egypt and Syria to Lebanon and Jordan through two pipelines, one being off-shore. The Decree specifies rules for setting up pipeline companies defined by the High Committee, which includes the energy ministers of the four countries. The Decree provides for the creation of the Arab Gas Commission formed jointly by the four governments and established in Beirut. The commission would review transport tariffs, study transmission system expansion, maintain data, ensure contracts are enforced, and develop a dispute resolution procedure.

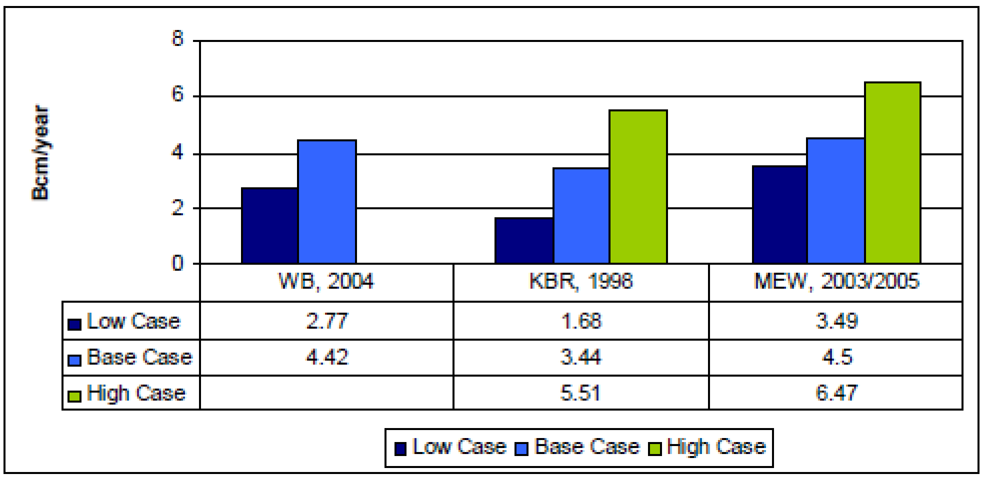
The lone gas pipeline in Lebanon, Gasyle, is owned by Lebanon Oil Installations.

6.5. Gas Demand and Supply

Given the current absence of infrastructure and supply, it is difficult to forecast gas demand. However, a number of gas demand projections have been developed. The primary gas consumer will be the electricity sector, followed by industry. In 2020 the Ministry of Energy and Water expects the electricity sector to consume 89 percent of total gas demand, the cement industry to consume 3 percent, and other sectors to consume the remaining 8 percent. It is unlikely that a gas distribution system to supply the commercial and residential sectors could be developed economically.

According to various forecasts developed for Lebanon, gas demand is expected to range from 1.68 bcm to 6.47 bcm per year. World Bank 2004 estimates range between 2.8 bcm and 4.4 bcm per year. Figure 6.10 compares gas demand forecasts under different scenarios.

Figure 6. 10: Gas Demand Forecasts



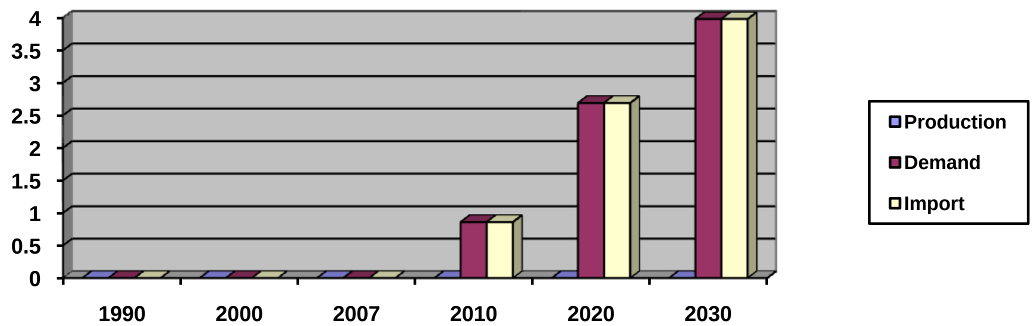
	WB, 2004	KBR, 1998	MEW, 2003/2005
Low Case	2.77	1.68	3.49
Base Case	4.42	3.44	4.5
High Case		5.51	6.47

The existing pipeline feeding into Lebanon from the AGP at Homs in Syria was constructed to serve the 2001 gas supply agreement between the Governments of Syria and Lebanon. The receiving station at Lebanon's Beddawi generating station is equipped with a connection for a future pipeline to Zahrani. It was envisaged that Beddawi would receive 1.5 mcm per day; and that once infrastructure was completed, Zahrani would receive 3.0 mcm per day. Ultimately, it was anticipated that supply would reach 6 mcm per day to meet all of Lebanon's gas needs in the medium to long term. It is estimated that the pipeline could support 7 bcm per year, exceeding the gas demand forecast for 2020. Unfortunately, gas delivery was delayed owing to shortages in Syria, and only recently began to flow with imports from Egypt in quantities enough to supply a single turbine at Beddawi TPS.

As noted, expansion of infrastructure is still in the planning stages. A number of options are being considered for supplying gas to other electricity-generating stations and industry in the Beirut area. These options include development of a floating or permanent LNG terminal at Zahrani, a pipeline connection from Baddawi to Zahrani, and a pipeline from Masnaa to Zahrani. This last option would provide an additional connection to the AGP, bringing additional supply security, albeit at high cost.

The gas demand/supply balance is shown in figure 6.11. Lebanon will import 100 percent of its gas requirement, which will be 0.9 bcm in 2010, ramping up to 2.7 bcm in 2020, and to 4.0 bcm in 2030.

Figure 6. 11: Gas Demand/Supply Balance ***(bcm)***



Source: Various – see Appendix A.

Chapter 7. WEST BANK AND GAZA PROSPECTS FOR ENTERY INTEGRATION

7.1. Overview

The West Bank and Gaza (WBG) has a population of about 3.84 million (2008) and a GDP of 12.6 billion US$ (2009 purchasing power parity). It has a small energy market with virtually no developed domestic resources of energy, relying almost entirely on imports of electricity and oil products. Nearly all of its energy imports at present come from Israel with some electricity imports from Egypt and Jordan.

Aside from its dependence on Israel for energy, the separation of the West Bank and Gaza into two geographical areas with divergent economic characteristics poses challenges. The two geographic areas are not directly interconnected electrically. Most Palestinian economic activity is in the West Bank, as is the majority of the population. The West Bank borders Jordan which could become a regional energy transit center. Gaza has a smaller economy and population, but has a more favorable energy supply as sizable gas reserves lie offshore. Further, it could receive supplies by sea, and it borders Egypt, a country with energy resources that could provide an alternative to imports from Israel. The lone power plant in the WBG, a combined cycle plant burning expensive gasoil, is located in Gaza.

Gas reserves of about 35 bcm have been discovered off the coast of Gaza. These reserves are significant relative to the WBG energy needs; however, the reserves remain undeveloped as the consortium with the development rights has been unable to reach commercial agreement with a buyer.

WBG has experienced significant growth in electricity demand, exceeding 6 percent annually since 2000. The high levels of demand growth, constraints in fuel supply to Gaza power plant, and existing political situations have led to significant levels of load shedding and unsupplied energy mainly in Gaza area. Further, high commercial and technical losses and poor collection rates have resulted in erratic growth patterns. . However, the Palestinian Authority (PA) has embarked on a plan to address the situation, implementing a number of reforms to improve losses and collections performance, form a new regulatory agency, establish regional distribution companies, and develop a transmission system.

7.2. Power Sector Structure

The Palestinian Energy and Natural Resources Authority (PEA) was established in 1995 by Law Nº (12/1995). The PEA's roles and responsibilities were clarified under the Electricity Act by Decision Nº (13/2009). PEA is responsible for overseeing energy sector development. Its powers are wide-ranging, including responsibility for policy, coordination and development of the energy sector.

The PEA is responsible for consolidating power supply and distribution arrangements in the West Bank into four electricity distribution utilities. It has created three utilities: the Northern Electric Distribution Company (NEDCO) that was established in the northern region of the West

Bank in January 2008, and Hebron Electric Power Company (HEPCO) and Southern Electric Power Company (SELCO) created in 2003 in the southern region of the West Bank. NEDCO and SELCO are planned to take over the electricity operating assets and services of the municipalities and village councils in their areas. This process is taking several years to complete, especially for NEDCO which is still not operational. These distribution companies are in addition to the long-established utility serving the central area around Jerusalem - the Jerusalem District Electricity Company (JDECO). The Gaza Electricity Distribution Company (GEDCO) was established in the mid 1990s and is responsible for electricity transmission and distribution in Gaza.

The PA encourages private sector investment in the energy sector. The new Electricity Law requires that new generation capacity is developed by private sector and also allows private participation as shareholders in the public distribution companies.

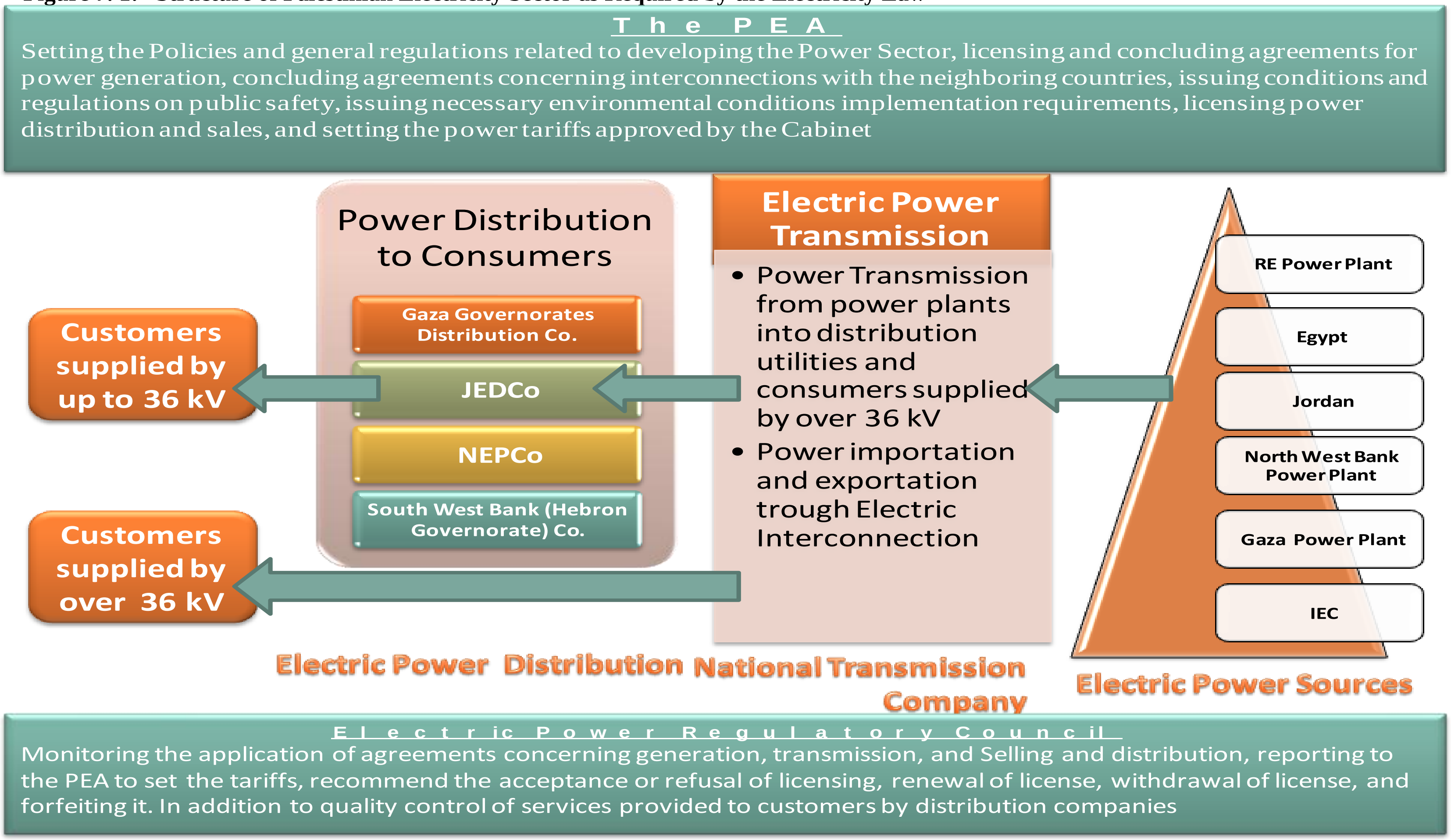
With respect to renewable energy, the PEA has established an internal Energy and Environment Research Center in charge of preparing studies and conducting research on renewable energy, and establishing the data and information needs for utilizing and developing renewable energy sources with the cooperation of other research centers at Palestinian universities. The research center will establish the Palestine Wind Atlas and Solar Energy Map, and establish an energy efficiency laboratory

Retail electricity prices in the West Bank and Gaza are close to collecting the full economic cost of supply. A report by the World Bank[23] shows that the retail electricity tariff for a residential customer in the WBG consuming 700 kWh per month is 86 percent of the benchmark tariff based on an average of the tariffs of France, Greece, Italy, Portugal, Spain, and Turkey. The WBG industrial tariff is about 65 percent of the European benchmark. The WBG's tariffs are well-above the average tariff paid by other countries in the Middle East and Africa (MENA), with the tariff for a residential customer consuming 700 kWh per month being 156 percent of the MENA average.

The new Electricity Law passed in May 2009 established the policy and framework for developing the electricity sector in West Bank and Gaza including establishing a new regulatory commission, transmission company and distribution companies to which electricity services will be transferred from the municipal and villages. Figure 7.1 shows the structure of the electricity sector to be developed as envisaged by the Electricity Law.

[23] See February 2009 World Bank report entitled *Tapping a Hidden Resource – Energy Efficiency in the Middle East and North Africa.*

Figure 7. 1: Structure of Palestinian Electricity Sector as Required by the Electricity Law



Source: Draft Energy Sector by PEA

7.3. Electricity Demand and Supply

7.3.1 Demand

The availability of data for the West Bank and Gaza is limited both in terms of power statistics and economic performance. Estimates of historical demand are further complicated by the levels of unsupplied energy (especially in Gaza), high commercial and technical losses, poor collection rates, and the numerous political problems that have resulted in erratic growth patterns. It is estimated that in 2008, there were 115 GWh of unsupplied energy and 1800 hours of load shedding.

With this in mind, historical electricity demand data are provided in table 7.1. In spite of the many problems in recent years, electricity demand has grown at high levels, at over 6 percent annually from 2000 to 2008. Most of the growth took place after 2003. The summer and winter peak demands are currently about equal.

Table 7. 1 Historical Demand

Year	***1996***			***2000***			***2008***		
	WB	***Gaza***	***Total***	***WB***	***Gaza***	***Total***	***WB***	***Gaza***	***Total***
Peak demand *(MW)*	215	118	333	324	171	495	530	280	810
Energy demand *(GWh)*	1086	517	1603	1634	752	2386	2643	1260	3903

Note: Total peak demand for 1996 and 2000 is estimated on the basis of the load factor in 2006 which was 55 percent.
Source: Norconsult

Over 99 percent of all households have access to electricity. In 2005 there were a total of 497,000 customers, including 417,000 (84 percent) households and the balance commercial. About 75 percent of electric energy is consumed by residential and the services sector (about 2/3 of this is consumed by the residential sector); the remaining 25% is distributed over the other consumer sectors.

It is very difficult to forecast electricity demand in the WBG. As already noted, the availability of data is limited. In addition, the past and current situation in the West Bank and Gaza areas is such that even data of adequate quality may be of limited value given the potential for abrupt changes in the political situation. In any regard, Norconsult[24] has developed a forecast of demand within the context of these limitations. They have based the forecast on an assumed load factor of around 55 percent at present, linearly increasing to 65 percent by 2030. The increase in load factor reflects a general maturing of the economy as well as observed tendencies in neighboring countries.

The base case forecast demand is shown in table 7.2. The average annual growth from 2008 to 2030 in the West Bank is about 6 percent for energy and about 5.8 percent for peak demand. The corresponding figures for Gaza are 6.5 percent and 5.5 percent, respectively. Overall, energy

[24] Interconnection of the Electrical Networks of Egypt – Gaza Strip, Final Report dated July 3, 2008 by Norconsult (see Chapter 2 on Power Demand Forecast for Gaza and the West Bank.

demand is forecast to increase by almost 5.8 percent annually in the WBG combined, and about 5.1 percent for capacity.

Table 7. 2 Forecast Demand

Year	***2008***			***2010***			***2020***			***2030***		
	WB	Gaza	***Total***	WB	Gaza	***Total***	WB	Gaza	***Total***	WB	Gaza	***Total***
Peak demand *(MW)*	530	280	810	579	306	885	892	501	1393	1505	896	2401
Energy demand *(GWh)*	2643	1260	3903	3061	1460	4521	5304	2831	8135	8571	5103	13,674

Source: Interconnection of the Electrical Networks of Egypt – Gaza Strip, Final Report dated July 3, 2008 by Norconsult (see Chapter 2 on Power Demand Forecast for Gaza and the West Bank.

Under the Norconsult high load growth scenario, peak demand is forecast to grow 6.5 percent and 7.0 percent in the West Bank and Gaza, respectively. Under the low load growth scenario, peak demand is forecast to grow 2.9 percent and 3.5 percent in the West Bank and Gaza, respectively.

7.3.2 Supply

The West Bank depends almost entirely on the Israel Electric Corporation Ltd (IEC) for electricity supply. It is mainly supplied through large number of 33kV and 22kV feeders directly from Israel to Palestinian purchasers of electricity (mainly municipal and village councils). The maximum supply capacity to the West Bank is 500 MW.

The West Bank is also served through a 2 x 132 kV interconnection with Jordan (about 30 km in length). The interconnection is currently operated at 33 kV to supply the Jericho District. The PA has entered into an agreement with Jordan for the supply of up to 20 MW, the maximum capacity of the interconnection. Imports from Jordan were 158 GWh in 2009, 141 GWh in 2008 and 112 GWh in 2007, the year the interconnection came into operation. The electricity can only be supplied by Jordan to Jericho on an isolated grid basis.

Gaza likewise imports most of its power from Israel through a number of 22 kV lines. Imports of electricity to Gaza have remained fairly constant in recent years and up to 2007 with the increase in demand being met by increasing output from the Gaza Power Plant. The current supply capacity from IEC is about 115 MW.

In addition to imports from Israel, Gaza is supplied as noted from GPP, a combined cycle plant burning diesel fuel. The GPP has two identical 70 MW blocks including two gas turbines of 23 MW and one steam turbine of 24 MW. The nominal capacity of the plant is about 140 MW with the actual capacity varying according to ambient temperature. Owing to substation and transmission capacity limitations only about 60 MW, or less depending on availability of fuel supply, can currently be evacuated from the plant. The GPP is the only major power generating facility in the two territories. It produced a total net generation of 410 GWh in 2008 (about 47

MW on average). The GPP output has been further limited owing to its high production cost relative to imports from IEC.

Since 2006, Gaza has also received up to 17MW (the maximum capacity of the interconnection) from Egypt on an emergency basis over a 1 x 22 kV interconnection. Imports in recent years from Egypt have totaled: 134 GWH in 2009, 123 GWh in 2008 and 28 GWh in 2007.

Total supply capacity is about 520MW to the West Bank and about 202MW (272MW with restored GPP transmission capacity) to Gaza. Load shedding is reportedly about 30-40MW during the winter and summer peaks. Load shedding in the West Bank appears to be minimal (although the load factor of 55% implies supply constraints). In 2008, the WBG imported 3291 GWh, or 92 percent, of its total consumption of 3590 GWh.. Load shedding has significantly increased in Gaza in and after 2009.

The cost of supply from IEC was a little above 8/US cents/kWh (excluding VAT) in 2007.[25] The cost of supply from GPP is high and over 31 US cents/kWh (21.4 US cents/kWh excluding VAT and taxes) due mainly to the high cost of fuel using imported oil gas from Israel instead of gas. Imports from Egypt averaged 6.4 US cents/kWh in 2007.

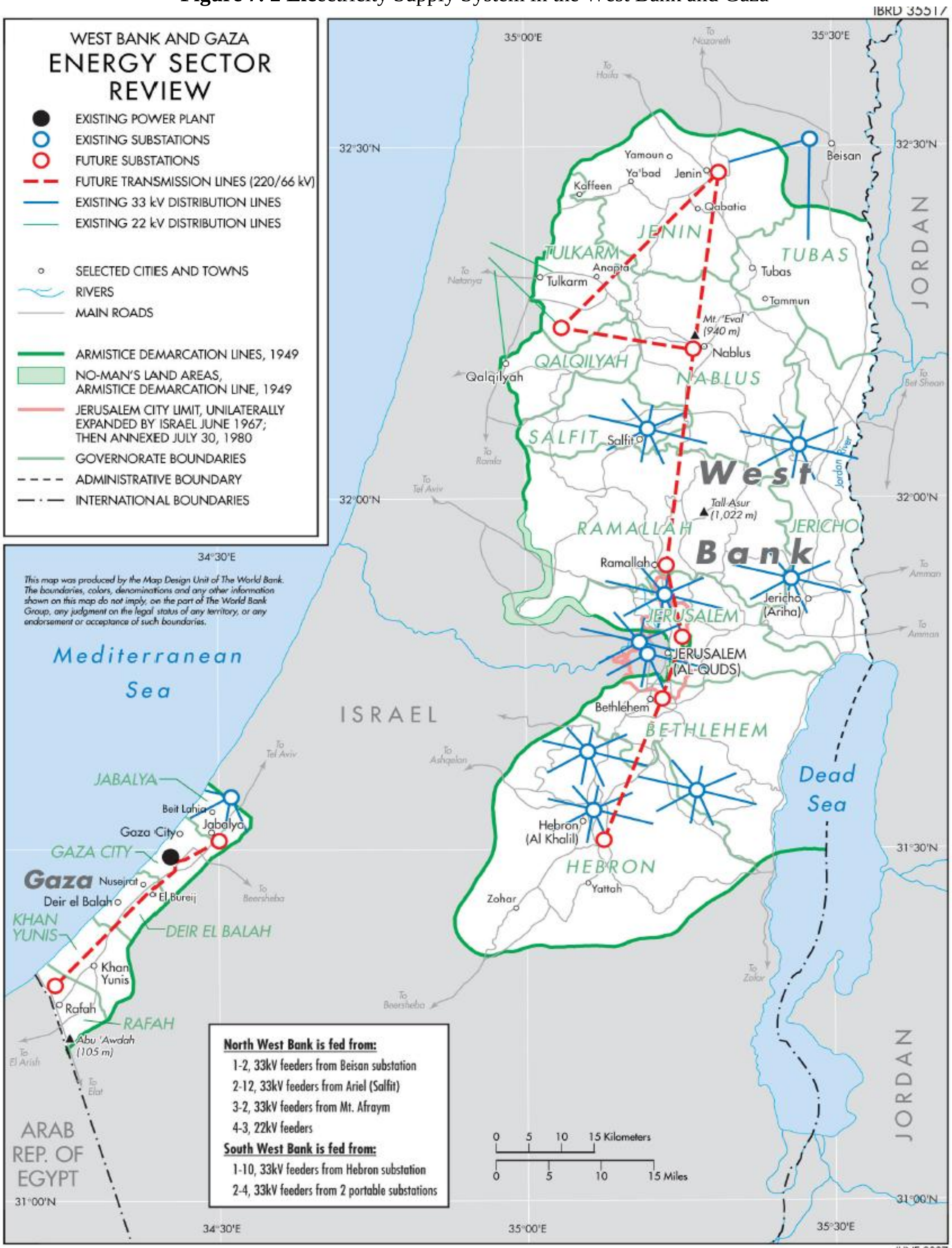
There is good potential for renewable energy development in the West Bank and Gaza, particularly for solar radiation (5.46 kWh/m2/day). Renewable thermal energy provides about 18% of the total energy consumed in the WBG. Solar water heaters have been extensively used with more than 1.5 million m2 of solar water heater panels installed in about 70% of the homes. Photovoltaic energy is being piloted, focusing on homes and community areas, and currently there is a total installed capacity of around 85 kWp. Biomass and agricultural wastes are used for cooking and heating in the rural areas, and provide about 9% of energy needs. Industrial biomass waste is also used in some regions to provide energy.

At the current time, there is no transmission grid in the WBG, although there are plans to develop one. The WBG has recently attained full membership in the seven (becoming eight with Palestine) countries electric project EIJLLST including Egypt, Iraq, Jordan, Lebanon, Libya, Syria and Turkey. The WBG has recently completed feasibility studies for interconnection of the electricity networks of Egypt - Gaza and Jordan – West Bank.

Electricity is primarily distributed at 33 kV, 22 kV and 11 kV. The power system in the West Bank and Gaza is shown in figure 7.2.

[25] See West Bank and Gaza Energy Sector Review, May 2007 by the World Bank.

Figure 7. 2 Eleectricity Supply System in the West Bank and Gaza



Source: West Bank and Gaza Energy sector Review, May 2007, Sustainable Development Department, Middle East and North Africa Region.

The Jordan – West Bank interconnection feasibility study considers three future power supply scenarios for the West Bank:

- Supply from thermal power plants in the West Bank (fuelled by natural gas)
- Supply from Jordan
- Supply from Israel

Two power plant developments were considered then by the study

- A 180 MW combined cycle power plant at Jayyus (two units) located on the northern part of the West Bank; and
- A 180 MW or 240 MW combined cycle power plant at Turqumia (3x60 MW or 4x60 MW) located in the southern part of the West Bank.

The feasibility study also recommends that the generation and transmission system in the West Bank be further developed based on cooperation with Jordan, with the first step including implementation of a 400 kV interconnection. The required time for implementation of the transmission and interconnection facilities is about the same as development of additional generation capacity in Jordan for supply to the West Bank. . The favored interconnection alternative with Jordan would originate at the Samra Thermal Power Plant north of Amman in Jordan, and connect to a new 400 kV substation in the Jerusalem area in the West Bank. The length of the interconnection is estimated to be 101 km.

There are three power supply options under consideration for Gaza:

- Supply from the Gaza Thermal Power Plant
- Supply from Egypt
- Supply from Israel

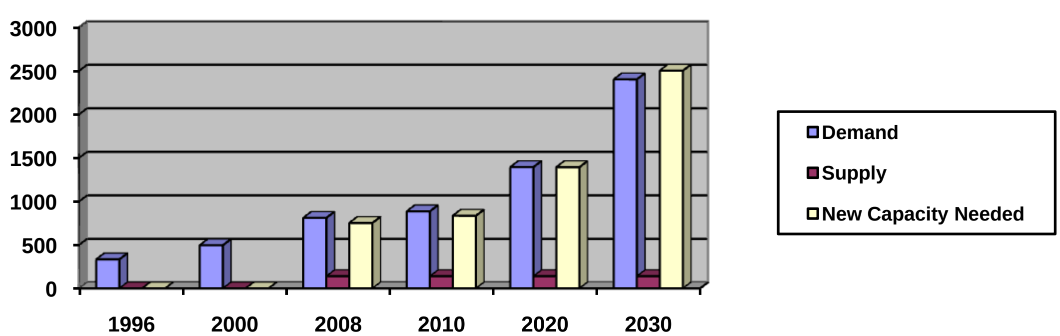
The GPP is located in the centre of Gaza, about 10 km south of the Gaza City centre and 3 km from the sea.. There is the possibility of expanding GPP to 280 MW in the medium term, and 560 MW in the longer term. Expansion of the GPP is possible as the seawater intake pipe has been sized for a plant capacity of 280MW and the land allocated for the plant can accommodate four generator blocks of 140MW each. Due to the current lack of a transmission system (transmission lines, substations and transformers) to supply the distribution systems and fuel supply constraints only 60-70 MW of the generation capacity at GPP can now be evacuated. The GPP uses light fuel oil which is very expensive, close to 20 US cents/kWh. The plant might be fuelled by natural gas via pipeline in the future.

Gaza might also be supplied in the future from Egypt in larger quantities over a 2 x 220 kV line from the main transmission grid to El'Arish, a town located 50 km south-west of Gaza. Both the GPP expansion and the Egyptian supply alternatives would require development of a 220 kV transmission system in Gaza to transfer power imports from Egypt and power production from GPP to substations on the Gaza strip. The 220 kV transmission alternative is favored over the 66 kV alternative because it has the capacity to transfer power to the West Bank if future conditions allow.

While conventional power plants, transmission and imports from neighboring countries are all potential supply options in the West Bank and Gaza, renewable energy is also under consideration. The Energy Sector Strategy 2011-2013 produced by the PNA indicates that goals for renewable energy will be established and suggests that 10 percent of locally-produced power should be produced by renewable by 2020. Wind potential is being considered near Bethlehem and Hebron city, with a capacity of 750 kWp. In addition, the Palestinian Authority is interested in further exploitation of solar resources and is considering the development of a concentrated solar power (CSP) plant in the Jericho area.

The WBG electricity demand/supply picture is summarized in figure 7.3. The blue bar shows historical and forecast demand. The purple bar shows historical generation capacity and existing capacity (in 2008) going forward. The yellow bar shows the amount of new capacity or imports needed to meet growing demand with adequate levels of reliability (10% reserve margin). This new generating capacity is needed to supplement existing generation capacity, and assumes the current transmission limitations for evacuation of GPP capacity would be eliminated. As can be seen, WBG will need 2500 MW of new capacity or purchases from neighboring countries by 2030.

Figure 7. 3 WBG's Demand/Supply Situation, 1996–2030 ***(MW)***



Source: Various – see Appendix A.

7.3.3 Power Sector Fuel Requirements

As noted, GPP is the sole generating station in the WBG, and it currently burns gasoil purchased from Israel at market prices. Consumption of gasoil at GPP in 2005 and 2008 is shown in table 7.3. Owing to a number of reasons such as the cost of production and transmission limitations, production from GPP has decreased since 2005.

Table 7. 3 Gasoil Consumption at GPP in 2005 and 2008[26]

	2005	***2008***
Production (GWh)	499.3	410
Plant Utilization Rate (based on 140 MW capacity)	41%	33%
Gasoil Consumption (tonnes)	95,000	78,000

Conversion of the GPP to burn natural gas would produce substantial savings depending on the purchase price of the gas. The West Bank and Gaza Energy Review estimates the savings at US$ 45 million annually based upon recent usage of 70MW of capacity, increasing to at least US$ 83 million per year if the full capacity of 140 MW were utilized. The level of investment required for conversion to gas use is estimated at about US$ 2.5 million. If natural gas supplied to the GPP cost US$4/mmbtu, the fuel cost of power generated at the plant would be equal to about US$0.03/kWh excluding taxes. This cost is only about 25% of the cost of power generated with gasoil (US$0.124/kWh) in June 2006.

At this time, it is difficult to know how much of the electricity needs of the WBG will be met with imports and how much will be met through construction of its own generation. It is also difficult to know how much renewable generation might be developed. However, if it were assumed that 5% of electrical energy requirements were met with renewable in 2020, increasing to 10% in 2030, and that all remaining forecast electrical energy requirements of the WBG were met by gas generation, the gas requirements for the electricity sector would be roughly as shown in table 7.4. Table 7.4 shows estimates of the total gas requirement for electricity generation whether the electrical energy is produced domestically or imported. This represents an upper level of gas consumption since some of the electricity requirement is likely to be produced from oil products.

Table 7. 4 Potential Gas Requirement for WBG Power Sector

	2010	***2020***	***2030***
Energy Demand (GWh)	4521	8135	13,674
Natural Gas Requirement (bcm)	1.0	1.8	2.8

7.4. Gas Sector

A Cabinet Decision issued on October 8, 1994 granted Palestinian Petroleum Corporation (PPC). responsibility for managing all oil, petroleum, and petrochemicals in the Palestinian Territories. Cabinet Decision Nº (17/2008) granted PPC responsibility for licensing gas distribution stations and agencies. A draft law concerning the PPC was prepared, approved on second reading by the Legislative Council, and then submitted to late President Yasser Arafat on 1997 for approval, but

[26] Based on data from West Bank and Gaza Energy Sector Review, May 2007, Sustainable Development Department Middle East and North Africa Region.

has not yet been approved. As a result, PPC has partial, but not full, oversight responsibility for the gas sector.

As noted, natural gas is not currently used as a fuel in the WBG. There are no developed gas reserves, no gas pipelines, and no infrastructure that would enable imports of LNG. The PA does however have natural gas reserves offshore. In 1999, the PNA granted a natural gas exploration license to a coalition lead by BG International Limited. The license covered the entire marine area offshore of Gaza for a term of 25 years. In 2000, the BG Group announced the successful discovery of two natural gas wells with about 35 bcm gas reserves (proved). The Gaza Marine field is located about 36 km offshore of Gaza.

In the ten years that have passed since the discovery of the gas, the fields have yet to be developed. There are several options for marketing the gas such as exporting it abroad through Egypt (in gaseous of liquid form), export via the AGP, or supplying Gaza power plant and exporting it to Israel for later re-export to the West Bank.

7.5. Gas Demand and Supply

As noted, there is currently no gas demand in the WBG, primarily because there is no gas supply and delivery infrastructure. The potential demand for gas in WBG is limited by its relatively small size. The development and use of gas in the WBG is dependent on developments in the larger Israeli market. In the short term, the only demand that could arise from conversion of existing facilities would come from the Gaza Power Plant. Replacement of gasoil with gas at the plant would require as much as 0.24 bcm/year if all power generating capacity could be used.

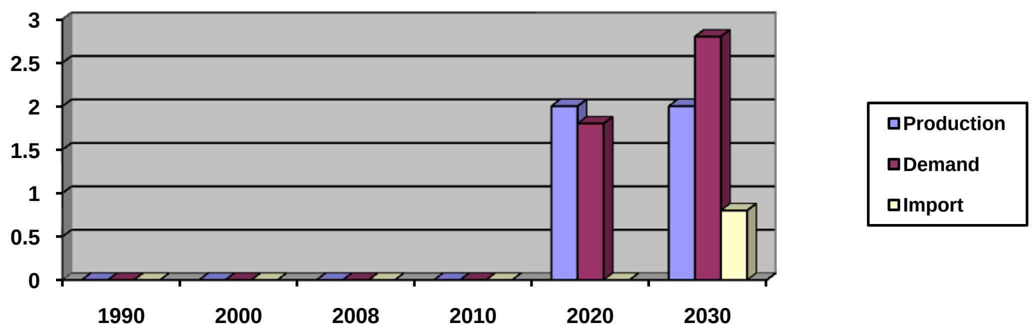
Beyond power, there is limited potential demand for gas from industry or other sectors in spite of its environmental and cost advantages. Expanded use of gas would require development of a domestic transmission and distribution system, or alternatively, demand could be met through transport of compressed natural gas (CNG). CNG could be used for transport, particularly in fleet applications where it might compete effectively with imported diesel and gasoline. Based solely on the potential use of gas for power generation, future demand might be as shown previously in table 7.5.

The gas demand/supply balance for WBG is shown in figure 7.4. The figure assumes:

- GPP will be converted to burn imported gas by 2020;
- All gas demand in WBG will relate to power generation; and
- The Gaza Marine gas field will be developed to produce 2 bcm of gas annually by 2020.

As can be seen in figure 7.4, all gas demand for electricity generation in WBG in 2020 could be met with gas from the Gaza Marine off-shore field. By 2030, WBG will need to import 0.8 bcm of gas annually to meet its electric energy demand (or alternatively, import the equivalent of gas-fired electricity). If gas customers other then the power sector are added to the system, there will be a need to import greater amounts of gas.

Figure 7. 4 Gas Demand/Supply Balance ***(bcm)***



Source: Various – see Appendix A.

In summary, even with development of the Gaza Marine off-shore gas field the West Bank and Gaza will remain an energy importer, including some combination of petroleum products, natural gas, and electricity. However, development of the Gaza Marine gas field would add considerably to supply diversity, security and price stability in the WBG. Expanding the renewable energy base with solar thermal and wind would further stabilize the WBG's energy future.

Chapter 8. **MASHREQ'S NEIGHBORING COUNTRIES**

The present study focuses on energy networks in the Mashreq countries. However, these countries also have significant current or potential inter-linkages with some neighboring countries. In particular, energy sector developments in four countries—Saudi Arabia, Libya, Turkey, and Iran—may have relevance to energy integration in Mashreq countries. Saudi Arabia is an important neighbor not only because of its own energy potential but also because it could serve as the gateway between Mashreq and the Gulf Cooperation Council (GCC) countries. However, at this stage, Saudi Arabia's energy linkage to Mashreq countries is limited to a potential electricity interconnection with Egypt that is being explored. Similarly, Libya could serve as a gateway between Mashreq and the Maghreb countries. However, at this stage, its linkage is limited to a 220kV interconnection with Egypt, which might be upgraded to 400 kV. On the other hand, Turkey and Iran are of significant relevance to Mashreq because of their extensive present and potential linkages with the Mashreq countries. This chapter reviews these linkages to assess the impact of developments in Turkey and Iran on energy trade among Mashreq countries.

Mashreq countries have aspired to connect their gas and power grids to the European Union (EU) system, and often envision this action taking place through Turkey. At the same time, Turkey has pursued a vision of becoming an energy hub. It thus has restructured its gas and electricity sectors in line with EU practices and according to the standards that facilitate cross-border energy trade. More recently, Turkey also is being considered as an avenue to import electricity/gas into Mashreq countries in the short to medium terms, when some of these countries may be short of gas and electricity. Therefore, a study of the Turkish gas and power systems and Turkey's reform experience can benefit the understanding of the type of cross-border practices that Mashreq countries should pursue as well as potentially energy trade (import and export) between Mashreq and Turkey.

Iran is another important neighboring country that, in many areas, complements the Mashreq energy network**.** At the same time, Iran has the potential to compete with the Mashreq region for electricity and gas exports to some common destinations, particularly Europe and Turkey. Thus, the Iranian impact on Mashreq energy networks is potentially substantial. However, the nature of this impact is quite complex due to numerous existing and potential linkages, as well as to uncertainty in Iran's ability to fund and implement new projects. This chapter's brief study of Iran is intended to provide a realistic sense of major gas and electricity interconnections that may affect the Mashreq countries.

8.1.Case of Turkey

Turkey has a population of 73.9 million and a per capita income of $8,020. Its economic growth has been impressive: 7 percent p.a. in 2000–08. Nevertheless, Turkey is feeling the effect of the worldwide recession through a decline in export demand and capital inflows.

Turkey's energy consumption is dependent on oil (35 percent) followed by natural gas (29 percent), coal and lignite (25 percent), and hydropower and other renewable energy (11 percent). Compared to the country's needs, its energy resource endowments are modest. Furthermore, major portions of the energy demand are met by gas, oil, and coal imports. The cost of energy imports in 2008 amounted to $48 billion, or approximately 36 percent of the value of Turkey's corresponding total exports.

8.1.1 Electricity Demand and Supply

During 2000–08, Turkey's electricity demand grew at 5 percent p.a. Industrial consumers had the largest share of total consumption (approximately 48 percent), followed by residential consumers (24 percent), and commercial consumers (15 percent). The daily peak occurs in the early evening hours. The seasonal peak occurs in winter. Moreover, as a result of the rise in tourism and air conditioning loads, summer loads (especially in July and August) are rising rapidly. From time to time, summer peaks approach the level of winter peak loads.

At 2,150 kWh, per capita annual electricity consumption in Turkey is approximately one-third of that in the EU, and income elasticity will have a major influence on demand growth. By 2020, the annual per capita electricity consumption is expected to rise to 5,200 kWh. Overall, for 2010–20, growth in electricity consumption is forecast at 7 percent p.a.

During the last decade, electricity supply capacity expanded rapidly from 23,354 MW in 1998 to 42,186 MW in 2008. Even though the installed generation capacity was 42,186 MW, the available capacity was only approximately 33,000 MW. The causes were the wide variations in the river flows from year to year that affected hydropower units and the old age of the lignite-fired thermal power plants. Consequently, balancing supply against the peak demand of approximately 32,500 MW was quite tight. Hydropower had the largest share (32.9 percent) of installed capacity, but contributed only 16.8 percent of the total generation. In contrast, natural-gas-fired combined cycle units had 32.3 percent of the capacity, but made the largest contribution to generation at 48.4 percent. Lignite and hard coal had 23.9 percent of the capacity and contributed 29.0 percent of the generation. Regarding ownership of the plants, private sector plants had 51.8 percent of total generation whereas the state-owned units had a lower share of 48.2 percent.

8.1.2 Structure of the Electricity Sector

The original state-owned vertically integrated Turkish Electricity Corporation (TEK) was unbundled over several years to enable private sector participation and the emergence of a competitive electricity market. Currently generation in the public sector is handled by the Electricity Generation Company of Turkey (EUAS). It directly owns most hydropower units and acts as the holding company for six portfolio-generation companies with thermal power units and some hydropower units. In addition, the private sector has established several generating units on the basis of power purchase agreements guaranteed by the Government. There are also a few privately owned independent power producers (IPPs). Industries with captive generating units (called auto-producers) and privately owned renewable energy units also supply to the grid.

Transmission and dispatch are being handled by the Turkish Electricity Transmission Company (TEIAS). It also operates the balancing market and acts as the settlement agency. Distribution is handled by 21 regional distribution companies. Turkish Electricity Trading and Contracting Company (TETAS) acts as single buyer and markets the power to distribution companies.

Electricity Market Regulatory Authority (EMRA) is the independent regulator of power, gas, petroleum, and LPG, and carries out licensing, tariff-setting, and other associated responsibilities.

8.1.3 Electricity Prices

Electricity prices in the balancing market fluctuate according to the short-term supply and demand conditions. During 2007, the average price in this market was YTL 128/MWh (approximately 11 US cents/kWh). At the retail level, The Government is maintaining a *national uniform tariff scheme*. It is accompanied by an *equalization scheme* involving transfer of revenues across the various distribution companies, so that each distribution company is able to secure a level of revenues warranted by its cost structure. The average end-user price/kWh in the fourth quarter of 2008 was 15.28 US cents, including taxes (12.68 cents excluding taxes). Corresponding average residential prices were at 15.81 cents (with taxes) and 12.82 cents (without taxes). The average nonresidential prices stood at 15.02 cents (with taxes) and 12.62 cents (without taxes).[27]

8.1.4 Electricity Trade

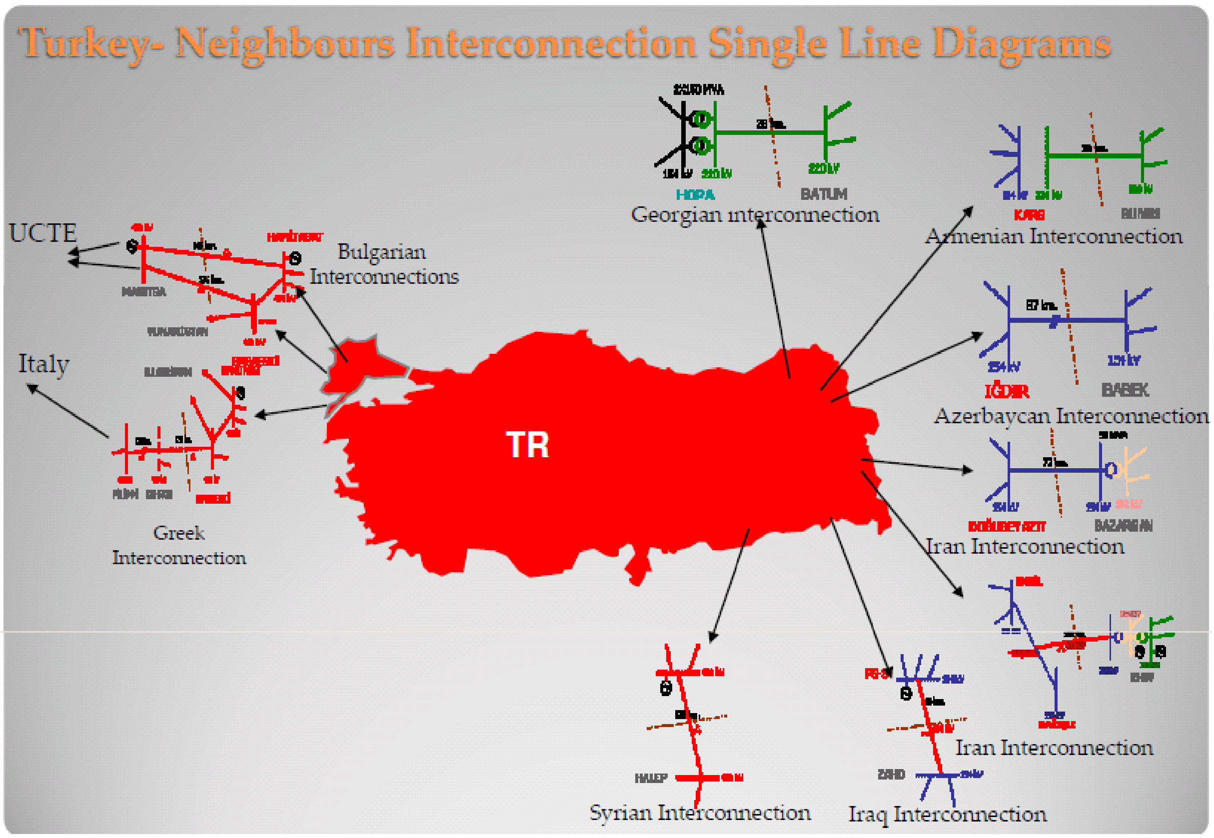
The Turkish grid is interconnected to those of Armenia (220 kV), Azerbaijan (154 kV), Bulgaria (400 kV), Georgia (220 kV), Greece (154 kV), Iran (154 kV and 400 kV), Iraq (400 kV), and Syria (400 kV). However, in recent years, the volume of electricity exchanges had been modest at less than 2 percent of Turkey's annual consumption. Imports from Bulgaria (significant in the earlier years) had ceased from 2004. Imports from Turkmenistan via Iran have been increasing notably since 2003, after the commissioning of the 270-km-long 220 kV line from Balkanabat (Turkmenistan) to Gonbad (Iran) and farther to Khoy Bashkale (Turkey) and the transmission line linking Serakhs (in Turkmenistan) to Sarakhs (in Iran). In 2004 the price for Turkey for imports from Turkmenistan was reported at 3.45 US cents/kWh. The transit fee payable to Iran was 0.65 cents/kWh. Georgia and Azerbaijan are seriously examining the possibilities of expanding their exports to Turkey by promoting investments in new Georgian hydropower projects and Azeri thermal power projects. Turkey's electricity exports increased steadily from 433 GWh in 2001 to 2422 GWh by 2007. Exports to Azerbaijan fell, reflecting the domestic supply improvements there. Electricity exports to Iraq and Syria have increased significantly.

Import and export of electricity in Turkey have been liberalized. Turkish electricity market import export regulations follow Regulation 1228/2003 of the European Commission. Besides TETAS, the state-owned power trading company, and the 22 distribution companies, there were over 36 licensed private sector wholesale power traders. All of them were eligible to import and export through the national grid. Many of the private licensees are large multinational firms.

Details of the existing interconnections between Turkey and its neighbors are given in table 8.1 and figure 8.1.

[27] Information from www.erra.net

Figure 8. 1: Details of Existing interconnections between Turkey and Its Neighbors



Source: Cem Ali Atilgan, A Spotlight on the Turkish Electricity Market, June 2009.

Table 8. 1: Turkey's Transmission Interconnection

Country	Details of existing interconnection
Bulgaria	Two 400 kV lines from Babaeskito in Turkey to Maritsa East Power station in Bulgaria. The first one is 136 km long; its thermal limit for transmission is 1000 MW. The second line is 150 km long; its thermal limit for transmission capacity is 2000 MW.
Greece	400 kV line from Babaaeski to Nea Santa in Greece. Turkish portion was completed in 2006, operated at 154 kV, and connects to Greece 154 kV network. Greece portion was completed in mid-2008. When operated at 400 kV, its transmission capacity will be 2000 MW.
Georgia	220 kV line from Hopa (Turkey) to Batumi. Price paid was 2.6 cents/kWh in 2007. Import in island mode
Armenia	220 kV. This has never been operated in the recent years.
Azerbaijan	One 110 kV line and one 154 kV line from Nakhchivan enclave of Azerbaijan to Turkey via Iran. Operates in island mode for import and export.
Iraq	400 kV line operated at 154 kV Exports to Iraq take place in the island mode. Prices paid by Iraq were reported at 4.9 Euro cents/kWh (approximately 6.3 US cents).

Iran	154 kV link currently not in operation. But the new 400 kV link is operated at 154 kV. Import of power from Iran takes place in island mode. Import price from Iran was reported at 3.5 US cents/kWh in 2007.
Syria	400 kV AC line from Birecik (Turkey) to Halep (Syria). Exports to Syria were done in unit direction mode in 2007 and in 2008.

- ***Turkey and UCTE:*** Turkey appears to be making good progress with its application (made initially in 2001) to join the UCTE with its 640 GW of generating capacity, annual consumption of 2,600 TWh, and population of 500 million covering 24 countries. Several studies financed by the European Commission (EC) under the Trans-European Networks (TEN) program have assessed different scenarios for connecting the Turkish system to UCTE through Bulgaria and Greece. In 2005 a study was started by UCTE to complete the transmission assessments including static and stability analyses to determine the technical conditions under which the synchronization could take place. Needed changes and improvements to the Turkish generation and transmission systems are being pursued on a priority basis. Their objective is to ensure synchronized operation with UCTE grids in 2010. When this happens, Turkey will become an active and physical part of the European internal power market.
- ***Turkey and ECSEE:*** Turkey also is a signatory of the Athens Memoranda of 2002 and 2003.The EC initiated these memoranda to develop the regional electricity and gas market in South East Europe and eventually integrate it with the internal power and gas market of the EU. Turkey had not signed the Energy Community of South East Europe (ECSEE) Treaty of October 2005 because some of the provisions are intertwined with Turkey's negotiations with EU for full EU accession. The country remains committed to the Athens Memorandum of 2003 and implements its provisions.
- ***Turkey and Other Interconnection Initiatives:*** Turkey's joining UCTE through interconnections with Greece is a key element of the Mediterranean Electricity Ring. It interconnects the systems of France, Spain, Morocco, Algeria, Tunisia, Libya, Egypt, Near Eastern countries, Turkey, Greece, and Italy. Similarly, the Turkey-Bulgaria link is a key element of the initiative of Black Sea Electricity Ring, which interconnects the systems of Russia, Ukraine, Romania, Bulgaria, Turkey, and Georgia.

Interconnections of Turkey with Syria and Iraq are key components of the Eight Countries Interconnection Project. It links the systems of Egypt, Iraq, Jordan, Lebanon, Libya, Syria, Palestine and Turkey. Studies are being carried out under EU financing to facilitate all of these interconnections.

Azerbaijan, Georgia, and Turkey recently signed a Memorandum of Understanding (MOU) for a Power Bridge Project to facilitate a much greater level of electricity trade among the three countries. The project envisages (a) the construction of a new 500 kV AC line from Azgunz (Azerbaijan) to Zeastaponi (Georgia) via Garadabani (Georgia); (b) construction of 500 kV AC lines from Zestaponi and Gardabani to Akhalsikhe (Georgia); (c) back-to-back AC to DC and DC to AC facility at Akhalsikhe; and (d) construction of a 400 kV AC line from this facility (in Georgia) to Borchka in northeastern Turkey. The power transfer capacity of this "Power Bridge" would be approximately 1000MW. Georgia is promoting investments in hydropower projects with export objectives, and Azerbaijan hopes to export its surplus thermal power. Details of other interconnection proposals under consideration appear in table 8.2.

Table 8. 2: Details of Other Electricity Interconnection Proposals

Country	**Details of proposals**
Georgia	Converting 220 kV line Hopa-Batumi to 400 kV AC line with back-to-back AC/DC/AC convertor station at Batumi (Georgia) is under consideration.
Iran	Asynchronous connection through back-to-back DC/AC convertor on existing 400 kV line and construction of additional 400 kV line are being considered.
Iraq	Construction of additional 400 kV line is under implementation. Cross-border point has been determined. Construction of line on Iraqi side has been initiated, and line in Turkish territory is to begin soon.
Romania	400 kV HVDC submarine cable under Black Sea from Constantin Romanito Pasakhoy in Turkey approximately 400 km long with expected commissioning date of 2018 is being pursued.[1] It will have convertor stations at both ends and transfer capacity of 600 MW.

Source: Transmission Development Plan, 2008, UCTE, www.ucte.org

8.1.5 Gas Sector Supply and Demand

Turkey's demand for natural gas grew from 0.5 bcm in 1987 to 22.1 bcm by 2004 and to 36 bcm by 2008. The average annual growth rate from 2000 to 2008 was 12 percent. The power sector has the largest share of the demand (55.5 percent), followed by households (22.3 percent) and industry (22 percent). Gas demand is forecast to grow at a much slower pace of 2.94 percent per year to 76.4 bcm by 2030.

Gas distribution is now entirely in the hands of the private sector. Coverage reaches 63 cities and encompasses more than 7 million customers. The end-user gas prices for the captive consumers of the distribution companies prevailed in the fourth quarter of 2008 appear in table 8.3.

Table 8. 3: Average End-User Gas Prices in Turkey ***(US$/Giga Joule)***

Consumer category	***Price without taxes***	***Price with taxes***
Average end-user	13.20	16.40
Average residential consumer	14.14	17.16
Average non-residential consumer	12.68	15.28

Source: www.erra.org

Wholesale market prices for eligible consumers are those that they negotiate with the importers. Since July 2008, Turkey's Oil and Gas Pipeline Corporation (BOTAS) wholesale market price has been governed by the "cost-based pricing mechanism." It allows for monthly variations based on variations in the import costs and exchange rates. BOTAS prices are listed every month on its website.

EMRA sets distribution tariffs annually for some distribution companies. For some others, privatization contracts or concession contracts incorporate agreed tariffs for 8–10 years.

8.1.6. Cross-Border Gas Trade

Almost all (98 percent) of the Turkish gas demand is met by imports from Russia, Azerbaijan, and Iran, and LNG from Algeria and Nigeria. Gas imports from Russia come by two routes. The first pipeline is via Ukraine and Bulgaria; the second is by the under-sea pipeline across the Black Sea (Blue Stream). Import from Azerbaijan comes through the Baku-Tbilisi-Erzurum pipeline via Georgia. Iranian gas comes by pipeline to western Turkey. Approximately 15 percent of the gas supplies come in the form of LNG imports from Algeria and Nigeria (figure 8.2). The existing contracts for the imported gas to meet future demand are summarized in table 8.4.

Table 8. 4: Turkey's Supply Contracts through 2020 ***(bcm)***

Source	Long-term contract period	2009	2010	2015	2020
Russia West	1987 to 2011	6.0	6.0	0.0	0.0
Iran	2001 to 2025	9.6	9.6	9.6	9.6
Russia West Additional	1998 to 2020	8.0	8.0	8.0	8.0
Russia (Blue stream)	2003 to 2025	14.0	16.0	16.0	16.0
Azerbaijan	2006 to 2020	6.6	6.6	6.6	6.6
Turkmenistan	16 bcm /year	0.0	0.0	0.0	0.0
LNG Algeria	1994 to 2011	4.4	4.4	0.0	0.0
LNG Nigeria	1999 to 2020	1.3	1.3	1.2	1.3
Total		49.1	51.1	40.8	40.8

Source: www.botas.gov.tr

Figure 8. 2: Gas Imports into Turkey and Main Transmission System

Source: Michael Prior, *Gas Market Study Report for Turkey* (February 2007).

Future cross-border projects that are being pursued also are indicated in figure 8.2. They include the following projects:

- ***Nabucco Pipeline Project:*** This project is intended to transport Caspian and Middle East gas (Azerbaijan, Turkmenistan, Kazakhstan, and Iran) to the European gas markets, while supplying gas to the countries en route in the first phase. The line will pass through Turkey (1,558 km), Bulgaria (392 km), Romania (457 km), Hungary (388 km), and Austria (46 km); and connect to Baumgarten, the hub for Russian gas for Europe. The German gas utility, RWE Midstream GmbH, recently joined as the sixth partner. The total capacity of this 3,300 km pipeline will be 5 bcm–31 bcm annually. Feeder lines from the Georgian border and from the Iranian border to Horasan in Turkey will be 226km and 214 km, respectively. The gas utilities in all six countries are cooperating in the studies to be carried out and agreements to be concluded. The technical studies are funded under the EU’s TEN program. Iraq’s gas export could be also added to this scheme if a large-scale pipeline is built to transport the Iraqi gas to Turkey.
- ***Turkey-Greece-Italy Gas Pipeline Project (ITGI):*** This project is conceived as a part of the Southern Europe Gas Ring Project to transport natural gas from Russia, Caspian basin, Middle East, South Mediterranean countries, and other sources through Turkey and Greece within the scope of the Interstate Oil and Gas Transport to Europe (INOGATE) program. The Turkey-Greece line (296 km) was completed, and gas has been delivered to Greece since November 2007. The Greece-to-Italy pipeline will go under the Adriatic Sea. The necessary intergovernmental agreements have been concluded, and the line is expected to be commissioned by 2012. The line will carry 13 bcm/year from Turkey and deliver 3.6 bcm of it to Greece and the rest to Italy.

- ***Turkmenistan-Turkey-Europe Pipeline***: Turkey and Turkmenistan concluded agreements to supply 30 bcm/year of gas as far back as May 1999. Of this amount, 16 bcm was meant for Turkey and the rest for onward transit to Europe. Not much progress has been made on this proposal, which involves a trans-Caspian submarine pipeline and increasing the capacity of the existing Azeri-Turkish Baku-Tbilisi-Erzerum (BTE) pipeline.
- ***Egypt-Turkey Pipeline:*** This project is an extension of the Arab Gas Pipeline. The former envisages supplying 2–4 bcm of Egyptian gas per year to Turkey and 2–6 bcm of gas to Europe via Turkey. The MOU was signed by the two countries in February 2006. Studies are being conducted.
- ***Iraq-Turkey Pipeline:*** In August 2007, Iraq and Turkey agreed to carry out studies to supply Iraqi gas to Turkey and Europe. Trade volumes of the order of 10 bcm/year were envisaged in the discussions.

8.2.Case of Iran

Iran has a population of approximately 72 million and a per capita income of approximately $3500. It is well endowed with oil and gas resources. Its proven oil reserves at the end of 2008 were estimated at 18.9 billion tons (10.9 percent of the world total and second largest in the world after Saudi Arabia). Its proven gas reserves were estimated at 29.61 tcm (16 percent of the world total and the second largest in the world after Russia). Its primary energy consumption in 2008 was estimated at 192.1 million tons of oil equivalent (MTOE), which comprised 55 percent gas, 43 percent oil, and the rest hydroelectric.

8.2.1 Electricity Demand and Supply

In 2008 Iran’s electricity consumption reached 153 terawatt hour (TWh). The largest share (33.4 percent) belonged to the residential consumers followed by 32.6 percent to industrial consumers, 12.9 percent to public offices and services, 11.6 percent to agricultural consumers, and the rest to miscellaneous consumers. The daily peak in the Iranian system is at approximately 9 PM. Base load demand is approximately 40 percent of peak demand. The system’s annual peak occurs in summer and minimum peak in winter or early spring. The seasonal variation in load is significant. Peak demand of the system was forecast to grow from 37,053 MW in 2008 to 88,166 MW by 2020 at a rate of 8 percent p.a., tapering off to 5 percent p.a. by 2020.

Iran’s generating capacity reached 49,413 MW in 2008. Of this amount, 43,907 MW (or 88.9 percent) was in the public sector under the control of Ministry of Energy. The remaining 5,506 MW was in the private sector in the form of IPPs and as captive generating units of large industries. Nearly 84.9 percent of the capacity was thermal, 15 percent hydroelectric, and remaining 0.1 percent wind power stations.

To meet the growing demand, new generation capacity of 22,204 MW is expected to be added from 2008 to 2016. Completion will bring the total installed capacity in the country to 71,617 MW. The new capacity will consist of 14,380 MW of gas-fired combined cycle units, 4,570 MW of hydro power units, 2,614 MW of gas turbine units, and 640 MW of steam turbine units. Approximately 55 percent of the total capacity additions will be in the private sector in the form of BOT and BOO type units. The remainder will come from the public sector.

8.2.2 Electricity Sector Structure

The Ministry of Energy is responsible for energy policy and for the regulation and control of all aspects of the electricity sector, including the formulation of tariffs for approval by the **Majlis.**[28] It also fully owns Tavanir, the sector holding company. It in turn is the main shareholder in the 16 regional electric companies (which own the thermal generation and transmission facilities within their territory) and the 42 distribution companies. Hydropower stations are owned and operated by either the Regional Water Companies or by the Iran Water Resource Management Company, which is fully owned by the Ministry of Energy. The Ministry of Energy also fully owns the Iranian Grid Management Company. This company is responsible for the operation of the transmission system (TSO), system dispatch, and market operations at the wholesale level. On the generation side, besides the public sector plants (owned by the regional electric companies), a number of private companies operate via energy conversion agreements (ECAs) with Tavanir. Tavanir supplies them with free fuel. They produce power and supply it to Tavanir for a conversion fee that covers capacity costs (related to the available capacity) and actual energy conversion costs (related to the volume of electricity delivered).

8.2.3 Electricity Prices

In FY 2007–08, Iran's overall average end-user electricity tariff was 164.98 Rials/kWh (1.8 cents). Agricultural consumers had the lowest rate at 0.23 cents, followed by households (1.36 cents), public facilities (1.74 cents), industries (2.25 cents), and commercial consumers (5.55 cents). Tavanir estimates the total average cost of supply at 310 Rials/kWh, or 3.39 cents.[29] The cost of supply was calculated based on highly subsidized low fuel prices.[30] Adjusting for this and other subsidies to the sector, in FY 2006–07, the "full average cost of supply" was estimated at 749 Rials/kWh (8.1 cents).[31]

8.2.4 Electricity Trade

Iran is interconnected to the power systems of Armenia, Azerbaijan, Turkey, Turkmenistan, Afghanistan, Pakistan and Iraq (figure 8.3). Details of the existing interconnections and the types of trade taking place are given in table 8.5.

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[28] The Majlis is the national legislative body known as the Islamic Consultative Assembly of Iran. It is also called the Iranian Parliament or People's House.

[29] Tavanir attributed approximately 53% of this total average cost of supply to generation costs, 21% to transmission costs, and 26% to distribution costs.

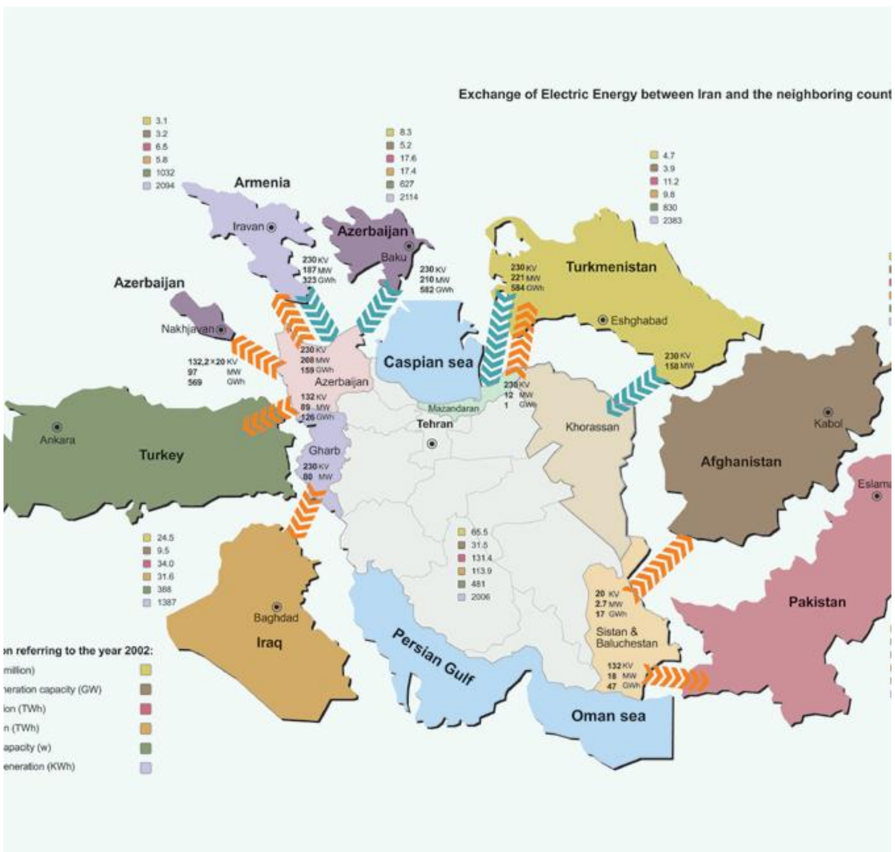
[30] Even after substantial revision in 2007, fuel prices for the power sector remained low. At approximately $2/million BTU, Iran's natural gas was lower than one-third of the prices prevailing in North American and European markets. Consumers were insulated from the impact of the fuel price increases, which fell on the state budget. The Government estimated the 2007 subsidies to the power consumers to be on the order of $9.3 billion.

[31] Islamic Republic of Iran Power Sector Report, June 2009, World Bank. The full cost of supply in 2007–08 is believed to have been approximately 773 Rials/kWh, or 8.44 cents.

Table 8. 5: Details of the Existing Interconnections and Trade

Country	Number of tie-lines	Voltage level/s	Type of trade	Capacity
Armenia	2	230 kV	Balanced energy exchange	300 MW
Azerbaijan	3+	230/132/20/11 kV	Transit	250 MW
Turkey	2	154 kV	Transit	250 MW
Turkmenistan	3	230 kV	Import and transit	300 MW
Afghanistan	2	132/20 kV	Export	40 MW
Pakistan	1+	132/20 kV	Export	40 MW
Iraq	2+	132/63 kV	Export	150 MW

Figure 8. 3: Iran's Electricity Interconnections to its Neighboring Countries



Source: www.tavanir.org.ir

Several new interconnections are either under construction or in the planning and negotiation phase (table 8.6). Interconnection with Russia (presumably via Azerbaijan), interconnection with Tajikistan via Afghanistan, submarine HVDC link to United Arab Emirates and high-voltage direct current (HVDC) link to Turkey are under active discussion and study.

Table 8. 6: Electricity Interconnections under Construction or Planning

Country	Number of tie-lines	Voltage level/s	Type of trade	Capacity
Armenia	1	400 kV	Barter-ECA	300-600 MW
Azerbaijan	1	400 kV	Interstate trade	Under study
Russia	NA	Under negotiation	Transit or Interstate trades	Under negotiation
Turkey	1	400 kV	Export	250-650 MW
Turkmenistan	1	400 kV	Import and Transit	300 MW + 500 MW
Tajikistan	Via Afghanistan	400 kV	Swap	1000 MW
Pakistan	Under study	400 kV		
Pakistan	1	230 kV	Export	120 MW
Iraq	Up to 9	400 /230/132 kV	Export	900 MW

Source: Presentation by the Iranian Ministry of Energy, February 19, 2008. www.igmc.ir/usrFiles/.../ElectricPowerIndustry-IRI-Feb-2008.ppt -

8.2.5 Natural Gas Sector

Iran's proven natural gas reserves were estimated at 29.61 tcm. Approximately one-third of the reserves consist of associated gas. The rest is non-associated. Current production is approximately 30 percent based on associated, and 70 percent based on non-associated, gas resources. Most of the gas reserves are located in the southern and southwestern end of the country. In contrast, most of the major demand centers are in the north and northwest and require an extensive transmission system for domestic use. A notable percentage of the gas produced is used for reinjection in oil fields to enhance oil recovery. It is reported that approximately 30 bcm of gas was re-injected in oil wells in 2008. This volume will peak at100 bcm/year within the next 10 years. Another notable portion of the associated gas is simply flared. The amount of gas flared came down from 11 bcm/year in prior years to approximately 8.4 bcm in FY 2007–08. This wasted resource surpasses the volume of Iran's gas exports to Turkey or imports from Turkmenistan.

The National Iranian Gas Company (NIGC) is the key institution in the gas sector. It has 44 subsidiaries including 8 gas treatment companies, 1 gas transmission company, 1 gas storage company, and 30 provincial gas companies. There also is a National Iranian Gas Export Company handling gas exports. It is a subsidiary of the National Iranian Oil Company (NIOC), not of NIGC. In the context of domestic gas shortages, this arrangement is not helpful. The need is to carefully coordinate domestic needs and export commitments.

Gas production and consumption have grown rapidly at 8.6 percent p.a. and 8.1 percent p.a., respectively. Gas transmission system consists of 28000 km of (42 inch–56 inch diameter) pipeline with a capacity of approximately500 mcm/day. The gas distribution network is extensive (approximately 150,000 km) and serves 660 cities and 5,700 rural areas. Households and commercial customers represent a major component of gas demand accounting for 40 percent of total consumption. The power sector uses 32 percent and the industrial sector 27 percent of the total gas sales. Encouraged by subsidized pricing, gas demand is forecast to grow rapidly. Residential and commercial demand is expected to grow at 6.3 percent annually during 2008–20. The growth rates forecast for industrial demand is 5.1 percent and those for power and transportation are 5.8 percent and 18.9 percent, respectively. Gas reinjection demand is expected to increase more than three-fold to approximately 103 bcm/year. The overall gas demand growth (including reinjection needs and other miscellaneous needs) is forecast at 6 percent/year during 2008–20.

8.2.6 Gas Prices

Gas prices for various categories of consumers range from 1–2 cents/m^3 compared to the range of 4–6 cents required for financial cost recovery in the sector. Retail tariffs in 2008 were approximately $0.37/million BTU (MMBTU) for residential consumers; $0.75/MMBTU for commercial, $0.47/MMBTU for industrial, and $0.15/MMBTU for the power sector. The Government estimates that the state subsidy to gas consumers was $5.76 billion. Such low prices have fostered rapid growth in consumption leading to a tight supply/demand balance, especially during the winter season when domestic demand peaks. In January 2008, the weather became very cold, and the demand for gas rose sharply. A gas crisis ensued. It was aggravated by the price dispute with Turkmenistan (discussed below), which suspended exports to Iran. Iran then had to renege on its export contracts to Turkey and divert export gas for domestic use. Similarly, Iran suspended supplies to industries, and diverted gas to household use.

Table 8. 7: Natural Gas Retail Tariffs 2001–02 to 2006–07 *(US cents/m^3)*

Consumer category	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07
Residential	0.88	0.83	0.88	0.90	0.88	0.87
Commercial	1.93	2.00	2.04	2.25	2.19	2.16
Industry	1.67	1.52	1.51	1.56	1.52	1.50
Power plants	0.32	0.33	0.33	0.33	0.32	0.32
Public services	1.93	2.00	2.04	2.25	2.19	2.16
Special commercial	0.26	0.26	0.27	0.39	0.38	0.38
Special religious	0.07	0.37	0.37	0.39	0.38	0.38
Educational	1.18	1.08	1.08	0.79	0.77	0.76
Sports	1.18	1.08	1.08	0.79	0.77	0.76

In 2003 the gas price to the power sector was raised from 15 cents/million BTU to $2.0/million BTU. However, retail power prices were not raised, so the costs had to be borne by state subsidy to the power holding company (Tavanir).

8.2.7 Gas Trade and Transit

Iran has a long list of existing and potential gas trade schemes. The existing schemes carry rather small volumes of gas. The potential schemes are aimed at exporting large volumes of gas but have not yet shown much progress.

- *Import from Turkmenistan:* To meet the gas requirements of northern parts of the country, Iran has imported gas from Turkmenistan since 1998. Commissioned in December 1997, the pipeline from Korpeje gas field of Turkmenistan to Kurt-Kui has a capacity of 8 bcm/year. In 1997 Iran entered into a 25-year import contract with Turkmenistan for 5–6 bcm/year. In the winter of FY2007–08, Turkmenistan demanded a revised price and, in the ensuing dispute, suspended supplies. Eventually, a new formula and new pricing were agreed, and supply resumed. Recently, the two governments agreed to construct a short 30.5 km Daulatabad-Serakhs-Khangaren gas pipeline linking Turkmenistan's Daulatabad gas field to Iran with a capacity of 12.5 bcm/year. After the pipeline is commissioned (expected in 2010), the export volume will be increased to 14 bcm. This level comprises 8 bcm from Korpeje field and 6 bcm from Daulatabad field. Eventually, the annual export level is expected to increase to 20 bcm.
- *Transit for Turkmen gas:* Turkmenistan recently agreed to supply gas to the Nabucco gas pipeline, which will convey Caspian area gas and Middle East gas via Turkey to Europe. Iran and Turkmenistan appear to have agreed that the latter will use the Iranian gas pipeline system to export gas to the Nabucco line.
- *Import and swap deals with Azerbaijan:* In late 2006, Azerbaijan entered into a swap deal with Iran to supply gas to its Nakhchivan enclave. Azeri gas is supplied to Iran via the Baku-Astra pipeline, and Iran supplies to Nakhchivan through a 30-mile long pipeline. Iran gets a 15 percent commission as transit fee. The 2006 transit level was 68 million m^3/year, increasing to 342 million m^3/year in 2009. Part of this was meant to help Iran tide over the suspension of supplies from Turkmenistan in 2007–08. Since 2008, Iran has explored the possibility of importing significant volumes of gas from the Shah Deniz field of Azerbaijan from 2012. Import of 12 bcm/year of gas using the spur to Iran from the Baku-Tbilisi-Erzarum pipeline is being considered to provide relief to the northwestern part of Iran, which exports approximately 7 bcm of gas to Turkey.
- *Export to Armenia:* A pipeline 139 km long, connecting Iran to Armenia has been completed with a capacity of 2.3 bcm/year. Iran initially will supply approximately 865 million m^3s of gas/year in exchange for 3.3 terawatt hours (TWh) of power from Armenia.
- *Export to Turkey:* Since 2002 Iran has exported gas to Turkey by the Tabriz-Bazargan-Erzarum pipeline (745 miles long and 45 inches in diameter) with an annual capacity of approximately 14 bcm. The contract volume for 2002–25 is 9.6 bcm/year. However, supplies have been at a much lower level of 5–6 bcm/year and were subject to disputes and interruptions.
- *Export to Europe:* Iran is pursuing the possibility of exporting gas to Italy through the Turkey-Greece-Italy (TGI) pipeline. The Greece-Italy link is not yet ready. Iran also is investigating an alternate route via Iraq, Syria, and a submarine link to Italy across the Mediterranean Sea. Iraq also is hoping to participate as a supplier to the Nabucco pipeline

via Turkey. Iran already agreed to allow Turkmenistan to supply the Nabucco line using Iranian pipelines for transit through Iran.

- *Export to Pakistan and India:* For over a decade, Iran pursued the idea of exporting gas from South Pars field to Pakistan and India via a 2,670 km long 48-inch or 56-inch in diameter pipeline at an estimated capital cost exceeding $7 billion. The pipeline would have an annual capacity of 5.4 billion cubic feet/day (or 54.3 bcm/year). In 2007 Pakistan and Iran agreed bilaterally that, for 30 years, Iran will supply 21.7 bcm/year of gas in the first phase, and 33.1 bcm of gas/year in the second phase. Iran will extend its east-west Iranian Gas Trunkline (IGAT) VII pipeline to the Pakistani border. Pakistan will construct 1,042 km of pipeline in its territory up to India's border. Pakistan will provide security for the line and take the responsibility to deliver to India its share of gas, for which Pakistan will charge a transit fee and a transmission charge. The prices discussed at that time were $4.93/million Btu for delivery to the Iran-Pakistan border, and $6.99/million Btu to the Pakistan- India border. Both were linked to the crude oil price of $60/barrel prevailing then. However, until now, India has not agreed to the various elements of the prices. It is possible that initially Pakistan will import approximately 30 bcm of gas/year and expect India to join at a later stage.
- *Trade with Other Gulf States:* Iran had been pursuing the possibility of exporting gas to UAE, Bahrain, Kuwait, Oman and also been looking to the possibility of gas exchange with some of these countries, since Iran's peak demand for gas occurs in winter, while the Gulf states have their peak demands in summer.
- *Iran's LNG schemes:* Iran has been pursuing three LNG projects: Iran LNG, Pars LNG and Persian LNG. South Pars Development Phases 11–14 is expected to provide the gas for these three LNG projects. Iran LNG is supposed to go into production in 2011 with a capacity of 10.8 million tons/year. Pars LNG, with a similar capacity, is scheduled to be commissioned by 2012. Persian LNG with a capacity of 16.2 million tons/year has a target commissioning date of 2013. Sanctions against Iran seem to be slowing investment by international oil companies and the use of US technology to liquefy gas. The commissioning dates of the Iran and Persian LNG plants are likely to be postponed. The Chinese company CNOOC signed an MOU in December 2006 for the fourth LNG project. It would have an annual capacity of 20 million tons with gas from the North Pars gas field. In addition, MOUs have been signed with a Malaysian group and an Australian group for a 10-million-ton plant using Golshan and Ferdowsi gas fields and a 3.5 ton LNG plant in Qeshm Island. All of the LNG schemes are facing challenges in financing. Prospects for implementation of these projects have further deteriorated due to the increase in the capital costs of LNG facilities and the soft conditions of the LNG market.

8.2.8 Conclusions

Turkey's case study provides very useful insights for the energy integration of Mashreq countries. First, Turkey is an excellent destination for both electricity and gas exports. It has attractive prices, market structures, and market players. In view of its impending membership in UCTE and synchronous operation with the European grid, Turkey would seem a convenient gateway to the European electricity markets. Turkey also is establishing itself as a transit country for natural gas transport to the European market.

Second, Turkey has been successful in establishing a market structure and regulation conducive to energy trade. This latter aspect provides very good lessons for Mashreq countries. Turkey's success in this area is to some extent related to its incentive to join the EU systems, but the accomplishments in both electricity and gas markets are applicable to Mashreq countries. In the electricity market, the approach is described well in the "Electricity Market and Security of Supply Strategy Paper" approved by the High Planning Council of Turkey on May 18, 2009. The approach for increasing electricity trade includes eight components:

- The goal is to join UCTE and operate the Turkish system in a parallel and synchronous manner with the European Transmission network in 2010.
- The studies and improvements to the grid must be completed in time to achieve this goal.
- The cross-border trade with Europe must conform to the EU Cross-Border Trade Directive and national legislation.
- Connections with other non-EU countries will have to comply with conditions required for Turkey's membership in UCTE and its connection to the European grid.
- For such countries, the direct current (DC) method will be used involving the construction and the use of AC to DC and DC to AC convertor stations. Convertor stations and facilities that have to be constructed within Turkey's border will be constructed by TEIAS as part of the national transmission system.
- Until such DC connection facilities become available, import /export will be possible through unit direction.
- Export/import also will be possible in an island mode.
- Trade carried out by unit direction or in island mode must not adversely affect the quality and security of supply on the Turkish system. Quality of imports must conform to Turkish legislation.

The Electricity Market Law of 2001 obliges the transmission and distribution companies to allow open, guaranteed, and nondiscriminatory access to the network by third parties to facilitate competition in the electricity market. All such third-party access to the networks, connection fees, and system usage tariffs are regulated by EMRA. The grid codes and electricity market licensing regulations incorporate the principles and practices of third-party access and its requirements. Transmission system capacity for export-import transactions is allocated pro-rata by TEIAS. TEIAS is obliged to use a bidding process when such demand from traders exceeds available capacity. Procedures relating to transmission access are broadly in line with EU directives. When the capacity demand for imports/exports is within the available capacity, normal regulated transmission tariffs apply.

The arrangements to facilitate cross-border gas trade have also been impressive. Until 2001, BOTAS was the monopoly responsible for imports, transmission, wholesale operations, storage, and distribution of natural gas. The Natural Gas Market Law of 2001 restructured the market to enable private sector entry and competition along the lines of the EU gas directives. Under this law, BOTAS was not allowed to sign new import contracts until its market share fell to 20 percent; was obliged to transfer 80 percent of the existing contracts or the volumes of supply under them, to new entrants by 2009**;** no longer was allowed to carry on distribution activity; and was obliged to privatize its distribution subsidiaries. Private sector investments were allowed in imports, exports, gas trading, storage, and distribution. Only transmission was envisaged to be in the public sector. BOTAS was further obliged to unbundle its transmission, trading, and storage functions and privatize the last two functions by 2009. The distribution segment was privatized, and some progress has been achieved on other aspects. However, the target date of 2009 proved optimistic, especially in relation to the transfer of contracts or volumes of contracted gas to new private entrants to the import trade.

Study of the Iran case is useful in that it separates real prospects from numerous ideas for cross-border energy trade. Iran's substantial gas reserves give it a comparative advantage in electricity exports to Turkey and also possibly via Turkey to the European systems. Iran also will be a key transit country for the electricity exports from Turkmenistan to Turkey and beyond. In the short term, a 180-km submarine HVDC link between Iran and UAE is imminent. The link will have a transfer capacity of 1,500 MW and will connect Iran to the Gulf Cooperation Council (GCC) Grid comprising the six Arab states of Kuwait, Saudi Arabia, Bahrain, Qatar, United Arab Emirates (UAE), and Oman.

Gas export projects include several LNG options as well as pipeline systems to South Asia and also to Europe. The pipeline to Europe is envisaged to carry up to 35 bcm/year of gas through either the proposed Nabucco pipeline system or alternative routes. Options for gas exports from Iran have been under negotiation among the involved parties for a long time. Although these options would have a significant impact on the regional markets, the likelihood of their implementation appears low. In view of the high growth of domestic demand and the steeply growing gas reinjection needs of the oil wells, Iran's ability to increase dramatically its volume of gas exports by pipeline in the near future is considered doubtful by many. This conclusion is particularly likely given the international sanctions, domestic policy stance, and organizational complexity of the country, which are unlikely to attract the foreign investment needed to increase production.

Chapter 9. **ANALYSIS OF REGIONAL POWER INTERCONNECTIONS**

9.1. Mashreq Electricity Demand and Supply: Past, Present, and Future

Electricity demand has grown significantly in the Mashreq countries in recent years and is forecast to continue growing at very high levels (table 9.1). From 1990 to 2008, peak electricity demand increased 145 percent, growing from 17,446 MW to 42,732 MW. Between 2000 and 2008, peak demand increased by 65 percent. Electrical energy demand has increased more than peak demand (236 percent compared to 145 percent from 1990 to 2008). This increased demand of the latter is explained in large part by the current supply constraints.

Table 9. 1: Historical and Forecast Demand in Mashreq Countries, 1990–2030

Country	**1990**	**2000**	**2008**	**2010**	**2020**	**2030**
Peak demand *(MW)*						
Egypt	6902	11,736	19,738	22,587	42,263	56,716
Iraq	5162	4865	10,900	11,910	16,006	21,510
Jordan	624	1206	2260	2539	4547	6110
Syria	3258	5990	6715	7518	10,448	14,041
Lebanon	1220	1681	2309	2403	3059	3875
WBG	280	495	810	885	1393	2401
Mashreq total*	17,446	25,973	42,732	47,842	77,716	104,653
Energy *(GWh)*						
Egypt	41,410	71,660	125,129	128,424	240,300	322,943
Iraq	20,720	30,020	66,839	73,032	98,150	131,900
Jordan	2807	5712	12,770	14,348	25,695	34,532
Syria	8310	23,870	40,273	44,783	62,237	83,639
Lebanon	2430	7390	10,152	14,866	18,924	23,972
WBG	1342	2386	3903	4521	8135	13,674
Mashreq total	77,019	141,038	259,066	279,974	453,441	610,660

Note: * The Mashreq total peak demand is a simple sum of the individual country demands. It does not take into account load diversity among the countries, which is not known.

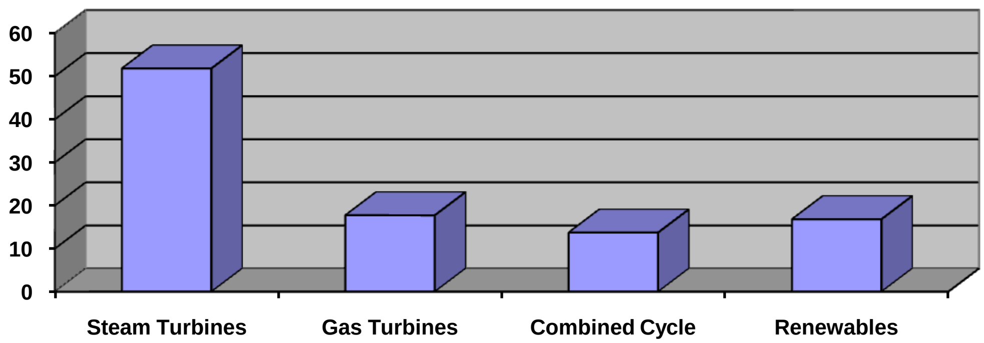
From 2008 through 2030, annual peak electricity demand is forecast to increase by an average of about 4.1 percent. Similar growth rates are expected for electrical energy demand. Peak electricity demand is forecast to increase by close to 62,000 MW from 2008 actual levels to levels forecast for 2030.

Note that forecast demands do not take into consideration demand diversity among the countries. Doing so would be appropriate if each country planned to meet its own demand. However, if a regional supply approach were to be taken, generation capacity additions could be reduced to take advantage of diversity of peak demand among the countries through sharing reserves. In other words, each country could rely on its neighbors to meet a portion of its reserve requirement.

In 2008, the Mashreq countries had a total installed generating capacity of over 40,000 MW composed of 52 percent steam turbines, 18 percent gas turbines, 14 percent combined cycle, and

16 percent hydro and other renewable generation. The breakdown by technology appears in figure 9.1.

Figure 9. 1: Mashreq Generation Capacity Breakdown by Technology ***(%)***



In all Mashreq countries, generating capacity additions have struggled to keep up with recent strong growth in electricity demand. In recent years, Iraq, Lebanon, Syria and the West bank & Gaza have experienced significant electricity supply interruptions. In 2007 Jordan's capacity reserves were minus 130 MW. If not for support from interconnections, Jordan would have experienced significant supply interruptions as well. Egypt's supply capacity is meeting demand, but unsupplied energy has been increasing. Egypt has embarked on an aggressive program to expand its generation capacity to continue meeting its high levels of demand growth reliably in the future. In summary, despite significant levels of investment in recent years, continued investment in the near future to expand generation and transmission capacity is necessary if the Mashreq countries are to reliably supply future demand growth.

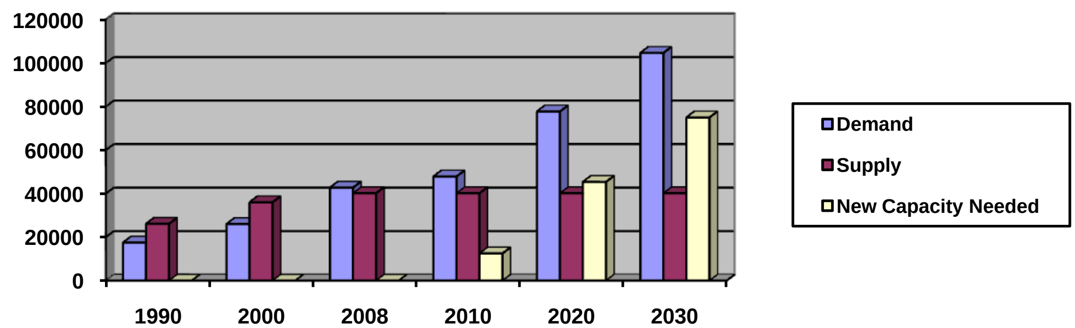
Table 9.2 shows historical and planned levels of generating capacity going forward in each Mashreq country and in total. By 2010 generation capacity is forecast to increase over 2008 levels by over 7,000 MW, or 18 percent. By 2020, another 46,000 MW of generation capacity additions will be needed, and by 2030, an additional 24,700 MW. These levels of capacity are necessary to meet growth in demand. However, capacity additions also will be needed to replace retired plants that are no longer economical to operate. Furthermore, significant investment in transmission and distribution will be necessary to transmit the new generating capacity to the load centers.

Table 9. 2: Mashreq Historical and Forecast Generating Capacity *(MW)*

Country	***1990***	***2000***	***2008***	***2010***	***2020***	***2030***
Egypt	11,474	17,861	21,944	27,882	54,656	65,791
Iraq	9522	9245	6128	6128	17,607	23,661
Jordan	624	1206	2524	2793	5002	6721
Syria	3258	5990	7700	8270	11,493	15,445
Lebanon	1220	1681	2309	2403	3059	3875
WBG	0	0	140	140	1532	2641
Total	26,098	35,983	40,148	47,198	93,200	117,911

The electricity demand/supply picture for Mashreq is summarized in figure 9.2. The blue bar shows historical and forecast demand. The purple bar shows historical and existing generation capacity (in 2008). The yellow bar shows the amount of new capacity needed to meet growing demand with adequate levels of reliability (assuming a 10 percent reserve margin). This new generating capacity is needed to supplement existing generation capacity, but does not take into account the new investment needed to replace retired plant. Mashreq will need almost 75,000 MW of capacity additions by 2030, representing a 187 percent increase over current levels of capacity, if it is to supply increasing demand at adequate levels of reliability.

Figure 9. 2: Mashreq Electricity Demand/Supply, 1990–2030 *(MW)*



The total investment that will be needed for the expansion of generation, transmission and distribution in the Mashreq countries is enormous, estimated at US$130 billion by 2020, and an additional US$108 billion by 2030[32]. This will pose a huge challenge for the Mashreq countries.

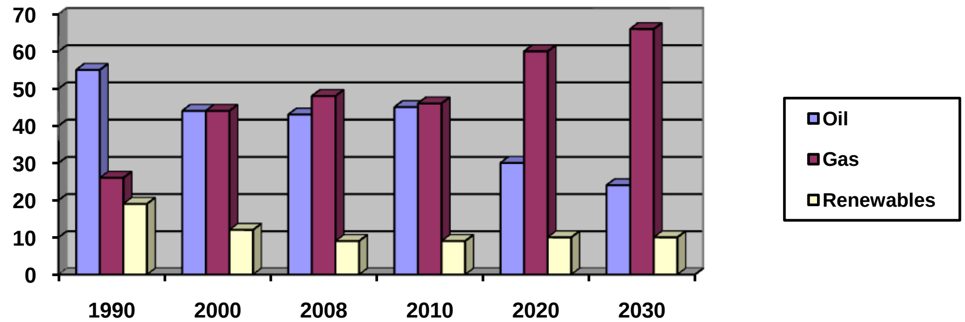
9.2. Mashreq Power Sector Fuel Requirements

Figure 8.3 shows historical and forecast generation production by fuel type in percentage terms. As can be seen, the Mashreq countries are increasing their reliance on natural gas as the primary fuel supply for electricity generation. The share of gas in electricity production increased from 25 percent in 1990 to 48 percent in 2008. Going forward, reliance on gas will be even heavier, increasing to 66 percent of all power generation by 2030.

Actual generation fuel mix going forward will be a function of gas availability and fuel diversity considerations. Gas-fired generation expansion options include steam and combined cycle for base load operation and gas turbines to meet peaking requirements. Going forward, renewable generation including hydro, wind, and solar thermal is expected to hold steady at approximately 10 percent of total electrical energy production. As noted, Egypt plans to add two new nuclear plants each with 1000 MW of capacity in 2017–18 and 2020–21. Jordan also is considering nuclear as an option to meet future generation requirements.

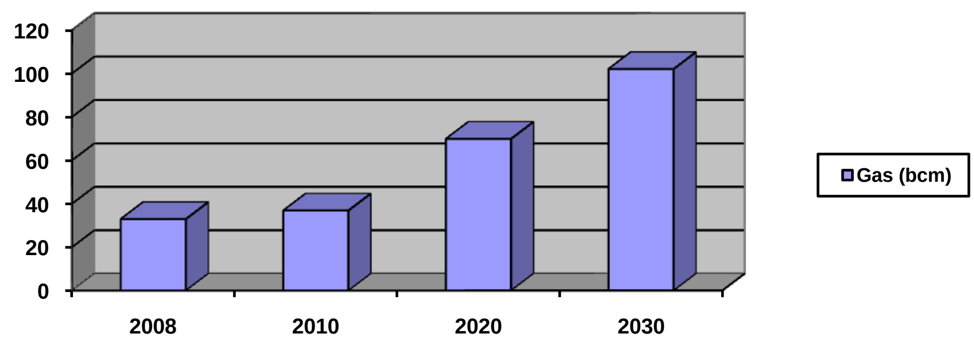
[32] Based on estimates for Egypt's expansion plan of approximately US$101 billion to meet 150,000 GWh of demand growth, with approximately 82% allocated for generation, 13% for transmission, and 5% for distribution (October 10, 2008 World-Bank-sponsored report, *Energy Cost of Supply and Pricing Report)*.

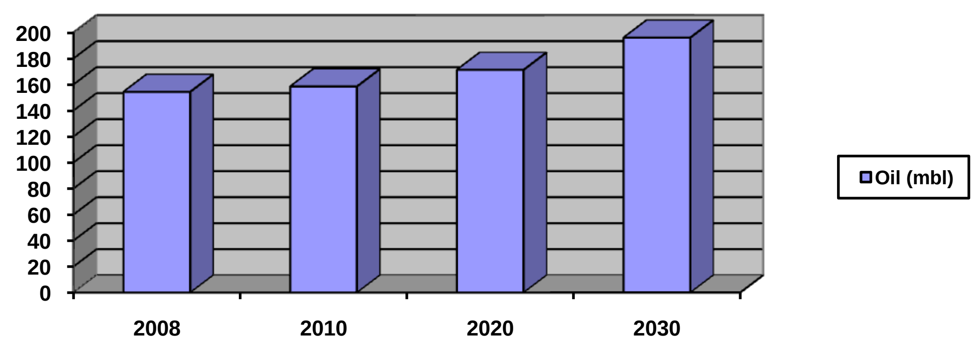
Figure 9. 3: Mashreq Generation Production by Fuel Type, 1990–2030 ***(%)***



Forecast consumption of natural gas and oil products in the electricity sector are shown in figure 9.4. Total gas use is expected to triple from almost 33 bcm in 2008 to about 102 bcm in 2030, an average annual increase of over 5 percent. While oil consumption for electricity generation is increasing, it is forecast to do so at much lower growth levels of about 1.1 percent annually from 2008 to 2030. In any case, large increases in the amount of primary fuel for electricity generation will be needed.

Figure 9. 4: Forecast Consumption of Gas and Oil by Mashreq Electricity Sector, 2007–30





9.3. Interconnection Capacity and Potential for Imports/Exports

Plans to interconnect the power systems of the Arab countries were initiated by a five-country agreement among Egypt, Iraq, Jordan, Syria, and Turkey in 1988. Each country undertook to upgrade its electricity system to a regional standard. The project was extended to eight countries with the addition of Lebanon, Libya, and the West Bank & Gaza (West Bank & Gaza was officially included in the project in 2008). The project comprises the 400 kV and 500 kV interconnections linking the national power systems of the member countries.

The Mashreq regional grid is interconnected with Iran, Libya, and Turkey as follows:

- Egypt is linked to Libya through a 220 kV line;
- Syria is linked to Turkey through a 400 kV line;
- Iraq is linked to Turkey through a 400 kV line currently operating at 154 kV
- Iraq is linked to Iran through a 400 kV line (as of April 2009).

Interconnections among the Mashreq countries, and with countries outside Mashreq, including Iran, Libya, and Turkey, are shown in figure 9.5.

Figure 9. 5: Electric Interconnections in Mashreq and Bordering Countries

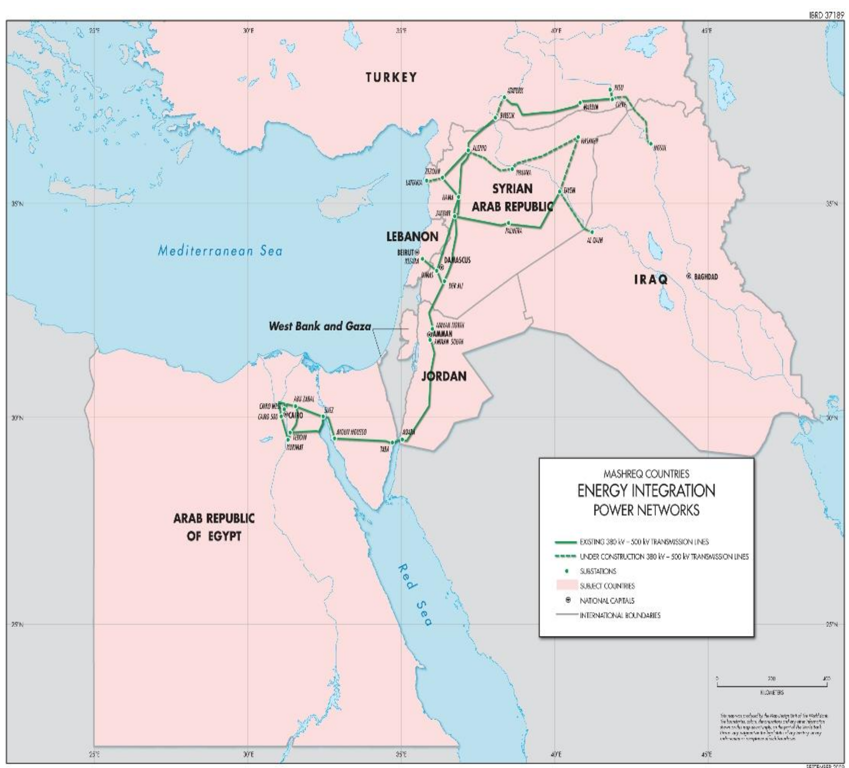


Table 9.3 sets out the voltage, capacity, and year of installation for each interconnection.

Table 9. 3: International Interconnections between Mashreq Countries, Selected Years 1993–2009

Countries	Circuits/voltage	Capacity	Year of operation
Turkey-Syria	1 x 400 kV	1135 MVA	2007
Syria-Jordan	1 x 230 kV	55 MVA	1977
Syria-Jordan	1 x 230 kV	267 MVA	1980
Syria-Jordan	1 x 400 kV	1135 MVA	2000
Syria-Lebanon	2 x 66 kV	110 MVA	1972
Syria-Lebanon	1 x 230 kV	267 MVA	1977
Syria-Lebanon	1 x 400 kV	1135 MVA	April 2010
Syria-Iraq	1 x 230 kV	267 MVA	2000
Jordan-Egypt	1 x 400 kV	550 MVA	1997
Jordan-West Bank	2 x 132 kV (operated at 33 kV)	20 MW	2007
Egypt-Libya	1 x 220 kV	120 MVA	1998
Egypt-Gaza	1 x 22 kV	17 MW	2006
Iraq-Turkey	1 x 400 kV (operated at 154 kV)	200 MW	2002
Iraq-Iran	1 x 400 kV	325 MW	From April 2009

Although the Mashreq countries appear to be strongly interconnected, numerous transmission constraints in the national systems limit transfers among countries and the systems are often not synchronized, meaning that part of a national grid system may have to be isolated from the main grid to accept imports from another country. For example, the interconnection between Syria and Turkey is used to supply Syria from an isolated power station in Turkey. When Syria is supplying Lebanon, part of the Lebanese grid must be disconnected from the main national grid. Moreover, when Turkey is exporting to Iraq, the interconnection is operated in isolated mode.[33]

A study being carried out by the Turkish Electricity Transmission Company (TEIAS) is analyzing the synchronization of Turkish, Syrian, Jordanian, and Egyptian electricity grids. Northbound and southbound transfers along the transmission corridor between Turkey and Egypt have a number of limitations owing to issues on the national systems. For example, low voltage problems in Jordan limit Syrian imports from Egypt to 350 MW (when Syria is importing from Egypt alone). Alternatively, generation capacity limitations in Jordan limit Syrian imports from Jordan to 300 MW (when Syria is importing from Jordan alone). Finally, low voltage problems in Jordan caused by the tripping of the 400 kV circuit between Aqaba Thermal Power Station and Amman South limit Syrian imports from Egypt and Jordan combined to 400 MW. A

[33] Electricity Network Interconnections of Turkey, MEDELEC Conference, March 24, 2009.

summary of the power transfer limits among the countries in this corridor is provided in table 9.4.

Table 9. 4: Power Transfer Limits ***(MW)***[34]

	Egypt can import	**Jordan can import**	**Syria can import**	**Turkey can import**
From Egypt	N/A	50[a]	350	350
From Jordan	260	N/A	350	300
From Syria	250	50[b]	N/A	500
From Turkey	220	50[b]	620	N/A
From Egypt and Jordan	N/A	N/A	400[c]	450[d]
From Syria and Turkey	250	50[b]	N/A	N/A
From Jordan, Syria, and Turkey	260[e]	N/A	N/A	N/A
From Egypt, Jordan, and Syria	N/A	N/A	N/A	700[e]

Source: Electricity Network Interconnections of Turkey, MEDELEC Conference, March 24, 2009.

Notes:
a 170 MW when only 4 units are in operation at Aqaba Thermal Power Station (TPS).
b 160 MW when 4 units only are in operation at Aqaba TPS.
c Maximum of 300 MW from Egypt.
d Maximum of 350 MW from Egypt.
e With limits above in table respected.

The current TEIAS study also notes that these limits are no longer valid following new developments both in the Mashreq region and in Turkey. Power exchange limits must be reviewed according to existing system conditions. With the numerous proposed power generation and transmission developments in the Mashreq, in both the near and longer terms, the transfer limitations will change constantly. National control centers will need state-of-the-art

[34] Y. Durukan, "Outcomes of the Operational Study on the Synchronization of Turkish, Syrian, Jordanian and Egyptian Electricity Grids," TEIAS (Turkish Electricity Transmission Company), MEDELEC Meeting, Istanbul, March 23–24, 2009.

system simulation software and up-to-date data and information on their own and neighboring systems if use of the interconnections is to be optimized through the use of multilateral trading arrangements.

Although, with the exception of Iraq and the West Bank & Gaza, the Mashreq countries are strongly interconnected, transactions between the countries are limited. There are a number of reasons for this, including, but not limited to, the following:

- There has been a shortfall of generation capacity in the Mashreq region, so there is little power available to sell.
- Primary fuel supply for generation is somewhat limited; when it is available, it tends to be quite expensive, for example, oil.
- The power sectors are in poor financial condition and are unable to afford the cost of imported power that reflects the economic cost of supply;
- The structures of the national markets generally are not set up for exchanges of capacity and energy. For the most part, transactions are between governments. The national markets do not allow for transactions among market participants. This lack of economic infrastructure tends to limit transactions to longer term bilateral contracts between directly connected countries.
- There is no region coordination center and no formal regional market to facilitate market transactions, promote regional trade and compensate entities for providing transport services, or to determine the technical feasibility of transactions; that is, to simulate sales to determine whether they can be made without destabilizing the system.

As stated in a January 2003 report concerning the establishment of a Coordination Control Center for the Mashreq region,[35] an interconnected power system requires the rational and secure operation of every subcomponent of the network, especially if there are multiple parties involved. The consultant who performed the study noted that it had not found thorough studies of power system stability to synchronize the entire regional power system, thus illustrating the need for coordinated action among the countries.

Despite the limited number of transactions over the interconnections, the interconnections still provide significant benefits, as follows:

- Reduced installed capacity
- Reduced spinning reserves[36]
- Construction of larger generating units with lower costs deriving from economies of scale.

For example, Jordan can rely on its interconnections with Egypt and Syria for about 250 MW of capacity during system emergencies. If Jordan alone had to supply this capacity, the annual replacement capacity would cost approximately US$38 million (based on a long-run marginal

[35] Final Report for "Feasibility for Establishment of a Coordination Control Center (CCC) for the Electrical Interconnection between Turkey, Lebanon, Syria, Iraq, Jordan, Egypt, Libya, Tunisia, Algeria and Morocco," SwedPower, January 2003.
[36] Spinning reserves include the unused portion of operable generating capacity which is synchronized to the system and ready to pick up load.

cost of capacity of US$154/kW).[37] In 2007 Jordan's reserve margin was minus 130 MW. In the absence of its interconnections, Jordan's loss-of-load expectation was 53 hours, more than triple the target level of 15 hours. The interconnections therefore enabled Jordan to avoid considerable load shedding in 2007. In addition, Jordan carries approximately 33 MW of primary spinning reserves and 32 MW of secondary reserves. The country relies on the reserves of Egypt and Syria over the interconnections, providing a combined spinning reserve for the 3 countries of 400 MW. By minimizing spinning reserve requirements in this manner, generation is operated closer to its optimum output level, thus improving efficiency and reducing fuel and maintenance costs.

Finally, interconnection capacity allows construction of larger power plants to capture the economies of scale. For example, if Jordan's interconnections with Egypt and Syria are expanded to increase transfer capacity, in the future, Jordan may be able to construct 600 MW generating units, rather than the 300 MW units currently assumed in its expansion plan.

Opportunities for short-term trades have been realized in the Mashreq countries to a limited extent through the diversity of demand among the countries. For example, Syria has a winter peak while Egypt and Jordan have summer peaks. Syria could make sales to Egypt and Jordan during summer when it has surplus generating capacity, and Jordan and Egypt could make sales to Syria in winter when they have surplus generating capacity. These staggered sales are particularly relevant when there are different generation technologies in the countries. For example, when Lebanon is forced to run its high-cost diesel turbines and Egypt has lower cost gas turbines on the margin, Egypt could sell power to Lebanon, enabling it to back off its high-cost diesel generation. Egypt and Lebanon could split the savings of increased revenues for Egypt and reduced production costs for Lebanon.

With significant generation expansion anticipated in the Mashreq countries, at times some countries will have capacity surpluses on their systems, enabling sales to countries in deficit positions. The nature of generation expansion is that investments tend to be lumpy, meaning a 300 MW generating unit may be brought on line when demand is increasing at 100 MW annually. During the early years of the generator's operation, there will be surplus capacity available for sale to other countries.

In summary, the existing interconnections among Mashreq countries provide significant value to consumers. However, there is scope to increase the utilization of the interconnections to provide greater value to the Mashreq region.

9.4. Potential Future Interconnection Projects

Interconnections linking Egypt, Jordan, Syria, Iraq, Lebanon and the West Bank & Gaza, and linking the Mashreq countries to countries outside the Mashreq region, already are in place. These interconnections are providing significant benefits, enabling construction of larger power plants with the resulting economies of scale, increased sharing of planning and operating capacity reserves, support during system emergencies, and economy energy exchanges taking advantage of demand diversity and capacity surpluses when there are differences in marginal production costs between systems.

[37] See Update of the 2006 Generation and Transmission Expansion Master Plan, August 15, 2008, p. 98.

A number of potential upgrades to the Mashreq interconnections are being considered. The main gaps within Mashreq are associated with Iraq and the West Bank & Gaza. The West Bank & Gaza is almost entirely dependent on imports, and imports have reached the limits of existing transmission capacity. Feasibility studies show that it is economic to increase interconnection capacity with Egypt and Jordan. There is scope to increase Iraq's import capacity since it cannot meet demand at present, and its plans to increase generation capacity are moving very slowly. Iraq already has a 400 kV link to Iran (recently completed), and 400 kV upgrades to interconnections with Syria and Turkey are under development. An interconnection with Jordan would be an attractive addition since Jordan's successful reforms in generation have led to a strong private generation sector. Furthermore, costs to construct generation in Jordan would be much less than in Iraq owing to the ongoing conflict in the latter. There is potential to reinforce interconnections between Mashreq and neighboring countries, notably between Egypt and Libya and between Iraq and Turkey as discussed. There is also potential to build new interconnections between a Mashreq country and Saudi Arabia. Egypt, Iraq, Jordan, and Syria all are possible candidates for interconnecting with Saudi Arabia.

The Mashreq region as a whole is in an electricity capacity deficit situation. In other words, its generation capacity falls short of both electricity demand and having a reserve margin to ensure adequate reliability of supply, generally 10 percent–15 percent. Therefore, any new generation project would provide economic benefits to the Mashreq region by reducing lost load. Furthermore, generation that is added based on least-cost principles would improve generation efficiency and reduce the overall cost of energy through both improved efficiency and displacement of higher-cost with lower-cost fuel. Generation expansion plans at the national level that are consistent with least-cost principles should be supported. However, generation expansion at the region level consistent with least-cost principles would achieve greater benefits, provided the countries can agree in principle to share the benefits. A generation project sized to meet regional market needs and fueled with local natural gas from an as-yet undeveloped gas field should be of significant interest.

Any new interconnection project should be accompanied by a technical assistance project that includes detailed modeling of the regional transmission system. Without such detailed modeling, it would not be possible to determine the increased transfer capacity between countries, as the national grids often are the limiting factor. Until the true transfer capacities are determined, it will not be possible to calculate the benefits arising from increased interconnection capacity. A detailed transmission planning study would:

- Identify the transfer capacities of the existing interconnection;
- Identify various interconnection upgrade scenarios and their increased transfer capacities;
- Determine benefits of various interconnection upgrade scenarios;
- Determine the favored interconnection upgrade scenario from both the individual country and the regional perspectives; and
- Determine the cost/benefit ratio of the favored alternative and identify capital requirements and schedule for implementation.

The analysis would have to be conducted in close coordination with the national counterparts, particularly with regard to their generation and transmission expansion plans. It should leverage the information and analyses being undertaken by the experts undertaking the TEIAS study.

Potential electric interconnection projects are summarized below. Projects with greater potential for implementation are elaborated in chapter 11.

- **Second Line between Egypt and Jordan:** The area of focus for strengthening the Mashreq interconnection is the link between Egypt and Jordan. This link is the gateway for trade between Egypt, the only Mashreq country that does not currently have a capacity deficit, and the other four Mashreq countries, which all are in capacity deficit.[38] Adding a second line from Egypt to Jordan has been under study for some time. It also would require transmission upgrades to national grids, and to the interconnection between Jordan and Syria. As a result, this project could be viewed as an upgrade to the main Mashreq thoroughfare from Egypt through to Syria.
- **Upgrade Interconnection between Syria and Lebanon:** In conjunction with the project to construct a second interconnection between Egypt and Jordan, the interconnection between Syria and Lebanon also might be upgraded. Currently, there are two 66kV and one 230 kV interconnection between the two countries. A 400 kV interconnection between the countries is expected to be completed by April 2010. Consideration is being given to adding a second 400 kV interconnection. Upgrading this interconnection has been under study, and construction could begin in 2012.
- **Upgrade Interconnection between Iraq and Syria:** Although Iraq is interconnected with Syria, and through Syria to the rest of the Mashreq network, Iraq has very little energy trade with the Mashreq countries. This lack of trade is in large part a result of electricity deficiencies in both Iraq and Syria, and in Mashreq as a whole. However, Iraq has significant gas reserves—in particular, the undeveloped Akass field in the western desert that is very close to the Syrian border. There are opportunities for Iraq to exchange its gas, which is much needed in Syria, for electricity, which is much needed in Iraq. Upgrading the interconnection between Syria and Iraq to 400 kV would be a critical step in realizing such an exchange. In fact, such a project is being implemented. Furthermore, construction of new generation in conjunction with the transmission upgrade would be far less costly in Syria, owing to the current conflict in Iraq. As noted, in March 2009, Iran's energy minister announced that a quadripartite electricity network will be formed among Syria, Iraq, Turkey and Iran and will include construction of generating plants. Details on this agreement are not yet available, but it can be expected to result in new project investment.
- **New Interconnection from Iraq to Jordan:** Again, Iraq has significant electricity shortfalls and significant gas reserves, so could benefit from development of additional regional power interconnections and gas pipelines. There are reports that the Government of Iraq is pursuing opportunities to link grids with Jordan. However, the recently announced quadripartite agreement would appear to slant Iraq's preferences toward trade with Syria over constructing a new interconnection with Jordan. The latter alternative does not forgo opportunities for Iraq electricity purchases from Jordan via Syria.

  A 400 kV interconnecting transmission line between Iraq and Jordan would be costly and would require an 800 km line at a cost of approximately US$560 million. However, the

[38] Although Egypt's current capacity surplus is limited, it has an aggressive generation expansion plan in place. Jordan's capacity situation has improved with its recent capacity additions, but supply is expected to remain tight in the near-term.

costs of the line might be overcome by the cost advantages of building new generation in Jordan rather than in Iraq, particularly considering Jordan's success in attracting independent power producers (IPPs).

- **Construct New Interconnection from Jordan to West Bank**: The West Bank is entirely dependent on imports, mostly from Israel, and a small amount from Jordan over an existing 2 x 132 kV line that is currently operated at 33 kV. It is necessary to operate this line in isolation mode. A feasibility study on a new Jordan – West Bank interconnection recommends further cooperation with Jordan, with the first step including construction of a new 2 x 400 kV interconnection developed in conjunction with a 132 kV transmission system in the West Bank. The favored interconnection alternative would originate at the Samra Thermal Power Plant north of Amman in Jordan, and connect to a new 400 kV substation in the Jerusalem area in the West Bank. The length of the interconnection is estimated to be 101 km with a cost of US$ 99.2 million (in 2008 Dollars). This estimate includes the cost of the interconnection and substation investments in both Jordan and the West Bank.
- **Construct New Interconnection from Egypt to Gaza**: Gaza is likewise almost entirely dependent on imports from Israel, and to a lesser extent, Egypt. Gaza might be supplied in the future from Egypt in larger quantities over a 2 x 220 kV line from the main transmission grid to El'Arish, a town located 50 km south-west of Gaza. A feasibility study shows that the least costly alternative for meeting Gaza demand through 2030 is the interconnection with Egypt, and recommends that further generation and transmission system development in Gaza be based on power cooperation with Egypt. The report suggests that the first step should be implementation of a 220 kV interconnection, and a strong 220 kV transmission system on the Gaza Strip. New generation would be needed in Egypt to support sales to Gaza. The estimated cost of the interconnection including substations in Gaza and Egypt is US$ 37.4 million (2008 prices). The interconnection would be a 2 x 220 kV line about 50 km in length.

- **Construct New Generation in Syria and/or Jordan:** In light of the shortfall of generation capacity in the Mashreq region, construction of new generation capacity would provide significant benefits. A 500 MW gas-fired generating plant could cost $300 million. Iraq has had significant difficulty building much needed generation capacity because costs are very high owing to conflict, limited private sector involvement, economies of scale, and other factors. Lebanon and the West Bank & Gaza have similar problems, although not on the same scale. Construction of generation in either Jordan or Syria(or both) for the benefit of the host country and Iraq would significantly improve energy integration, particularly if tied to gas exports from Iraq. New generation likely would require upgrades to transmission capacity in both the national networks and the regional interconnections, particularly between Iraq and Syria.
- **Mashreq Regional Coordination Center:** As discussed, the structures of the national markets generally are not set up for exchanges of capacity, energy, and ancillary services. There are no regional coordination center and no formal regional market to facilitate market transactions, relating both to promotion of regional trade and compensation to entities providing transport services, and in terms of determining the technical feasibility of making a transaction; that is, to simulate sales to determine if they can be made without creating congestion or instability on the system. In the absence of a regional coordination center, bilateral contracts can become complex, particularly when a

transaction is between nonadjacent countries. For instance, a sale by Egypt to Lebanon would require agreement between Egypt and Lebanon on the terms and conditions of the sale, as well as the agreement of Jordan and Syria to transport the energy.

An interconnected power system requires the rational and secure operation of every subcomponent of the network. In general, there has been no thorough study of power system stability to synchronize the entire regional power system. The TEIAS study is reviewing transfer capacities between Mashreq countries and Turkey. However, the study notes that (a) following new developments both in the Mashreq region and in Turkey, the limits are no longer valid, and that (b) power exchange limits should be reviewed according to existing system conditions. Numerous power generation and transmission developments in the Mashreq region and Turkey have been proposed, so transfer limits will be changing constantly. There is a need for ongoing monitoring and system simulation to ensure that transactions can take place without disrupting supply. A Regional Coordination Center can provide such services while ensuring fair and transparent treatment of transaction between participants in the regional market. It is important to understand that industry restructuring at the national level would not be a requirement, but over time would increase liquidity in the regional market and the benefits of a regional coordination center.

- **New Interconnection between Egypt and Saudi Arabia:** It is understood that Egypt and the Kingdom of Saudi Arabia are studying a potential electric interconnection. The two systems could be connected through the Jordanian interconnection (land connection), through the Gulf of Aqaba or close to Sharm el-Shekh at the islands of Tiran and Salah El Din. The distance from Egypt (Sharm El-Sheikh and Nowiba) to large load/generating centers in Saudi Arabia (Madina or Tabuk) is long at 400-500 km. The potential size of the line might be 3000 MW. Owing to the large distances and the difference in standard frequency (Egypt 50 Hz, Saudi Arabia 60 Hz), DC transmission is likely to be the most feasible alternative.
- **New Interconnection between Iraq and Saudi Arabia:** There are reports that the Iraqi Government is considering construction of an interconnection with Saudi Arabia, but discussions are very preliminary. Saudi Arabia has a generation capacity deficit as does Iraq, so this potential project is not a high priority.
- **New Interconnection between Jordan and Saudi Arabia:** Consideration reportedly is being given to construction of a new interconnection between Jordan and Saudi Arabia, but discussions are very preliminary. Both countries have supply shortages, so this project is a low priority.
- **Upgrade Interconnection between Iraq and Turkey:** Construction of an additional 400 kV line between Iraq and Turkey is being implemented.[39] The cross-border point has been determined, and construction of the Iraqi part of the line has been initiated. The construction of the Turkish part of the line is expected to be initiated soon. Current estimates are that the interconnection capacity with Turkey might be increased by an additional 400 MW.
- **Upgrade Interconnection between Iraq and Iran:** The interconnection between Iraq and Iran reportedly was upgraded to 400 kV in April 2009, increasing the interconnection capacity by 200 MW to 325 MW. There appears to be little need at this time for

[39] Electricity Network Interconnections of Turkey, paper presented at MEDELEC Meeting, Istanbul, March 24, 2009.

additional upgrades to the interconnection. However, they may be under study as part of the announced quadripartite electricity network to be formed among Syria, Turkey, Iraq, and Iran.

- **Upgrade Interconnection between Egypt and Libya:** Egypt is linked to Libya through a 220 kV line. Reinforcement of this interconnection through the addition of a new 500 kV line has been investigated by both MEDRING and ELTAM. Commissioning of the new line was envisaged in the year 2015. The project would reinforce the connection between the Mashreq countries and Libya, and on to the Maghreb countries, including Morocco, Algeria, and Tunisia. The Mediterranean Ring project sponsored by the EU aims to create a transmission ring around the Mediterranean by interconnecting the national grids, although reports are that work is progressing slowly. It is understood that there are synchronization issues between Libya and the other northern African countries, so a direct current (DC) back-to-back link may be needed between Egypt and Libya.[40]
- **Support Development of Proposed Syria-Turkey-Iraq-Iran Electricity Market:** As noted, recent press releases indicate that a quadripartite agreement has been reached among Syria, Turkey, Iraq and Iran to develop transmission and, potentially, generation projects. This agreement may result in projects to support integration of the Mashreq energy market.

[40] See Evolution of the Electrical Interconnections around the Mediterranean Sea, due to the Mediterranean Solar Plan, March 19, 2009.

Chapter 10. ANALYSIS OF REGIONAL GAS INTERCONNECTIONS

10.1. Mashreq Natural Gas Demand: Past, Present, and Future

Historically, gas demand in the Mashreq countries has been driven by availability of gas supplies. Through the 1990s, Jordan, Syria, and Egypt utilized all gas production domestically. Jordan and Syria continue to do so, whereas Egypt began exporting gas in the early 2000s. Lebanon and the West Bank & Gaza have no domestic gas and little gas infrastructure. Lebanon only recently began importing gas from Egypt. Iraq has significant gas reserves. However, owing to conflict, limited gas infrastructure, and other reasons, historically, the country has consumed only limited quantities of gas. Nevertheless, overall, gas consumption in the Mashreq countries has grown significantly in recent years. In 1990 their total combined gas consumption was only 12 bcm, but by 2007, the amount had quadrupled to over 51 bcm. Historical and forecast consumption of natural gas is shown in table 10.1.

Table 10. 1: Historical and Forecast Gas Consumption in Mashreq Countries ***(bcm)***

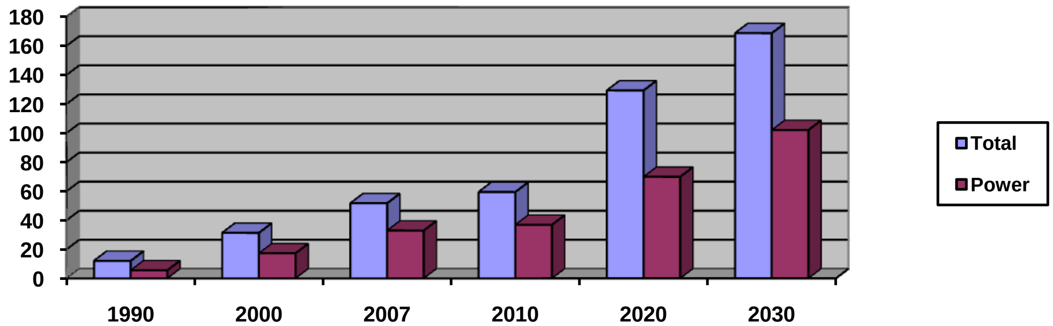
Country	**1990**	**2000**	**2007**	**2010**	**2020**	**2030**
Egypt	8.24	21.78	37.60	38.80	51.70	63.80
Iraq	1.98	3.15	4.28	4.28	46.63	62.00
Jordan	0.12	0.26	3.53	4.50	7.09	8.55
Syria	1.69	6.10	6.25	10.95	19.35	27.53
Lebanon	0	0	0	0.86	2.69	3.98
WBG	0	0	0	0	1.8	2.8
Total	12.03	31.29	51.66	59.39	129.26	168.66

Gas demand is forecast to continue growing in all Mashreq countries, bypassing 2007 actual gas demand by 15 percent by 2010, and by 226 percent by 2030.

The primary consumer of gas in the Mashreq region has been the power sector. Figure 10.1 compares historic and forecast gas use for power generation versus gas overall use in the Mashreq region. The power sector has accounted for an increasing share of gas consumption, increasing from 46 percent of total consumption in the Mashreq region in 1990 to over 63 percent in 2008. The share of gas consumed by the power sector is forecast to continue at high levels of about 60 percent through 2030 in the Mashreq region as a whole. Total gas consumption by the power sector is expected to increase by 200 percent by 2030 from 32.9 bcm in 2008 to 102 bcm.

Figure 10. 1: Historical and Forecast Mashreq Gas Demand, 1990–2030

(bcm)



The Mashreq region has large gas reserves. Iraq and Egypt individually account for 55 percent and 39 percent of the region's total, respectively. These two countries combined account for 94 percent of the Mashreq region's total. Gas reserves by country and for the Mashreq region as a whole are shown in table 10.2. Estimates of reserves yet to be found in Iraq and Egypt are substantial. In other words, with successful exploration, appraisal, and development of infrastructure, these two countries could become leading suppliers of natural gas to the region.

Table 10. 2: Mashreq Natural Gas Reserves ***(bcm)***

Country	Gas Reserves
Egypt	2170
Iraq	3022
Jordan	6
Syria	289
Lebanon	0
WBG	35
Total	5522

Historical and forecast gas production is shown in table 10.3. In 1990 only 14 bcm of natural gas in total was produced by the Mashreq countries. Since that year, gas production has increased dramatically, rising to 64.76 bcm in 2007—a 362 percent increase. The dramatic growth in natural gas production is forecast to continue. Gas production in the Mashreq countries is forecast to increase over 2007 actual production levels by 10 percent in 2010. By 2030, gas production in the Mashreq countries is forecast to increase over 2007 actual production levels by over 200 percent. Approximately 94 percent of Mashreq gas production in 2030 is expected to come from Iraq and Egypt— 46 percent and 48 percent, respectively.

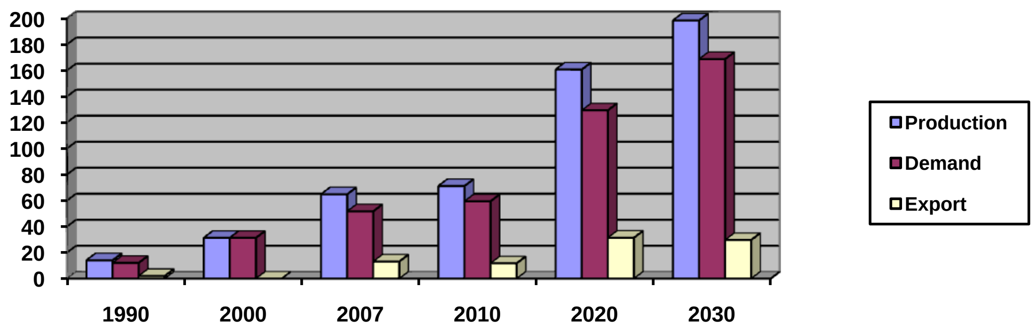
Table 10. 3: Historical and Forecast Gas Production in Mashreq Countries, 1990–2030 ***(bcm)***

Country	1990	2000	2007	2010	2020	2030
Egypt	8.24	21.78	54.00	56.80	71.00	92.00
Iraq	3.98	3.15	4.28	4.28	78.33	95.00

Jordan	0.12	0.26	0.23	0.23	0.23	0.23
Syria	1.69	6.10	6.25	9.78	9.05	9.08
Lebanon	0	0	0	0	0	0
WBG	0	0	0	0	2	2
Total	14.03	31.29	64.76	71.09	160.61	198.31

The gas demand/supply balance is shown in figure 10.2. In 2007 the Mashreq countries had net exports of approximately 13 bcm. Going forward, these countries are forecast to have net exports of approximately 12 bcm in 2010, ramping up to 30 bcm in 2020 and beyond through 2030. These gas quantities are available for export outside the Mashreq region, that is, they are net of total demand of the Mashreq countries.

Figure 10. 2: Gas Demand/Supply Balance in Mashreq Countries, 1990–2030 ***(bcm)***



Source: Various – see Appendix A.

10.2. Interconnection/Pipeline Capacity: Arab Gas Pipeline

The Arab Gas Pipeline (AGP) connects Egypt, Jordan, and Syria and, ultimately, will connect Syria to Turkey. The pipeline has three phases, as follows:

- Phase I: From El Arish in Egypt to Aqaba in Jordan (completed)
- Phase II: From Aqaba to Rehab in Jordan (completed)
- Phase III: Includes Parts 1 and 2
    - Part 1: From Rehab to Al Rayyan (near Homs) in Syria (completed)
    - Part 2: From Furglus (east of Al Rayyan) to Kilis on the Syria-Turkey border Includes two subphases:
        - Subphase 1: From Aleppo to Kilis
        - Subphase 2: From Furglus to Aleppo.

All but Phase III, Part 2 have been completed. Feasibility studies on the technical, economic, and financial components of Phase III, Part 2 suggest that the project should be pursued. A schematic of the AGP is shown in figure 10.3.

Figure 10. 3: Arab Gas Pipeline

Source: Egyptian National Gas Company

A key gap in the AGP is the relatively short (45 km) onward link to the Turkish gas network (Kilis to Gaziantep). BOTAS, the state-owned Turkish gas operator, reportedly was procuring the pipe and other materials.. This pipeline is a priority for Syria, as it wishes to import gas from Iran through Turkey to meet its supply shortfall.

A 43 km pipeline, Gasyle 1, which goes from Syria to the Beddawi Power Plant in Tripoli, north Lebanon, is officially part of the AGP. Iraq and the West Bank & Gaza are the only Mashreq countries not connected to the AGP. Once the AGP is completed, the planned Nabucco gas project might be utilized for exports to Europe. New gas sources would reinforce the reliability and security of gas supply in the region.

To date, trade on the AGP has been limited, far below its design capacity of 10 bcma. Until recently, the only firm sales on the AGP have been made between Egypt and Jordan. The contract with the Al Fajr Company is described in detail in chapter 4. The contract is for 30 years, with the possibility of a 10-year extension. The Al Fajr Company constructed the second phase of the AGP on a build-own-operate-transfer basis, with transfer taking place after 30 years. In return, the company received exclusivity rights for 18 years.

Egyptian gas piped via the AGP is a preferred fuel alternative for electricity generation in the Mashreq countries. Egypt started exporting to Syria in 2008 to supply the Deir Ali 750 MW combined cycle gas plant. Egypt's gas exports to Syria reached 0.9 bcm in 2009 and are expected to ramp up to 2.2 bcm by 2013. In addition, Egypt started exporting gas to Lebanon in late 2009 to supply the Beddawi power station. Egypt's exports to Lebanon reached 0.3 bcm in 2009 and are expected to ramp up to 0.6 bcm by 2013. Egypt exported 3.3 bcm to Jordan in 2009, and expects to ramp up gas exports to Jordan to 4.2 bcm by 2013. Total exports on the AGP in 2009 reached 4.5 bcm, about 45 percent of the AGP capacity. By 2013, total exports on the AGP are expected to reach 7 bcm, or about 70% of the full AGP capacity.

Egypt's gas program has been hugely successful (chapter 2). Since the early 1990s, gas reserves and production have approximately quadrupled. With its gas reserves and successful gas exploration activities, its LNG export terminal, and the completion of the AGP, Egypt is poised to remain an energy leader in the region. In 2007 Egypt's gas production was approximately 54 bcm, of which 16.4 bcm, or 30 percent, was exported internationally.

After a tailing off of gas discoveries in Egypt, changes to the terms offered for exploration led investment to pick up, and, more recently, there has been a string of new discoveries. Egypt is the starting point and sole supplier for the AGP, although expectations that Egyptian gas will be exported to Europe via Turkey appear optimistic. Egypt also has a gas pipeline to Israel.

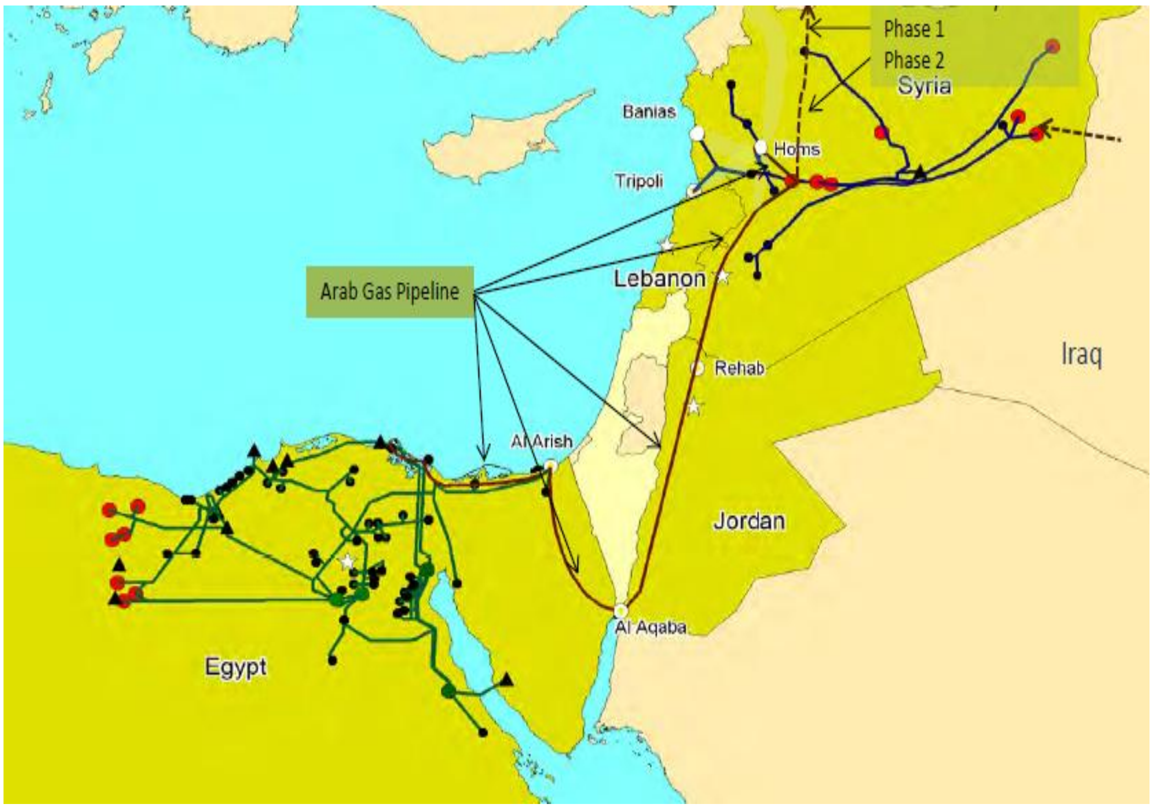
As mentioned, gas exports have become politically sensitive in Egypt. Egyptian consumers enjoy highly subsidized gas and are concerned about price increases. In 2008 consumers' sensitivity on this issue led the Ministry of Petroleum to announce a policy of allocating 33 percent of gas for export, 33 percent for domestic consumption, and 33 percent to be reserved for future generations, With increases in industrial gas prices, gradual tariff reform has begun, and the Cabinet has agreed to establish an independent gas regulator.

Nevertheless, if Egypt is to continue to be a gas exporter, it will require successful expansion of its production and delivery systems. Currently, Egypt's electricity sector is in balance, with generation capacity in amounts necessary to meet the country's demand at reasonable levels of reliability. However, in the coming years, the electricity demand is forecast to grow at more than 6 percent annually, placing considerable stress on electricity and gas infrastructure. Egypt's expansion plan to meet its future electricity requirement will be fuelled with a significant share of the country's domestic gas production. Furthermore, the ministry has announced an ambitious expansion of residential gas connections. To date, progress has been slow due to difficulties with financing. Financing its aggressive electricity and gas expansion will be challenging for Egypt because domestic prices for all forms of energy are heavily subsidized.

10.3. Potential for Expansion of Exports: Egypt and Iraq

In the future, Jordan, Syria, Lebanon and the West Bank & Gaza expect to be net importers of natural gas. Domestic demand will be driven primarily by power generation. Egypt is expected to continue in its role as primary exporter of natural gas. To help finance its aggressive energy expansion initiatives, Iraq is expected to develop its huge gas reserves for domestic consumption and for export. Of course, if Iraq's aggressive energy expansion is to be realized, considerable progress must be made in resolving the current conflict. An overview of the Mashreq gas infrastructure is provided in figure 10.4.

Figure 10. 4: Overview of Gas Infrastructure in Mashreq and Surrounding Area



Going forward, exports from Egypt and Iraq are forecast by the International Energy Agency (IEA) (table 10.4). These export figures are over and above what Egypt and Iraq will need to serve their domestic gas needs. As can be seen, the available export volumes increase steadily to over 61 bcm by 2030.

Table 10. 4: Forecast Availability of Gas for Export from Egypt and Iraq ***(bcm)***

	2007	2010	2020	2030
Egypt	16.4	18.0	19.3	28.2
Iraq	0	0	31.7	33.0
Total	16.4	18.0	51.0	61.2

The development of Iraq's large gas endowments will provide the country with the potential to become a major regional exporter of gas, both to its neighbors and to larger markets in Europe. Prior to the 1990–91 Gulf War, Iraq exported natural gas to Kuwait through a pipeline that no longer operates.

The Government of Iraq is understood to be interested in exporting gas from its northern gas fields to Turkey and Europe, including linking up to the Azeri-Turkish Baku-Tbilisi-Erzerum (BTE) line, the planned Nabucco (Iran-Europe) pipeline, or the Arab Gas Pipeline. Iraq plans to use its southern gas reserves, which are associated primarily with oil production, for domestic consumption and for export to points south, including Kuwait. There is also the possibility of exporting gas from the new Akass Field in Iraq's western desert. A connection with Iraq would be of substantial benefit to Syria, not only as an alternate source of gas for its own use, but also as a source of revenue from transporting gas to Turkey and perhaps beyond to Europe if the Nabucco gas project goes ahead.

Syria had earlier signed an MoU to purchase gas from Iraq, initially 1.5 bcma from the Akass field. One bcma of this is to be exported. Iraq's Akass gas field is close to the border with Syria and approximately 50 km from the Syrian gas network, in which Syria has spare processing capacity at the nearby Deir Ezzor and Omar plants. Syria has let a contract to a Chinese company to build the necessary pipeline, but it will have a relatively small diameter of only 10 inches. If there are significant new discoveries at Akass, a new pipeline will be needed. Reports out of Iraq initially indicated that Shell had been contracted to develop the Akass field, but reports now are that it will be included in the upcoming Iraq oil and gas exploration licensing round. Syria and Iraq have been discussing options for a second pipeline to carry gas from Iraq's northern gas fields across Iraq to the AGP and potentially to the port of Banias, from which it could be exported as LNG. Unfortunately, these plans to connect Iraq's Akkaz field to Syria were not implemented as earlier envisaged.

In the short term, Egypt will be the likely supplier of gas to the AGP. The combined gas demand of Jordan, Lebanon, Syria and the West Bank & Gaza to be supplied from imports in 2010 is 6.3 bcm. This amount is well below the AGP capacity of 10 bcma, but is consistent with gas availability and contract negotiations. In the longer term, the combined gas import needs of Jordan, Lebanon, Syria and the West Bank & Gaza will be approximately 20 bcm in 2020 and over 31 bcm in 2030.

The combined gas export forecast from Egypt and Iraq will cover Mashreq needs with gas to spare for export to other countries, including 51 bcm in 2020 and 61.2 bcm in 2030. However, there are a number of competitors for this gas. For exports to be available in these quantities, a continuation of Egypt's highly successful gas exploration activities will be required to produce gas from yet-to-be-found reserves. The competition for gas also will require progress on development of gas delivery infrastructure. In Iraq's case, conflict resolution combined with substantial investment in exploration and development of its gas reserves and delivery infrastructure will be necessary

10.4. Potential Future Cross Boarder Projects

The Arab Gas Pipeline connects Egypt, Jordan and Syria. The 43 km pipeline connecting the Beddawi Power Plant in north Lebanon to the AGP in Syria also forms part of the AGP. The AGP ultimately will connect to the Turkish pipeline network, which in future may include the planned Nabucco pipeline, which will deliver gas to Europe.

The AGP design capacity is 10 bcma. Transport on the AGP has been well below that number. Most activity has been associated with the gas contract between Egypt and Jordan. Under most future scenarios, transport on the AGP will remain well below its design capacity in the near future. However, longer term there is prospects which would materialize if gas supplies from Egypt and/or Iraq are added to the system. The main gaps in the regional gas network are quite clear. The most feasible candidates for future cross-border projects include extending the AGP to other countries, including completing the final two stages of the AGP to connect the AGP to Turkey, connecting Iraq to the AGP, and extending the AGP to countries outside Mashreq.

As noted in the previous chapter, there will be a need to accompany capital projects with technical assistance projects. Furthermore, any new cross-border project should be coordinated with other ongoing studies in the region to ensure consistency and avoid overlap. The gas integration projects with greater potential for implementation are discussed in chapter 10 and listed below for reference:

1. Completion of the Arab Gas Pipeline (AGP) through construction of two segments within Syria and one segment in Turkey. The investment costs of these three segments are estimated at: $350 million for Furglus-Aleppo within Syria; $80 million for Aleppo –Kilis within Syria; and $67 million for Kilis - Goziantep within Turkey. The construction of the first segment is not likely without a firm commitment from Egypt to supply gas. However, construction of the other two segments is under serious consideration to enable Syria to import gas via Turkey.

2. Construction of the Iraq-Syria gas pipeline which could be of small or large scale. The small scale pipeline is intended to transport gas from the Akkas gas field in Iraq's western desert to Syria. This would be a 50 km pipeline with an estimated cost of US$ 75 million. It has significant mutual benefits for Iraq and Syria. Iraq would not need to build a gas processing plant at Akkas; Syria has the capacity to process the gas in its own plants. The gas could be utilized for power generation in Syria with part of the power exported back to Iraq. This would be highly beneficial to Iraq with a generation gap of about 50% and fast growing demand. Iraq's efforts to install new capacity have progressed very slowly. The larger scale gas pipeline between Iraq and Syria would be of a completely different nature, including an 800 km pipeline at a cost of about US$ 1.2 billion. This project would represent a major source of gas input to the AGP and a major gas outlet from Iraq. It could potentially be an avenue for selling Iraqi gas to Turkey and beyond. This pipeline and the potential pipeline projects from Iraq to Jordan (Item 5) and from Iraq to Turkey (Item 6) are likely to compete, so only one might proceed to implementation.

3. Construction of the Iraq-Jordan gas pipeline which would import gas from Iraq's northern and/or southern gas fields to the AGP via Jordan's Risha gas field. It would include an 800 km pipeline with an estimated cost of US$ 1.2 billion. It would enable regional gas trade, an additional export route for Iraq, and second option for gas imports for Syria, Lebanon and Jordan.

4. Construction of Iraq-Turkey gas pipeline which would include two distinct (and not mutually exclusive) alternatives for exporting gas from Iraq to Turkey and on to Europe. The first option focuses on delivering gas from Iraq's Kurdistan region to Turkey. Investment is under way to develop the gas fields in Kurdistan for domestic use. Private firms involved in the development of these fields are now negotiating gas sales to Turkey and others through the Nabucco pipeline system that is expected to transport gas from the Caspian countries to Europe. The second option for exporting Iraqi gas to Turkey is based on the gas resources of Iraq's northern and/or southern fields and possibly its Akass field in the western desert, for export to Turkey via the AGP, either through Syria or Jordan. This latter alternative has been addressed above.

Chapter 11. **ENERGY INTEGRATION PROJECTS WITH GREATER POTENTIAL FOR IMPLEMENTATION**

11.1. Ongoing Mashreq Gas and Electricity Studies and Initiatives

Identification and implementation of new energy integration projects must take account of various studies and initiatives to ensure synergy and to avoid duplication and overlap. There have been numerous studies and initiatives in the area of energy integration some of which have resulted in significant findings. In particular the EU has funded and implemented a set of useful initiatives summarized in the following table:

Name :	**Euro-Arab Mashreq Gas Market Project**
Countries:	Egypt, Jordan, Lebanon, and Syria (Iraq and Turkey are observers)
Summary:	***Aim:*** Contribute to integrate gas markets to create a regional internal gas market that will be integrated with EU internal gas market. ***Approach:*** Elaborate a regional Gas Master Plan; identify projects and prepare feasibility studies; identify and facilitate legislative harmonization and reform needed to foster creation of competitive and efficient Mashreq gas market; transfer know-how and expertise to Partner Countries. Establish Euro-Arab Mashreq Gas Co-operation Centre in Damascus. Phase 2 being prepared to start in 2010.
Name:	**Euro-Mediterranean Energy Market Integration Project (MED-EMIP)**
Countries:	Algeria, Egypt, Israel, Jordan, Lebanon, Morocco, Palestinian Territories, Syria, Tunisia, and Turkey
Summary:	***Aim:*** Support implementation of Euro-Mediterranean Energy Partnership on key energy policy and industry issues. ***Approach:*** Acts as a catalyst to reinforce Euro-Mediterranean Partner Countries' energy cooperation, with emphasis on enhancing energy security and sustainability. **This** study includes policy research, technical harmonization, and know-how transfer. Establish Energy Information Centre in Cairo to assess progress and prospects for energy sector reforms, particularly legal and regulatory framework, including a regional database of information on status and progress of energy reforms in Mediterranean Partner Countries.
Name:	**Mediterranean Working Group on Electricity and Natural Gas (MED-REG)**
Countries:	Albania, Algeria, Bosnia-Herzegovina, Croatia, Cyprus, Egypt, France, Greece, Israel, Italy, Jordan, Malta, Montenegro, Morocco, Palestinian Authority, Portugal, Slovenia, Spain, Tunisia, and Turkey
Summary:	***Aim:*** Promote collaboration among energy regulatory authorities of EU, Energy Community Member States, and other Mediterranean countries. Diffusion of modern regulatory culture may accelerate deployment of infrastructure and improved quality of service with reasonable electricity and gas prices. ***Approach:*** Exchange information; develop common positions on regulatory issues; promote Euro-Mediterranean regional electricity and natural gas markets; promote harmonized, transparent, and nondiscriminatory market rules; and exchange energy regulation know-how. Project is run from Italian electricity regulator's office in Milan.
Name:	**Energy Efficiency in Construction (MED-ENEC)**
Countries:	Algeria, Egypt, Israel, Jordan, Lebanon, Morocco, Palestinian Territories, Syria, Tunisia, and Turkey

Summary:	***Aim:*** Improve energy efficiency in construction sector. ***Approach:*** Focus on strengthening business services and supporting markets, improve institutional capacities, and establish favorable institutional structures as well as fiscal and economic instruments. Carry out pilot projects for demonstration and training purposes; disseminate results to ensure knowledge transfer. Capacity building combines national and regional workshops and consulting events. Project offices are in Lebanon and Tunisia.
Name:	**Mediterranean Electric Ring (MEDRING)**
Countries:	Europe and Southern and Eastern Mediterranean countries
Summary:	***Aim:*** Analyzing the behavior of the power system as a whole and formulate a series of recommendations on how to progress in the closure of the ring ***Approach:*** Assess the potential energy exchanges between the countries with consideration of the European targets of efficiency enhancement and cO2 reduction, and export of RE-based electricity from the neighboring countries to Europe.

In addition to the studies carried out by the EU and the World Bank and others, there are also a number of forums that attempt to coordinate and support energy integration. These include:

- Arab Union of Producers, Transporters and Distributors of Electricity (AUPTDE)[41] comprising Jordan, UAE, Bahrain, Tunisia, Algeria, Saudi Arabia, Sudan, Syria, Iraq, Sultanate of Oman, Palestine, Qatar, Lebanon, Libya, Egypt, Morocco, Mauritania, and Yemen. Established in 1987 by a group of Arab electrical companies, the aim of this forum is to strengthen ties among members to improve power manufacturing in the Arab world.

- Arab Electricity Regulators' Forum (AERF) comprising Abu Dhabi, Algeria, Bahrain, Egypt, Jordan, Lebanon, and Saudi Arabia. The Forum's objectives are to develop electricity regulation on a national level in the Arab countries; support and develop performance of Arab electricity regulators; promote cooperation and information exchange; facilitate access to information and international experience and promote training opportunities; and develop and share key performance and technical indicators.

- The Energy Charter Treaty comprising two membership categories: members and observers[42]. The Energy Charter Treaty entered into legal force in April 1998 and is a legally binding multilateral instrument. Its fundamental purpose is to strengthen the rule of law on energy issues by creating a level playing field of regulations to be observed by all participating governments, thereby mitigating risks associated with energy-related investment and trade.

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41 In December 2009, AUPTDE was renamed to the Arab Union of Electricity (AUE).

42 Observers to the Energy Charter have the right to attend all Charter meetings and to receive all related documentation, and to participate in the working debates. The intention is for observer status to provide the chance for a country to familiarize itself with the Charter and its functions in order to facilitate its assessment of the benefits of accession to the Energy Charter Treaty.

- *Members:* Albania, Armenia, Australia, Austria, Azerbaijan, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, European Communities, Finland, France, Georgia, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Kazakhstan, Kyrgyzstan, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Moldova, Mongolia, the Netherlands, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Tajikistan, Macedonia, Turkey, Turkmenistan, Ukraine, United Kingdom, and Uzbekistan
- *Observers:* Afghanistan, Algeria, Bahrain, China, Canada, Egypt, Iran, Jordan (moving to full member status), Korea, Kuwait, Morocco, Nigeria, Oman, Pakistan, Palestinian National Authority, Qatar, Saudi Arabia, Serbia, Tunisia, United Arab Emirates, United States of America, Venezuela.

11.2. Integration Projects with Greater Potential for Implementation

Based on the overall analysis of regional integration opportunities in chapters 8 and 9, the cross-border projects with the greatest potential for implementation are identified and discussed below.

11.2.1 Upgrade Electrical Interconnection between Iraq and Syria

This project is in the implementation phase, but there are still further investment needs. The project includes completion of the 400 kV interconnection between Syria and Iraq. The project's focus is on the Iraqi side, although there may be a need to complete the Syrian side as well. The project includes a single circuit 400 kV overhead line of 165 km from Tayem Substation in Syria to Qa'im Substation in Iraq. The estimated cost of the project ranges from US$700,000–750,000/km (US$115 million–125 million).[43]

The primary benefits of the project are that it would help address Iraq's electricity shortage, improve energy security for the Mashreq region, strengthen economic cooperation between Syria and Iraq, and facilitate development of a proposed regional electricity market, which initially would include Iran, Iraq, Syria, and Turkey. The added benefit of this project is that it could be combined with development of the Akass gas field for the potential swap of surplus Iraqi gas into electricity, in which Iraq has a deficit.

On the downside, neither country has an electricity surplus at this stage. Syria may be unable or unwilling to export power that it needs for domestic supply. But still the project presents a strong business case. Iraq has an electricity crisis, with a generation gap of approximately 50 percent and fast-growing demand . Efforts to install new generating capacity have progressed very slowly. The Akass field is close to the Syrian gas network, which has spare processing capacity, and Syria has let a contract for construction of the pipeline on its side of the border. Therefore, this project could be put in place more quickly than building a new power plant and associated gas infrastructure in Iraq itself.

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[43] Based on 2004 figures for construction of a 400 kV line in Iraq. These costs included US$375,000/km plus line bays, transformers, and a 43.5% mark-up for design and management. These figures illustrate the very high costs of construction in Iraq under the current conflict conditions.

Although Syria has its own generation gap, its gap is due in part to insufficient gas rather than to insufficient generation capacity. Between Iraq's need for electricity and Syria's need for gas, there is space to reach commercial agreement. Syria has exported electricity to Iraq in the past, curtailed only by its own shortage of supply, so there is an established path for this arrangement. The project is at a fairly advanced stage and could be implemented relatively quickly.

11.2.2 Expand and Strengthen Electrical Transmission Corridor from Egypt to Syria

This project involves upgrading the main trunk of the Mashreq interconnected system between Egypt and Syria via Jordan. According to Jordan's Updated Master Plan, the existing interconnection with Egypt was designed for potential future expansion, including possible conversion to DC operation, which would make use of a spare fourth cable and increase the capacity of the interconnection to 1000 MW. It would be necessary to construct additional AC circuits in both Egypt and Syria. The project would increase interconnection capacity not only between Jordan and Egypt but also between Jordan/Egypt and Syria, and potentially on to Lebanon and Turkey. The total cost of the reinforcement is estimated at US$735 million.

An alternative would be to install 2 more submarine cables and operate the interconnection as a double circuit 400 kV AC link, increasing interconnection capacity to 1100 MVA. This alternative also would require upgrades to the national power systems including the link between Jordan and Syria. Thus, it would increase the transfer capacity between Jordan/Egypt and Syria as well, and potentially on to Lebanon and Turkey. The estimated cost of this alternative is US$400 million.

Benefits from increasing interconnection capacity are numerous, although difficult to define in the absence of a detailed transmission modeling study. Egypt's system is summer-peaking while Jordan's system is winter-peaking. Furthermore, there are opportunities for energy exchanges during the day owing to diversity in daily peak demands between the two countries. Upgrading the interconnection also would improve system security; improve the ability to install larger generating units, thus taking advantage of economies of scale (unit sizes could be larger than the 300MW units assumed in Jordan's expansion plan); increase potential for integrating renewable energy resources and eventual export of electricity to Turkey and Europe and increase income to Jordan from wheeling energy from Egypt to Syria and Lebanon, and perhaps Iraq and the West Bank & Gaza. The system security benefits are probably the most significant. With energy shortages expected in Lebanon, Syria and the West Bank & Gaza, Jordan and Syria are likely to gain increased revenues from wheeling. Finally, it is noted that the transmission corridor, particularly the segment in Jordan would facilitate the development of renewable energy and could be eligible for financial support from the Clean Technology Fund (CTF).

The interconnections between Syria and Lebanon, Jordan and the West Bank, and Egypt and Gaza represent important components of the integrated Mashreq transmission system. Therefore, upgrades to these interconnections (or new interconnections) should be considered in conjunction with this project. Otherwise, it would be very difficult to determine the benefits and resulting cost-sharing arrangements. For example, there could be little benefit in upgrading the interconnection between Syria and Lebanon if Syria remains in a capacity deficit and Egypt is unable to sell any capacity surplus that it might have to Lebanon owing to transmission limits.

11.2.3 Complete Arab Gas Pipeline (AGP)

This project would complete the construction of the remaining links of the Arab Gas Pipeline (AGP). Feasibility studies show that completion of the AGP is economical and should be pursued.

Completion of the AGP requires construction of 2 pipeline segments within Syria and one pipeline segment within Turkey. The total cost of the 3 segments is estimated at US$497 million. The three segments would be:

- Furglus-Aleppo (186 km within Syria) at an estimated cost of $350 million
- Aleppo-Kilis (60 km within Syria) at an estimated cost of $80 million
- Kilis-Gaziantep (within Turkey) at an estimated cost of $67 million (based on 45 km of 36-inch pipe at US$1.5 million/km).

Construction of the first segment is not likely before Egypt provides a firm commitment to supply gas. Homs and Aleppo already are indirectly linked. However, bottlenecks in the Syrian system would prevent significant traffic from the south of the country to the north. This project will address these bottlenecks.

Preparation and implementation of the second and third segments are at advanced stages. Indeed, the second segment is already tendered and being constructed with an estimated cost of US$80 million. The third segment would tie the AGP to the Turkish gas network. Preparation and implementation arrangements are proceeding for a 10 inches pipeline with a capacity of 3-4 bcma.

The project addresses Syria's gas shortages by enabling it to import from Iran through Turkey. In the longer term, it would provide a route for gas from Egypt and Iraq to Europe. An MOU between Syria and Iran provides for sales of up to 3 bcma. This amount may be increased. Failure to meet gas demand shortfalls will exacerbate existing electricity shortages. The project also provides an opportunity for Lebanon and possibly Jordan to purchase gas from other sources. In the longer term, the project provides an export route for Syria if future exploration identifies significant gas reserves. At 40 inches, the Iran-Turkey pipeline should be sufficient to allow enough gas to be delivered from Iran to Turkey, although the transit route across Turkey would be complex. Furthermore, the project provides an export route for significant quantities (10 bcma, up to 15 bcma with compression) from Egypt/Iraq to Turkey and Europe, with significant benefits for European energy security and gas supply diversity.

The project provides an uninterrupted north-south link within Syria, allowing for a more efficient network configuration and use. It completes the AGP and locks in many of the benefits of the entire pipeline: "*The costs of failing to invest are likely to be significantly greater than the investment cost.*"[44] The Euro-Arab Mashreq Gas Co-operation Centre's (EAMGCC) financial and economic analysis concludes that there is sufficient evidence that the project is justifiable

[44] EAMGCC Financial and Economic Analysis, 2008.

economically and viable financially.[45] In the wake of the global recession, construction costs are falling, which could further improve the economics. The Feasibility Study, environmental impact assessment (EIA), and tender documents are largely complete, drawn up by EAMGCC to international (EIB) standards. The project could proceed relatively quickly to implementation.

11.2.4 Construct Iraq-to-Syria Gas Pipeline

A number of alternatives are under consideration for exporting Iraqi gas to Turkey and perhaps onward to Europe. The export route would include construction of a new pipeline, either directly from Iraq to Turkey, or from Iraq to the AGP, terminating in either Syria or Jordan. The export routes to Turkey and Jordan are discussed below. This section focuses on options for exporting Iraqi gas to the AGP in Syria.

The primary alternatives for exporting Iraqi gas to Syria include both smaller scale and larger scale projects. The alternative ultimately chosen will be influenced by the amount of gas available for export from the Akass field in Iraq’s western desert. As noted earlier, Syria signed a MOU to purchase gas from Iraq, initially 1.5 bcma from the Akass field, with 1 bcma of this to be exported. The Akass gas field in Iraq is close to the border with Syria and approximately 50 km from the Syrian gas network, where Syria has spare processing capacity at the nearby Deir Ezzor and Omar plants. It is understood that Syria has let a contract to a Chinese company to build the necessary pipeline but that it will have a relatively small diameter of only 10 inches. If there are significant new discoveries at Akass, a new pipeline will be needed. Initial reports from Iraq indicated that Shell had been contracted to develop the Akass field but that it now will be included in the upcoming Iraq oil and gas exploration licensing round.

Syria is the only viable export route for gas from Akass. If exploration identifies significant reserves, the planned 10-inch pipeline would limit exports. Consequently, a second pipeline would be required to carry gas from Akass to the AGP in Syria. This smaller scale alternative is estimated to cost US$75million. The larger scale alternative would include construction of a gas pipeline from central Iraq to export gas from its northern and/or southern gas fields to the Syrian port of Banias via the AGP. The project would include approximately 800 km of pipeline at an estimated cost of US$1.2 billion and would take approximately 60 months to complete.

Project benefits include:

- It would enable regional and extra-regional gas trade.
- It would provide a gas export route for Iraq.
- It would channel gas to the AGP, strengthening its economics.
- It would provide a second option for Syria gas imports from Iraq (after Akass, in the larger scale alternative).
- It would provide potential to link up with Iran (the announced “Peace Pipeline”), providing additional supplies and sponsorship for the project.

[45] The purpose of the EAMGCC is “To contribute to the integration of the gas markets of Egypt, Jordan, Lebanon and Syria in view of creating a regional internal gas market to be integrated with the EU Internal Gas Market.” www.eamgcc.org

- It would provide an alternative source of supply for Lebanon.

Project constraints include that:

- Building an LNG terminal at Banias would be expensive and time consuming, although there may be potential for offshore gasification (possibly as an interim solution).
- Gas reserves in the unexplored areas in west Iraq need to be confirmed. Confirmation is dependent on the upcoming exploration license round in Iraq for which details have not yet been finalized.
- The pipeline route has yet to be determined. While the obvious route parallels the oil pipeline that is being restored, the governments also are considering alternatives, which could lead to further delays.
- There could be competition for gas supplies if the pipeline via Jordan or Turkey is built. However, the size of the Iraqi reserves and the long-term demand potential indicates sufficient justification for 2 of the 3 alternatives.

The project would allow Syria to import sufficient gas from Iraq to meet its long-term demand requirements. It also would provide an opportunity for Lebanon and Jordan to purchase gas from Iraq. The project provides Iraq access to gas export markets[46] and opens up the western desert areas for gas development.

11.2.5 Construct Iraq-to-Jordan Gas Pipeline

This project would include construction of a gas pipeline from central Iraq to export gas from its northern and/or southern gas fields to the AGP through Jordan via the Jordanian Risha gas field. The project would include construction of approximately 800 km of pipeline for US$1.2 billion, and take approximately 60 months to complete.

Project benefits include:

- It would enable regional and extra-regional gas trade.
- It would provide a southern gas export route for Iraq.
- It would channel gas to the AGP, strengthening its economics.
- It would provide a second option for Jordan to import gas (after Egypt).
- In the longer term, it would facilitate export of Iraqi gas to Egypt, and potentially, the West Bank & Gaza.
- It would provide a route to the AGP for gas from the Risha field.

Project constraints include:

- Gas reserves in the unexplored areas in the west of Iraq need to be confirmed. Confirmation will depend on the upcoming exploration license round in Iraq, for which details are not yet finalized.

[46] The Akass connection, which will be completed earlier, is only 10 inches in diameter so will have limited capacity.

- Possible competition for gas supplies and exports with the potential pipeline through Syria, and/or the potential pipeline through Turkey. On the other hand, the size of the Iraqi reserves and the long-term demand suggest that there could be sufficient justification for 2 of these 3 alternatives for exporting Iraqi gas; i.e., through Turkey, Jordan or Syria.

The project would enhance Jordan's energy security and ensure that sufficient gas is available to meet its growing demand. The recent positive results for gas exploration at Risha improve the economics of the project since Jordan will need a way to transport the gas to other parts of the country where it is needed.[47] The project would provide access to gas export markets for Iraq (if the Akass connection were completed, it would be only 10 inches diameter, so would have limited capacity) and open up the western desert areas for gas development.

The project further strengthens the economics of the AGP by linking to a second large supply source. Egypt no longer would be the sole supplier of gas to the AGP, reducing the pressure on it to exploit its resources in the face of public opposition. In the longer term, the project offers Egypt a source of supply once its own reserves are used up.

11.2.6 Construct Iraq-to-Turkey Gas Pipeline

As noted, there are two distinct—and not mutually exclusive—alternatives for exporting gas from Iraq to Turkey and Europe. The first option focuses on delivering gas from Iraq's Kurdistan region to Turkey where investments are underway to develop the gas fields in Kurdistan for domestic use. Already discussed, the second option for exporting Iraqi gas to Turkey is based on the gas resources of Iraq's northern and/or southern fields, and possibly its Akass field in the western desert via the AGP through Syria or Jordan. The latter alternative is addressed above.

Project benefits include:

- It would provide an additional northern gas export route for Iraq to Turkey and on to Europe.
- It would provide an additional options *(other than Egypt) for Syria, Jordan and Lebanon to import gas via Turkey; i.e., Iran (assuming the AGP is completed).
- In the longer term, it would facilitate export of Iraqi gas to Egypt (assuming the AGP is completed.
- This project would be consistent with the quadripartite agreement among Iraq, Syria, Turkey, and Iran.

Project constraints include:

- It would enable regional gas trade only if the AGP were completed.
- It likely would weaken the economics of the AGP.
- It could compete for gas supplies and exports with the proposed pipeline through Syria.
- Without contracts, demand for the pipeline will be uncertain.

[47] Risha is distant from population centers.

- Transit tariffs in Turkey are undecided and politically sensitive, linked to EU accession.
- The project may risk getting caught up in the ongoing Turkey-EU dispute over gas transit and EU membership.

11.2.7 Construct New Electric Generating Capacity in Syria or Jordan

The Mashreq region as a whole has an electricity capacity deficit. In other words, generation capacity falls short of electricity demand plus a reserve margin necessary to ensure adequate reliability of supply, generally 10 percent–15 percent. Therefore, any new generation project would provide economic benefits to the region in reductions of lost load. Generation that is added based on least-cost principles would be more efficient. Using least-cost principles also would reduce the overall cost of power, through both improved efficiency and displacement of higher-cost with lower-cost fuel. Generation expansion plans at the national level that are consistent with least-cost principles should be supported. However, generation expansion at the regional level consistent with least-cost principles would achieve greater benefits provided the countries could agree in principle on how to share the benefits. A generation project sized to meet regional market needs and fueled with local natural gas from an as-yet undeveloped gas field should receive significant interest from the region's Governments.

Iraq has a significant supply gap in electricity generation capacity and meets only approximately half of current demand. The Ministry of Electricity's Master Plan indicates that substantial investment in generation and transmission capacity is needed through 2015 to raise capacity to the levels necessary to meet projected demand. Financial constraints mean that private investors will be needed to fill much of the gap. Iraq has had significant difficulty in building much needed generation capacity, and its costs are very high owing to conflict, limited private sector involvement, lack of economies of scale, and other factors. Lebanon and the West Bank & Gaza have similar problems, although not on the same scale. Current cost estimates for gas-fired plants in Iraq are approximately US$1300/kW. Plants in Turkey, Jordan, or Syria are likely to cost significantly less, closer to US$800/kW for a 500 MW combined-cycle gas plant. Investors would be less concerned about building a power plant in Jordan or Syria. Jordan has experience with IPPs.

This project would explore the potential for private sector-funded-power plants in Syria and Jordan for export of electricity to Iraq and possibly Lebanon and the West Bank & Gaza. Construction of new generation capacity in Syria or Jordan would benefit the host country, Iraq, Lebanon and the West Bank & Gaza. Locating such plants near gas pipelines would improve the economics and reduce risks by guaranteeing a supply of primary fuel. These investments would be linked to proposed electrical interconnections and pipeline projects. The first phase could cost $400 million for a 500 MW gas-fired plant. A regional generation project would significantly improve energy integration, particularly if tied to gas exports from Iraq.

11.2.8 De-bottleneck Gas and Electricity Supply Systems in Egypt

The Egyptian gas supply system has been expanded rapidly. However, there is a need to de-bottleneck certain segments of Egyptian gas pipeline system in order to increase gas exports from Egypt. The resultant project should be supported as a regional integration project while will also serve the domestic needs. Similarly, there may be some potential interest from private sector to build power plants that could target partly domestic supply and partly export to other countries. This could be particularly relevant to the IPPs which are being considered to supply power to the large industries. The Government of Egypt has made it a requirement for the large industries to secure their energy needs through private sector ventures that do not burden the public sector investments. The private builders of power plants (potential IPPs) may not be able to secure immediate stable load domestically. The ability to supplement the load with exports to other countries (Jordan or Saudi Arabia) could turn into a win-win arrangement for all the the stakeholders. It would be useful to explore these potential prospects in the form of developing private-public ventures that would also serve cross-border energy trade.

11.2.9 Construct new interconnection from Jordan to West Bank:

A feasibility study on a new Jordan – West Bank interconnection recommends further cooperation with Jordan, with the first step including construction of a new 2 x 400 kV interconnection developed in conjunction with a 132 kV transmission system in the West Bank. The favored interconnection alternative would originate at the Samra Thermal Power Plant north of Amman in Jordan, and connect to a new 400 kV substation in the Jerusalem area in the West Bank. The length of the interconnection is estimated to be 101 km with a cost of US$ 99.2 million (in 2008 Dollars). This estimate includes the cost of the interconnection and substation investments in both Jordan and the West Bank.

11.2.10 Establish Regional Coordination Center for Electricity

A study undertaken by SwedPower shows that the benefits of a Regional Coordination Center exceed the costs. The benefits remain even under very conservative estimates of the benefits that are expected to increase as the power system expands to meet increased demand. The system has continued to expand since 2003, when the study was completed. The SwedPower study calculated costs and benefits (table 11.1).

Table 11. 1: Costs and Benefits of Regional Coordination Control Center ***(US$ mil)***

Costs	
Investment	1622
Annual operation	57
Benefits	
Avoided investment	105
Annual savings	7

Benefits result from a reduction in the cost of investments for generation expansion (planning on a regional rather than national level) and from reductions in investment in settlement systems (one central settlement system rather than separate settlement systems for each national system). Annual savings benefits result from energy trading and network security; that is, reduced interruptions and loss of load.

The favored Regional Coordination Center alternative would have the following features:

- Single Coordination Control Center for the region responsible for both technical and trade related functions[48]
- SCADA/EMS application for technical functions
- Office applications for trade-related functions combined with dedicated application for metering collection
- Single central settlement function
- Establishment of an effective communication system to exchange information between the national control centers and the regional Coordination Control Center
- An independent organization with initial staffing from all participating countries.

Additional benefits of a Regional Coordination Center include optimization of the use of the regional power grid, resulting in improved system security and increased cooperation of the participating countries. These benefits are important for harmonizing the rules governing the design and use of the power grid. Additional gains would accrue from the exchange of data, information, and experience.

The SwedPower feasibility study points out that there are no significant technical or economic risks involved with the project. The main concern is institutional: can the countries agree to international trade and central control of such trades through the Regional Coordination Center?

The next steps in the Regional Coordination Center project would be to undertake a TA project to (a) determine the interest of the participating countries in the development of a Regional Coordination Center; and (b) if interested, develop the legal and governance documentation, including the roles and responsibilities of the regional system operator and its interaction with the national control centers.

11.3. The Impact of Renewable Energy Development on the Regional Integration Agenda

Regional integration efforts are becoming somewhat intertwined with the development of renewable energy (RE). The impact is four folds. First, most RE sites (wind farms and solar fields) are far from the power grids and would require dedicated transmission lines to evacuate power to the grid; this affects the overall transmission capacity and the possibility of electricity trade. Second, RE power supply is expected to grow substantially and provide a source of electricity export. For example, Egypt alone is planning to add more than 7000 MW of wind energy over the next 10 years. Third, regional integration of power networks results in larger and more diversified power generation capacity than in isolated national markets, and thereby provides a better opportunity for the development of RE and possibly stronger commercial incentives for the development of a local industry in the manufacturing of the RE equipment. Fourth, there is a substantial international financial support for RE development which could be tapped into by the public and private entities in order to expand RE generating capacity while strengthening cross-border interconnections that offer synergy between RE and regional integration.

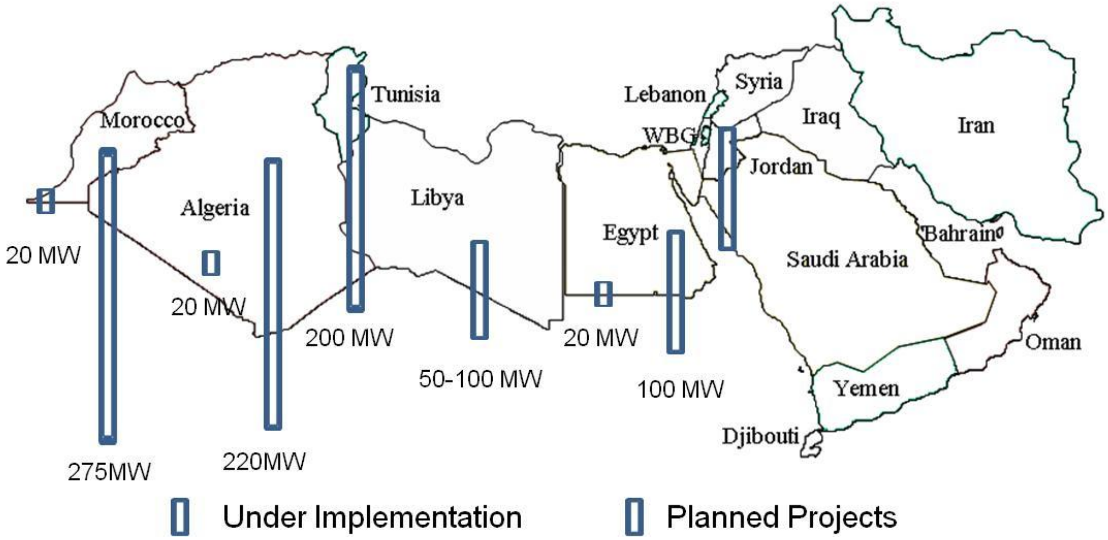
[48] The SwedPower study involved the EIJLST (Egypt-Iraq-Jordan-Lebanon-Syria-Turkey) and LTAM (Libya-Tunisia-Algeria-Morocco) countries.

The impact of RE on the regional integration agenda has been explicitly addressed in various solar initiatives. In particular, the Middle East and North Africa (MENA) Concentrated Solar Power (CSP) Initiative has received a lot of support from the international community. It follows the recommendation of the International Energy Agency that identifies CSP as a key technology that would drive the forthcoming energy revolution aimed at reducing greenhouse gas emissions. It is at the same time recognized that CSP has higher costs and risks than current technologies, and that these costs and risks can only be reduced by a large scale deployment of the technology. The MENA Solar Initiative is formulated to promote the application of CSP in the MENA region which receives some of the most intensive solar radiation in the world and has some of the best markets for solar energy within the region. The Initiative has received approval from the Clean Technology Fund (CTF) for $750 million concessional financing in support of a proposed investment plan with a total cost of $6 billion. The investment plan is aimed at:

- Supporting the deployment of about 1 Gigawatt of generation capacity (about 15% of the projected pipeline globally) in five CTF-eligible countries that have demonstrated strong commitment to participate: Algeria, Egypt, Jordan, Morocco and Tunisia.
- Supporting associated transmission infrastructure for domestic supply and exports, as part of Mediterranean grid enhancement.
- Leveraging over US$ 3 billion in public and private investments for CSP power plants alone (thereby tripling current global investments in CSP),
- Helping MENA countries contribute the benefit of their unique geography to global climate change mitigation, and
- Helping MENA countries achieve their development goals of energy security, industrial growth and diversification, and regional integration.

A Gigawatt-scale regional CSP deployment program has the potential to trigger significant cost reductions by virtue of volume of production, increased plant size, and technological advance. A deployment program of 10-12 utility-scale CSP plants in a number of countries would send a strong signal to the market that would enable the industry to plan manufacturing capacity expansions, which is central to driving down the costs of solar thermal technology and production processes. Moreover, the program utilizes the best solar resources in the world to help bring down cost of production. Deployment of this program would also provide the critical mass of investments necessary to attract private sector interest.

Presently, three countries – Morocco, Algeria and Egypt have each a 20 MW CSP plant under construction, and the UAE is implementing a 100 MW CSP plant in Abu Dhabi. However, these, as well as some other countries in the region have much larger CSP projects under preparation (Chart below).



In the course of the past few years, several MENA countries have set specific targets for RE's share of national power generation. These targets range between 6 to 20% by 2020. Most notably, The Government of Egypt has committed to increasing the share of renewable energy to 20% by year 2020 as a means of meeting growing electricity demand and achieving the economic objective of utilizing natural gas for higher value purposes. A 2500 MW wind scale-up program is under implementation which is envisaged to be expanded even further to more than 7000 MW. The country's generation expansion plan also includes 100 MW of CSP capacities to be implemented by 2017. The Government of Egypt is a champion of RE in the Mashreq and more broadly the MENA region and has taken significant leadership in this regard through the creation of a regional Renewable Energy and Energy Efficiency Center, supported by the European Commission, GTZ and Danida, and is co-President of the Mediterranean Solar Plan.

Jordan has also a keen interest to develop RE generation capacity considering the fact that it is almost entirely dependent on fuel imports for its energy requirements. The new energy strategy, which was adopted in 2007, emphasizes RE and sets a target of 10% by 2020. Jordan is taking some concrete steps to develop its RE resources, including installation of wind, solar, and landfill gas plants. With respect to CSP, the first pilot facility and training center is being proposed under grant support from the European Commission. The first commercial scale CSP project is being proposed in the range of 100 MW, as a private sector project in the Maan province in Southern Jordan.

Syria is embarking on implementation of an ambitious wind power program that aims for development of up to 2500 MW of wind power plants by 2030. This policy is based on wind measurements obtained from the 17 sites identified for potential development of wind farms. Syria is also keen to develop solar power projects based on CSP and PV technologies. The West Bank & Gaza are likewise showing an interest in CSP and wind power.

Finally, it is worth noting that the regional CSP scale-up program will be further strengthened by some relevant developments in the European Union. In 2008, the EU adopted a landmark piece of legislation that will drive the expansion of RE in its member countries and the neighboring regions. Each of the 27 EU member states will be obliged to increase its share of energy from RE sources in gross final consumption of energy from 8.5% in 2008 to 20% by 2020. The legislation provides the flexibility that the EU member states can import electricity from non-EU member countries and count it towards the RE target if two criteria are fulfilled:

- Renewable capacity in the corresponding non-EU country is installed or added after June 25, 2009.
- The amount of renewable electricity produced and exported has not received support from the host country other than investment aid granted to the installation.

If the above conditions are fulfilled, the EU Member States may decide to support imported electricity from non-EU countries within their national support schemes in effect making their subsidized tariffs available to non-EU countries. Projects under the MENA CSP program could be eligible for such sale of electricity to Europe.

Financial support for the development of RE generating capacity is essential in order to make RE commercially competitive with the conventional sources of power generation. The cost of RE electricity generation is higher than that of conventional power due RE's high upfront capital cost and its low capacity factor. In the case of wind power both of these factors have improved substantially in the last two decades though still the average cost of delivered electricity is somewhat above a conventional plant such as natural gas fired combined cycle power generation (Table 11.2). The CSP technology, on the other hand, is still at an early stage of the cost cycle and will not be competitive with a conventional plant without a significant reduction in its capital costs. For example, a CSP plant with US$4,000/kW capital cost operating at 20% capacity factor (most likely parameters in MENA countries) would be 3.7 time as expensive as combined cycle gas turbine technology (CCGT). Under a more optimistic scenario, a CSP plant with US$2,696/kW (the cheapest model currently available) at 30% capacity factor (which could be possible in MENA), would be 66% more expensive than the CCGT power plant. The comparison becomes more favorable to CSP if one adds the environmental benefits of CSP, such as climate change mitigation and reduction of local air pollution. For example, 1 MWh of electricity produced from CSP would reduce CO_2 emissions in MENA countries by 0.51 tons to 0.83 tons. This implies that even if the CO_2 mitigation is sold at US10/tCO_2, the economic costs of CSP would be reduced from 13.2 to 8.2 cents/kWh.

Table 11. 2: ***Levelized Cost of Electricity Generation from Renewable Energy Resources***

	Solar CSP (4000 US$/kW, 20% CF)	Solar CSP (2696 US$/kW, 30%, CF)	Wind	Gas CCGT	Simple Cycle GT[a]
Plant Economic Life (yr.)	25	25	25	25	25
Discount rate	10%	10%	10%	10%	10%
Capacity Factor	20.0%	30.0%	27.0%	90.0%	90.0%
Capital Costs US$/kW	4,000	2,696	1,931	813	735
Variable O&M ($/MWh)	-	-	-	2.40	3.36
Fixed O&M ($/kW-yr.)	74.38	50.13	28.8	11.15	11.52
Nominal heat rate (GJ/MWh)	-	-	-	6,917	10,807
Fuel Price (US$/MMBTU)	-	-	-	7.75	7.75
Economic Costs (US cents/ kWh)	29.4	13.2	10.2	8.0	11.6

Source: World Bank, Middle East and North Africa, CSP Investment Plan, November 2009.

Exports of renewable electricity to Europe from MENA countries in general and Mashreq countries in particular, will require capacity reinforcement of major transmission corridors within Mashreq countries (e.g. Egypt-Jordan-Syria transmission corridor) as well as expansion of the transmission interconnection between Syria and Turkey leading in the long term to the synchronization of the Mashreq transmission grid with the larger Turkey and EU transmission grids. Scenarios for transmission integration and options for transmission interconnections have been evaluated by interested governments and regional forums, some of which are about to progress to the implementation stage. The regional power transmission projects indentified in this chapter will facilitate connecting to the grid larger scale renewable power plants and increase potential for renewable electricity exports as well.

Chapter 12. **CONCLUSIONS**

The country analyses contained in this study show significant benefits for integration of electricity and gas networks of Mashreq countries. These countries are facing a rather unprecedented situation where they are all potential buyers of electricity due to the rapid growth in electricity demand and tight reserve margins. Thus the demand-supply picture indicates significant opportunities for electricity and gas trade. Aside from the trade opportunities, electricity interconnections impart other benefits such as peak sharing, improved system reliability, reduced reserve margin, reactive power support, etc. However, despite their substantial benefits, cross-border projects face significant economic and institutional constraints. The main recommendation of this study is that the governments of Mashreq countries should attempt to alleviate these constraints improving economic incentives and reducing institutional risks.

12.1. Electricity and Gas Price

Mashreq countries have energy prices that are far below the economic cost of supply. As discussed in the country chapters (chapters 2–7), with the exception of Jordan, none of the Mashreq countries has truly “independent and informed” regulation.[49] With the exception of Jordan and the West Bank & Gaza, tariffs do not reflect the economic cost of supply, requiring Governments to convey substantial subsidies to the domestic energy sector and cross-subsidization between and within customer classes that goes well beyond assistance to the socially disadvantaged. In some cases, segments of the population are unable to pay prices that reflect the economic cost of supply, but the difficult challenge facing Governments is that the long history of subsidization and cross-subsidization in fuels and electricity prices has resulted in the population’s unwillingness to pay for energy. It is proving to be a difficult task to eliminate the complex system of subsidies that have developed over the years. As noted, Jordan is the exception in that its regulatory authority is able to act in an independent and informed manner, establishing tariffs that reflect the cost of supply. Not surprisingly, Jordan’s privatization and IPP programs have enjoyed a high level of success.

The countries that are energy deficient are under pressure to reduce subsidization, which is taking a significant toll on their treasuries. Even countries that are relatively rich in energy resources, such as Egypt, Syria and Iraq, will not be able to sustain subsidies indefinitely, particularly under the very high levels of growth in energy consumption forecast in the immediate and longer terms. Subsidies lead to numerous problems, three of which are:

- Utilities do not have the funds necessary to maintain, let alone expand, the system to meet increasing demands and replace retired plant, decreasing reliability.
- The signals for investment are distorted, leading to less than optimal investment decisions and higher energy costs.
- Subsidies distort consumption decisions, resulting in an inefficient allocation of resources. Generally, subsidized prices lead to increased consumption. They also provide incentives for consumers to use the subsidized energy form rather than alternative energy forms that may be more economical in certain applications.

[49] “Independent and informed” regulation means that an entity exists with extensive expertise and background in the energy sector and that is able to make decisions and establish tariffs free of political interference and that are in the best interests of the energy sector as a whole including suppliers and consumers.

The use of subsidies distorts investment, production, and consumption decisions, leading to significant costs, which are largely hidden. The costs of energy production and delivery are incurred whether or not they are reflected in tariffs. By the Government's not reflecting economic costs in tariffs, consumers are making unwise consumption decisions that result in even higher costs of energy supply and delivery and additional reductions in the reliability and quality of supply.

Electricity tariffs for residential and industrial customers in the Mashreq countries are shown in table 12.1. The tariffs shown include taxes. The average tariff for the residential class is based on a monthly consumption of 500 kWh. The tariff for industrial customers is for high voltage supply. The Iraq figures are based on tariffs for Kurdistan. The average is a simple average of the residential and industrial tariffs.

The cross-subsidization in the tariff systems is evidenced by the fact that, in all cases but Jordan and the West Bank & Gaza, the industrial tariff is equal to or greater than the residential tariff. Tariffs for residential customers should be higher than tariffs for industrial customers because it costs more to supply them.

Table 12. 1: Mashreq Electricity Tariff Comparison ***(US cents/kWh)***

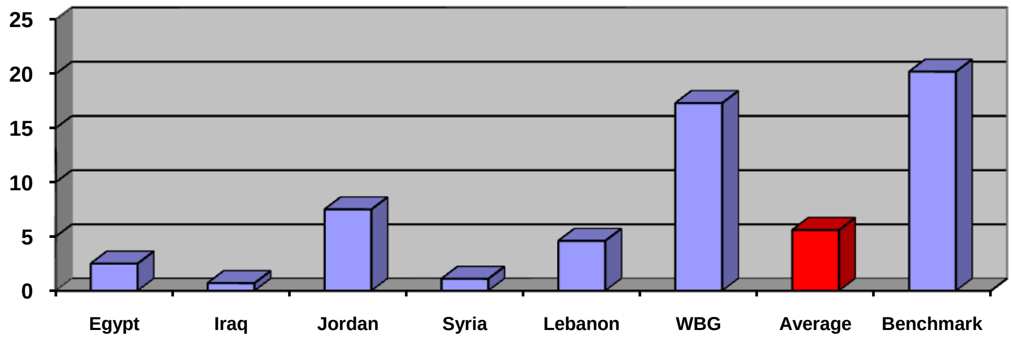
Country	Residential	Industrial	Average *
Egypt	2.5	2.5	2.5
Iraq	0.7	1.6	1.2
Jordan	7.5	6.7	7.1
Syria	1.1	8.9	5.0
Lebanon	4.6	7.6	6.1
WBG	17.3	10.8	14.1
Average	5.6	6.4	6.0

Note: * = simple average of the residential and industrial tariffs.

In many of these countries, it can be difficult to determine the actual cost of electricity supply because the subsidies provided by their Governments to the energy sector are largely hidden. However, a good proxy of the level of subsidization comes from comparing tariffs to a benchmark based on the average of the tariffs of countries whose tariffs reflect the full economic cost of supply. A report by the World Bank[50] compares the tariffs of countries in the Middle East and Africa to a benchmark based on an average of the tariffs of France, Greece, Italy, Portugal, Spain, and Turkey. This benchmark provides a reasonable approximation of the opportunity cost of electricity. The Mashreq country tariffs for a residential customer consuming 500 kWh/month are compared to this benchmark tariff in figure 12.1 As can be seen, the Mashreq country residential tariffs are far below the benchmark tariff. The average of the Mashreq country tariffs is only 28 percent of the benchmark.

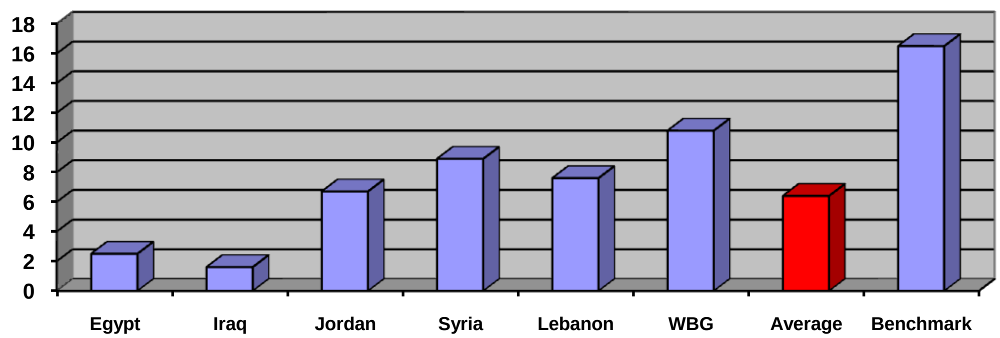
[50] See February 2009 World Bank report entitled *Tapping a Hidden Resource – Energy Efficiency in the Middle East and North Africa.*

Figure 12. 1: Comparison of Mashreq Residential Tariffs to Benchmark Tariff ***(US cents/kWh)***



The Mashreq industrial tariffs do not fair much better. Figure 12.2 shows Mashreq country industrial tariffs compared to the benchmark for the same countries. It assumes a 10 MW load at 80 percent load factor spread evenly throughout the month. As can be seen, all Mashreq country industrial tariffs are far below the benchmark tariff. The average of the Mashreq country tariffs is only 39 percent of the benchmark.

Figure 12. 2: Comparison of Mashreq Industrial Tariffs to Benchmark Tariff ***(US cents/kWh)***



The situation in the gas sector of the Mashreq countries is much the same. The Mashreq Gas Market Project[51] states that despite recent gas price increases to industrial customers, a value of US$1.25/MMBTU is a reasonable estimate of the current internal bulk price (IBP) for gas in Egypt. The current internal bulk price of gas in the various Mashreq countries provided in the Mashreq Gas Market Project is shown in Table 12.2. There is no price shown for Lebanon and the West Bank & Gaza since neither country has domestic gas consumption. The price for Iraq is based on a World Bank study completed for 2005. Note that the gas prices do not incorporate recent gas price changes in Syria.[52]

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[51] The Euro-Arab Mashreq Gas Market Project, Strategy and Policy Gas Master Plan funded by the EU,

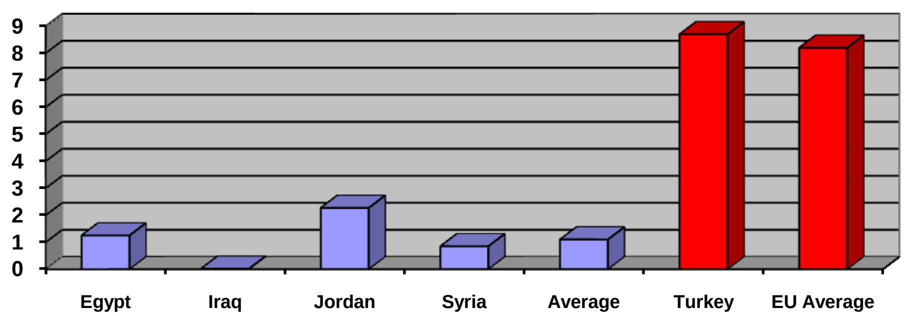
[52] The domestic gas price in Syria was about US$21/tcm but in 2007, but was adjusted to US$ 104/tcm in 2008 and to US$ 387/tcm for 2009. The 2008 gas price was previously below the European gas price, but the 2009 price is well above the European gas price and the regional gas import price of about US$ 260/tcm (including local pipeline transport cost).

Table 12. 2: Mashreq Internal Bulk Price of Gas ***(US$/MMBTU)***

Country	***Gas price***
Egypt	1.25
Iraq	0.02
Jordan	2.27
Syria	0.85
Average	1.10

Figure 12.3 compares the Mashreq country internal bulk prices of gas to gas prices for Turkey with the average border price for gas imports to the EU from Russia. The prices for Turkey and the EU average represent benchmark prices for the region. As can be seen, the Mashreq country internal gas prices all fall well below the benchmarks. The average Mashreq price is only 13 percent of the benchmarks, and the highest Mashreq domestic gas price in Jordan is approximately only 27 percent of the benchmarks.

Figure 12. 3: Comparison of Mashreq Internal Bulk Price of Gas to Benchmark ***(US$/MMBTU)***



12.2. Pricing Gas Exports

A critical barrier to regional integration is the unavailability of gas or electricity to sell. This shortage is due in part to the lack of economic/financial incentive to develop export capacity. Gas and electricity trades impart significant benefit to the importing countries. For example for most countries in the region the import of gas yields a benefit of more than US$ 11/MMBTU, but their expectation is to pay a substantially lower amount for the imported gas. Traditionally, electricity and gas trade have been viewed as means of utilizing idle capacity or an idle resource. However, the nature of the business has changed. Sellers must develop additional capacity for export so will not undertake the required investments unless they are confident of attractive returns on their investments.

The Mashreq countries have been planning and operating under the assumption that natural gas is abundant and cheap. Cheap gas is no longer the case, so they are now forced to shift to a business environment in which gas has become the fuel of choice, with scarce availability and a high premium. There is a necessity for the Government to set up stronger economic incentives if suppliers of gas and electricity are to invest in capacity expansion aimed at the export market. Stronger incentives, in turn, would require the energy-consuming public in the Mashreq countries to accept higher prices of gas and electricity, and the importing country governments to agree to higher prices than previously anticipated.

An additional complication and deterrent to gas trade in the Mashreq region relates to the lack of transparency in gas supply and transmission pricing. Confidentiality often is used to justify data and information limitations. Efficient market development requires transparency so that informed decisions can be made about production, investment, and consumption, particularly as they relate to transmission in the AGP. The lack of transparency hinders the development of accurate pricing upon which gas export prices can be negotiated. There is not yet a generally accepted international price for natural gas, so cross-border transactions are based on negotiated prices. In the absence of pricing transparency, it is challenging for two countries to come to terms on what constitutes a "fair price."

There often is a wide range for price negotiation—from the seller's cost of supply, typically ranging from US$1–3/MMBTU—to the buyer's benefit from using gas, potentially exceeding US$11/MMBTU. This wide range creates a problem of differing expectations between sellers and buyers. Even though the LNG market accounts for only a small portion of the world's natural gas demand (approximately 7.5 percent in 2008), the LNG market has helped to narrow the range of price negotiation. LNG is linking the gas prices in the markets of Asia, Europe, and the US to the expectation of gas prices in the local markets around the world. Since any significant gas exporter has the option of selling its gas in the form of LNG, it expects at least the same net yield from selling piped gas.

It is not the intention of this study to play a role in gas negotiations. However, to assist the Mashreq countries negotiate more effective cross-border energy prices, a framework for such negotiations highlighting gas pricing principles follows.

Framework for Negotiating Effective Cross-Border Energy Prices

The price of gas should be based on its economic cost,[53] which includes two components: (a) the long-run marginal cost of gas supply and (b) a depletion premium. The cost of gas supply can be assessed at several delivery points. The first is the *wellhead*, which includes the cost of investment and operating expenses related to exploration and field development. By adding transmission expenses, the cost is determined at the *city gate*. By adding distribution expenses, the cost is determined at the *burner tip*. Gas production and transmission require large front-end investments whose costs can be recovered only over time as sales and capacity utilization increase. As a result, the long-run average incremental cost of gas production and transmission often is used to approximate long-run marginal cost. Calculation of long-run average incremental cost is based on the stream of costs and benefits over a long period, such as 2010–30. Costs include exploration and development and operations and maintenance (O&M). The discounted value of the costs divided by the discounted value of the incremental gas output is the long-run

[53] For a complete description of the pricing of gas in negotiations see *Natural Gas Pricing in Countries of the Middle East and North Africa* by Hossein Razavi, The Energy Journal, IAEE, Volume 30, Number 3, 2009.

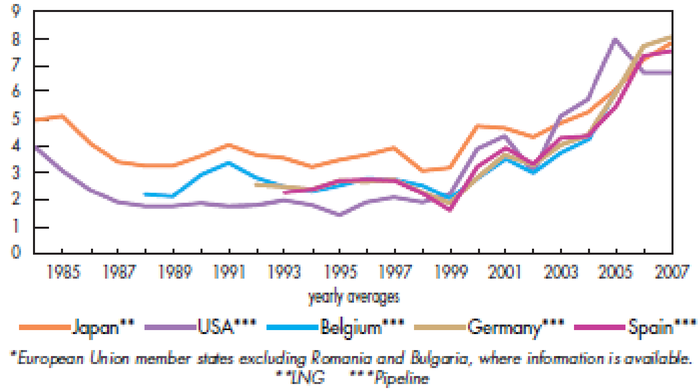
average incremental cost of gas at the wellhead. The same methodology yields the long-run average incremental cost of transmission and distribution.

The depletion premium is determined by a country's gas reserves. It represents the opportunity cost of consuming a unit of an exhaustible resource now rather than in the future. This calculation is somewhat arbitrary because assumptions must be made relating to the price of the alternative fuel and the time over which the exhaustible resource will be utilized. The depletion premium is based on the cost of the substitute fuel at the time that the depletion constraint becomes binding and users would need to switch to the alternative fuel. Countries that have large gas reserves expected to support forecast production for 40–50 years or more have a negligible depletion premium because the present value becomes insignificant. In their case, the economic cost of gas becomes the long-run average incremental cost of gas supply. Countries that have constrained reserves have a large depletion premium approaching the price of the alternative fuel, that is, the cost to convert a power plant and produce electricity from oil.

In addition to the concepts of long-run marginal cost and depletion premium, negotiations often take into account the "market," or "netback," value, which refers to the economic benefit of using gas for various purposes, that is, power production. In a free market environment, the economic benefit of gas, or its "market value," is based on the economic cost of the replaced fuel with adjustments to take account of differences in capital costs, operating costs, thermal efficiency, and the cost of fuel processing and delivery. However, in countries in which the Government sets prices of gas and alternative fuels, "netback" value often is used as a substitute for "market" value. Netback value can be used to estimate the net gain from (a) gas exports, (b) using gas as a feedstock for fertilizer and petrochemicals, or (c) using gas for gas-to-liquid conversion processes to identify the most economically attractive purposes for gas allocation. The netback value can represent an opportunity cost benchmark for internal gas use. It is obtained by deducting the cost of delivering the gas to the consumer from the market value. The netback value of gas use in the power sector often is used as the benchmark for gas pricing and for decisions relating to gas allocation. Power generation in the Mashreq countries primarily consists of oil- and gas-fired plants, supported by some renewable generation, mostly hydro. In the short to medium term, generating stations usually can be converted from oil to gas, or vice versa. In the longer term, new plants can be constructed to burn either oil or gas, so netback values are calculated assuming an oil plant as the alternative to gas-fired generation.

In the future, the growth of the LNG market could become an accepted international reference price benchmark, and to some extent already has. Many countries now use LNG prices in negotiations for gas export contracts. The 2008 piped gas prices in Europe closely tracked the 2007 Japanese LNG prices (IEA Statistics 2008) (Figure 12.4).

Figure 12. 4: Natural Gas Import Prices ***(US$/MMBTU)***



The main benchmarks that need to be considered in discussions of gas prices are shown in table 12.3. The estimated values are representative of the value of gas based on the different pricing approaches. The values are sensitive to the assumptions that go into the calculations, particularly those relating to the cost to develop yet-to-be-found reserves, discount rate, demand forecast, capital costs, and forecast oil prices. Pricing is influenced by recent events, such as the volatility in the capital and commodities markets over the past two years. Therefore, while the different pricing approaches should be given full consideration in gas price negotiations, care must be exercised in using the actual figures. The framework in table 12.3 is based on Egyptian gas information and follows the Egyptian decision chain to determine the:

- Amount of gas to be produced at each given time
- Amount to be allocated for domestic use
- Amount to be allocated to exports in the form of LNG
- Amount to be allocated to exports in the form of piped gas to Mashreq countries.

Table 12. 3: Estimated Price for Egyptian Gas ***(US $/MMBTU in 2009 Prices)***

Estimated price	**Explanation**
Benchmarked on Egypt's cost of gas supply	
LRMC = $1.50 to $2.60 Depletion premium = $1.40 to $3.60 Economic cost = $2.90 to $6.20	Cost of gas development and production in Egypt's new gas fields is expected to be much higher than in past.[1] Based on projected gas production profile and current reserves, Egypt would need to switch to alternative fuels as gas supply becomes a constraint, resulting in depletion premium of $1.4 in 2010, increasing to $3.6 by 2020.
Benchmarked on Egypt's opportunity cost	
Benefit from domestic use: Avoided cost in power = $7.50 to $12.50 Avoided cost in residential and commercial sectors = $11.0	Power sector serves as first vehicle for shifting in and out of gas consumption. Avoided cost (or netback value) in power constitutes important measure of gas use in domestic market estimated based on a steam plant fired with heavy fuel oil compared with gas use in a steam plant (lower netback), or a combined cycle plant (higher netback). Avoided cost in residential/commercial sector is based on alternative of using diesel oil and LPG.
Benefit from LNG export: Henry Hub gas price = $6.5 (-) Regasification cost = $0.35 (-) Shipping cost = $1.0 (-) Liquefaction cost = $1.1 (-) Pipeline cost = $0.25 (-) $3.8	LNG prices normally are linked to basket of energy products but increasingly are correlated with US gas prices. Benchmark Henry Hub price is a long-term projection provided by US EIA. Average levelized cost of regasifying LNG at receiving terminal. Average shipping cost of LNG to US Henry Hub market. Average levelized cost of liquefaction based on data for LNG plants built in Egypt. Average levelized cost of pipeline transportation of gas to LNG plant.
Benchmarked on the benefit of gas use in receiving countries	
Netback value (avoided cost) estimated for: Jordan = $8.00 Syria = $7.60 Lebanon = $8.20 to $10.00 Turkey = $8.00	Alternative plant built in absence of gas is steam-plant-fired with heavy fuel oil. Jordan, Lebanon, and Turkey import fuel oil. Syria uses mostly domestic oil. Netback values are reduced by cost of transmission to destination country.
Expected price for Egyptian gas	
At the Egyptian border: $4.0–$6.0 Transport to Jordan = $0.50 Transport to Syria = $0.65 Transport to Lebanon = $0.70	Estimating a fair price is not an exact science. However, Egypt should receive a price that would encourage gas exploration and development, and allocation of gas to pipeline exports rather than to LNG. Based on average levelized cost of transportation from Egypt to each destination country.

Note:
1 LRMC is estimated at $1.5 to $2.6. Financially, Egypt buys gas from producers at approximately $3.0 while receiving some of the gas in return according a production-sharing contract. The average cost is approximately $1.6.

Based on prices shown in table 12.3, domestic gas use imparts the highest economic benefit to Egypt at US$7.50 to $12.50/MMBTU even though the financial return may be low due to the prevailing energy price subsidies. The US$7.50/MMBTU benchmark price represents the value of gas when used in a steam plant and compared with the alternative of HFO-fired plant. The economic value of gas will be much higher at $12.50/MMBTU if the gas is used in a combined cycle power plant. The price of oil is based on World Bank forecasts of international oil prices. Domestic use imparts the greatest economic benefit, suggesting that Egypt should assign the highest priority to meeting the (present and future) gas requirements of its own economy.

Should there be additional gas to allocate to exports, Egypt is likely to give priority to LNG with a net benefit of US$3.80/MMBTU rather than piped gas to other Mashreq countries because of the lower commercial return on piped gas exports (based on historical experience). The essence here is that Jordan, Syria, and Lebanon[54] should provide a commercial incentive to encourage Egypt to supply the Mashreq market via the AGP prior to any additional allocation to LNG.. The benchmark benefit of gas in countries receiving (importing) Egyptian gas is calculated based on the long-run average incremental cost of a 500 MW oil plant in each country with the price of oil based on World Bank forecasts of international oil prices. The avoided cost figures are reduced to account for the cost of transmission to deliver the power from Egypt to the importing country.

In summary, while the relevant price levels are subject to research and negotiation, the emerging gas price is likely to be much than the underlying price of previous contracts among Egypt, Jordan, and Syria. Higher gas prices would provide a strong commercial incentive for gas exploration and the development of Egypt's large estimated yet-to-be-found reserves.

While Egypt has potential to expand its gas exports, any significant gas increase is likely to come from Iraq. Therefore, a gas price that would encourage development and export of Iraq's gas supply also should be assessed. Unfortunately, there is little reliable cost data for gas production in Iraq. Nevertheless, it is clear that gas development and transportation would be undertaken through private sector investment and management. Thus, access to gas exports from Iraq is likely to be on commercial terms. Since the Iraqi gas can be sold directly to Turkey, the price at the Turkish network represents a benchmark for Iraqi gas sales to Jordan and Syria

12.3. Pricing Electricity Exports

In a competitive electricity market such as that of the EU, market participants, including generators, customers, and traders/suppliers, are allowed to freely negotiate contracts whose supply terms, conditions, and prices are determined by the parties to the contract. Open and equal access to the transmission and distribution networks is ensured through commercial/market codes, grid codes, and metering codes. Opening up the electricity market to numerous buyers and sellers able to trade domestically and internationally creates competition, with its attendant incentives to improve efficiency. Furthermore, regulation is reduced and market liquidity (that is, transactions) is increased, as is price transparency. None of this now exists in Mashreq. Not surprisingly, the number of international transactions countries is minimal; subsidization and cross-subsidization in the tariff regime are significant; and price transparency is limited. In addition, the efficiency of the electricity sectors is suboptimal.

Although open access and competition do not exist in the Mashreq countries, there are some signs of movement in that direction. Furthermore, bordering on the Mashreq region, Turkey has

[54] Currently, the West Bank & Gaza does not have the pipeline infrastructure to enable gas imports.

taken significant strides in this direction. Turkey has unbundled its power sector into generation, transmission, and distribution functions. The Turkish Electricity Transmission Company (TEIAS) provides transmission and dispatch services, operates the balancing market, and act as the settlement agency. Turkey has also established the Electricity Market Regulatory Authority (EMRA) to act as the independent regulator over power, gas, petroleum, and LPG. In all, Turkey has 129 licensed market participants consisting of 103 private entities and more than 20 regional distribution companies.

Prices in Turkey's electricity market are allowed to move freely in step with the market and changing primary fuel prices. For example, the balancing market, which is used to settle differences between contracted amounts and actual deliveries and off-takes, reflects the marginal cost of electricity at the wholesale level. The average price at which power was sold in the balancing market in 2007 was approximately 11 US cents/kWh. By March 2008, the average price had risen approximately 25 percent to 13.7 US cents/kWh, reflecting the increasingly tight supply position.[55] From May 2007 to May 2008, prices were in the range of 4–7 US cents/kWh during the off-peak load period (1AM–7AM), and 11–14 cents/kWh during the remainder of the day, reflecting both high gas prices and the relative tight supply position.[56] The average base load price from August 2006 to April 2009 was Euro 73.88/MWh (approximately 10.8 US cents/kWh at an exchange rate of 1 US$= 0.6822 Euros). These wholesale prices are well above the average Mashreq retail tariff of 6.0 US cents/kWh.[57]

By any standard, competitive market conditions do not yet exist in the Mashreq countries. Consequently, cross-border electricity transactions have been limited, generally falling under two categories: short-term power exchanges and longer term power trades. Short-term power exchanges usually occur when there are surpluses and deficits owing to daily or seasonal load variation or significant equipment outages, and diversity in the marginal cost of supply among participating countries. These exchanges normally are small in volume. On the other hand, longer term power trades refer to significant volumes of energy transferred from one to another country on a regular and more sustained basis. The framework discussed here takes account of the short-term and long-term nature of electricity transactions. The economics of such transactions are summarized in table 12.4.

Short-term exchanges often are based on idle capacity and are feasible so long as the price covers variable costs including fuel and O&M. For example, there may be an economic basis for short-term exchanges of electricity between Egypt and Syria because their peak demand occurs at different times of the day. However, the exchange will be feasible only if there is a difference in marginal operating costs among the countries. The costs will not vary if both countries have oil-based generation with high production costs on the margin. The benefits of such exchanges must exceed the transaction costs, which are quite high in the Mashreq region owing to the limited number of market participants with access to the transmission systems. The lack of transparency

[55] World Bank, Implementation Completion Report on Turkish National Transmission Grid Project, June 2008.
[56] Electricity Export Opportunities from Georgia and Azerbaijan to Turkey. A Report Prepared by **A.S. Poyry**, Norway, for the Government of Georgia. www.minenergy.gov.ge
[57] Retail prices should be greater than wholesale prices owing to higher equipment costs and losses associated with distribution facilities.

and defined rules governing transmission costs also increases transaction costs and has a dampening effect on the number of transactions.

Longer-term trades generally occur when a country has a comparative advantage over another country, or has excess generating capacity forecast for an extended period of time. Currently, the more likely scenario is for Egypt to export electricity to other Mashreq countries and Turkey. Egypt has committed to an aggressive generation expansion program while the other Mashreq countries and Turkey have shortages. Furthermore, as discussed, Turkey is subject to significantly higher wholesale electricity prices at present and for the foreseeable future.

Indicative calculations of the cost of electricity generated in Egypt for short-term power exchanges during the peak period when it has an oil plant on the margin would be 10.0 US cents/kWh (based on World Bank forecasts of international oil prices) (table 10.9). This scenario is representative of the case today when Egypt's demand and supply are in balance. However, indicative calculations of the cost of electricity generated in Egypt for short-term power exchanges when it has a gas plant on the margin would be much lower at 4.1–6.1 US cents/kWh (based on an open-cycle plant fired with natural gas at prices ranging from US$4 to 6/MMBTU). There is much greater latitude for short-term power exchanges if Egypt has a gas plant on the margin.

In the future, indicative calculations of Egypt's cost of electricity for longer-term trades range from 3.9– 5.1 US cents/kWh. This cost assumes that Egypt would construct a new combined-cycle power plant fired with gas at prices ranging from US$4.00 –6.00/MMBTU to support the export. Short-term exchanges and longer-term trades of Egyptian electricity would make sense only if the importing countries were willing to pay prices in excess of these levels plus the cost of transmission, ranging from a low of 0.03 US cents/kWh to Jordan to a high of 0.36 US cents/kWh for Turkey. Another implication is that Egypt may want to weigh the potential returns from the export of electricity versus the export of gas. It appears that electricity export to a market such as Turkey, whose wholesale prices are quite high at close to 11 US cents/kWh average in recent years, may prove more profitable than gas exports to the same market. A detailed simulation and analysis of Turkey's electricity market would be necessary to confirm this.

Note that the terms of delivery would need to be clearly stated in the export contract, particularly with regard to the firmness, or reliability, of supply. Shorter term exchanges recover variable costs plus a profit only, so must not hold the exporting country, in this case Egypt, responsible if unable to make delivery. In this case, power is delivered only when available. Egypt would make a profit on each kWh delivered, so has the incentive to continue exports except when it has a power system emergency.

In the case of a longer-term trade similar to that discussed above, the importer is effectively buying a "piece" of the power plant. In other words, the importer receives delivery only when the particular combined-cycle power plant is available. For example, if Egypt agreed to sell 200 MW of a 500 MW combined-cycle power plant to Syria at a price determined in accordance with table 10.9, Syria would receive 200 MW as long as the combined-cycle plant is operating. The combined-cycle plant would be expected to be operating approximately 80 percent of the time. If

Egypt were to guarantee delivery consistent with the reliability of its own network, Syria would in effect be buying "system energy." It would be worth much more than the 3.9–5.1 US cents/kWh price shown in the table because Egypt would need to set aside an additional 30 MW of peaking capacity to supply the export (assuming a 15 percent reserve margin on a 200 MW export).

Table 12. 4: Expected Price for Egyptian Power ***(US cents/kWh in 2009 Prices)***

Expected price	Explanation
Short-term exchange-oil: Fuel cost: 9.3 Variable O&M cost: 0.7 Generation cost: 10.0	In Egypt's present configuration, peaking and some intermediate units run on HFO. Fuel cost is calculated as levelized value of HFO based on World Bank forecasts of international oil prices.
Short-term exchange-gas: Fuel cost: 3.9–5.9 Variable O&M cost: 0.2 Generation cost: 4.1–6.1	Egypt may have gas-fired open-cycle generation available for sale at certain times of the day and year. Fuel cost is calculated as levelized value of gas at US$4–6/MMBTU.
Long-term trade: Capital cost: 1.0 Fuel cost: 2.5–3.7 O&M cost: 0.4 Generation cost: 3.9–5.1	The long-term trade is based on a large volume electricity export over an extended period in which Egypt would invest in gas-based, combined-cycle generation. Fuel cost is based on a natural gas price of US$4–6 per MMBTU.
Market price in Turkey: Wholesale: 10.8	Average wholesale price in Turkey's balancing market from August 2006–April 2009 (73.88 Euros/MWh converted at exchange rate of US$1= 0.6822 Euros).
Transmission costs: To Jordan: 0.03 To WBG: 0.03 To Syria: 0.21 To Lebanon: 0.26 To Turkey: 0.36	

12.4. Institutional Constraints

Technology risks associated with the potential regional integration projects identified earlier are relatively minor. The generation, transmission, and pipeline technologies all are well developed, having been implemented in numerous countries around the world including the Mashreq countries. If tariffs reflected costs, the economic risks would be relatively minor as demand is increasing significantly in all Mashreq countries. Economic risks would be further reduced as a result of moving to a regional market. However, while increasing demand reduces market risk by increasing the probability of a buyer for generation and transmission services, it also elevates risks in the Mashreq countries in that it will place increasing pressure on the financial, economic and technical capacity of each country. Development of a regional market with regional coordination would reduce pressures in each of these areas because it would optimize generation, transmission, and pipeline planning and operations for a broader region as opposed to having a much smaller, national perspective.

Nevertheless, development of a regional market has its own set of problems. Similarly to the problems described above, regional problems relate to domestic tariffs and export prices. They also relate generally to the policy, legal, and regulatory framework necessary to make a regional market successful. A successful regional market is amenable to raising the necessary capital to reliably meet expanding energy demand. Regardless of the type of energy integration project, a legal, regulatory, and governance structure conducive to international trade must be in place. The participating countries must have the political will to relinquish a portion of their energy supply responsibilities for the greater good of the region.

There are numerous challenges to establishing competitive electricity trade among the Mashreq countries. The challenges to energy market reform include:

- Natural monopoly characteristics of electricity/gas transmission and distribution
- Lack of fungibility of energy commodity. A kWh has different values in different time periods. In other words, a kWh is worth more during peak periods of demand than during off-peak periods of demand
- State control of utilities
- Difficulty in imposing change on monopolistic electric utilities.

Considerable experience has been gained in recent years in addressing these challenges in both the European Union and elsewhere, including:

- Reforming the existing structure of vertical integration
- Defining the form and jurisdiction of regulation
- Establishing the contractual basis for transmission capacity
- Ensuring that traded markets have sufficient liquidity.

Changes to policy, legislation, and regulation normally are required to achieve truly competitive energy markets, as described below.

Removing Exclusive Rights to Supply

This change entails removing the exclusive right of a single supplier, often a state-owned entity, to supply all energy to the market by opening up the supply component to any entity with the technical expertise and financial resources necessary to produce natural gas or generate electricity. By opening up the supply component to multiple sellers, supply entities are forced to compete with one another for sales. Competition forces them to continue to maintain their facilities and improve efficiency. Otherwise, they will be unable to remain a going concern. Competition results in improved supply reliability and reduced costs for consumers.

Unbundling Supply and Transmission and Introducing Third-Party Access to the Transmission System

Fundamental to the success of a competitive energy market is open and equal access to the transport/transmission system. To ensure open and equal access, the transmission function (that is, operation and asset management) must be unbundled from the supply and distribution functions to guard against one entity having a technical advantage over another entity. The transmission network must be operated by an independent entity. In addition, all market participants including suppliers and buyers must be subject to the same terms, conditions, and prices for similar uses of the transmission system.

Establishing an Independent and Informed Regulatory Agency to Oversee the Market and Regulate the Monopoly Transmission and Distribution Services Including Tariffs

An independent regulatory agency is an entity that is able to make decisions that are in the best interests of the energy industry without fear of Government intervention. An informed regulatory agency is an entity that has the background and experience necessary to make decisions that are in the best interests of the industry, in contrast to a political appointee who lacks the necessary background in the industry. It is paramount that the regulatory agency has full authority to establish tariffs based on the cost to provide service. The Government is reduced to a legislative and policy role in the energy sector. The regulatory agency makes the decisions, consistent with the law and the Government's documented energy policy.

As proven in market reform efforts around the world, an independent and informed regulatory agency is fundamental to the successful operation of a competitive energy market. In fact, it is enshrined in the European Community Directives which are a requirement of any country wishing to join the European Union. It is not expected that a country will implement all such steps at once, but rather reform its energy sector over a transition period to allow time to address the various constraints peculiar to its particular energy sector. Turkey provides a good example. It has adopted the EU model, with independent regulation, unbundling, and private investment in generation and distribution; but it has taken many years to reach this stage. Furthermore, state ownership remains dominant in Turkey's power sector, and retail tariff increases are staged through long-term wholesale transitional, or vesting, contracts that will remain beyond 2010.

While the Mashreq countries are at different stages of market development, none of the countries meets the basic requirements for competition outlined above. None of the countries has third-party access or independent and informed regulation. Furthermore, as discussed, all Mashreq countries face an additional daunting challenge to address the unwillingness, and in many cases, the inability of large segments of the population to pay prices that reflect the cost to produce and deliver electricity.

In addition to these challenges, regional projects by their very nature are more complex than single-country projects. The number and scope of risks and the likelihood of their occurrence increase exponentially with the number of countries involved. Similarly, the cost of administering and implementing multi-country projects is significantly higher due to increased travel and communication requirements, greater complexity in getting the necessary permits (especially for infrastructure projects), and the need in some cases to negotiate international agreements as well as address country-specific issues. Moreover, regional projects are higher profile and more politically sensitive than single-country projects. Considerations of national pride and international relations become significantly more complex. Thus, not only are the risks of failure greater, so are the costs. Therefore, the economic justification for a regional project must be greater to counterbalance the increased cost, complexity, and risk.

12.5. Next Steps

Regional projects by their very nature are more complex than single country projects. The number and scope of risks increase exponentially with the number of countries involved. Similarly, the cost of administering and implementing multi-country projects is significantly higher due to greater complexity in getting the necessary permits and the need to negotiate international agreements as well as to address country-specific issues.

To move forward the preparation and implementation of gas and electricity integration in the Mashreq region one should pursue two parallel tracks. The first track relates to the harmonization of: (i) technical codes and standards for the national energy systems; (ii) regulation in the national energy sectors; (iii) goals and milestones for energy sector reform relating to, in particular, open access and consistent and fair pricing of transport; (iv) energy pricing and taxation; and (v) identifying an independent process and procedure for resolving disputes relating to regional energy transactions.

Most of these issues have been addressed by various initiatives including: Euro-Arab Mashreq Gas Market Project; Euro-Mediterranean Energy Market Integration Project; Mediterranean Working Group on Electricity and Natural Gas; Energy Efficiency in Construction; MENA Regulatory Forum; and Regional Center for Renewable Energy and Energy Efficiency. Substantial work is also being done by various regional forums such as:

- The Arab League;
- Arab Union of Electricity (AUE);
- The Arab Electricity Regulators’ Forum (AERF);
- The Energy Charter Treaty;
- Mediterranean Ring; and
- Mediterranean Solar Plan.

The second track relates to help in cross-border transactions. This is an area with significant gaps in terms of realistic information, preparatory steps and structuring such transactions. The World Bank and its partners can assist Mashreq countries in this particular area by:

- Playing the role of convener and facilitator by bringing together the stakeholders: governments, regional entities, private sector, financiers and donors, NGOs, etc.
- Proposing specific schemes to the relevant sub-sets of stakeholders;
- Supporting project implementation by providing finance from its own funds, and mobilizing resources from other donors and the private sector, and
- Coordinating project implementation, which is often the biggest challenge in regional integration projects.

The World Bank plans to continue its support in both the above tracks. In the area of harmonization, the Arab League and the World Bank have agreed to carry out a joint study on the institutional and regulatory framework for electricity trade. The study will assist Arab countries to develop and set up a harmonized legislative structure and electricity cross border codes necessary for promoting electricity trade among Arab countries and with targeted neighbouring regions including the EU market. There will be a comprehensive mechanism for coordination and joint work among the stakeholders. A Steering Committee composed of technical/policy representations from the member countries, the Arab League, the World Bank and the Arab Fund for Economic and Social Development will provide strategic directions and country input while also assessing the practical relevance of the study results. A Technical Committee consisting of technical staff from the power utilities, or Ministries of Electricity, of individual member countries, will also work directly with the study team to provide technical details, and to convey the outcomes of various stages of the study to the Steering Committee, and their own management and technical staff.

In regard to the second track, i.e., formulating transactions, the World Bank has planned an operational activity to pursue with the participating countries the possibility of implementing each of the projects identified in this study. These activities have varying time-frames and degrees of uncertainty that would need to be clarified among the relevant stakeholders through a systematic consultation process. A distinct feature of regional energy projects is the length of preparation time. Many regional projects have taken years (or several decades) to prepare. Projects tend to be structured and restructured a number of times owing to the long implementation periods. It is sometimes the deficiency in the initial formulation that results in further revisions. It is also the difficulty of working out the cross-border issues, and coordinating solutions among the participating countries. This is an area that the World Bank and its partners can help countries foresee and resolve cross-border issues before they paralyze the progress of the project.