Securing Energy for Development in the West Bank and Gaza

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ESMAP
Energy Sector Management Assistance Program

THE REPRESENTATIVE OFFICE OF NORWAY TO THE PALESTINIAN AUTHORITY

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The report was prepared under the guidance of Vivien Foster (Global Lead, GEEDR, co-task team leader) and Roger Coma-Cunill (Senior Energy Specialist, GEE05, co-task team leader).

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Abbreviations

bcm	billion cubic meters
CAPEX	capital expenditure (Note: CAPEX, capex, and CapEx are all used by the WB and various other organizations. CAPEX is used here for internal consistency. It is used commonly, although not consistently, by the WB.
CCGT	combined cycle gas turbine
COGAT	Coordinator of Government Activities in the Territories Unit (Israeli entity)
CSP	concentrated solar power
DISCO	distribution company
GDP	gross domestic product
GEDCO	Gaza Electricity Distribution Company
GPP	Gaza Power Plant
GWh	gigawatt hour
IEC	Israeli Electric Corporation
IPP	independent power producer
HEPCO	Hebron Electricity Distribution Company
JDECO	Jerusalem District Electricity Company
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LNG	liquified natural gas
LPG	liquid petroleum gas
MVC	municipality and village council
MW	megawatt
MWh	megawatt hour
NEDCO	Northern Electricity Distribution Company
NEPCO	National Electric Power Company (Jordan)
NIS	new Israeli shekel (Israeli currency unit)
PCBS	Palestinian Central Bureau of Statics
PEC	Palestinian Energy and Environmental Research Center
PENRA	Palestinian Energy and Natural Resources Authority
PERC	Palestinian Electricity Regulatory Council
PETL	Palestinian Electricity Transmission Company
PPA	power purchase agreement
PUA	Public Utility Authority (Israeli)
PV	photovoltaic
RE	renewable energy
SELCO	Southern Electricity Distribution Company
tcf	trillion cubic feet
TEDCO	Tubas Electricity Distribution Company
TOU	time of use
VRE	variable renewable energy

Executive Summary

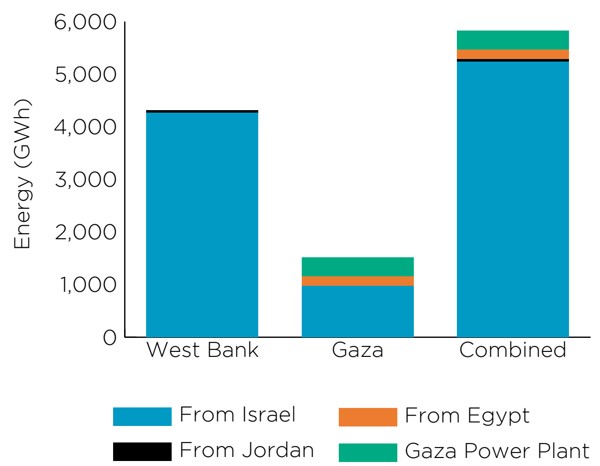
What Is the Current Energy Supply Situation in the West Bank and Gaza?

Energy security challenges are already severe in Gaza and are emerging in the West Bank. The power supply meets only half the demand in Gaza, leading to rolling blackouts of eight hours on and eight hours off. Although the West Bank generally enjoys 24-hour power supply, shortages have emerged during peak winter and summer months. With demand projected to grow at an average annual rate of about 3.5 percent in the foreseeable future—slightly higher in Gaza and lower in the West Bank—shortages are likely to become worse unless new supply options are found.

The West Bank and Gaza rely primarily on Israeli imports to meet electricity needs. In 2015, about 90 percent of their electricity was supplied by the Israeli Electric Corporation (IEC) (figure 1). The situation differs significantly between the West Bank, where IEC imports represent 99 percent of consumption, and Gaza, where they represent 64 percent. Modest amounts of electricity are imported from Jordan into the West Bank and from Egypt into Gaza. The Palestinian Authority has set targets to develop 130 megawatts (MW) of renewable energy by 2020, but only 18 MW had been developed as of June, 2017.

The only large-scale generation capacity in the territories is the troubled Gaza Power Plant (GPP). The 140 MW diesel-fired plant was developed as an "independent power project" (IPP) and has been operating since 2004 on a 20-year power-purchase agreement (PPA) involving significant take-or-pay capacity charges. Due to the high cost of diesel fuel, the plant is so expensive to operate — NIS 1.05–1.65 (US$0.29–0.46) per kilowatt hour — that it can typically be run only at half capacity. It has also suffered repeated damages during armed conflicts, which affected its fuel storage capacity. The best prospect is to convert the plant to natural gas, which would reduce operating costs to about a third of current levels. In parallel, considering the expected long lead time of such a conversion, the development of renewable technologies such as rooftop solar photovoltaic (PV), with shorter implementation time, should be prioritized.

Figure 1: Main Sources of Electricity in the West Bank and Gaza, 2015



Source: Palestinian Central Bureau of Statics. 2015. "Quantity of Electricity Imported (MWh) in the West Bank by Source and Month, 2015" and "Quantity of Electricity Imported and Purchased (MWh) in Gaza Strip by Source and Month, 2015", Ramallah City. http://www.pcbs.gov.ps/site/886/Default.aspx

The electricity sector in West Bank and Gaza has undergone several institutional reforms, which still require further consolidation. In 1995, the sector was reorganized to cluster most of the former municipal service providers into six local distribution utilities. The Electricity Law of 2009 created the Palestinian Electricity Regulatory Council (PERC), with responsibility for tariff setting and monitoring, as well as the Palestinian Electricity Transmission Company Ltd (PETL), a new transmission operator and wholesale single buyer. While there is no Palestinian transmission infrastructure at present, PETL will take charge of four high-voltage substations, three of which have been built, to manage the flow of high

voltage power from Israel into the West Bank, which previously took place through a myriad of low voltage connection points.

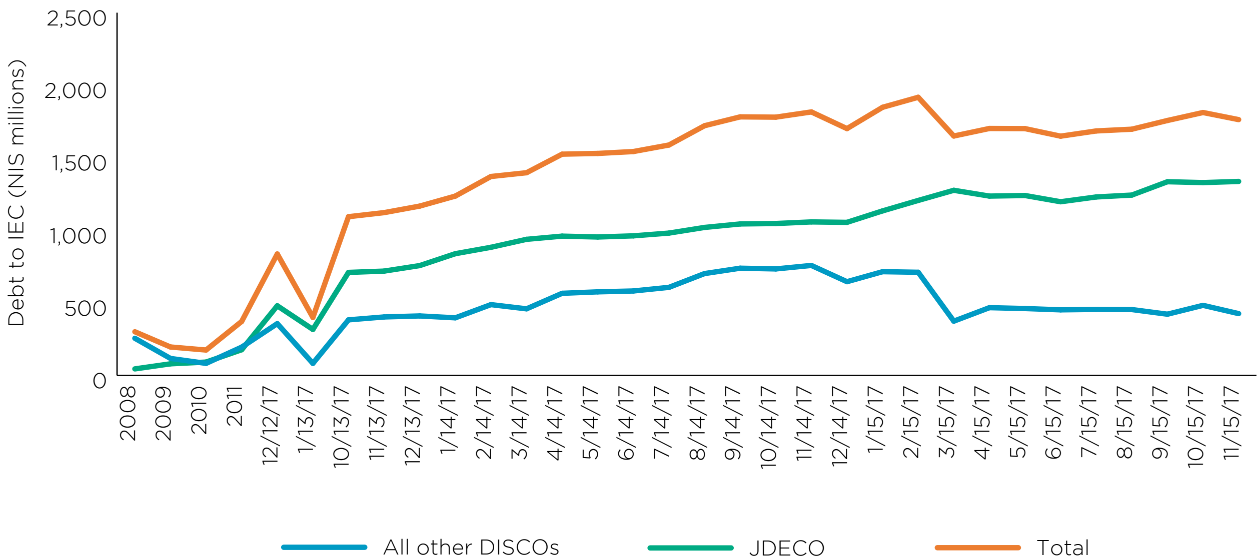
The electricity sector has yet to establish a track record as a creditworthy buyer for wholesale power. There are three layers to this problem. First, despite important efforts by PERC, electricity is not priced at cost-recovery levels throughout the West Bank and Gaza. The gap between tariffs and costs is particularly large in Gaza, where tariffs have not been adjusted during the past decade. Second, while the operational performance of the distribution utilities has been improving, full cost recovery has not yet been achieved. In 2015, Distribution Companies (DISCOs) recovered revenue for only 64 percent of the electricity they purchased in the West Bank (table 1), and 50 percent in Gaza. Third, even when revenues are collected, they are sometimes diverted by municipal governments to cover other subnational expenditures rather than being channeled to the purchase of power. Thus, implicit subsidies to the electricity sector have been estimated at close to 1 percent of gross domestic product (GDP) in the West Bank and 4–5 percent of GDP in Gaza.

TABLE 1: OVERVIEW OF WEST BANK AND GAZA ELECTRICITY DISTRIBUTION COMPANIES, 2015[1]

	GEDCO	TOTAL WEST BANK[1]	JDECO	NEDCO	HEPCO	SELCO	TEDCO
Scale							
Customers	231,500	436,389	256,314	90,265	45,660	25,650	18,500
Purchased electricity (NIS millions)	795	1,398	871	250	164	71	42
Billed electricity (NIS millions)	518	1,509	949	245	193	76	46
Net annual income/loss (NIS millions)	n.a.	-76	-82	9	9	-15	3
Performance							
Losses: Technical and nontechnical	26%	22%	24%	17%	20%	28%	16%
Collection ratio	65%	89%	91%	98%	81%	71%	76%
Overhead costs (ie, Operations and maintenance) as percentage of purchased electricity	8%	17%	22%	5%	10%	21%	17%

Source: Information provided by the Gaza Electricity Distribution Company (GEDCO), Jerusalem District Electricity Company (JDECO), Northern Electricity Distribution Company (NEDCO), Hebron Electricity Power Company (HEPCO), Southern Electricity Distribution Company (SELCO), Tubas Electricity Distribution Company (TEDCO).

Figure 2: Electricity Sector Debt to IEC, 2008–2015



Source: Information provided by ECO Energy.
Note: IEC = Israeli Electric Corporation; DISCO = Distribution Company; JDECO = Jerusalem District Electricity Company.

The poor record of paying for power imported from Israel has led to the so-called net lending crisis and a large accumulation of outstanding debt. The power purchased from IEC is only partially paid for by the DISCOs, with the unpaid portion being partially covered through net lending (a fiscal mechanism whereby money is deducted from clearance revenues that would otherwise be transferred from Israel to the Palestinian Authority) and partially accumulated as outstanding debt. By September 2016, the accumulated debt owed to IEC exceeded NIS 2 billion (US$500 million) (figure 2). An agreement was reached in September 2016 that allowed for the settlement of past accumulated debt and laid the vision for a future power market with imports channeled through the new high-voltage substations and tariffs set according to a new, long-term power-purchase agreement. According to this vision, PETL would act as the single buyer, purchasing power from IEC and selling it to the DISCOs.

What Options Exist for Improving Energy Security in the West Bank and Gaza?

Looking forward, the West Bank and Gaza have several tangible options for expanding and diversifying electricity supply. For example:

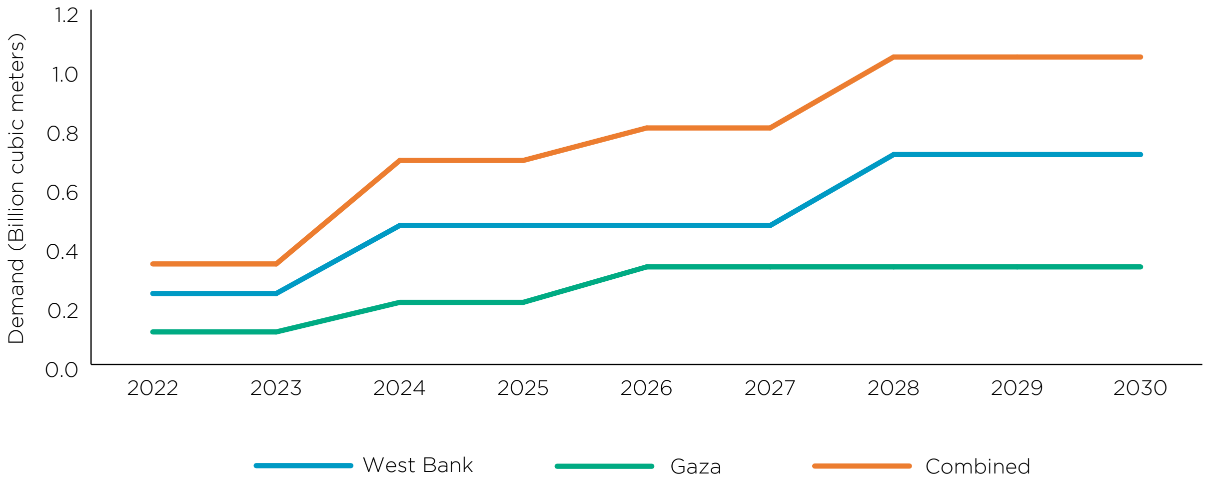
Israeli electricity imports continue to be a valid option, but this route requires a significant scaling up of interconnection capacity. Israel has a strong track record of providing reliable power supply to the West Bank and Gaza. As long as the net lending crisis can be satisfactorily resolved, there is potential to increase Israeli power imports to the two economies, provided the existing interconnection capacity is upgraded accordingly. The West Bank and Gaza combined already represent IEC's largest and fastest-growing electricity customer. However, IEC is facing high levels of indebtedness and an uncertain operating structure. Under the current Israeli power sector reform, all new Israeli generation capacity is being developed by independent power producers, which may present an alternative and more commercially oriented Israeli power supply option for the West Bank and Gaza in the future.

Increasing power imports from Jordan and Egypt is a realistic medium-term option, although it is not without challenges. Jordan and Egypt have recently overcome power supply crises caused by a shortage of Egyptian gas and are now heading for significant power surpluses. In principle, the existing interconnection capacity of 20 MW from Jordan and 20–30 MW from Egypt could be upgraded to support higher volumes of imports. Jordanian electricity has been more expensive than Israeli power, due to heavy reliance on liquefied natural gas, but is expected to become cheaper as Israeli gas enters the Jordanian market and as the share of renewables increases in Jordan. Egyptian power is currently cheaper than Israeli power due to the historic low cost of natural gas, while the size of Egypt's power system is about 30 times that of West Bank and Gaza's demand, making it relatively easy for Egypt to supply the scale of power needed in West Bank and Gaza. Nevertheless, historical imports from Egypt into Gaza, which have been managed through the local Egyptian distribution company rather than the national Egyptian transmission operator, have proved unreliable due to security issues in Sinai. In addition, Gaza has not yet established any payment record with Egypt, since the cost of these imports has been covered by third party benefactors to date. Finally, neither Jordan nor Egypt has access to the controversial net-lending mechanism that has provided Israel with an informal payment-security mechanism to at least partially offset payment risk from the West Bank and Gaza.

Thanks to major gas discoveries in the eastern Mediterranean, it would be feasible in the medium term to import gas to the West Bank and Gaza for power generation. Israel became a major gas producer in 1999 with the discovery of the 10.9 trillion-cubic-foot (TCF) Tamar field. The imminent development of the 21.9 TCF Leviathan field will make Israel a gas exporter. The Israeli government has already given approval for a 40-kilometer pipeline extension from the Ashkelon terminal in Israel into Gaza, which would enable the conversion of GPP to operate on natural gas, as well as for a 15-kilometer spur from the Israeli national gas transportation network into Jenin in the north of the West Bank, to allow for the construction of a new 400 MW combined cycle gas turbine (CCGT) plant.

The Gaza Marine gas field, discovered almost two decades ago, has yet to be developed. The eventual development of this 1.2 TCF gas field could eliminate the need for Israeli gas. The investment costs of developing Gaza Marine have been estimated at US$0.25 billion to US$1.20 billion, depending on the extent to which existing gas infrastructure is shared with Israel. However, development would require a gas supply contract with a creditworthy buyer, and it will take some time before gas demand in the West Bank and Gaza builds up to the requisite levels (figure 3). Once developed, Gaza Marine has the potential

Figure 3: Estimated Natural Gas Demand in the West Bank and Gaza until 2030



Source: Information provided by ECO Energy.

to generate US$2.7 billion in fiscal revenues for the Palestinian Authority over an estimated 25 years of production.

There is substantial potential for solar electricity in the West Bank, particularly in Area C (table 2). Solar energy is the only significant renewable resource in the Palestinian Territories. The technical potential in the West Bank is estimated to be around 530 MW of rooftop solar PV, and at least 100 MW of utility scale solar in Areas A and B. This is dwarfed by the vast solar potential of over 3,000 MW estimated in Area C, which would be suitable for both PV and CSP technologies. Nevertheless, the significant political challenges associated with securing Israeli approval for construction in Area C cast some doubt over the possibility of developing this resource. By contrast, extreme land constraints in the Gaza strip limit the available solar potential to 160 MW of rooftop solar. However, even this limited solar capacity could play a vital role in increasing energy security and acting as an electricity safety net.

TABLE 2: SOLAR ENERGY POTENTIAL IN THE WEST BANK AND GAZA

POTENTIAL AVAILABLE RE CAPACITY (MW)				
Utility scale PV or CSP				
		Areas A and B	Area C	Total
West Bank		103	3,374	3,477
Gaza				0
Combined				3,477
Rooftop solar				
	Residential	Public	Commercial	Total
West Bank	490	13	31	534
Gaza	136	8	19	163
Combined	626	21	50	697

Source: World Bank estimates.
Notes: For utility scale PV or CSP, according to PETL and the Palestinian Energy and Environmental Research Center (PEC), 0.12 percent of Areas A and B and 3 percent of Area C are available for solar installations. The land requirement is about 28 square meters per kilowatt peak (includes space for control rooms and so forth). For rooftop PV, according to the Palestinian Central Bureau of Statistics and PEC, in West Bank and Gaza, there are over 400,000 residential, 2,500 public sector, and 5,000 commercial sector rooftops. The rooftop areas range from 150 to 300 square meters, and 30–50 percent of the rooftops are available for solar installations. The rooftop space requirement is nine square meters per kilowatt peak. RE = Renewable Energy; MW = Megawatts; PV = photovoltaic; CSP = concentrated solar power.

Measures to improve energy efficiency can make a valuable contribution to energy security. The National Energy Efficiency Action Plan aims to make savings equivalent to 1 percentage point of energy consumption annually through 2020. It focuses primarily on reducing electricity consumption by improving the energy efficiency of residential buildings. A much more ambitious action plan is under consideration by the Palestinian Energy and Natural Resources Authority (PENRA) for 2020–2030. It aims to save 5 percent of the anticipated energy consumption during that period. The new strategy encompasses use of high-impact, energy-efficient appliances (such as heaters, fridges, and air conditioners); tightening of efficiency standards for buildings; and smart grid infrastructure to allow consumers to participate in the energy market as demand response. Investments to improve energy efficiency are proven to be much more cost-effective than expanding power generation capacity. Many of the measures included in the government's plans cost between US$0.01 and 0.05 per kilowatt hour (kWh), while new generation would cost at least US$0.10 per kWh.

As domestic generation capacity expands, transmission infrastructure must develop. At present, there is no significant power transmission infrastructure in the West Bank and Gaza. Most power is simply absorbed and distributed from the Israeli grid at low voltage. As the Palestinian territories increase their domestic generation capacity, there will be an increasing need to move power from the point of generation to centers of demand, which may be located some distance away. In Gaza, this will call for creating a transmission backbone within the compact urban area. In the West Bank, this could initially be managed by putting ("wheeling") power out into the Israeli grid at one location and bringing it back into the West Bank at a different location. The level and structure of associated wheeling charges will have a significant effect on the cost of power to end consumers. As the volume of wheeling rises, it will become increasingly attractive to develop a domestic transmission backbone in the West Bank. However, since the backbone would need to traverse Area C, the issue of securing the necessary construction permits from Israel would present a significant challenge.

How Can the West Bank and Gaza Choose among the Options?

Choosing among the available energy supply options involves balancing technical and financial considerations. Meeting electricity needs typically involves developing a balanced portfolio that represents a reasonable, affordable cost.

From a technical standpoint, the options must be sequenced and packaged into an investment plan that reliably meets demand. The options described in the previous section vary in production cost, physical production characteristics, availability, and associated risks. For example, gas-fired power generation will be feasible only after gas transportation infrastructure is completed and a gas supply agreement can commence, while generating solar power from PV panels is subject to variability in solar radiation throughout the day and from one day to another. Gas-fired power generation may be vulnerable to a curtailment of gas supply, while solar power is a fully indigenous resource. Also, the costs of gas-fired power generation are relatively well understood, although they are susceptible to variations in the price of natural gas, while the costs of generating solar power are declining rapidly along a path that is not straightforward to predict. These considerations must be carefully balanced to define the best possible power generation investment plan, and a range of alternative scenarios must be considered. (Box 1 provides an overview of alternative scenarios that were considered in a novel Robust Power System Planning Model developed uniquely for this study)

It is important to understand the tariff implications of the preferred investment plan and whether it is affordable to the population. The costs of providing a secure electricity service include the cost not only of power generation but also of the associated transmission and distribution infrastructure. Inefficient operation could inflate costs. Given fiscal constraints in the West Bank and Gaza, domestic power generation could be developed by the private sector under a power-purchase agreement, leaving public investment for transmission and distribution, for which private investment would be difficult to harness. Ultimately, these costs must be paid either by the consumer through retail tariffs or by the government through subsidies. Both sources of funding are constrained, given the relatively low income of the population and

Box 1: A Robust Power-Systems Planning Model for the West Bank and Gaza

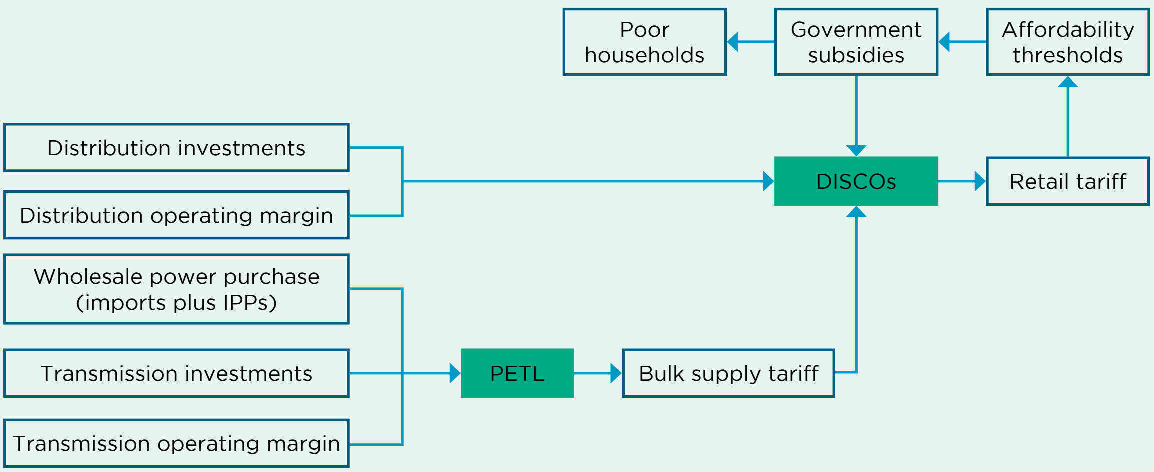
To select from among the energy supply options, a traditional least-cost power-systems planning model is modified to account for the uncertain nature of the Palestinian context and used to identify investment plans that are as resilient as possible to alternative states of the world. Five illustrative planning scenarios for West Bank and Gaza are explored, covering the period through to 2030.

1. **'Do nothing'** considers how rapidly energy security will deteriorate if no further investments are made.
2. **'Planned future'** looks at the impact of implementing all investment projects currently in the pipeline.
3. **'PENRA vision'** explores limiting dependence on any one source of energy to no more than 50 percent.
4. **'Maximum cooperation'** considers meeting demand growth primarily through increased Israeli imports.
5. **'Maximum independence'** considers the fullest possible extent of domestic power generation.

Box 2: A Power-Sector Financial Model for the West Bank and Gaza

The planning model (see box 1) feeds into a comprehensive financial model of the West Bank and Gaza power sector. This sheds light on the financial implications of any investment scenario. The financial model looks at how the selected generation investment plan translates into an average cost of power generation, converts this into a wholesale power tariff by incorporating the costs of any future transmission system, overlays a distribution margin to create a retail tariff, and, finally, assesses the affordability of this tariff to the population, as well as the fiscal implications of any remaining subsidies.

Figure B2.1 The Power-Sector Financial Model



Note: IPP = independent power producer, PETL = Palestinian Electricity Transmission Company Ltd, DISCO =

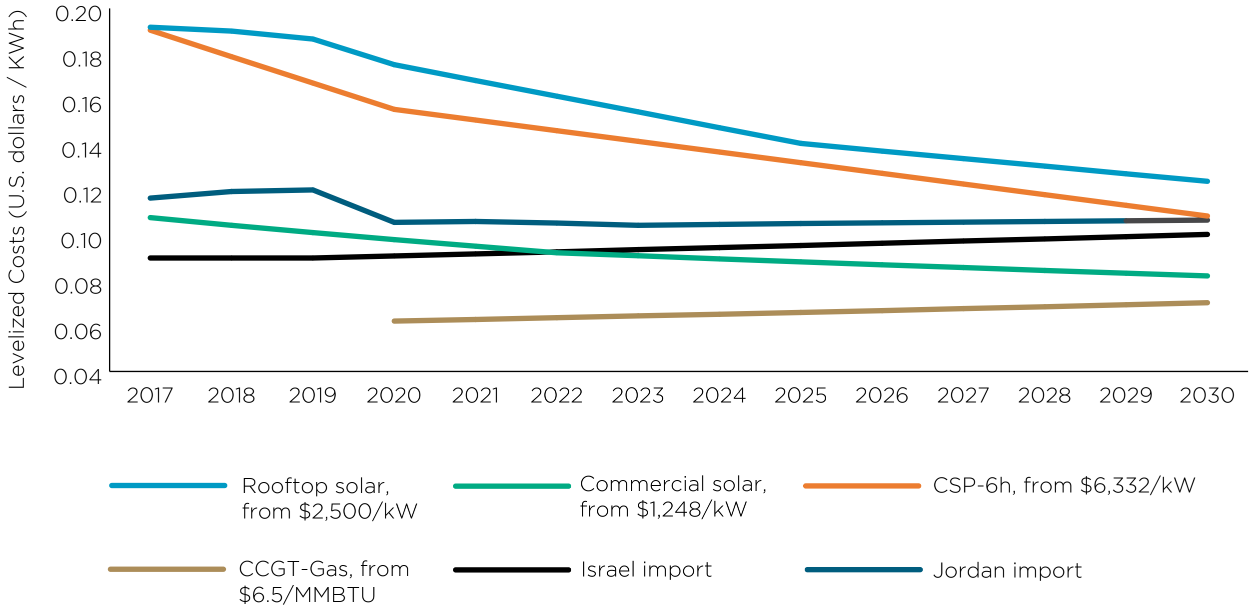
the limited budget of government. An important reality check for any power-sector investment plan is to examine its impact on retail tariffs, determine whether these are affordable, and, if not, determine what the potential size of the associated subsidy bill would be. Due to the diverse features of the power sector in the two territories, the study analyses the West Bank and the Gaza Strip separately. (For more information on the financial model of the electricity sector developed for this study, see box 2.)

WHAT DOES THE WEST BANK'S ENERGY FUTURE LOOK LIKE?

Failure to invest in the West Bank's power sector would lead to deepening shortages over time. Under the '*do nothing*' scenario, unserved demand rises from negligible levels today to reach 9 percent of the forecasted load by 2030, with certain locations—such as Jenin and Nablus—having already experienced unserved demand in 2016. To avert this outcome, the West Bank must develop several alternative energy supply options.

The development of gas-fired power generation and renewable energy should be pursued more intensively, considering the cost convergence of different energy supply options over time (figure 4). As of 2017, there is a wide variation in the cost of the different energy supply options available to the West Bank, and Israeli imports carry a cost advantage over any of the alternatives. However, this changes over time. Gas-fired power generation, once available, proves to be cheaper than Israel imports. While continuing technological change in renewable energy brings the cost of utility-scale PV below the cost of Israeli imports before the end of the planning horizon. Rooftop solar and even concentrated solar power

Figure 4: Time Trends for the Levelized Cost of Energy for Different Supply Options in the West Bank



Source: World Bank estimations
Note: kW = kilowatt hour; GPP = Gaza Power Plant; MMBTU = Million British Thermal Units .

start to look a lot more competitive. These evolving relative costs of power generation are one important driver of project selection.

There are several attractive power-development scenarios available to the West Bank, all of which are broadly competitive with Israeli power imports. The performance of the five alternative scenarios presented by the planning model can be compared along several dimensions, with no single scenario dominating on every dimension (table 3).

1. **Average cost of power generation:** This is a key driver of retail tariffs and varies remarkably little across the scenarios considered for the West Bank, ranging from US$0.098 to US$0.102 per kWh. This is due to the convergence in the cost of different power-generation technologies already noted.
2. **Capital expenditure:** Scenarios contemplating continued reliance on Israeli imports require hardly any capital expenditure to be made, whereas those involving the development of domestic power generation capacity would entail private investments of between US$0.85 billion and US$2.28 billion.
3. **Unserved demand:** All scenarios that bring new investment into power generation ensure that all demand can be reliably met.
4. **Reliance on electricity imports:** The degree of reliance on Israeli imports ranges from 96 percent in the "*maximum cooperation*" scenario to 36 percent in the "*maximum independence*" scenario. Hence, Israel remains a significant source of electricity under any eventuality.
5. **Reliance on imported fuel:** All the scenarios entailing significant development of power generation capacity include reliance on gas imports to meet between 32 and 37 percent of electricity needs.
6. **Reliance on domestic renewables:** The maximum share that can be reached for domestic renewables, even under the most optimistic scenario, is 19 percent if production is limited to Areas A and B or 30 percent if sites in Area C can be developed.

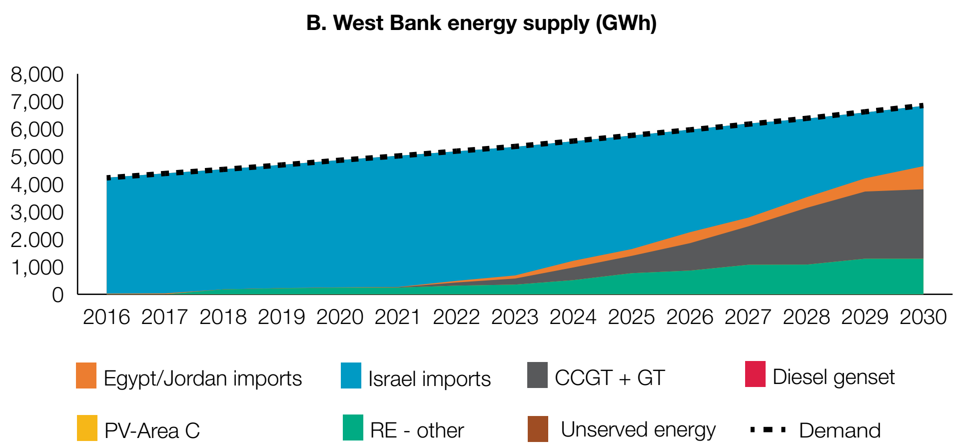
TABLE 3: COMPARISON OF RESULTS ACROSS PLANNING SCENARIOS FOR THE WEST BANK

	AVERAGE COST OF POWER (US$ PER KWH)	CAPEX (US$ MILLIONS)	UNSERVED DEMAND IN 2030	ELECTRICITY IMPORTS IN 2030	DOMESTIC GENERATION FROM IMPORTED FUEL IN 2030	DOMESTIC RENEWABLE ENERGY GENERATION IN 2030
1. Do nothing	0.0979	0	9.0%	90.0%	0%	0.4%
2. Planned future	0.1006	850	0%	64.0%	32.0%	4.0%
3. PENRA vision	0.1016	2,133	0%	45.0%	37.0%	19.0%
4. Maximum cooperation	0.0978	174	1.0%	96.0%	0%	4.0%
5. Maximum independence	0.0988	2,284	0%	36.0%	34.0%	30.0%

Note: CAPEX = capital expenditure; PENRA = Palestinian Energy and Natural Resources Authority.

Figure 5: Results of the PENRA Vision Scenario for the West Bank

PENRA Vision: "Dependency ratio on any one source should not exceed 50% in best conditions, with a possibility of importing all needs in case of emergency."

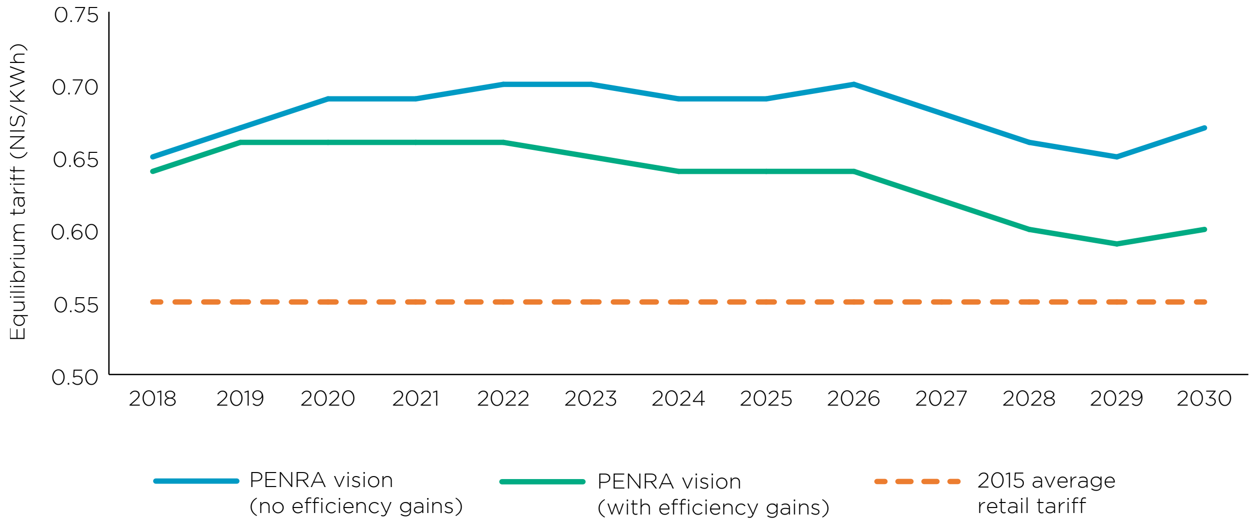


Note: RE = renewable energy; PV = photovoltaic; CCGT= combined cycle gas turbine; GT = gas turbine, Genset = Generator.

Overall, the PENRA vision scenario looks relatively attractive (figure 5). It calls for development of gas-fired power-generation capacity along with aggressive expansion of solar energy on rooftops and in Areas A and B to attain over 500 MW of solar PV capacity by 2030—about four to five times the current target. By 2030, this scenario achieves a relatively balanced consumption of domestic solar and gas-fired power generation with Israeli imports. Import capacity is nonetheless kept higher than strictly needed to provide backup in the case of shortfalls in the other sources of energy.

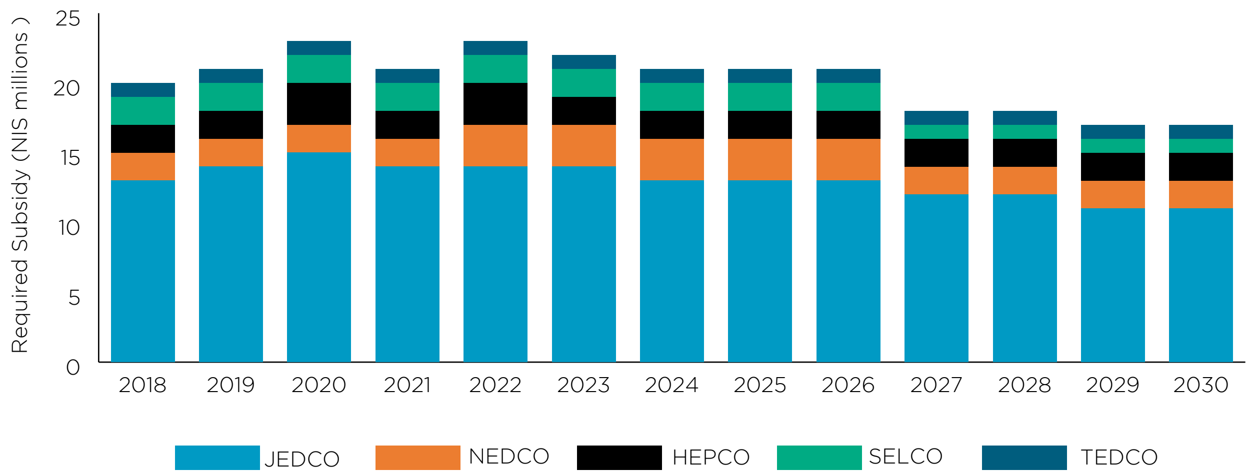
To implement the PENRA's vision, electricity tariffs would need to increase significantly in the medium term, but could decline over time if efficiency targets are met. The financial equilibrium tariff needed to sustain the envisaged investments in generation in the West Bank, as well as the associated transmission and distribution costs, rises in the medium term to NIS 0.66 (US$0.18) per kWh, well above current levels of NIS 0.55 (US$0.15) per kWh (figure 6). However, if the operational and commercial efficiency of the distribution utilities could be improved over the same time, the financial equilibrium tariff could drop toward NIS 0.58 (US$0.16) per kWh by 2030. Essentially, addressing the shortcomings of the distribution utilities can reduce the retail tariff by as much as NIS 0.07 (US$0.02) per kWh. Failure to adjust tariffs as needed would create a financial deficit in the sector peaking at NIS 600 million (US$165 million) per year by 2022 (equivalent to 6 percent of the 2016 public budget for the West Bank).

Figure 6: Equilibrium Tariff Needed to Finance Preferred Sector Investment Plan for the West Bank



Note: PENRA = Palestinian Electricity and Natural Resources Authority

Figure 7: Targeted Subsidy Requirement to Offset Affordability Concerns for the Bottom Income Decile in the West Bank



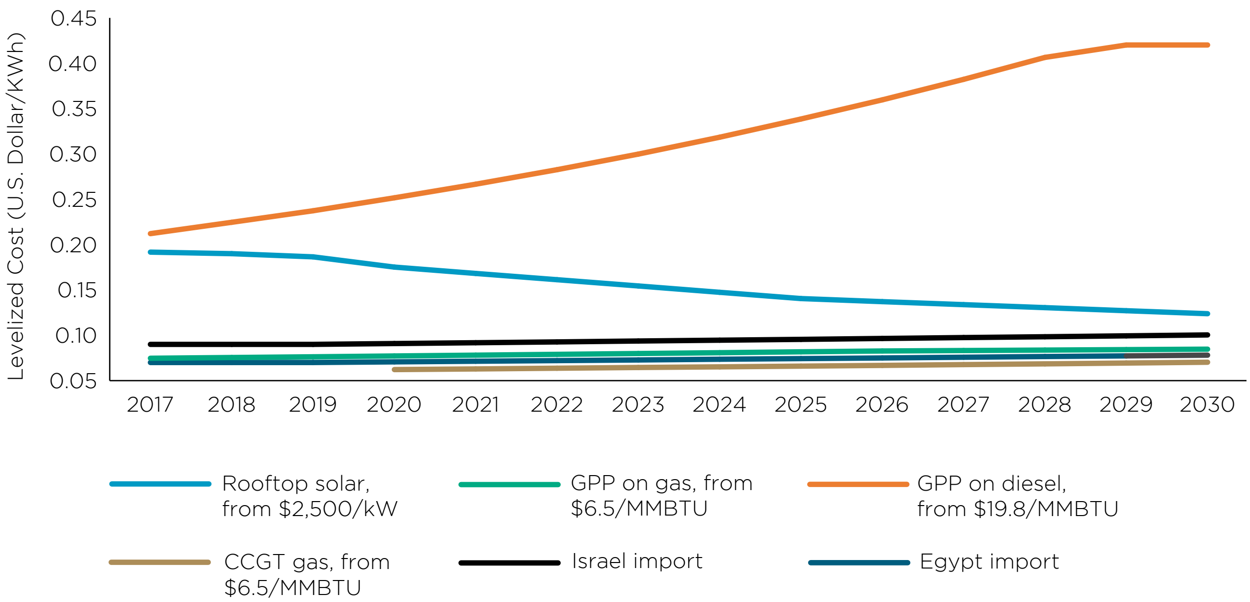
These tariffs would present an affordability problem only for the poorest households in the West Bank, and this could be addressed through a modest targeted subsidy. According to usual practice, electricity service is considered affordable if households can meet their electricity basic needs without spending more than 5 percent of their monthly budget. In the context of the West Bank and Gaza, the retail tariff increases with higher consumption in pre-defined blocks. The first block of the tariff schedule, set at 160 kWh per month, broadly allows households to meet their basic electricity needs. Based on the distribution of income in the West Bank, only the poorest 10 percent of the population would struggle to buy 160 kWh per month at the required financial equilibrium tariff of NIS 0.66 (US$0.18) per kWh. Assuming that these needy households could be identified using existing social registries, the cost of a targeted subsidy to safeguard their basic consumption would amount to no more than NIS 25 million (US$7 million) per year in 2022, declining further as tariffs come down thereafter (figure 7).

WHAT DOES GAZA'S ENERGY FUTURE LOOK LIKE?

Failure to invest in Gaza's power sector would make an already dire situation worse. Gaza is unable to meet 50 percent of its demand today. If no further power options are developed, the extent of unserved energy would escalate to 63 percent of demand by 2030. To avert this outcome, Gaza needs to develop additional power supply options, albeit from a much more limited menu than that available to the West Bank.

The cost of the diesel-fired GPP becomes increasingly unattractive over time relative to alternative options (figure 8). As of 2017, the GPP is already very expensive compared to alternatives and this cost is projected to rise along with the international oil price. Israeli electricity can be imported at fraction of the cost of current domestic generation, and Egyptian imports are even cheaper though heavily restricted in supply and rather unreliable. Conversion of the GPP to natural gas would make it competitive with Israeli and Egyptian imports. While rooftop solar looks relatively expensive today (though still undercutting

Figure 8: Time Trends of Levelized Cost of Energy for Different Supply Options in Gaza



Note: kWh = kilowatt hour; GPP = Gaza Power Plant; MMBTU = Million British Thermal Units; CCGT = combined cycle gas turbine.

TABLE 4: COMPARISON OF RESULTS ACROSS PLANNING SCENARIOS FOR GAZA

	AVERAGE COST OF POWER (US$ PER KWH)	CAPEX (US$ MILLIONS)	UNSERVED DEMAND IN 2030	ELECTRICITY IMPORTS IN 2030	DOMESTIC GENERATION FROM IMPORTED FUEL IN 2030	DOMESTIC RENEWABLE ENERGY GENERATION IN 2030
1. Do nothing	0.1468	0	63%	26%	11%	0%
2. Planned future	0.1339	1,035	0%	26%	68%	6%
3. PENRA vision	0.1230	1,066	0%	47%	46%	6%
4. Maximum cooperation	0.1037	385	0%	93%	0%	6%
5. Maximum independence	0.1515	1,185	2%	9%	83%	6%

Note: CAPEX = capital expenditure; PENRA = Palestinian Energy and Natural Resources Authority.

the GPP), the cost is expected to fall significantly over the planning horizon converging towards Israel imports. These changing patterns of relative costs are one key driver of investment planning decisions.

The options for Gaza are much more constrained than for the West Bank, and the premium associated with energy independence is particularly high. The key energy policy issue for Gaza is where to strike the balance between Israeli imports and domestic gas-fired power generation, while intensively developing solar rooftop PV. The performance of the five alternative scenarios presented by the planning model can be compared along several dimensions (table 4).

1. **Average cost of power generation:** This is a key driver of retail tariffs and varies greatly across the scenarios considered for Gaza, ranging from US$0.10 per kWh, if power is entirely sourced from Israeli imports, to US$0.15 per kWh if domestic generation is developed to the fullest extent. In marked contrast to the West Bank, the premium for energy independence in Gaza amounts to a substantial 50 percent of costs.
2. **Capital expenditure:** Scenarios contemplating continued reliance on Israeli imports require hardly any capital expenditure to be made, whereas those involving the development of domestic power-generation capacity would entail private investments of just over US$1 billion.
3. **Unserved demand:** All scenarios that bring new investment into power generation ensure that all demand can be reliably met, although some chance of unserved demand remains when there is no diversification from Israeli imports.
4. **Reliance on electricity imports:** The degree of reliance on Israeli imports ranges from 93 percent in the "maximum cooperation" scenario to only 9 percent in the "maximum independence" scenario.
5. **Reliance on imported fuel:** All the scenarios

entailing significant development of West Bank and Gaza power-generation capacity rely on gas imports to meet between 46 and 83 percent of electricity needs. In that sense, the "maximum independence" scenario essentially only replaces dependence on electricity imports with dependence on gas imports.

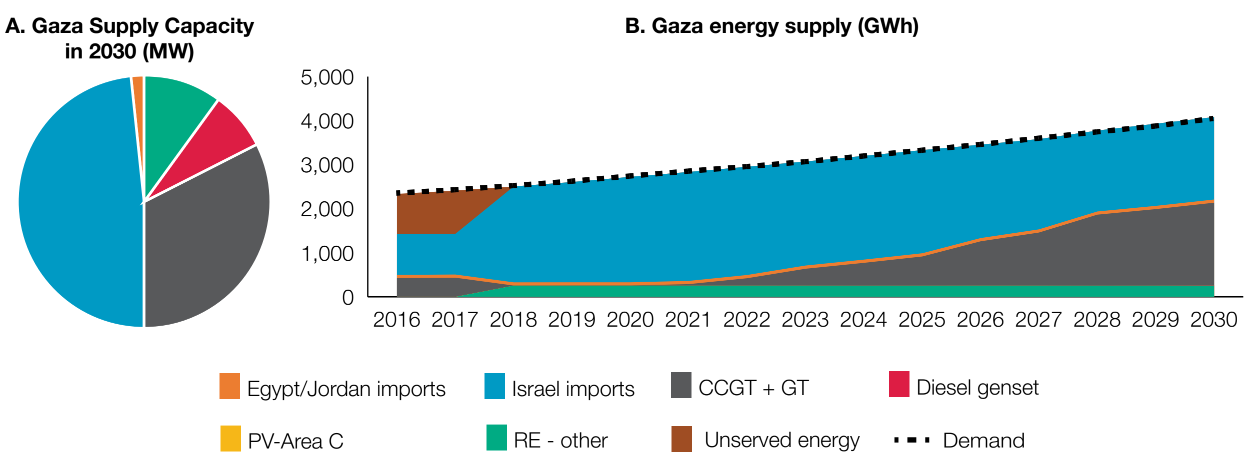
6. **Reliance on domestic renewables:** Gaza's renewable energy potential is limited to rooftop solar, and this is unable to meet more than 6 percent of energy needs under any scenario but should still be maximized to provide a basic safety net where possible.

Among the energy diversification options for Gaza, the PENRA vision is the one offering the lowest cost premium for energy independence. The differential average cost of generation between PENRA's vision and the "maximum cooperation" scenario is NIS 0.07 (US$0.02) per kWh, or about 20 percent, still relatively high but preferable to the alternatives. The PENRA vision scenario envisages a phasing out of diesel-fired power generation in the short run and increased reliance on Israeli imports (figure 9). This brings a double benefit by bringing power generation costs down to a third of current levels while at the same time expanding supply to a point where current outages can be offset. This achievement is contingent on the commissioning of new 161 kilovolt lines to expand import capacity from Israel. Further out, once gas becomes available, the GPP comes back into service and plays a growing role in meeting energy needs. By 2030, the scenario sees an almost 50:50 reliance on self-generation through gas and Israeli imports. In addition, rooftop solar provides a safety net to meet critical needs under emergency conditions.

The tariff impact of implementing the PENRA vision is substantial, although it can be somewhat offset by operational efficiency gains. Any scenario involving significant investment in domestic power generation in Gaza entails financial equilibrium tariffs of the order of NIS 0.91 (US$0.25) per kWh in the medium term, well above the current levels of NIS 0.52-0.56 (US$0.14-0.15) per kWh (figure 10). These would eventually decrease to about NIS 0.62 (US$0.17) per kWh, but only if the Gaza utility substantially improves its operational and commercial performance in line with regional best practice; this can reduce the retail tariff by as much as NIS 0.47 (US$0.13) per kWh by 2030. Failure to adjust tariffs would result in a financial shortfall of around NIS 700 million (US$200 million) by the mid-2020s (equivalent to 12.5 percent of the public budget for 2016).

Figure 9: Results of the PENRA Vision Scenario for Gaza

PENRA Vision: "Dependency ratio on any one source should not exceed 50% in best conditions, with a possibility of importing all needs in case of emergency."



Note: RE = renewable energy; PV = photovoltaic; CCGT= combined cycle gas turbine; GT = gas turbine, Genset = Generator.

Figure 10: Equilibrium Tariff Needed to Finance Preferred Sector Investment Plan for Gaza

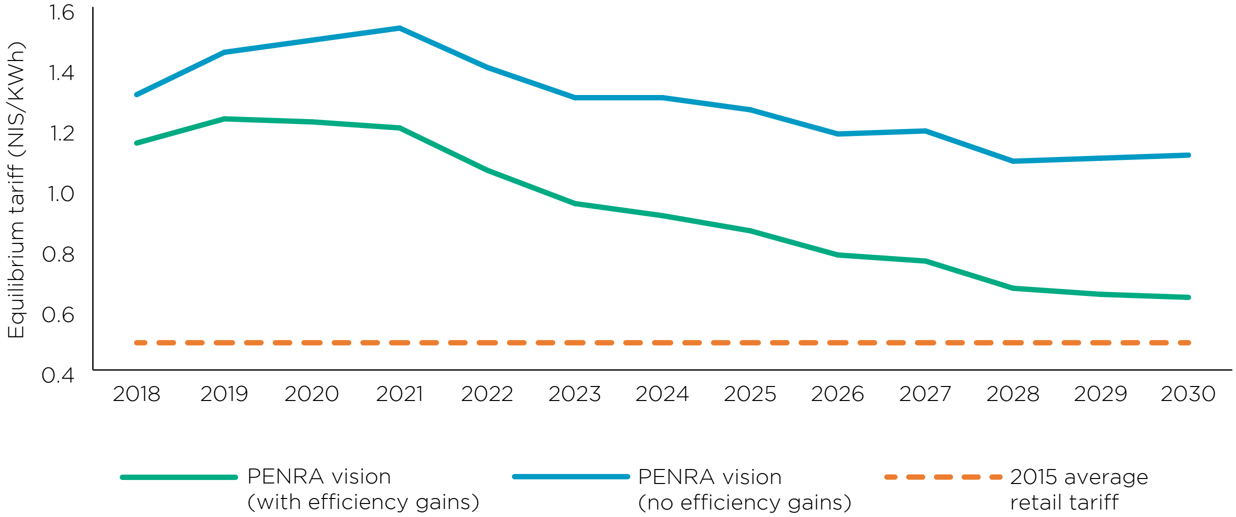
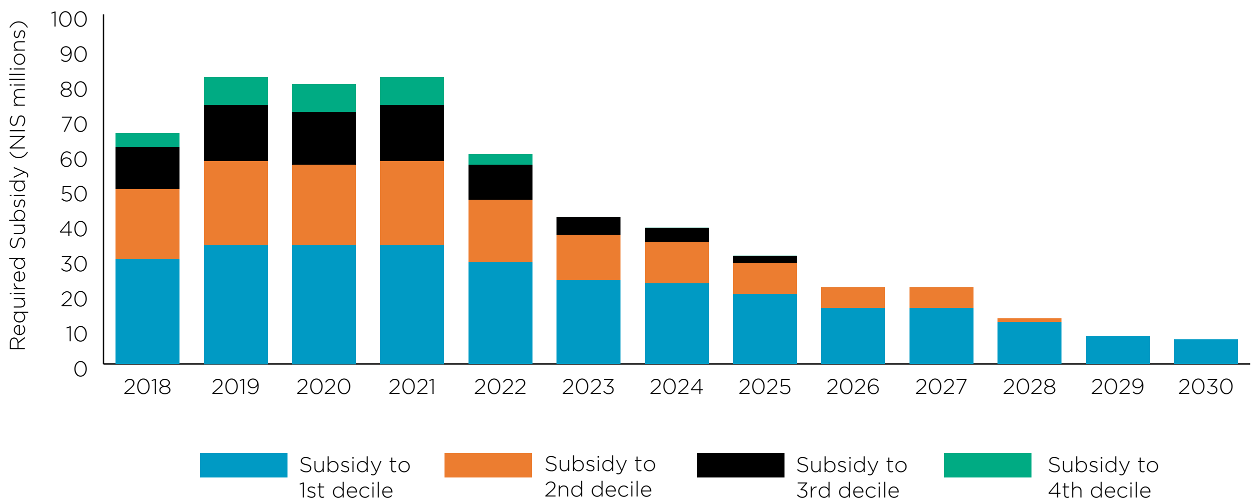


Figure 11: Targeted Subsidy Requirement to Offset Affordability Concerns in Gaza



Affordability is a much more serious concern in Gaza than the West Bank, given higher costs of electricity and a more impoverished population. Based on the distribution of income in Gaza, as much as 40 percent of the population would struggle to buy 160 kWh per month at the required financial equilibrium tariff of NIS 0.91 (US$0.25) per kWh. Assuming that these needy households could be identified using existing social registries, the cost of a targeted subsidy to safeguard their basic consumption would amount to approximately NIS 80 million (US$22 million) per year in 2021. However, as tariff levels decline toward 2030, they would also become more affordable, such that by the end of the planning horizon social protection would be needed for only the poorest 10 percent of the population (figure 11).

What Measures Need to Be Taken by Government?

To make progress toward greater energy security, the Palestinian Authority needs to adopt a sequenced approach to addressing critical policy bottlenecks. The starting point for this roadmap is the completion of the power-purchase agreement with Israel currently under negotiation and the subsequent energization of PETL's four high-voltage substations in the West Bank. Considering the delays in the bilateral negotiations, PETL should seize the opportunity to agree on power supply agreements with Palestinian distribution companies. These downstream arrangements need to be in place before the power-purchase agreement with Israel is signed. Once these immediate measures are taken, the question becomes what needs to be done next to move toward the vision of improved energy security in the Palestinian territories. The analysis suggests that a certain sequence of measures needs to be taken. Four distinct phases have been identified (table 5).

PHASE 1

The first phase, and absolute priority, is to improve the creditworthiness of the sector, without which none of the alternative supply arrangements could be consummated. Progress on all other aspects of the Palestinian energy sector depend on greater creditworthiness. Without it, the sector cannot sign new power-import deals or close power-purchase agreements with independent power producers for increased domestic power-generation projects, let alone import natural gas. None of these ventures can get off the ground unless the Palestinian electricity sector strengthens its creditworthiness. Financial security will bring about energy security, but the reverse is not true. There are several distinct components that must be tackled if creditworthiness is to be improved.

First, replace generation from the GPP with increasing electricity imports from Israel to provide relief until a conversion to gas can be undertaken. The cost of diesel-fired generation at the GPP is very high, at approximately US$0.30 per kWh, even at current low oil prices. This is approximately three times the cost of power imports from Israel, which provides a more reliable source of supply. Until the GPP is ready for the switch to gas-fired generation, which would slash costs to US$0.068 per kWh, it would be desirable to substitute domestic diesel-fired power generation with Israeli power imports, taking advantage of the new 161 kilovolt line that is in an advanced stage of planning. Even if the capacity charges of US$0.026 per kWh to the GPP continue to be paid as per the existing 20-year PPA, every reduction of one kWh in diesel-fired power generation would be sufficient to buy two kWh of Israeli imports. Such a move would simultaneously reduce costs and increase quantity and reliability of supply, and thereby increase prospects for improved cost recovery through tariff revenues.

Second, accelerate improvements in the operational and commercial performance of Palestinian DISCOs. Cost recovery tariffs could be reduced substantially over time if the operational and commercial performance of the Palestinian DISCOs improved to reasonable regional benchmark levels. For the utilities in the West Bank, improved operational performance would take US$0.03 per kWh off the financial equilibrium tariff, while in Gaza improving operational performance is worth as much as US$0.11 per kWh. Achieving further improvements can build on some recent successes with the introduction of prepaid and smart meters that helped to raise revenue collection rates to 85 percent on average across the utilities. Moreover, across the board, attention needs to turn toward improving network losses, which remain very high despite all efforts. It is recommended that a revenue protection program be established to permanently measure and bill every kWh sold to the largest DISCO customers with state-of-the-art technology.

Third, create securitization mechanisms to ensure that Palestinian DISCO revenues are not diverted to other municipal projects. Due to the lack of a subnational financing framework in the Palestinian territories, DISCO revenues remain vulnerable to diversion into municipal budgets. The long-term solution, which is to strengthen the basis of subnational public finance, is important for development reasons that go well beyond the energy sector. However, it will likely take some time to achieve. Hence the importance of finding interim mechanisms to securitize the revenues needed for the DISCOs to meet the costs of wholesale power purchase. This could take the form of escrow accounts to ring fence electricity bill payments with a payment prioritization hierarchy ensuring payment to wholesale suppliers. The issue of securitization of revenues is particularly critical in Gaza, and would be an essential component of any moves to substitute increased Israeli power imports for domestic diesel-fired power generation.

Fourth, ensure that all Palestinian DISCOs move toward cost recovery. Not all Palestinian DISCOs are charging cost-recovery tariffs. Only two utilities, JEDCO and NEDCO, make formal tariff submissions to PERC. The resulting uniform tariff that is applied across all Palestinian utilities in the West Bank is estimated to under recover costs for all but NEDCO. Moreover, PERC's practice of not passing through collection inefficiencies to the retail tariff, while defensible from the standpoint of consumers, further weakens the financial solidity of the sector. In addition, GEDCO in Gaza does not follow PERC tariff guidelines and has not adjusted its electricity tariff for a decade, currently charging a retail tariff that is US$0.03–0.05 per kWh lower than the wholesale purchase price of electricity, without considering the costs of power distribution. The higher costs of electricity production in Gaza combined with the sensitive social context suggest that efforts to improve cost recovery in Gaza would need to be preceded by the measures noted to both reduce costs and improve the availability of power supply.

Fifth, build the capacity of PETL to play its envisaged role in the sector. In the new sector architecture, PETL has been assigned a dual role of transmission system operator and single buyer and central bookkeeper of the electricity sector. However, its start of commercial operations has been delayed pending the closure of a power-purchase agreement with Israel and the energization of four high-voltage substations. The signing of an interim power-purchase agreement with Israel to energize the Jenin high-voltage substation, which took place in July 2017, was the first step toward PETL's financial and operational sustainability. PETL is now able to resell the discounted high voltage power to DISCOs at a slight markup, allowing it to obtain revenues. The start of PETL's commercial operations enable the company to gradually move beyond donor dependency, paving the way for development of domestic independent power projects. In the meantime, until the full power-purchase agreement for all four substations is signed with Israel, PETL should make further progress toward its goal of being the single buyer, by ensuring that all wholesale power purchases are undertaken through its intermediation to improve transparency and discipline of the sector.

PHASE 2

While the absolute priority is to improve the creditworthiness of the electricity sector, there are several other no-regrets measures that can advance in parallel during a second phase. Even after decisive steps are taken to address creditworthiness, time will be needed for a payment record to be established and a reputation to be built. During this period of consolidation, it would be helpful to accelerate measures that facilitate the development of other power supply options that will become feasible once the issue of creditworthiness has been adequately addressed.

First, create the infrastructure needed to support the import of natural gas into the Palestinian territories. All the planning analysis confirms the strategic role that natural-gas-fired power generation can play in the electricity mix for both the West Bank and Gaza as well as its relatively attractive cost. The first step in making this possible is to construct the relatively modest pipeline extensions needed for the import of gas from the Israeli system. These will create the platform to have credible negotiations for gas supply agreements and ultimately the construction of new gas-fired plants, or the conversion to gas in the case of Gaza. The Gas-for-Gaza Project led by the Office of the Quartet has focused its efforts on removing key obstacles for the construction of a gas pipeline from Israel to the GPP.

Second, pursue an aggressive program to promote rooftop solar PV. Unlike utility scale solar power, rooftop solar PV is highly decentralized and is not contingent on progress toward sector creditworthiness and the capacity of PETL. Moreover, it has been shown that rooftop solar PV can play a valuable role as an electricity safety net to increase the resilience of the Palestinian electricity system and ensure that critical humanitarian needs can be met. This is particularly true in the case of Gaza, where efforts to pilot rooftop solar programs are already under way.

Third, complete the domestic transmission backbone in Gaza. Domestic transmission constraints are already an issue in Gaza, and these will become more severe as efforts to increase the supply of power bear fruit. It is important to ensure that the modest but needed transmission and distribution upgrades are completed in a timely fashion, and certainly well ahead of any future expansion of the GPP.

Fourth, improve the enabling environment for independent power projects. While the financial creditworthiness of the sector is the single largest impediment to the implementation of independent power projects, there are several simple measures that could improve the quality of the enabling environment, and which could be handled through secondary legislation or executive regulations that develop broad provisions in the existing sector legislation. These include further clarifying the provisions for licensing new generators and the provisions associated with connection to the grid. The roles of PERC and PETL in this process need to be further spelled out.

Fifth, establish a risk-mitigation mechanism to support the next generation of Palestinian independent power projects. Risk mitigation is no substitute for addressing fundamental creditworthiness issues, and it does not make sense to move ahead with risk mitigation until the Palestinian Authority has demonstrated a sustained and credible commitment to improving the underlying financial standing of the sector. Nevertheless, risk mitigation may play a valuable role in getting the next generation of Palestinian independent power projects off the ground. It would therefore be valuable to work with donors to develop a suitable mechanism for risk mitigation, evaluating the relevance of a range of financial instruments such as guarantees, first loss, blended finance, and viability gap finance.

PHASE 3

In a third phase, it will become possible to make progress with the first major wave of Palestinian independent power projects. These will build on the critical foundational elements tackled under the first two phases. It makes sense to begin with those projects that look to be the most tractable from a technical and political perspective, which suggests focusing on developing CCGT capacity and utility-scale solar PV in Areas A and B.

First, convert the GPP to CCGT gas-fired technology as the most urgent of the domestic power-generation projects. Conversion of the GPP once a gas pipeline comes on stream would save between US$45–62 million annually in fuel bills and provide Gaza with a cost-effective domestic source of power generation.

Second, progress with the construction of a new CCGT gas-fired plant, initially in Jenin and eventually in Hebron. Once the gas transportation infrastructure is in place, and some improvements to the sector environment have been achieved, the implementation of the Jenin CCGT plant should be relatively straightforward. Guarantees may be required to reduce the risk of nonpayment by the off-taker. Two important issues need to be addressed in the project design. One is the arrangement for selling any surplus energy back to the Israeli grid. The other is to ensure that the terms of a future gas supply agreement are sufficiently flexible to allow for an eventual switch of supply to or from the Gaza Marine gas field should this prove desirable.

Third, embrace a more ambitious target for utility-scale solar PV farms in Areas A and B. As noted in the planning analysis, it looks feasible to develop more than 600 MW of solar PV capacity in the West Bank based on potential just in Areas A and B as well as rooftop. This goes far beyond the current target of 130 MW by 2020. With the improvements in the enabling environment in place, as well as the establishment of risk-mitigation mechanisms, it should become feasible to scale up and accelerate efforts to develop this solar potential.

Fourth, establish suitable wheeling arrangements with Israel*.* As the volume of domestic power generation in the West Bank ramps up, there will be increasing need to move power away from generation

plants and toward Palestinian load centers. At present, this can be done only by wheeling power out through the Israeli grid and reimporting it into the West Bank at another location. The analysis suggests that wheeling charges are relatively costly, particularly if low-voltage networks are needed. It will therefore be important to ensure that the number of substations in the West Bank increases to keep pace with the expansion of domestic supply. It would also be important to have a dialogue with the Israeli regulator, regarding the charges for wheeling and to explore possible alternative arrangements (such as power swaps) that may help to contain costs.

Fifth, engage in dialogue over the use of Area C for the development of Palestinian power infrastructure and renewable energy generation. The planning analysis highlights the economic value of Area C, both as a location for grid-based solar generation and as the conduit for any future Palestinian electricity transmission infrastructure. While there is much that still needs to be done before the issue of Area C becomes a binding constraint, the political complexity of the issue suggests that it may be helpful to begin a dialogue process that over time can help clarify the modalities for making use of Area C. A related issue is the need to coordinate Palestinian plans to ramp up renewable-energy generation with those that also exist on the Israeli side, in order to ensure that challenges related to grid stability and the integration of intermittent sources can be adequately handled to the benefit of both sides.

PHASE 4

The fourth and final phase would build on earlier success to tackle the more challenging, and potentially transformational, projects needed to complete the Palestinian energy vision. These include the construction of solar generation and transmission backbone infrastructure in Area C, as well as the development of the Gaza Marine gas field.

First, develop a Palestinian transmission backbone in the West Bank. The analysis has shown that as domestic Palestinian power generation ramps up, the cost of wheeling power through the Israeli grid rapidly become quite significant. A more economic option in the long term would be to construct a Palestinian transmission backbone. It would need to cut across Area C, which would present significant technical and political challenges.

Second, develop utility-scale solar PV and CSP projects in Area C of the West Bank. If a successful track record of solar farm development can be established on the more limited land endowments of Areas A and B, and suitable transmission backbone infrastructure can be put in place across Area C, the West Bank would be ready to benefit from larger scale solar development in Area C. This would entail both solar PV and CSP technologies.

Third, move ahead with the development of the Gaza Marine gas field. The development of the Gaza Marine gas field is critically dependent on having a creditworthy buyer to sign the gas purchase deal. Given the abundance of gas discoveries in the eastern Mediterranean and the relatively small nature of the field, development of the field will likely need to be underwritten by a significant Palestinian demand for gas. This demand will take time to develop and would be achieved only once significant gas-fired power generation was on-stream and a solid gas-purchase payment record had been established in both the West Bank and Gaza. That would be a suitable juncture to enable signing a bankable deal for the development of the field, allowing the Palestinian gas-fired plants to switch gradually from Israeli to Palestinian gas as the new field becomes productive. Given the relatively small volume of Palestinian demand, it may make sense to consider the options for Gaza Marine development that require the least infrastructure development—by making use of stranded infrastructure from the Israeli Mari B field—thereby making the field economic at lower levels of throughput. The primary value of the Gaza Marine field to the Palestinian economy lies not so much in a supply of gas, which is abundantly available in the region, nor as a source of energy security, since Palestinian gas would likely be transported through Israeli infrastructure. Rather, the field is an eventual source of revenue for the Palestinian Authority, estimated at US$2.7 billion over 25 years.

What Are the Costs and Benefits of Achieving Energy Security?

The overall investment costs of pursuing energy security for the West Bank and Gaza are estimated to be US$4 billion to US$5 billion (table 6). Of this, almost all would take the form of private sector investment in domestic power-generation capacity, with only US$0.3 billion taking the form of public investment in supporting infrastructure for electricity transmission and distribution as well as gas transportation. Just over half would be needed for the West Bank and the remainder for Gaza. Significant investments would begin in phase 2 of the roadmap, peaking in phase 3, and remaining significant in phase 4.

Macroeconomic simulations indicate that the wider development impacts of pursuing these energy investment pathways would be substantial. According to modeling undertaken for this project, implementing the proposed investments and associated reforms would boost GDP growth by 0.3 percentage points per year in the West Bank and 0.5 percentage points per year in Gaza. Relative to the counterfactual “do nothing” scenario, the energy subsidy bill would come down by 1.7 percentage points of GDP in the West Bank and 5.1 percentage points of GDP in Gaza. The main macroeconomic benefits would come through freeing up resources for higher levels of productive investment in these economies.

This study shows that it is possible to envisage a path toward greater energy security for the West Bank and Gaza, and even if the way is fraught with financial, technical, and political challenges, inaction is not an option.

TABLE 5: INVESTMENT NEEDS FOR THE PALESTINIAN ELECTRICITY SECTOR, 2017–30 (US$ MILLIONS)

	WEST BANK		GAZA		COMBINED	
	PUBLIC	PRIVATE	PUBLIC	PRIVATE	PUBLIC	PRIVATE
Phase 1	-	-	-	-	-	-
Phase 2	7	800–1,100	135	240–320	142	1,040–1,420
Phase 3		930		900–990	-	1,830–1,920
Phase 4	188	375–500	-	250–1,200	188	620–1,700
Total	195	**2,105–2,530**	135	**1,390–2,510**	330	**3,495–5,040**

Source: World Bank estimates

TABLE 6: OVERVIEW OF THE PROPOSED ROADMAP FOR PALESTINIAN ENERGY SECURITY

PHASE 1: IMPROVE SECTOR CREDITWORTHINESS	PHASE 2: ADVANCE PARALLEL NO REGRETS MEASURES
Substitute Israeli imports for diesel-fired generation in Gaza	**Create infrastructure for import of natural gas**
P : Gradually ramp down GPP and use the savings to buy additional IEC supply until GPP can be converted to gas. **I** : Provide additional power to Gaza through 161kV.	**P**, **I** : Construct natural gas pipelines for West Bank and Gaza paving the way for construction of new/ upgraded power plants.
Improve operational and commercial efficiency	**Improve enabling environment for IPPs**
P : Continue improvement of DISCO performance by reducing losses, increasing collection rates and bringing down overhead costs. One mechanism can be through a revenue protection program aiming to permanently measure and bill every KWh sold largest DISCO consumers.	**P** : Update and improve legislation and licensing provisions that would help IPPs enter the market and also clarify roles and responsibilities of PERC and PETL in this environment.
Securitize payments of wholesale electricity	**Promote uptake of rooftop solar PV**
P : Strengthen sub national public finance to avoid diversion of electricity bill collections to municipal budgets and set up escrow accounts both in Gaza and West Bank to ring fence collections.	**P** : Set aggressive targets for 160MW of rooftop PV in Gaza and 530MW in West Bank.
Adjust tariffs to better reflect cost recovery	**Develop transmission backbone in Gaza**
P : Reexamine the retail tariffs and increase rates to allow better cost recovery by DISCOs.	**P** : Upgrade T&D network to allow increase in power supply and reduction in losses.
Build the capacity of PETL to play its role	**Design a risk mitigation mechanism for IPPs**
P : PETL to streamline billing to and payments from DISCOs while in parallel pushing to energize the new substations and sign the PPA with IEC. **I** : Sign bulk supply PPA and energize new substations.	**P**, **D** : After creditworthiness issues from Phase I have been improved, develop financial risk mitigation instruments such as guarantee mechanisms.

P: Palestinian measures **I: Israeli measures** **D: Donor community measures**

PHASE 3: IMPLEMENT FIRST WAVE OF IPPS	PHASE 4: IMPLEMENT TRANSFORMATIONAL PROJECTS
Convert GPP to CCGT gas-fired technology	**Develop grid-scale solar PV/CSP farms in Area C**
P : Complete conversion and upgrade of GPP ensuring flexible gas supply agreement to allow switch to Gaza Marine. **I** : Enter into gas supply agreement for GPP.	**P** : Begin development of renewables in Area C only after a successful track record of renewable development in Areas A and B. **I** : Provide permits for construction in Area C.
Construct new CCGT plant at Jenin, then Hebron	**Develop transmission backbone in the West Bank**
P : Complete JPP and HPP construction with flexible gas supply agreement to allow switch to Gaza Marine. Build additional substations to keep pace with increased domestic generation. **I** : Enter into gas supply agreement for JPP and HPP.	**P** : Begin development of a transmission backbone, considering also the possibility of negotiating a swap mechanism that eliminates the need for wheeling or building of infrastructure. **I** : Provide permits for construction in Area C and/or provide swap alternatives to building a backbone.
Increase renewable energy targets	**Develop Gaza Marine Gas Field**
P : Increase renewable energy targets to 600MW in West Bank and 160MW in Gaza by 2030 (includes rooftop solar) but only after the right enabling environment has been established from Phase I.	**P** : Develop Gaza Marine with least amount of infrastructure development to keep costs low. **I** : Allow permission to use existing Israeli infrastructure for evacuation of Gaza Marine.
Establish wheeling arrangements with IEC	
P, **I** : Negotiate lower wheeling tariffs and/or swap arrangements until a transmission backbone is built	
Engage in dialogue over use of Area C	
P, **I** : Coordinate on Area C access and permitting issues as well as grid stability and regional integration for supply expansion and transmission infrastructure.	

Note: IPP = independent power producer; GPP = Gaza Power Plant; CCGT = combined cycle gas turbine; PV = photovoltaic; CSP = concentrated solar power; IEC = Israeli Electric Corporation; DISCO = Distribution Company; PERC = Palestinian Electricity Regulatory Council; PETL = Palestinian Electricity Transmission Company Ltd; JPP = Jenin Power Plant; HPP = Hebron Power Plant; T&D = Transmission and Distribution; PPA = power-purchase agreement.

ENDNOTES

1. Total West Bank is made up of JDECO, NEDCO, HEPCO, SELCO and TEDCO which are the 5 DISCOs in the West Bank. GEDCO is the only DISCO in Gaza.

PART I

The West Bank and Gaza Energy Sector Context

CHAPTER 1

The West Bank and Gaza Electricity Sector

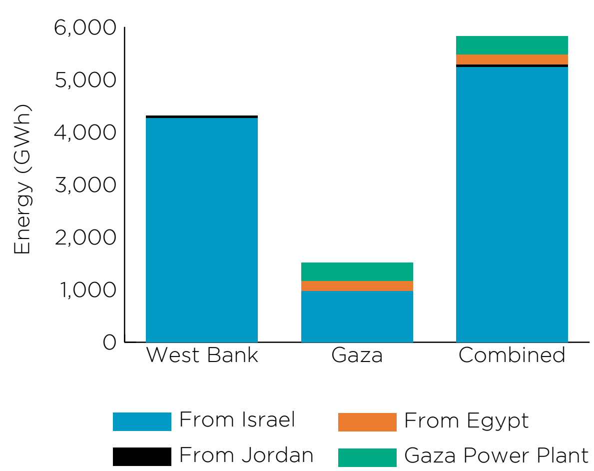
SECTOR OVERVIEW AND CHALLENGES

The Palestinian territories face significant energy security challenges, already severe in Gaza, and emerging in the West Bank. Limited power supply is rationed through rolling blackouts, which are increasing in duration in Gaza and in frequency in the West Bank. In Gaza, the available power supply meets only half the demand, and the rationing of power results in 8 hours of power supply followed by 8 hours of power cuts. During peak summer and winter load conditions, the power schedule is reduced to 3–4 hours per day. Although the West Bank generally enjoys 24 hours of power supply, in recent years it has also begun experiencing power shortages during peak winter and summer months. Electricity shortages in both the West Bank and Gaza are often met with mass protests and demonstrations.

The West Bank and Gaza rely primarily on electricity imports from Israel, particularly in the West Bank. Imports of electricity from the Israeli Electric Corporation (IEC) account for 99 percent of electricity supply in the West Bank and 64 percent in Gaza, but they have recently been constrained as the existing power lines are becoming overloaded (see figure I-1.1). Up to now, Israeli power has been provided through over 270 low and medium-voltage connection points between Israel and the West Bank, with a total contracted capacity of 890 megawatts (MW). In Gaza, 10 connection points with Israel provide 120 MW of capacity. Due to the low and medium-voltage connection points, Palestinian consumers have historically paid higher Israeli tariff rates of NIS 0.33–0.37 (US$0.09–0.10) per kilowatt hour (kWh), and cannot benefit from the lower tariff rates available to higher voltage customers. Furthermore, the proliferation of connection points has made it difficult to monitor electricity flows across the territories. In the West Bank, four new 161 kilovolt (kV) substations have recently been constructed with donor support, which will allow for the import of electricity from Israel through a small number of high-voltage lines. For Gaza, an additional 161 kV interconnector with Israel is planned. Refer to part 1, chapter 7 for more detail on the Palestinian transmission and distribution system. See appendix A, map A.1 and map A.2 for the existing electricity supply options.

The Palestinian Authority does not have control over most of its territory, adding layers of complexity to the implementation of infrastructure projects. The Oslo II Accord divided the West Bank in three administrative divisions: Areas A, B, and C. The distinct areas were given different statuses, according to their governance, pending a final status accord. Area

Figure 1.1: Main Sources of Electricity in the West Bank and Gaza, 2015



Source: Palestinian Central Bureau of Statics (PCBS), 2015, “Quantity of Electricity Imported (GWh) in the West Bank by Source and Month, 2015” and “Quantity of Electricity Imported and Purchased (GWh) in Gaza Strip by Source and Month, 2015,” Ramallah City. http://www.pcbs.gov.ps/site/886/Default.aspx.

A constitutes around 18 percent of the West Bank and is administered exclusively by the Palestinian Authority. Area B makes up around 22 percent and is administered by both the Palestinian Authority and Israel. Area C, which contains Israeli settlements, makes up the remaining 60 percent of the West Bank and is administered by Israel (see map G.3 in appendix G). A key Israeli actor in the Palestinian power sector is the Coordinator of Government Activities in the Territories Unit (COGAT), which operates under the Israeli Ministry of Defense and is responsible, among other issues, for dealing with energy and electricity supply issues in Area C.[1] COGAT's authorization is required for regional electricity projects, such as interconnectors with neighboring counties, as well as any power generation or transmission infrastructure to be built within the West Bank. COGAT plays an important role in the monitoring and maintenance of distribution infrastructure and provides assistance in dealing with failures.

In addition to the Israeli supply, modest volumes of power are imported from Jordan to the West Bank and from Egypt to Gaza. Egypt's Al Kanal Electricity Company can supply up to 30 MW of electricity through three-medium voltage 33 kV connections points at the southern end of the Gaza strip (see map A.2 in appendix A). The power lines from Egypt are frequently out of service, delivering significantly less than the 30 MW capacity. Furthermore, the available electricity is of poor quality and subject to frequent voltage and frequency deviations that damage expensive and sensitive equipment at hospitals such as magnetic resonance imaging (MRI) machines and computed tomography (CT) scans. The majority of the power from Egypt is paid for through the Arab League as a donation relieving the obligation of payment on Gaza and the Palestinian Authority. As a result, there is no track record of payment between the Egyptian power utility that supplies electricity to Gaza and the local distribution company Gaza Electricity Distribution Company (GEDCO). As for the West Bank, Jordan's National Electric Power Company (NEPCO) can supply up to 20 MW through a medium-voltage connection. Jerusalem District Electric Company (JDECO) currently purchases power from NEPCO by arbitraging time-of-use (TOU) prices between IEC and NEPCO. NEPCO prices are on average NIS 0.11–0.15 (US$0.03–0.04) per kWh higher than IEC prices, except at certain times of day during specific seasons. Refer to part 1, chapter 5.2 for more details on the cost of Jordanian versus Israeli power. While there are plans to upgrade the Jordanian interconnector to allow more imports, similar to the case of Egypt, the question of payment remains the main concern.

The Gaza Power Plant (GPP) provides the only significant domestic generation capacity in the Palestinian energy portfolio, and it has been plagued with difficulties. GPP is owned by the Gaza Power Generation Company, which is in turn owned by the Greek- Lebanese construction company Consolidated Contractors Company. The plant entered into commercial operation on March 15, 2004, under a 20-year Power Purchase Agreement (PPA) contract, which requires that the Palestinian Authority cover take-or-pay capacity charges of NIS 0.096 (US$0.026) for the full 140 MW capacity of the plant. This capacity charge is paid to the owners of GPP regardless of the level of the plant's actual production and output. In addition, the Palestinian Authority must cover the cost of fuel, which, depending on the level of fuel taxes and exemptions applied, can range from NIS 0.74 to NIS 1.3 (US$0.20–0.40) per kWh for the diesel fuel alone. Although the plant has a rated capacity of 140 MW, it normally operates at less than 50 percent of its capability due to the inability of the Palestinian institutions to pay the high costs of diesel fuel. As international donor support to the West Bank and Gaza has declined in recent years, budget constraints have resulted in the Palestinian Authority reducing the exemption on fuel taxes to Gaza, more than doubling the cost of fuel for GPP. The plant has also suffered repeated damage during armed conflict, affecting its fuel storage capacity. Considering both the capacity charges and the fuel costs, GPP is very expensive to run at approximately NIS 1.05–1.65 (US$0.30–0.45) per kWh, to more than three times the IEC power import tariff. GPP is already designed to operate on natural gas, which would significantly bring down its cost of power production. This will become possible once the planned gas pipeline project linking Gaza to gas terminals at Ashkelon in Israel is completed.

In the West Bank and Gaza, renewable energy generation is still in its infancy. The Palestinian cabinet adopted a renewable energy strategy in 2012 that set a target of 130 MW for domestic renewable generation by 2020, of which only 18 MW has been installed as of 2017. The renewable energy laws, which laid out the rules and regulations for entering the Palestinian renewable energy market, were released only in mid-2015. In terms of utility-scale solar photovoltaic (PV), many private-sector entities have shown great interest and several licenses have been granted. However, by law, projects over 1 MW can sell only to the single buyer, Palestinian Electricity Transmission Company Ltd. (PETL), which is not currently credit worthy and lacks any kind of payment record. This high risk of nonpayment, together with the possibility of significant construction delays, is discouraging project developers and financiers alike. Further obstacles, are lack of access to prime land in Area C as well as the lack of transmission infrastructure to evacuate the power. In terms of rooftop solar, the Palestinian Solar Initiative, launched in 2012, aimed to install on-grid residential rooftop solar systems in the West Bank, each with a range of 1-5 kW, for a total installed capacity target of 5 MW by 2015. Under the plan, households purchase the solar systems themselves through "green loans" and sell energy back to the grid in return for a feed-in-tariff. Although initially attractive, over time the Palestinian Authority reduced the feed-in-tariff rates due to budgetary restrictions, making the program progressively less attractive to consumers. As of December 2016, the Palestinian Energy and Natural Resources Authority (PENRA) reported that approximately 300 systems were installed under the Palestinian Solar Initiative. Refer to part I, chapter 6 for further details on the Palestinian renewable energy sector.

An unfinished power sector reform, which started over 20 years ago, consolidated the distribution segment into a handful of local distribution companies. PENRA, established in 1995, launched key institutional reforms, including the consolidation of hundreds of small municipality and village councils' (MVC) electricity services into six larger distribution companies (DISCOs) to benefit from economies of scale. These include GEDCO, Hebron Electricity Distribution Company (HEPCO), JDECO, Northern Electricity Distribution Company (NEDCO), Southern Electricity Distribution Company (SELCO) and Tubas Electricity Distribution Company (TEDCO). Despite considerable progress, a significant number of MVCs continue to distribute power independently, rejecting the legal imperative to integrate electricity services and merge with the DISCOs. Together, these independent MVCs represent up to 30 percent of total power sales in the West Bank. In the long run, the goal is to further consolidate all DISCOs and MVCs in the West Bank into one central DISCO, thereby reducing overhead costs and in turn bringing down the retail sales tariff. See appendix A, tables A.3 to A.4 for the financial statements provided by each DISCO from 2011 to 2015.

JDECO is the longest standing distribution company in the Palestinian territories and is regulated by both Israeli and Palestinian authorities due to the nature of its service area. In contrast to the other five DISCOs

that were created as part of the recent sector reform, JDECO is a longstanding utility that has been in existence since 1914. JDECO's coverage area includes (i) East Jerusalem (30 percent), which falls under Israeli control with tariffs and regulations set by the Israeli Public Utility Authority (PUA), and (ii) the central West Bank (70 percent), including Ramallah and Jericho, which falls under the control of the Palestinian Authority, with tariffs and regulations set by the Palestinian Electricity Regulatory Council (PERC). As noted, JDECO purchases the bulk of its supply from IEC, supplemented by Jordanian imports when demand peaks or pricing differences prove advantageous.

The Electricity Law of 2009 created several new sector institutions and provided the beginnings of a legal framework for public-private partnership (PPP) in the sector. The new legislation paved the way for a new sector regulatory entity, as well as the creation of a separate transmission company. In addition, the law provides a basis for new generation projects to be developed in the West Bank and Gaza on a PPP basis by classifying this as a licensed activity. Nevertheless, few details are provided about the detailed terms and conditions of licenses or their classification into different categories, and the law is silent about roles and responsibilities for the grid connection of new generation plants. In the absence of broader PPP framework legislation, these kinds of issues would need to be settled through secondary legislation or supporting regulations.

The establishment of PERC has helped provide a more solid technical basis for the determination of tariffs. It was created in 2009, with support from the World Bank and the European Union, with a mandate of regulating and monitoring the energy sector. A key contribution of PERC has been to adopt a clear tariff-setting methodology and set a unified end-user tariff for the Palestinian territories (see appendix A, tables A.1 and A.2, for a breakdown of PERC's tariff structure). In addition, PERC has managed to significantly improve data collection over the past few years, allowing the regulator to track key technical, financial, and customer service performance indicators for each DISCO on a quarterly basis.

The new transmission company, PETL was also been established as part of a move to rationalize power import arrangements with Israel. PETL was created in 2013, with support from the World Bank, and has a mandate to be the single buyer and transmission system operator for the Palestinian energy sector. Although the Palestinian energy sector does not yet have any transmission infrastructure, PETL will be responsible for maintaining and operating the new substations and acting as the single buyer of wholesale power purchased from Israel, as well as from any future Palestinian independent power producers (IPPs). In the absence of transmission infrastructure, the electricity network in the West Bank takes the form of a series of "electricity islands," all connected to the Israeli grid, rather than one interconnected Palestinian network. Refer to part I, chapter 7 for further discussions on PETL and the transmission and distribution grids.

The political division between the West Bank (ruled by Fatah) and Gaza (ruled by Hamas) reduces the ability of PENRA, PETL, and PERC to exercise their jurisdiction in Gaza. In principle, the new institutional structure applies across the Palestinian territories. However, in practice, GEDCO, the Gaza utility, operates independently of this framework. For example, GEDCO does not follow the unified tariff set by PERC and adopted by all the DISCOs in the West Bank. In fact, PERC has no enforcement capability in Gaza, as the board and governance structure of GEDCO do not report to the Palestinian Authority. PENRA does have a branch office on the ground in Gaza, which works very closely with GEDCO and with PENRA Ramallah to coordinate activities, but it does not have direct control over GEDCO. PENRA in Gaza supports GEDCO by facilitating materials entry for energy projects in Gaza, organizing provision of fuel for GPP, and communicating and coordinating with the international community on energy projects in Gaza.

Despite some improvements, the electricity sector suffers from operational and financial problems due to high losses and low collection rates. In 2015, DISCOs in the West Bank and Gaza billed consumers for 76 percent of the power they purchased from suppliers, with the other 24 percent lost and never billed due to the poor state of the infrastructure and illegal connections. Of the electricity billed to consumers, DISCOs collected 84 percent of invoices, with 16 percent accumulating as outstanding debt from consumers to DISCOs. Overall, this means that for every 100 kWh supplied to the DISCOs from IEC, only 64 kWh actually generate revenue; although, there is significant variation in performance across companies (see table I-1.1). The net annual income

TABLE I-1.1: OVERVIEW OF PALESTINIAN ELECTRICITY DISTRIBUTION COMPANIES, 2015

	GEDCO	TOTAL WEST BANK	JDECO	NEDCO	HEPCO	SELCO	TEDCO
Scale							
Customers	231,500	436,389	256,314	90,265	45,660	25,650	18,500
Purchased electricity (NIS millions)	795	1,398	871	250	164	71	42
Billed electricity (NIS millions)	518	1,509	949	245	193	76	46
Net annual income/loss (NIS millions)	n.a.	-76	-82	9	9	-15	3
Performance							
Losses: technical and nontechnical	26%	22%	24%	17%	20%	28%	16%
Collection ratio	65%	89%	91%	98%	81%	71%	76%
O&M as percentage of purchased electricity	8%	17%	22%	5%	10%	21%	17%

Note: GEDCO = Gaza Electricity Distribution Company; JDECO = Jerusalem District Electric Company; NEDCO = Northern Electricity Distribution Company; HEPCO = Hebron Electricity Distribution Company; SELCO = Southern Electricity Distribution Company; TEDCO = Tubas Electricity Distribution Company.

of JDECO has been negative year after year over the past five years, despite the company's scale advantages and relatively high collection rates arising from the successful implementation of prepaid meters. However, the company faces challenges in terms of high distribution losses and operating expenditures. On the other hand, NEDCO is by far the most efficient DISCO in the West Bank and Gaza, with the lowest losses and overhead costs and the highest collection rates.

Bill collection rates are particularly low in Gaza and in refugee camps in the West Bank, due to difficult living conditions and a culture of nonpayment. In Gaza, paying electricity bills is not considered a high priority, particularly given the low quality of service. This is understandable given that the population has been affected by armed conflict every two to three years over the past decade and faces the highest unemployment rate in the world at 42 percent. Refugee camps in the West Bank are also challenging in terms of revenue collection, as they combine high levels of per capita consumption with very low rates of bill payment. According to a recent survey, underlying reasons for nonpayment of electricity bills are the high cost of electricity, low income, poor quality of service, and perceived exemption due to refugee status. Moreover, the poor security conditions in the camps make it difficult for DISCO staff to enter and enforce revenue collection or disconnect service. A recent cabinet decision enforces all DISCOs and MVCs in the West Bank to establish an escrow account for collection of electricity bills. This mechanism, which has already been adopted by over 100 local authority councils, aims to monitor, streamline, and audit the flow of electricity payments, preventing diversion of funds.

Current electricity tariffs are low relative to the costs of service provision, leading to implicit subsidies of over NIS 600 million (US$166 million). The regulatory authority, PERC, has set a uniform tariff of NIS 0.53–0.56 (US$0.14–0.15) per kWh for the Palestinian DISCOs. However, financial analysis of the sector suggests that the full cost of service provision—given current levels of inefficiency—ranges from about NIS 0.66 to NIS 1.42 (US$0.18–0.39) per kWh, depending on the DISCO. Even if operating and commercial efficiency could be improved to more typical levels, tariffs would still need to increase significantly to ensure the financial viability—and hence creditworthiness—of the sector. It is estimated that the shortfall between tariffs and costs amounts to implicit subsidies of over NIS 600 million (US$166 million) in 2015.

However, it is important to recognize that there are genuine affordability issues among the poor. A widely used international benchmark is that electricity remains affordable when households are able to meet their basic needs without spending more than 5 percent of income. Based on current practice in West Bank and Gaza, it is estimated that 160 kWh is an adequate level of consumption to meet basic household needs.

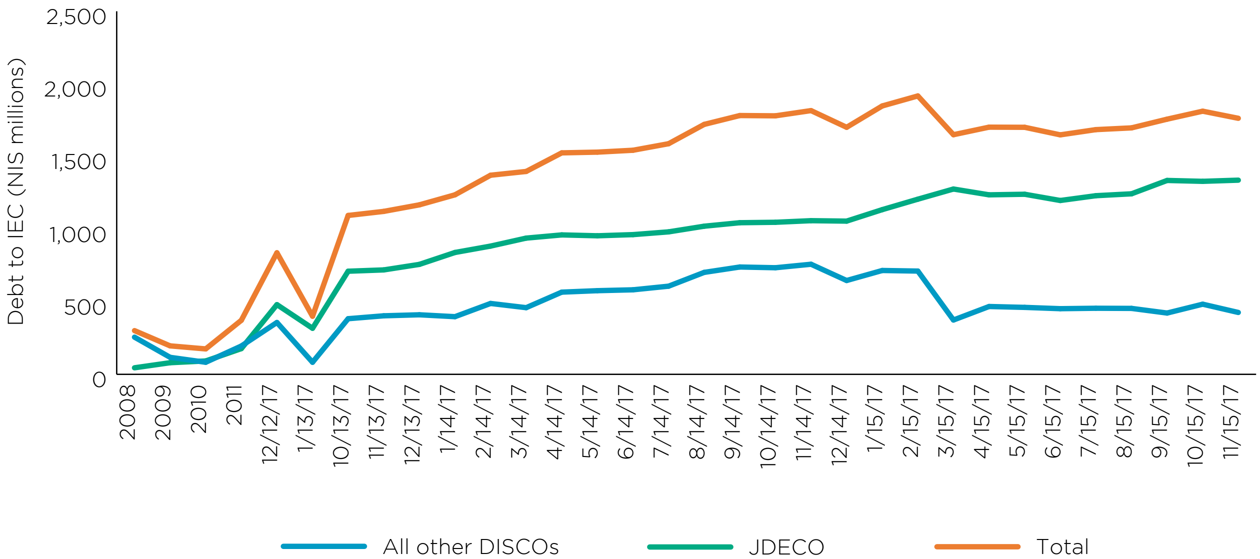
Given the current income distribution, the lowest income decile can only afford to pay a rate of NIS 0.43 (US$0.11) per kWh. The mechanism currently used to safeguard affordability is a rising block tariff, with first block of 160 kWh per month currently set at NIS 0.43 (US$.11) per kWh, matching the lowest income decile's ability to pay. However, given that average residential electricity consumption in the West Bank and Gaza is only 200–300 kWh per month, this means that most consumption benefits from this subsidized rate.

In addition to the challenge of collecting revenue from customers, the scarcity of subnational fiscal resources means that power sector revenues get diverted to municipal budgets. No regular and predictable intergovernmental fiscal transfer exists to cover the recurring expenditures of municipalities or fund basic capital investments. Thus, MVCs have developed a practice of diverting revenues from service fees to meet their expenditures needs, making electricity revenues among the more important sources of municipal funds. Data for the years 2011–13 show that total revenues per capita for village councils (VCs) in charge of electricity distribution can be up to four times higher than for those VCs without that responsibility. VCs with electricity distribution functions were able to spend over twice as much in per capita operating and development expenditures each year in the 2011–13 period than VCs not in charge of electricity distribution. For municipalities, there is almost a 100 percent difference between the two groups of municipalities in total revenues per capita in the 2010–12 period. This consideration may be one of the factors discouraging the remaining municipalities from incorporating their electricity service under the umbrella of the local DISCOs. However, even in municipalities that have ceded electricity service to the Palestinian DISCOs, there is evidence that some dividend income is still being paid by the DISCOs back to the municipalities. While data on this phenomenon is sparse, it is known that at least NIS 5.1 (US$1.4) million were paid to various municipalities by three Palestinian DISCOs in 2014. Breaking this vicious circle will require (i) increasing local revenue collection; (ii) improving transparency of payment flows, including interagency arrears; (iii) placing sanctions on entities that divert funds for nonessential or unproductive use; and (iv) providing financial support to those Local Government Units that do not have the fiscal capacity to ensure basic service provision.

As a result, the DISCOs have developed a culture of nonpayment for wholesale electricity supplied by IEC, leaving the Palestinian Authority to step in through a "net lending" mechanism. Given the weak state of cost recovery, some DISCOs and MVCs pay only partially for electricity supplied by IEC, which amounts to 58 percent of the total cost of electricity; others don't pay at all, preferring to use the collected revenues for financing municipal activities. For years, the Palestinian Authority has indirectly paid a portion of the outstanding bills owed by DISCOs and MVCs to IEC through a mechanism called 'net lending'.[2] Outstanding payments owed to the IEC are either (i) deducted from the Palestinian Authority's clearance revenues by the Israeli Ministry of Finance and registered as net lending or (ii) are accumulated as debt owed to the IEC. Net lending reduced the Palestinian Authority's available revenues by an estimated NIS 1 (US$0.3) billion in 2012, representing 13.5 percent of the Palestinian Authority's total revenues. This mechanism sets a precedence in which service providers continue to receive electricity from suppliers, and consumers continue to receive electricity from service providers even if they do not pay their bills, with an assurance that the Palestinian Authority will pay on their behalf, reducing a sense of responsibility and accountability. Since Israel considers JDECO an Israeli company, the debt owed by JDECO to IEC cannot be paid through the net lending, mechanism making JDECO the second largest contributor, after GEDCO, to Palestinian electricity sector debt to Israel.

A new electricity agreement between government of Israel and the Palestinian Authority has settled past debt and plans to pave the way for improvements in the Palestinian energy sector. The unpaid portion of outstanding bills from IEC to Palestinian service providers started to accumulate substantially from 2011 onward (see figure I-1.2). The debt can be divided into two portions, the larger share that relates directly to JDECO and a smaller share owed by the Palestinian Authority relating to the remaining five Palestinian distribution companies and MVCs. In view of the situation, IEC made payment of past debt a precondition for energization of the four, new high-voltage substations as well as a precondition for the scale-up of the capacity of the connection points. On September 13, 2016, the Palestinian Authority and the Israeli government signed an agreement to settle past electricity sector debt, which stood at NIS 2.03 billion (US$534 million) and created joint committees to work on three key issues: (i) energization of the

Figure I-1.2: Electricity Sector Debt to IEC, 2008–2015



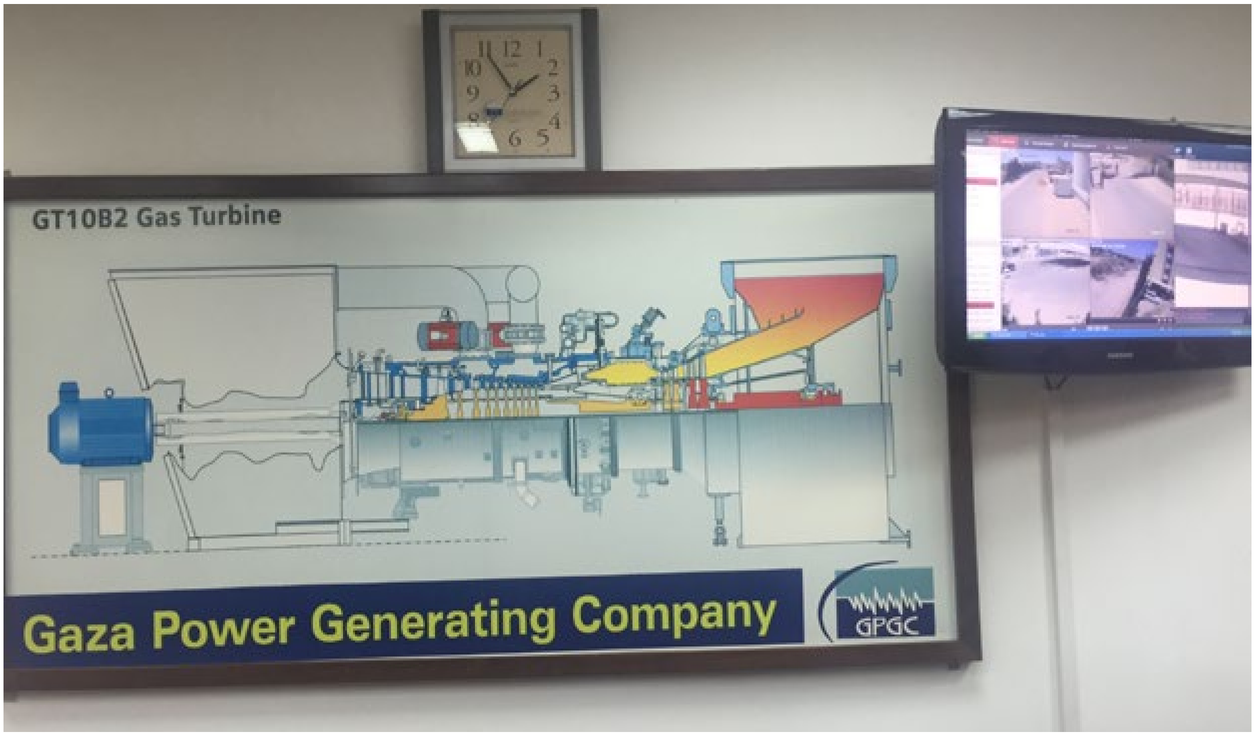
Source: Information provided by Eco Energy.
Note: IEC = Israeli Electric Corporation; DISCO = Distribution Company; JDECO = Jerusalem District Electricity Company.

TABLE I.1.2: MACROECONOMIC IMPACT OF ELECTRICITY SECTOR UNDERPERFORMANCE

	WEST BANK			GAZA		
	2013	2014	2015	2013	2014	2015
Implicit subsidy (US$ millions per annum)	94.8	65.9	72.6	136.0	178.1	125.4
Implicit subsidy (NIS millions per annum)	342.3	235.9	281.5	491.1	637.7	486.5
Implicit subsidy (% of GDP)	1.0	0.6		4.4	5.0	
Subsidy rate (% of tariff)		17.5		50.9	65.5	56.7

new high-voltage substations to bring more power to the West Bank, (ii) signing of a long-term PPA at a lower wholesale tariff rate, and (iii) transfer of over 200 connection points to PETL in order to have a single point of transaction (single buyer) between Israeli and Palestinian entities. On July 10, 2017, an interim PPA was signed for the energization of the Jenin substation alone, which was an encouraging step in the right direction, until the full negotiations for the long term PPA are concluded. Overall, the success of the new electricity agreement rests on the ability of PETL to pay for 100 percent of the power purchased from IEC. In turn, DISCOs and end consumers need to follow suit along the value chain.

The economic burden associated with the subsidization of the electricity sector is several times higher in Gaza than in the West Bank. Based on computable general equilibrium models developed for both the West Bank and Gaza, the magnitude of the subsidies associated with the electricity sector were estimated (table I-1.2). The implicit subsidies due to underpricing, distribution losses, and undercollection of revenues amounted to between NIS 236 and NIS 342 million (US$65 million to US$95 million) per year for the West Bank, which amount to no more than 1 percent of the West Bank's GDP for 2013–15. This is equivalent to a 15–20 percent subsidization rate for the retail tariff. In the case of Gaza, the implicit subsidies are much larger, both in absolute and relative terms, amounting to NIS 487–638 million



(US$125–175 million) per year, which amounts to as much as 4–5 percent of Gaza's GDP in 2013–15. This is equivalent to a 60 percent subsidization rate of the retail tariff.

IMPLICATIONS FOR WEST BANK AND GAZA

The energy sector context carries several important implications for the future of the Palestinian electricity sector.

There is scope to diversify Palestinian electricity supply, particularly in the West Bank. The Palestinian energy sector, particularly in the West Bank, has long relied primarily on Israel for power imports, which for the most part have been relatively reliable and cost-effective. Yet energy security could be further enhanced by greater diversification of power sources in the West Bank, including the development of indigenous gas-fired and solar power options.

The Gaza Power Plant provides a cautionary tale of independent power projects. Nevertheless, the experience of GPP, which has proved expensive and unreliable, demonstrates that indigenous power generation does not necessarily represent an improvement over power imports. It is important to ensure that contractual terms are sufficiently attractive and adequate supplies of cost-effective fuel are available. For Gaza, a key priority is the conversion of the current plant to natural gas to reduce the cost of fuel.

Palestinian's power-sector reform process has made strides but remains incomplete. Significant institutional reforms have already been undertaken in the Palestinian electricity sector, but these are still fragile and need to be sustained. Institutional strengthening is needed for all sector institutions, including PERC, PETL, and the DISCOs. PETL is expected to be commercially operational and financially sustainable following the energization of the Jenin, Nablus, Hebron, and Ramallah high-voltage substations and the signature of a long-term PPA with IEC. In the meantime, the signing of the interim PPA for the Jenin substation allows PETL to begin operations gradually until the full PPA is signed.

Distribution utilities are the Achilles' heel of the Palestinian electricity sector. The underperformance of the DISCOs is the deepest challenge faced in the electricity sector, because the DISCOs are the foundation of the payment chain for the sector and because the difficulties faced are institutional and political in nature. Without improving the ability of the DISCOs to capture customer revenues and reliably pay for wholesale power, PETL's viability will be compromised, as will the creditworthiness of the sector as an off-taker for future independent power projects in the West Bank and Gaza.

Addressing subnational financing issues is key to the future of the power sector. Even after the performance of the DISCOs is improved, their financial viability will remain vulnerable to municipal capture of revenues, until and unless the fundamental challenges of subnational municipal finance are addressed. Indeed, without this, as DISCOs enhance their own efficiency they risk simply becoming an increasingly attractive source of municipal revenues without solving the fundamental problem of creditworthiness in the sector *In Gaza, it is possible to pay for additional IEC supply by ramping down generation at GPP and using the money to buy double the power from IEC.* As shown in table I-1.3, between 2011 and 2015, GPP was operating an average capacity of 45 MW, while IEC imports accounted for 119 MW. Factoring in the capacity charge that is paid for IEC, the unit cost of power from GPP is three times more expensive than IEC. If the GPP take-or-pay capacity-charge payments continue to be paid, for every 1 MW that GPP is ramped down, 2 MW can be purchased from IEC for the same cost. If GPP's take-or-pay capacity-charge payments are terminated, for every 1 MW that GPP is ramped down, 3 MW can be purchased from IEC for the same cost. This means that if GPP, running on diesel, is turned off completely and the money is used to buy power from IEC, Gaza can have access to 30 percent more power. This does not require additional payments by the Palestinian Authority through clearance revenues or net lending. Later, once GPP is converted to operating on natural gas, which is expected to have a lower cost of production, on par with Israeli imports, then GPP can be turned on again. However, in the immediate term, the best solution for Gaza is to ramp down GPP operating on diesel.

To ensure bill collection revenue continues to be forwarded from GEDCO to the Palestinian Authority, it is important to set up a separate escrow account into which collections are deposited and which is monitored by an international oversight committee. There is a legitimate concern that, if GPP is turned off, authorities in Gaza will no longer have any incentive to forward bill collections to the Palestinian Authority, which will then bear the responsibility of paying for all IEC supply through clearance revenues. Currently, fuel for GPP is procured by the Palestinian Authority from the money that is forwarded to the Palestinian Authority by GEDCO from bill collections amounting to NIS 20 million to NIS 25 million per month. To ensure that this forwarding of bill collections continues as GPP ramps down, an escrow account should be set up, separate from Palestinian Authority budgets, into which GEDCO can forward its collections. This account should be monitored by a high-level international committee that serves to ensure transparency. At NIS 20 million to NIS 25 million per month, the collections will be enough to pay for 30–40 percent of the total supply to Gaza, which is on par with the current setup.

TABLE I-1.3: FINANCING ADDITIONAL IEC POWER BY RAMPING DOWN GAZA POWER PLANT

Status quo: 2011–15 historical average values			
	IEC		**GPP**
Cost of purchased power (NIS per month)	31,807,885	Cost of capacity charge (NIS per month)	10,097,360
		Cost of diesel fuel (NIS per month)	24,430,783
Quantity of purchased power (kWh per month)	85,576,569	Quantity of purchased power (kWh per month)	32,633,872
Corresponding capacity (MW)	119	Corresponding capacity (MW)	45
Average purchase tariff (NIS per kWh)	0.37	Average purchase tariff (NIS per kWh)	1.06
		Cost of fuel per kWh produced (NIS per kWh)	0.75
Total cost per month (NIS)	**66,336,028**		
Phase 1: Ramp down GPP by 12 MW, ramp up IEC by 25 MW			
	IEC		GPP
Cost of purchased power (NIS per month)	38,498,290	Cost of capacity charge (NIS per month)	10,097,360
		Cost of diesel fuel (NIS per month)	17,740,378
Quantity of purchased power (kWh per month)	103,576,569	Quantity of purchased power (kWh per month)	23,697,039
Corresponding capacity (MW)	144	Corresponding capacity (MW)	33
Average purchase tariff (NIS per kWh)	0.37	Average purchase tariff (NIS per kWh)	1.06
		Cost of fuel per kWh produced (NIS per kWh)	0.75
Total cost per month (NIS)	**66,336,028**		
Phase 2: Ramp down GPP by 25 MW, ramp up IEC by 50 MW			
	IEC		GPP
Cost of purchased power (NIS per month)	45,188,695	Cost of capacity charge (NIS per month)	10,097,360
		Cost of diesel fuel (NIS per month)	11,049,973
Quantity of purchased power (kWh per month)	121,576,569	Quantity of purchased power (kWh per month)	14,760,206
Corresponding capacity (MW)	169	Corresponding capacity (MW)	21
Average purchase tariff (NIS per kWh)	0.37	Average purchase tariff (NIS per kWh)	1.06
		Cost of fuel per kWh produced (NIS per kWh)	0.75
Total cost per month (NIS)	**66,336,028**		
Phase 3: Ramp down GPP by 45 MW, ramp up IEC by 91 MW			
	IEC		GPP
Cost of purchased power (NIS per month)	56,160,959	Cost of capacity charge (NIS per month)	10,097,360
		Cost of diesel fuel (NIS per month)	0
Quantity of purchased power (kWh per month)	151,096,569	Quantity of purchased power (kWh per month)	0
Corresponding capacity (MW)	210	Corresponding Capacity (MW)	0
Average purchase tariff (NIS per kWh)	0.37	Average purchase tariff (NIS per kWh)	1.06
		Cost of fuel per kWh produced (NIS per kWh)	0.75
Total cost per month (NIS)	**66,258,319**		

Note: IEC = Israeli Electric Corporation; GPP = Gaze Power Plant; kWh = kilowatt hour; MW = megawatt.

NOTES

1 For large energy projects in Areas A and B, COGAT has been requesting that their approval be obtained in advance.
2 *Net lending* refers to the process by which Israel deducts a portion of unpaid electricity bills, owed by Palestinian distributors, to IEC (which supplies over 95 percent of the energy to West Bank and Gaza) from collection revenues that are collected by the Israeli Ministry of Finance on behalf of the Palestinian Authority. This process essentially forces the Palestinian Authority to indirectly pay for the outstanding bills of distribution companies through collected revenues meant for the national budget.

CHAPTER 2

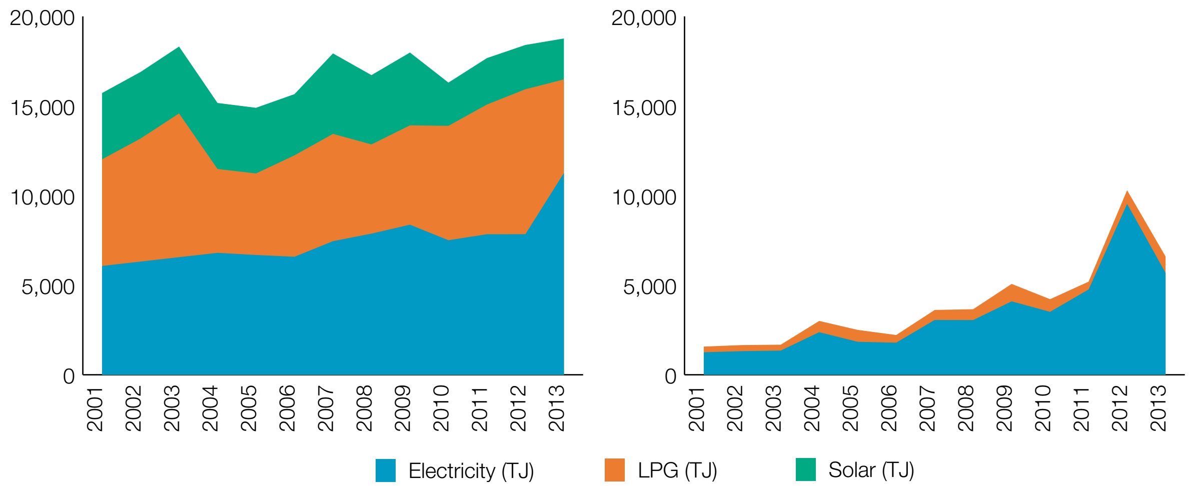
Electricity Demand

THE CURRENT CONTEXT

Electricity accounts for 27 percent of Palestinian energy consumption, which is dominated by the residential sector. From 2001 to 2013, electricity demand grew at an average annual rate of 7.2 percent. Residential electricity consumption has been growing slightly below that average, at 5.3 percent, with average household electricity consumption reaching some 250 kilowatt-hours (kWh) per month by 2013. This is a modest level of consumption by regional standards, at about half the levels found in the Maghreb countries. Nonresidential electricity consumption was negligible in the early 2000s, and despite steep growth rates of 13.4 percent annually from 2001 to 2013, still accounted for only a small percent of total electricity consumption relative to the residential sector in 2013 (see figure I-2.1). It is unusual for the share of nonresidential consumption to be so low, and this illustrates the underdeveloped nature of the economy. It also represents a disadvantage for the utilities, which typically count on large industries as anchor customers.

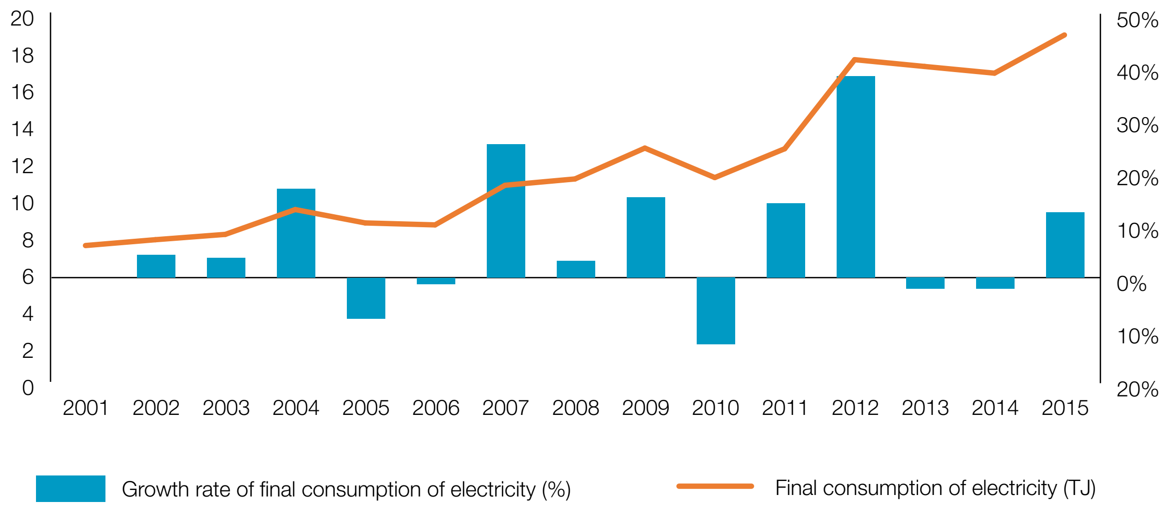
While enjoying diversified energy sources, Palestinian households increasingly rely on electricity. While nonresidential energy consumption almost entirely takes the form of electricity, Palestinian households meet their energy needs through a mixture of electricity, liquefied petroleum gas (LPG) and solar water heaters. A long series of household energy surveys documents a trend of substitution of electricity for other forms of household energy over time, particularly for baking but also for water and (to a lesser extent) space heating applications (see appendix B, figures B.1 and B.2). Since 2009, there has also been a notable increase in the uptake of air-conditioning units. Based on econometric analysis of the 2013 household energy survey, air-conditioning units add over 100 kWh per month to a household's consumption during the summer months, while electric water and space heating each add 50 kWh per month during the winter months (see appendix B, tables B.1 and B.2).

Figure I-2.1: Palestinian Energy Consumption by Sector



Source: PCBS, "Energy Balances, 2001–2013." http://www.pcbs.gov.ps/site/lang__en/886/Default.aspx
Note: LPG = liquefied petroleum gas.

Figure I-2.2: Volatility of Electricity Consumption over Time



Electricity demand patterns in the West Bank and Gaza have historically been quite volatile, making it challenging to predict the future. For example, electricity consumption grew at 38.2 percent in 2012, shrunk by 2.1 percent in the next two years, and increased again by 12.4 percent in 2015 (see figure I-2.2). As a result of strong swings in historic demand as well as limited data availability, Palestinian electricity demand cannot be reliably forecast using standard econometric techniques. There is some evidence, however, that electricity demand does tend to follow GDP growth trends. Indeed, for the Middle East and North Africa region as a whole, the elasticity of electricity output to real GDP growth, based on 370 country-year observations, finds a regionwide elasticity value of 1.07.

A simple and defensible approach is to base electricity demand forecasts on real GDP growth forecasts. The most recent real GDP demand forecasts from the Palestinian Central Bureau of Statics (PCBS) and the International Monetary Fund stand at 2.63 percent for the West Bank and Gaza as a whole, ranging from 2.51 percent in the West Bank to 3.02 percent in Gaza. These become the starting point for forecasting electricity demand. However, it is also important to consider the current base from which electricity demand is forecast to grow.

Observed electricity consumption is not a reliable indicator of existing electricity demand. Effective demand for electricity is the amount that would be consumed at current tariffs if all electricity were fully paid for and there were no restrictions on the available supply. Neither of these two conditions holds for the West Bank and Gaza. Due to problems of network theft and under-collection of bills, a significant share of electricity consumption is supplied for free and therefore likely exceeds what would be consumed if tariffs were fully enforced. At the same time, severe supply restrictions and associated rationing—particularly in the Gaza Strip—mean that even paying consumers cannot access all the power they would like to buy. As a result, electricity demand is partially suppressed. These two effects pull the base year demand in opposite directions, and their net impact needs to be considered.

Inflated consumption is observable and relatively easy to estimate. It can quite readily be estimated from utility operational data, by calculating the absolute amount of electricity lost to theft and under-collection, based on the reported rates for nontechnical losses and revenue collection, respectively. Based on the literature, it is assumed that this inflated demand would drop by one-half if tariffs were effectively applied.[1] In the West Bank and Gaza, with total unpaid consumption amounted to 903 megawatt hours (MWh) and 558 MWh in 2030, implying that baseline consumption should be reduced by half of this amount, that is, 452 MWh and 279 MWh, respectively.

Suppressed demand is unobservable and can be estimated only indirectly. Utilities can provide some indication based on their knowledge of demand patterns. In the West Bank, the Palestinian Energy and Natural Resources Authority (PENRA) reports that this is 235 MW, or 20 percent of load. For Gaza, the Gaza Electricity Distribution Company (GEDCO) reports that this is somewhere between 145 MW and 245 MW, or around 50 percent of the load. This 50 percent shortfall for Gaza is reasonably consistent with the results obtained by comparing average residential and total industrial electricity consumption in Gaza with that in the less-constrained environment of the West Bank.

TABLE I-2.1: ADJUSTING CURRENT ELECTRICITY CONSUMPTION IN THE WEST BANK AND GAZA TO EFFECTIVE DEMAND

2013 MWH	WEST BANK	GAZA	WEST BANK AND GAZA
Current consumption	3,166	1,344	4,510
- Inflated consumption	452	279	731
+ Suppressed demand	655	768	1,423
= Effective demand	3,370	1,832	5,202

Source: Based on utility data from the Palestinian Energy and Natural Resources Authority and Palestinian Electricity Regulatory Council for 2013.
Note: MWh = megawatt hour.

Since estimates for suppressed demand exceed those for inflated consumption, the electricity demand forecast needs to be adjusted upward. For the West Bank and Gaza combined, the amount of suppressed demand is found to exceed the magnitude of inflated consumption, indicating that current electricity consumption is lower than it would be in a normal environment. In the West Bank, suppressed demand slightly exceeds inflated consumption by a margin of about 6 percent of registered consumption. In Gaza, the suppressed demand is substantially larger than the inflated consumption, by a margin of 36 percent of registered consumption. It is unrealistic to assume that suppressed demand can be eliminated overnight; it would take some time for supply to catch-up. The demand forecast is therefore adjusted in such a way as to ensure that this consumption shortfall is gradually eliminated over the period 2016–30. This entails an extra annual growth rate of 0.9 percent for the West Bank and Gaza as a whole: 0.4 percent in the West Bank and 1.9 percent in Gaza (see tables I-2.1 and I-2.2). A range of plus and minus 1 percent around these central growth estimates is recommended to capture the uncertainty in electricity demand growth. A full set of year-by-year demand forecasts is provided in appendix B, table B.3.

FIGURE I-2.2: FORECAST ELECTRICITY DEMAND GROWTH RATES FOR THE WEST BANK AND GAZA

AAGR %	WEST BANK	GAZA	WEST BANK AND GAZA
Real GDP growth forecast	2.51	3.02	2.63
+ Adjustment for suppressed demand	0.40	1.90	0.90
= Electricity demand forecast	2.91	4.92	3.53

Note: AAGR = Average Annual Growth Rate

The contrast in the electricity supply situation in the West Bank and Gaza is also evident in patterns of generator ownership among firms and households. Owning and operating a small backup generator in the West Bank and Gaza is expensive and works out to NIS 2.77 (US$0.76) per kWh for a diesel generator, and NIS 4.0 (US$1.01) per kWh for a more common gasoline generator. According to enterprise surveys, 47 percent of firms in Gaza reported owning a generator, and they depend on it for 42 percent of their electricity supply. By contrast, only 13 percent of firms in the West Bank reported owning a generator, depending on it for only 15 percent of their supply. Throughout the West Bank and Gaza, generator ownership is strongly linked to the size of the firm, and hence the available capital. Despite the high cost, as many as 20 percent of households in Gaza reported owning generators in 2013, compared to less than 1 percent in the West Bank. Nevertheless, Northern Electricity Distribution Company (NEDCO), a distribution company in the West Bank, has used large utility-scale generators in the past to meet summer peak load energy shortages.

Combining all the assumptions and methods discussed so far, the low, central, and high demand forecasts for the West Bank and Gaza are provided in table I-2.3.

TABLE I-2.3: SUMMARY OF ELECTRICITY SUPPLY FORECAST REQUIRED TO MEET EFFECTIVE DEMAND BY 2030 (GWH)

	CENTRAL CASE			LOW CASE			HIGH CASE		
	WEST BANK	GAZA	WEST BANK AND GAZA	WEST BANK	GAZA	WEST BANK AND GAZA	WEST BANK	GAZA	WEST BANK AND GAZA
2013 consumption	3,166	1,344	4,510	3,166	1,344	4,510	3,166	1,344	4,510
2013 effective demand	3,370	1,832	5,202	3,370	1,832	5,202	3,370	1,832	5,202
2013 supply for effective demand	3,938	2,141	6,079	3,938	2,141	6,079	3,938	2,141	6,079
2014	4,037	2,206	6,239	3,998	2,185	6,179	4,076	2,227	6,300
2015	4,138	2,272	6,403	4,058	2,229	6,279	4,220	2,317	6,529
2016	4,242	2,341	6,572	4,119	2,273	6,382	4,368	2,410	6,766
2017	4,349	2,412	6,745	4,182	2,319	6,485	4,521	2,507	7,011
2018	4,458	2,484	6,922	4,245	2,366	6,591	4,680	2,607	7,266
2019	4,570	2,559	7,104	4,309	2,414	6,699	4,844	2,712	7,529
2020	4,685	2,636	7,291	4,374	2,462	6,808	5,014	2,821	7,803
2021	4,803	2,716	7,482	4,440	2,512	6,919	5,190	2,934	8,086
2022	4,923	2,798	7,679	4,508	2,563	7,031	5,373	3,052	8,379
2023	5,047	2,882	7,881	4,576	2,614	7,146	5,561	3,174	8,683
2024	5,174	2,969	8,088	4,645	2,667	7,262	5,757	3,302	8,999
2025	5,304	3,059	8,301	4,715	2,721	7,381	5,959	3,435	9,325
2026	5,437	3,151	8,519	4,786	2,776	7,501	6,168	3,572	9,664
2027	5,573	3,246	8,743	4,859	2,831	7,623	6,385	3,716	10,014
2028	5,713	3,344	8,973	4,932	2,889	7,747	6,609	3,865	10,378
2029	5,857	3,445	9,209	5,007	2,947	7,874	6,841	4,020	10,755
2030	6,004	3,548	9,451	5,082	3,006	8,002	7,081	4,182	11,145

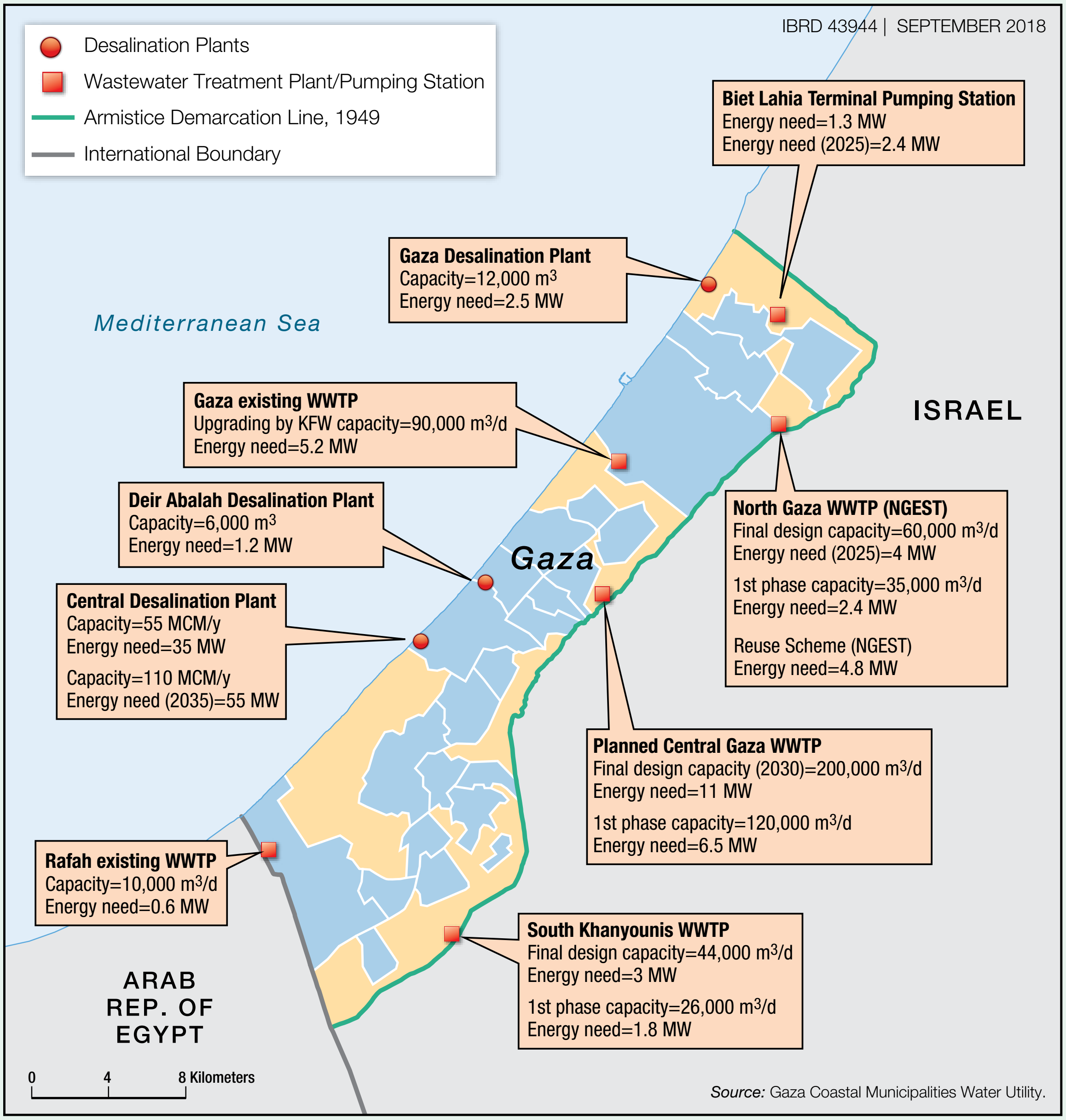
Source: World Bank elaboration.
Note: GWh = gigawatt hour.

Beyond the general demands of the population and productive sector, several humanitarian activities have critical energy needs. Few detailed needs assessments have been done, but box I-2.1 provides an important illustration for the water and wastewater sector in Gaza.

Box I-2.1: Existing and Future Electricity Needs for Gaza's Water Sector

The electricity needs of essential infrastructure, such as water and sanitation, must be incorporated into any supply expansion plan. In Gaza, the existing water and wastewater facilities required approximately 34MW of electricity as of 2014. By 2030, this is expected to increase to 127 MW as additional desalination and wastewater treatment plants come online (details provided in appendix figure B.3). Supply expansion plans must consider a holistic view that considers the needs of critical infrastructure, such as water, sanitation, and health services.

Map BI-2.1.1: Gaza Water and Wastewater Infrastructure Plans



Source: Gaza Coastal Municipalities Water Utility.

IMPLICATIONS FOR THE WEST BANK AND GAZA

These patterns of electricity demand have important implications for energy planning in the West Bank and Gaza.

Palestinian energy planning should recognize the inherently uncertain nature of electricity demand. The challenges in predicting electricity demand underscore the importance of not relying on a single estimate for planning purposes but ensuring that the wide range of uncertainty of demand is reflected in power system planning.

Electricity demand is strongly influenced by broader policies on household energy. Given the weight of residential electricity demand and recent substitution trends, it is important to recognize that broader household energy policies will have an important impact on the demand for electricity. Historical policies to promote solar water heaters have been successful in dampening household electricity demand, but usage appears to be in decline. Similarly, government policy needs to carefully consider the economic case for using LPG (as opposed to electricity) for space and water heating, and ensure that incentives are adequately aligned.

Moderate electricity demand growth is anticipated in the West Bank and Gaza. Because of macroeconomic challenges as well as constraints faced by the productive sector, electricity demand is forecast to slow from historic levels of 7.2 percent annually to levels of around 3.5 percent annually.

Electricity demand will grow more rapidly in Gaza than in the West Bank. Due to higher GDP growth forecasts and the need to catch up with higher levels of suppressed demand, electricity consumption in Gaza is forecast to grow substantially faster than in the West Bank, at 4.9 percent versus 2.9 percent annually. Given the much tighter supply situation in Gaza, this will represent a challenge going forward.

Current levels of electricity consumption understate existing demand. Observed electricity consumption does not provide a reliable demand baseline, given that a significant amount of electricity is supplied free of charge, while there is also significant rationing due to supply shortages. The dampening impact of rationing on current consumption is estimated to outweigh the inflated consumption resulting from nonpayment, particularly in the case of Gaza.

A number of humanitarian activities have critical energy needs that need to be better documented. The example of water and wastewater services in Gaza was provided as an illustration, but a similar case could be made for health-care facilities.

NOTES

1 For more on this, see Peter Meier. 2016. *Guidelines for Economic Analysis of Energy Projects* (forthcoming).

CHAPTER 3

Importing Electricity from Israel

THE CURRENT CONTEXT

The Israeli and Palestinian electricity sectors are closely intertwined. On the one hand, the Palestinian territories depended on the Israeli Electric Corporation (IEC) for 90 percent of electricity supply in 2015, ranging from 64 percent in Gaza to 99 percent in the West Bank. On the other hand, taken as a whole, the West Bank and Gaza are the IEC's single largest customer, accounting for 6 percent of Israeli electricity demand in 2015 (see appendix C, table C.3). Moreover, Palestinian electricity demand has been growing historically, at 7.2 percent per annum from 2001 to 2013, much faster than Israeli electricity demand, which expands at only 5.2 percent per annum. This is also reflected in demand forecasts (see tableI-2.3), which project annual demand growth of 3.5 percent for the West Bank and Gaza versus only 2.9 percent for Israel. This means that over time Palestinian needs will inevitably represent a growing share of the Israeli total, estimated to increase to 11 percent of Israeli electricity demand by 2030.

Israel's power sector remains largely vertically integrated and is in the midst of a shift from coal-fired to gas-fired power generation. Due to a lack of interconnection with neighboring Arab countries, the Israeli power system operates as an island that must be fully self-sufficient and capable of fully meeting its own demand in all circumstances. The only slight exception to this are the transmission links with the West Bank and Gaza, whose power systems in turn have modest interconnections with Jordan for the West Bank and Egypt for Gaza. As of the end of 2015, Israel had an installed generation capacity of 17.3 GW and generated 65.4 million MWh. About 45 percent of energy came from IEC's two large coal-fired plants, while the remainder came almost entirely from natural gas (see appendix C, tables C.1 and C.2). Use of natural gas for electricity generation has expanded rapidly during recent years, as a result of major Israeli gas discoveries in the eastern Mediterranean. See appendix C, table C.4 for the Israeli demand forecast.

The power sector in Israel is regulated by the Public Utilities Authority (PUA) under a modern regulatory framework. The PUA was established in 1996 and operated originally as an independent regulatory entity reporting to the public and the Knesset. In January 2016, however, the PUA's scope of action was moved under the Ministry of Energy. The PUA sets electricity tariffs based on IEC's cost of service, excluding costs considered excessive or unnecessary, while providing for allowed returns on equity according to the risk profile of each activity (see appendix C, table C.6). By law, PUA is prohibited from setting tariffs that create deliberate cross-subsidies between customer classes. PUA is involved in the determination of five categories of tariffs: (i) electricity usage tariffs (for end users); (ii) network wheeling tariffs (for use of the transmission grid); (iii) production tariffs (for electricity generated by independent power producers, IPPs); (iv) interconnection tariffs (to access the grid); and (v) system management or ancillary services (to cover back-up provided by IEC to other market players). The PUA also assesses the marginal production costs of different generators as input to economic dispatch by the system manager's office, which is still a department within IEC. For the largest consumers, time-of-use tariffs are applied, differentiating nine different time blocks with different cost characteristics. (Full particulars of the regulated power tariffs determined by PUA can be found in appendix c, tables C.5 through C.10.)

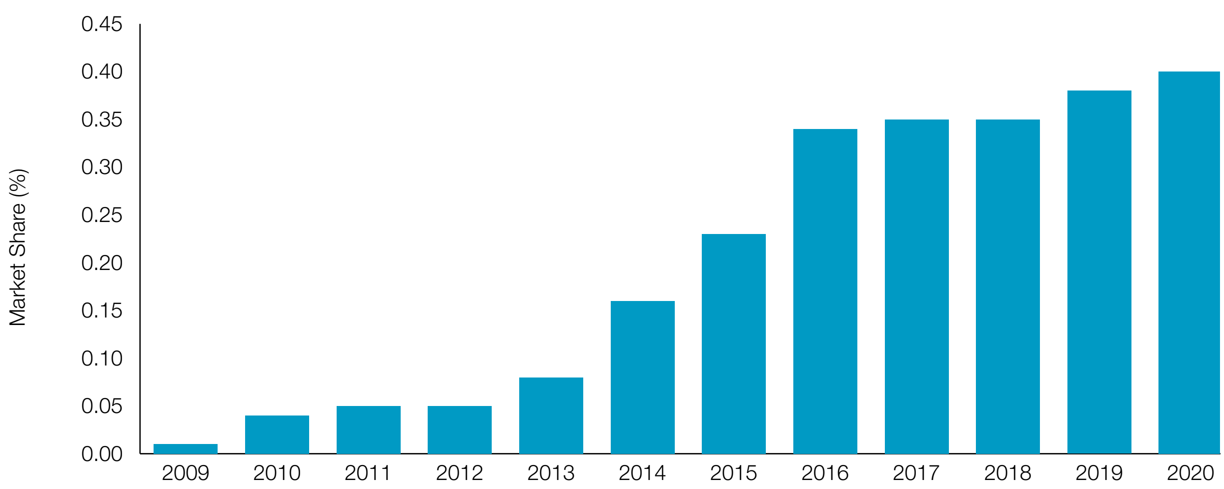
Israel's electricity industry has been undergoing a protracted, and still incomplete, process of sector reform. This began with the 1996 Electricity Sector Law and its subsequent amendments. Implementation has proved challenging, with negotiations between the government and IEC management ongoing since 2002. In the meantime, a number of different blueprints of reform have been put forward. IEC itself envisions becoming a holding company with subsidiaries for generation, distribution, transmission, and services, with potential privatization of at least 49 percent of the generation and distribution subsidiaries. At the same time, the recommendations of the government's Yogev Committee in 2014 envisaged divestiture of some of IEC's generation assets to cap market share at 58 percent, as well as a separate transmission system operator and the possibility of limited private-sector entry into the distribution segment.

During the past decade, IEC has experienced severe financial difficulties and accumulated debts of NIS 65 billion (US$16.6 billion) as of end 2015. A number of factors contributed to this situation, including the employee union's wage demands, the electricity regulator's unwillingness to pass on costs deemed inefficient into consumer tariffs, and substantial debt service obligations. The specific debt from the Palestinian Authority, which reached NIS 2 billion (US$0.5 billion) in 2016, while substantial in absolute terms is a relatively small share of IEC's overall debt burden (no more than 3 percent).

Nevertheless, dramatic changes have already taken place as a result of the strong entry of IPPs. Since 2009, IEC has been prohibited from building new generation plants, and there has been strong entry of gas-fired IPPs that received construction and operation licenses from the PUA. Installed IPP capacity increased from some 100 MW in 2009 to some 5,500 MW at May 2017, with further 4,000 MW already licensed and expected to be commissioned by 2022. As a result, the market share of IPPs in Israeli power generation has climbed steeply, spurred by abundant availability of natural gas, already rising from 1 percent in 2009 to 33 percent in 2016 and projected to rise further to reach 40 percent by 2020 (see figure I-3.1). The rapid entry of IPPs during a period of relatively flat demand growth has helped to reduce generation costs, increase reserve margins, and pave the way for the replacement of aging coal plants.

A clear set of regulations governs commercial transactions between IPPs and other market participants. To stimulate the first generation of IPPs, the companies were provided with a safety net: IEC would purchase up to 80 percent of their power production at normative tariffs set by PUA. As the sector has matured, these financial supports have been removed so that more recent IPPs operate as merchant plants. Only transactions between IPPs and IEC (the "essential services provider") are currently subject to price regulations; all other transactions are deemed private and prices can be freely agreed by bilateral negotiation. Sales from IPPs to IEC can take the form of capacity and energy contracts or energy-only contracts, with the former being subject to closer regulation. IPPs are required to provide demand forecasts for their customers and show how these

Figure I-3.1: Market Share of Israeli IPPs Climbs Steeply over Time



will be reliably met by a combination of their own generation and power purchased from other private producers. They also need to provide IEC with day-ahead maintenance and output schedules for each 30-minute time interval.

The next wave of IPPs will include a substantial scaling up of renewable energy. The Israeli government has introduced technology-specific feed-in tariffs. These are designed to support scaling up of renewable energy from levels of 2 percent in 2015 to reach targets of 10 percent renewable energy by 2020 and 17 percent by 2030. This will lead to a second wave of policy- driven IPPs for renewable energy, and will raise technical challenges for the Israeli system to accommodate a much higher share of variable renewable energy.

IMPLICATIONS FOR THE WEST BANK AND GAZA

These recent developments in the Israeli electricity sector have significant implications for the future energy plans of the West Bank and Gaza.

The West Bank and Gaza will represent a growing share of IEC's client base. As Palestinian electricity demand growth outpaces that in Israel, and as IEC's share of the Israeli power market continues to decline, the Palestinian Single Buyer PETL may represent an increasingly large share of IEC's client base, further intertwining the economic prospects of these two companies. This means that Palestinian energy planning decisions, as well as the financial viability of the Palestinian electricity sector, will have an increasingly large impact on IEC.

The West Bank and Gaza will have the option of buying power from Israeli IPPs. With the growth of the Israeli IPP sector, the Palestinian single buyer would also increasingly have opportunities to purchase power directly from IPPs on negotiated commercial terms outside of the context of any intergovernmental framework. Given the relatively rapid pace of Palestinian demand growth, this may make it an increasingly attractive market for Israeli IPPs. Nonetheless, this option may be difficult to pursue until the Palestinian electricity sector reestablishes a strong payment record with IEC. Moreover, a commercial power import agreement would likely also entail harder enforcement of payment discipline, given that parallel fiscal channels would not be available.

The West Bank and Gaza could also consider selling any future electricity surpluses to Israel. Any future Palestinian IPP could potentially sell surplus electricity into the Israeli grid, and this would likely be a necessary backstop arrangement if PETL is to sign take-or-pay contracts with future IPPs. The arrangements for trading surplus electricity would need to be agreed to on a case-by-case basis and regulated in a power purchase agreement.

The West Bank and Gaza may stand to benefit from time of-use pricing for Israeli electricity. The current renegotiation of the Palestinian Power Purchase Agreement with IEC, in the context of the switch to high-voltage electricity imports, offers the opportunity to benefit from the time-of-use tariff structures that have been developed by the PUA in Israel. This offers potential advantages, given that the Palestinian and Israeli daily and annual peaks do not coincide. Historically, only Jerusalem District Electric Company has been charged based on time-of-use, while other Palestinian imports have rather been charged based on the (less attractive) bulk supply tariff (see appendix C, table C.9). On the retail side, Palestinian distribution companies could also benefit from selling electricity to their consumers on a time-of-use basis, which would encourage demand-side management and energy efficiency.

The West Bank and Gaza may need to purchase ancillary services from Israel. The current renegotiation of the Palestinian Power Purchase Agreement with IEC will also need to consider the future role for management (or ancillary) services from IEC. This is particularly relevant in the context of the planned construction of new Palestinian IPPs in the West Bank based on gas-fired and renewable energy technologies. As such new plants come on stream, the West Bank will continue to require backup services (such as reserves and system balancing) that are most efficiently provided by IEC, and for which PUA has already established regulatory tariffs (see appendix C, table C.10).

Palestinian renewable energy plans need to be coordinated with the Israeli system. Given that the Israeli power system is already contemplating a substantial scaling up of variable renewable energy generation, additional scaling up on the Palestinian system would need to be carefully coordinated with the Israeli system operator to ensure that the additional variability is appropriately managed.

CHAPTER 4

Importing Natural Gas for Domestic Power Generation

THE CURRENT CONTEXT

The discovery of sizable gas resources in the eastern Mediterranean has the potential to be game changing for the region. Discoveries have been made in the Levant Basin, a geological structure that straddles the territorial waters of Cyprus, Israel, the Palestinian territories, Lebanon, and Syria, and more recently, in Egypt's Nile Delta Basin. Currently net energy importers,[1] these countries are now faced with the prospect of long-term energy self-sufficiency and even energy exporting status, with the prospect of a new revenue stream for their economies. In 2010, the United States Geological Survey estimated that there could be up to an additional 122 trillion cubic feet of undiscovered natural gas resources in the Levant Basin. As a result, the eastern Mediterranean is now the focus of much interest on the part of major upstream investors. However, in the short to medium term, the development and monetization of these resources present stakeholders with a set of challenges over and above the standard technical difficulties relating to the development of these resources. The challenges originate in the region's complex political make-up and include the downturn of international gas prices, rapidly falling costs of solar energy as an abundant alternative to gas, as well as the underdeveloped nature of their energy and gas utilization policies.

The West Bank and Gaza plan to use natural gas to support development of domestic gas-fired power-generation capacity, leading to modest estimated demand of 1 billion cubic meters (bcm) per year by 2030. Development of gas-fired power generation capacity is one of the main options available to support diversification away from Israeli power imports (although in itself that does nothing to diversify dependency away from Israel, if the gas is imported from Israel). In the West Bank, plans are already under way to commission a 400-megawatt (MW) gas-fired combined-cycle power plant in the northern region of Jenin and potential subsequent addition of a second plant of a similar scale in the southern region of Hebron. The associated natural gas demand is estimated to start at 0.24 bcm per year in the early 2020s and climb to 0.71 bcm per year by 2030. In Gaza, the priority may be conversion of the Gaza Power Plant (GPP) from fuel to gas and restoration of its full production capacity. This gas conversion could save the Palestinian Authority as much as NIS 164–226 million (US$45–62 million) per year in its current fuel bills (depending on the price of oil).[2] This would create a gas demand of 0.21 bcm per year by the mid-2020s, potentially climbing to 0.33 bcm per year by 2030 if further capacity expansion takes place. Demand for natural gas in the industrial sector is not expected to be economically viable due to the absence of major industries in the Palestinian territories (see appendix D, table D.1).[3] Therefore, referring to table I-4.1, the maximum estimated gas demand for the Palestinian territories would begin at around 0.34 bcm per year in the early 2020s and climb to a maximum of 1.04 bcm per year by 2030. (Further details of the assumptions behind this forecast can be found in appendix D, tables D.2 and D.3).

TABLE I-4.1: ESTIMATED NATURAL GAS DEMAND IN THE PALESTINIAN TERRITORIES UNTIL 2030

YEAR	WEST BANK	GAZA	WEST BANK AND GAZA
2022	0.24	0.11	0.34
2023	0.24	0.11	0.34
2024	0.47	0.21	0.69
2025	0.47	0.21	0.69
2026	0.47	0.33	0.80
2027	0.47	0.33	0.80
2028	0.71	0.33	1.04
2029	0.71	0.33	1.04
2030	0.71	0.33	1.04

Source: Information provided by Delek Drilling.

Israel has become a major natural gas producer due to substantial offshore discoveries that began in 1999. Since then, some 36 trillion cubic feet (tcf) of natural gas were discovered offshore Israel (equivalent to over 1,000 bcm). About 94 percent of this resource is concentrated in just two huge fields: Tamar with 10.9 tcf and Leviathan with 21.9 tcf. To backup domestic gas production, Israel connected in 2013 a Floating Storage Regasification Unit (FSRU) to the domestic gas pipe grid. The FSRU, located 10 kilometers offshore from the Israeli city of Haedera, enables imports of modest quantities of liquified natural gas (LNG) at prices that ranged during the period of 2016 to April 2017 at NIS 18–26 (US$5–7) per million British thermal units (MMBTU), excluding the FSRU leasing cost.

Tamar is the only offshore gas field active today and supplies the entirety of Israeli gas needs at prices ranging from NIS 17–24 (US$4.7–6.5) per MMBTU. The reliance of Israel on one gas source creates a major national security risk, since the entire gas supply is exposed to technical and security risks. Hence, there is an urgent need for Israel to diversify its gas supply sources by developing additional fields. Tamar's gas production is also constrained by a serious bottleneck in the submarine pipeline that connects it to shore, since the capacity of the pipeline is lower than the demand for gas in peak hours. In February 2017, the developers of the larger Leviathan field finally reached a final investment decision (FID) for the NIS 14.6 billion (US$4 billion) development of the field. (For further details of recent Israeli prices for natural gas, see appendix D, table D.4.)

The commissioning of Leviathan is expected in December 2019. The FID decision was delayed for three years due to domestic professional and public regulatory debates, including an antitrust case brought against Noble Energy and Delek, the companies that hold major equity stakes in both the Tamar and the Leviathan fields. The case was eventually resolved in 2016 with the High Court authorization of the government-led Natural Gas Framework. According to this framework, Noble Energy has agreed to partially divest its interests in the Tamar field and Delek has agreed to divest all of its interests in the Tamar field. In addition, the two companies had to sell their Karish and Tanin assets, which were purchased in 2016 by Energian Energy of Greece. It should be noted, however, that geological reports suggest that current discoveries represent only about half of the potential available in Israeli waters, providing the basis for ongoing exploration efforts. In this regard, the Israeli government published in late 2016 its first offshore exploration round, tendering 24 blocks in its exclusive economic zone (each of 400 square kilometers). Proposal are expected by July 2017. Table I-4.2 provides an overview of current Israeli natural gas discoveries and proven reserves.

TABLE I-4.2: NATURAL GAS DISCOVERIES AND PROVEN RESERVES IN ISRAELI WATERS

FIELD	DATE OF DISCOVERY	OPERATOR	RESERVE (TCF)
Noa	1999	Noble Energy	0.3*
Mary Band	2000	Noble Energy	1.0*
Or	2000	Isramco	0.1
Dalit	2009	Noble Energy	0.5
Tamar	2009	Noble Energy	10.9
Leviathan	2010	Noble Energy	21.9
Tanin	2011	Noble Energy	1.2
Dolphin	2011	Noble Energy	0.1
Shimshon	2012	Isramco	0.5
Karish	2013	Noble Energy	1.8
Total			38.2

Note: tcf = trillion cubic feet.
* These fields have already been depleted.

Israeli gas demand for both power generation and industry has been growing rapidly. Since the discovery of domestic natural gas reserves, Israel has been actively promoting a switch in its power-generation mix from oil-fired to gas-fired, resulting in annual savings to the economy estimated at NIS 11 billion (US$3 billion) annually, as well as important air quality benefits. Natural gas is also being taken up for industrial use. All this is bringing important fiscal proceeds to the Israeli economy, estimated to amount to NIS 220 billion (US$60 billion) over the next 25 years. As a result, gas demand has already growth from negligible levels in the early 2000s to 8.3 bcm per year by 2015 and is projected to expand further, reaching 18 bcm per year by 2030.

Israel has a regulatory regime in place to govern its natural gas sector. Israel's Natural Gas Authority was created in 2002 and has jurisdiction over both economic and technical (safety) regulation of the sector. The Natural Gas Authority aims to create conditions suitable for private-sector development of the gas sector through promoting competition wherever possible, while regulating monopoly segments of the industry. Israel operates an open third-party access regime for its gas transportation network, with regulated tariffs for the national transportation company, Israeli Natural Gas Lines (INGL), as well as the local distributors. The prices of the natural gas itself, however, are not subject to regulation but rather determined through negotiation between the parties, although negotiated prices and resulting profitability must be publicly disclosed to create transparency in the market. According to the Natural Gas Framework for policy that was approved in 2016, gas export prices cannot be lower than average domestic prices. The regulatory regime for gas in Israel has been subject to considerable political contention but appears to have now stabilized.

Once Leviathan comes on stream, there is the possibility that Israel will become a significant natural gas exporter. Once under production, the Leviathan field will substantially exceed projected domestic gas demand, allowing Israel to become an exporter. In 2013, the Zemach Committee established that 15 tcf of Israeli reserves could be allocated for export purposes, as the balance was more than adequate to cover domestic needs for the next 30 years. Gas export quotas could increase, however, as additional gas reserves are established.

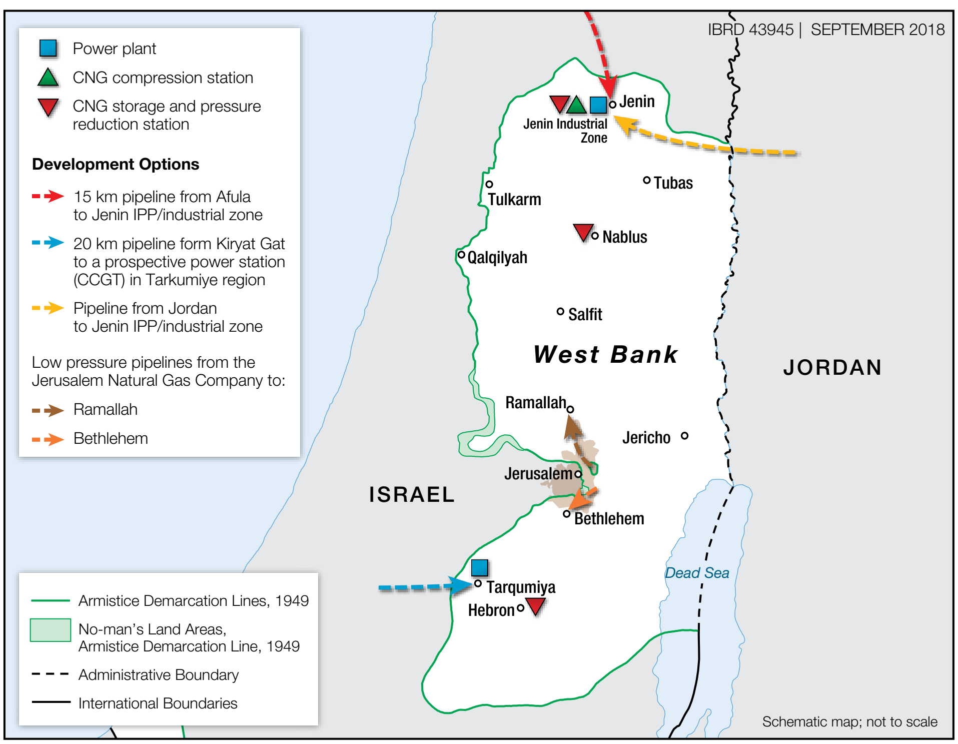
Israel started to export gas to Jordan in 2017 by supplying 1.8 bcm from the Tamar field. The destination was two of the Jordanian Arab Potash plants that are located at the southern Dead Sea. Moreover, in September 2016 Nobel Energy (on behalf of the Leviathan partners) signed a final binding 45 bcm take-or-pay contract with the Jordanian state-owned electric utility National Electric Power Company (NEPCO) for the supply of 3 bcm per annum for 15 years. It is expected that additional Jordanian independent power producer (IPPs) and industrial consumers may sign gas import contracts with Leviathan in the near future.[4]

Israeli gas may also be exported to Egypt. An arrangement to export 5 bcm per year to the Egyptian industrial sector is under discussion with Dolphinus Holdings, possibly by reversing the flow of the idle EMG pipeline that previously supplied gas from Egypt to Israel, or by utilizing the Arab Pipeline, once gas from Leviathan reaches Jordan (expected at December 2019 or early 2020). In addition, two separate memoranda of understanding (MOUs) were signed in 2014, to supply 4.5 bcm per year and 7 bcm per year for 15 years, with Egyptian idle LNG export facilities of Union Fenosa Gas and ENI in Dumyat and British Gas (currently Royal Dutch Shell) at Idku. It is doubtful, however, whether these MOUs will evolve to binding contracts, as market conditions have changed significantly since 2014. The major hindering factors are the steep decrease in oil and LNG prices, on the one hand, and the very large discoveries of additional gas fields in Egypt, with the leading discovery of Zohr field by ENI in 2015, on the other.

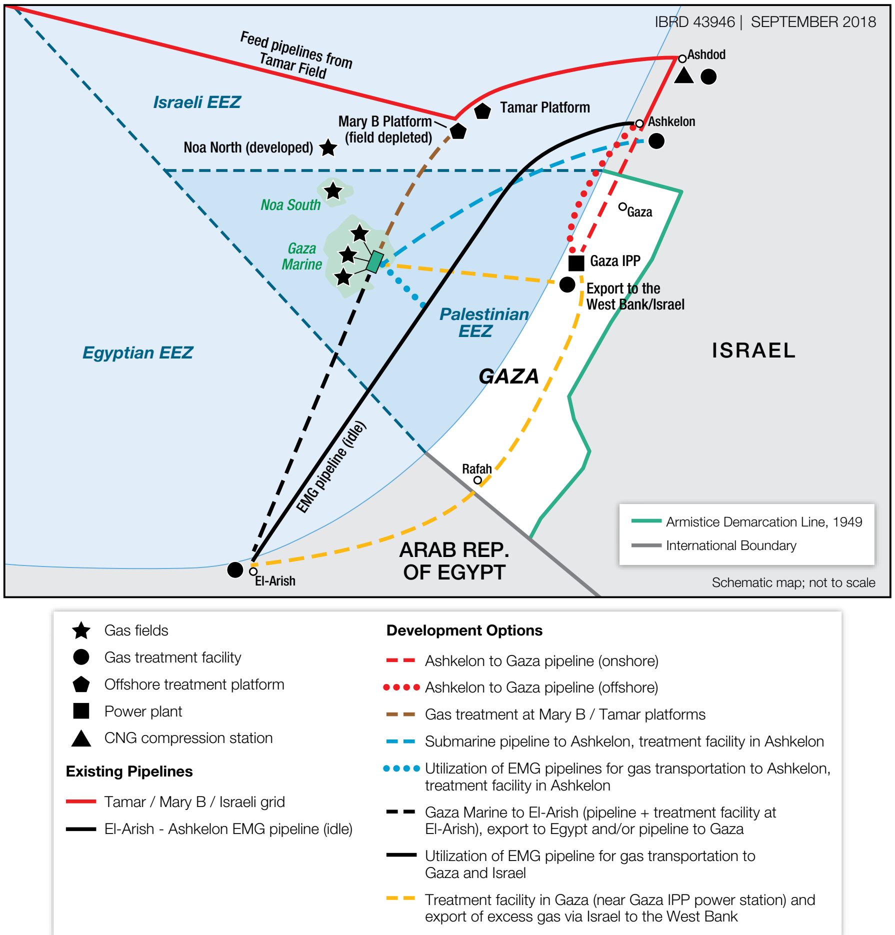
Israel's gas fields could provide an immediate source of gas for the West Bank and Gaza. Palestinian gas demand, estimated to rise toward 1 bcm per year by 2030, is tiny in relation to Israeli gas reserves already in excess of 1,000 bcm. Israel has already indicated its openness to supply gas to the Palestinian territories under commercial agreements, and a letter of intent for Noble Energy to supply gas to the future Jenin gas-fired power plant was signed in 2014 but later cancelled in 2015. Further discussions are reportedly under way. Meanwhile, the Israeli authorities have indicated the feasibility of interconnecting the Palestinian territories with the Israeli gas transportation infrastructure.

The West Bank could relatively easily be supplied with natural gas from Israel by constructing short spurs from the nearby Israeli gas-transportation network. In the northern West Bank (see map I-4.1), the construction of only 15 kilometers of pipeline from Afula (Israel) to the Jenin Industrial Zone, near the border with Israel, could supply high-pressure gas to the planned 400 MW Combined Cycle Gas Turbine (CCGT) plant in Jenin. This work has received the required authorizations from the Israeli Civil Administration and is straightforward from a technical standpoint. It could be conducted by INGL, the Israeli high-pressure gas transmission company, up to the border with the West Bank, at which point another company will need to build the pipeline all the way to the plant. The gas could flow through this

Map I-4.1: Natural Gas Supply Options to the West Bank



Map I-4.2: Natural Gas Supply Options to Gaza



pipeline within five years prior to the commissioning of the Jenin gas-fired combined cycle power plant by 2022. The pipeline could deliver gas from Israeli sources (such as Tamar, Leviathan, or Karish-Tanin) or eventually others. A similar arrangement could be envisaged in the southern West Bank. This would involve the construction of a high-pressure pipeline from Kiryat Gat to the Tarkumiya area, west of Hebron, to supply gas for a proposed future second gas-fired plant for the West Bank. This option is not expected to materialize before the end of the 2020s.

An additional option that has sometimes been raised is the construction of a dedicated gas pipeline from Jordan to the northern West Bank. This could be used to supply gas from the Arab gas pipeline or imported LNG from Jordan (map I-4.1). While this option is technically feasible, its economic viability can be called into question. Such a dedicated pipeline would need to be a relatively long 80-kilometer spur from the Jordanian grid to Jenin, over hilly terrain, and could be expected to cost more than US$100 million. It would also need to cross the Jordan River, which is the border between Jordan and the West Bank, that is currently held by Israel. Given that a pipeline from Israel to Jordan is already planned to support the export of Israeli gas, the same infrastructure could potentially be used to transport gas from Jordan into the West Bank using the same spur from the INGL network already noted.

It is also relatively straightforward (from a technical point of view) to supply Gaza with Israeli gas through a short dedicated pipeline from the Israeli production terminal in nearby Ashkelon. There are two main options for the supply of Israeli natural gas to Gaza. The first option is the supply of Israeli gas through a high-pressure 18-kilometer pipeline from Ashkelon in Israel to GPP that is located to the south of Gaza City. Technically it is a relatively simple project (8-kilometer

TABLE I-4.3: ALTERNATIVE OPTIONS FOR DEVELOPING THE GAZA MARINE GAS FIELD

	OPTION 1	OPTION 2	OPTION 3
Anchor client	Israel and West Bank and Gaza (possibly also Jordan)	Egypt and West Bank and Gaza	West Bank and Gaza
Gas transportation infrastructure	45-kilometer (km) offshore pipeline to Ashkelon (Israel)	70-km offshore pipeline to El Arish (Egypt)	25-km offshore pipeline to Mari B and Tamar Platforms
Gas treatment infrastructure	New gas treatment facility in Ashkelon (Israel)	Supply to Gaza or Egyptian market or feed-gas to LNG liquefaction plants in Egypt	Use existing offshore gas treatment facility (Israel)
Project duration	3–4 years	3–4 years	2 years
Investment costs	US$1.2 billion–1.5 billion	US$1.2 billion–1.5 billion	US$0.3 billion–0.4 billion
Required throughput	2.0 bcm per year	2.0 bcm per year	0.2-0.3 bcm per year (rising in a flexible manner with demand)
Supply to Gaza	23-km pipeline from Ashkelon (Israel) to GPP	65-km pipeline from El Arish (Egypt) to GPP	23-km pipeline from Ashkelon (Israel) to GPP
Supply to West Bank	Via injection into INGL gas transportation network	None	Via injection into INGL gas transportation network

Note: bcm = billion cubic meters; GPP = Gaza Power Plant; LNG = liquified natural gas.

pipeline from Ashkelon to Erez, the Gaza crossing, and an additional 10 kilometers to the station). The European Union is currently sponsoring a technical study to support the Gas to Gaza initiative led by the Quartet. The second option is the supply of Egyptian gas via a 60-kilometer pipeline from El Arish to GPP.
In addition to the Israeli discoveries, a much smaller Palestinian gas field has been discovered offshore from Gaza. The so-called Gaza Marine field is located 36 kilometers offshore from Gaza in relatively shallow waters, and has estimated reserves of 1.2 tcf. In November 1999, a 25-year contract for gas exploration and development of the field was signed between British Gas Group, the Consolidated Construction Company, and the Palestinian Investment Fund, a sovereign wealth vehicle that reinvests in Palestinian projects. The Palestinian Authority has recently renegotiated the terms of the concession agreement with British Gas to grant a 15-year extension and increase the Palestinian Investment Fund equity share from 10.0 percent to 17.5 percent and limit British Gas rights to Gaza Marine only.

The development of the Gaza Marine field is highly contingent on securing export markets, since the Palestinian market is too small to justify the necessary investment. It has been estimated that the Gaza Marine field would need to be developed with a throughput of 2 bcm per year in order to provide adequate returns to the necessary investment of NIS 3.6–4.4 billion (US$1.0–1.2 billion). This is about twice the maximum levels of demand that could be reached in the West Bank and Gaza by 2030. Hence, the development of the field is contingent on securing a suitable export agreement, either to Israel (and possibly Jordan) or to Egypt. The first option of export to Israel would entail construction of an offshore pipeline to Ashkelon in Israel, where a new gas treatment plant could also be located. The second option of export to Egypt would be based on an offshore pipeline to El Arish in Egypt and use of the gas as feedstock in the Egyptian LNG export terminal at Idku. A third possible option would be to develop the Gaza Marine field at a lower level of throughput more compatible with domestic demand. This could be viable if existing Israeli infrastructure could be shared with the Tamar field and the soon to be depleted Mari B field, which are located relatively nearby, reducing development costs to NIS 910 million (US$250 million). The main features of the three options are summarized in table I-4.3. In all three cases, a part of the gas could be brought back by pipeline into Gaza, as noted. The two Israel options would also allow transportation of Palestinian gas into the West Bank through the Israeli gas transportation network, as already described.

The development of the Gaza Marine field would bring significant fiscal revenues to the Palestinian Authority. Based on a typical 60 percent public sector profit-sharing arrangement, it is estimated that Gaza Marine could bring fiscal proceeds of almost NIS 10 billion (US$2.7 billion) over its 25-year life. These would be phased as follows: NIS 146 million (US$40 million) per year in the first 3 years of operation; NIS 310 million (US$85 million) per annum in the rest of the first decade of operation; and NIS 475 million (US$130 million) per annum in the next 15 years of operation. Out of these revenues, royalties set at 12.5 percent of sales would amount to 26 percent of overall fiscal proceeds, with the remainder being taxes.[5] In 2005, the Palestinian Authority signed an agreement in principle to sell the natural gas to the government of Egypt via the terminal at El Arish, but this deal did not receive Israeli approval. From 2006 to 2008, negotiations took place with Israeli Electric Corporation regarding possible sale of the gas to Israel via the terminal at Ashkelon. Due to the failure to reach a purchase agreement, the private companies pulled out, and the development of the Gaza Marine field has subsequently been on hold.

IMPLICATIONS FOR THE WEST BANK AND GAZA

These recent developments in the natural gas sector have significant implications for the future energy plans of the West Bank and Gaza.

The development of gas-fired power-generation plants in the Palestinian territories should not be contingent on development of Gaza Marine. Given the relatively small initial levels of Palestinian gas demand, their relatively slow ramp-up, and the unproven creditworthiness of the West Bank and Gaza as a purchaser of natural gas, it does not look practical to base development of Palestinian gas-fired power generation on development of Palestinian gas resources. Instead, the well-established Israeli gas market with its abundant reserves provides a more practical immediate source of gas for the West Bank and Gaza, with the ability to supply at relatively small volumes, providing flexibility for demand growth (although the Palestinian credit worthiness issue still needs to be addressed).

There may be strategic value in developing gas transportation links between Israel and the Palestinian territories. Whether gas is ultimately sourced from Israeli or Palestinian sources, connecting the West Bank and Gaza to the Israeli gas transportation infrastructure looks to be a necessary prerequisite for accessing any gas supplies. Fortunately, the required investments to connect the West Bank and Gaza to the Israeli high-pressure gas grid are relatively small. These costs are estimated at some NIS 55 million (US$15 million) to connect the prospective Jenin IPP in the northern West Bank, and some NIS 73 million (US$20 million) to connect Gaza IPP. These connections have already been established as technically and economically viable and seem to have some political support from both the Israeli government and the Palestinian Authority.

The main economic benefit of the Gaza Marine project to the West Bank and Gaza lies in its contribution to fiscal balance rather than to energy security. In view of the preceding considerations, it is clear that Gaza Marine gas is not critical to the development of gas-fired generation capabilities in the Palestinian territories. Nor does it necessarily guarantee greater energy independence to the West Bank and Gaza, given that Palestinian gas would in any case need to travel through Israeli infrastructure to reach the West Bank or Gaza. It follows, therefore, that the main advantage of developing Gaza Marine may lie in its contribution to public finances rather than to energy security.

There may be merit in considering the smaller scale development options for Gaza Marine. It is unclear whether export arrangements of Gaza Marine gas to either Israel, Jordan, or Egypt would prove to be feasible. Israel itself is on the brink of having a large gas surplus, once the Leviathan field comes on stream. Egypt, on the other hand, has become a significant importer of LNG (rather than an exporter as previously envisaged), although this may change with the discovery of the Zohr field. While Jordan has previously shown an interest in Palestinian gas, the recent agreement of import arrangements with Israel may limit the scope for this. Given the uncertainties surrounding all the potential export possibilities, the option of developing Gaza Marine at a slower pace that could be entirely absorbed by the Palestinian market could prove to be a practical solution for getting the project off the ground. However, it may be more feasible to get this project off the ground once some gas-fired generation capacity has been built in the West Bank and Gaza, the required gas transportation infrastructure is in place, and a track record of payment has been established based on experience with Israeli gas imports.

Any gas-import agreement with Israel should not foreclose the eventual development of Gaza Marine. If the ultimate goal is to anchor the development of Gaza Marine from an established base of Palestinian gas consumption, it would be important to ensure that any gas import agreements with Israel provide adequate flexibility for an eventual transition from Israeli to Palestinian gas supplies. However, it is likely that this flexibility will come at a cost premium relative to a longer term rigid take-or-pay arrangement for the supply of gas.

Development of gas-fired power in the West Bank and Gaza may in future become uneconomic. Given the rapid pace of development of solar photovoltaics, concentrated solar power, and energy storage technologies, it should not be precluded that gas-fired power will become uneconomic in the West Bank and Gaza, or simply less desirable given the energy security advantages for solar energy. Solar energy supply to the West Bank and Gaza could be from Palestinian territory and/or from Jordan (which is scaling up solar energy very rapidly) and/or from Egypt (which is planning to scale up solar).

NOTES

1 With the partial exception of Egypt, which has oscillated between being a net importer and a net exporter.
2 The exact magnitude of the savings is sensitive to the oil price and is estimated at current oil prices of US$50 per barrel and prevailing gas prices for independent power producers in Israel. The savings could increase to NIS 226 million (US$62 million) per annum in case oil prices increase to US$100 per barrel.
3 The existing factories could be converted to natural gas supplied in compressed natural gas form (by road tankers). But their modest consumption of diesel and liquified petroleum gas and current oil prices do not make it a viable option.
4 It should be noted that no existing IPP in Jordan purchases its own fuel; all supplied with fuel by NEPCO, at NEPCO's own risk.
5 These results derive from the following simplistic assumptions: Gaza Marine development via the Tamar Platform scheme; development costs of $250 million; gas treatment and variable costs of $1 per MMBTU and gas price of $5 per MMBTU. Gas production quantities would be 0.5 BCM per year in the first 3 years of operation, 1 BCM per year in the next 7 years of operation, and 1.5 BCM per year in the next 15 years of operation.

CHAPTER 5

Importing Electricity from Jordan and Egypt

CURRENT CONTEXT

In addition to its power imports from Israel, the West Bank and Gaza also have the possibility to consider further increasing the current modest imports from Jordan and Egypt. The validity of these options depends to a considerable extent on the domestic power sector situation in each of these neighboring countries, as well as the relative costs of their power export tariffs compared with Israel and domestic Palestinian options. Expanding imports from either of these countries would also entail significant upgrades to cross-border transmission infrastructure, which is currently quite modest, and would require various levels of political and governmental approvals to allow permitting for construction. For both countries, the lack of payment security from Palestinian buyers is also a concern, as the risk of nonpayment is deemed high, and unlike Israel, neither Egypt nor Jordan has access to the controversial *net lending* mechanism to recover their costs. Finally, although Jordan is typically considered as a supplier to the West Bank and Egypt to Gaza, since Egypt and Jordan are fully connected it is—at least in principle—possible to envisage Jordanian power flowing to Gaza via Egypt or Egyptian power flowing to the West Bank via Jordan.

JORDAN

In 2008, the West Bank started importing 20 megawatts (MW) of power from the Jordanian grid through a 33 kilovolt (kV) feeder to Jericho. The Palestinian strategy was to reduce its dependence on Israeli electricity supply and access the Arab network in a moment when Israeli electricity supply to the Gaza Strip was being reduced.[1] The Jericho area was disconnected from the Israeli power grid and connected to the Jordanian grid. Since then, the Jerusalem District Electricity Company (JDECO) has been managing a separate electricity supply system for the customers in the Jericho area.

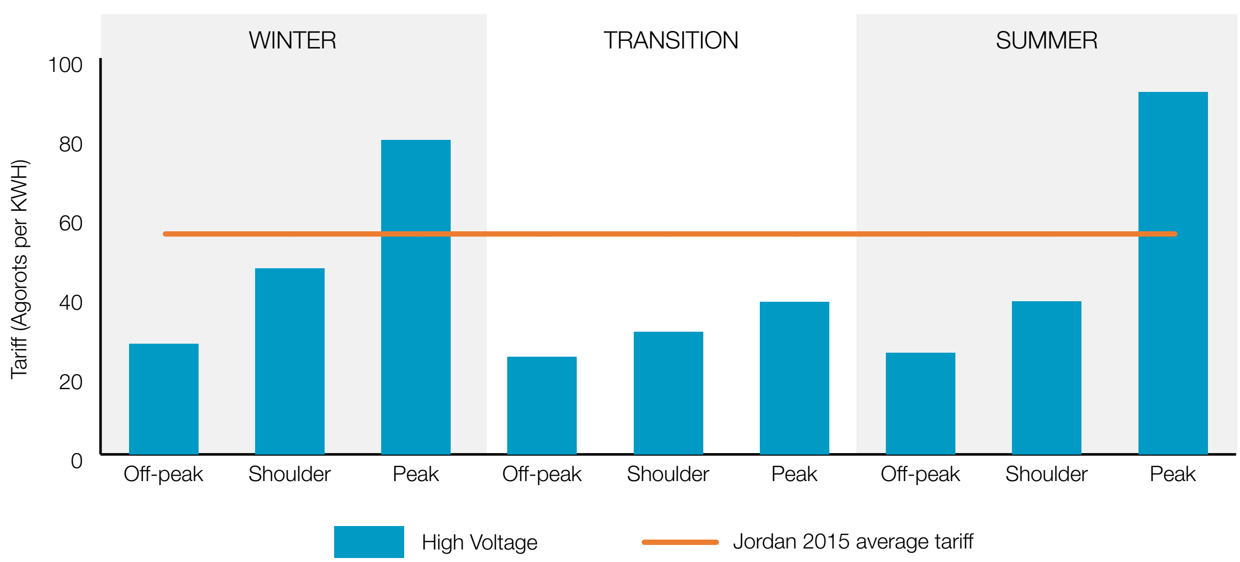
The upgrade of the existing connection inside Jericho from 33 kV to 132 kV would further increase power supply in the West Bank and diversify Palestinian electricity sources. This project is backed by Palestinian Energy and Natural Resources Authority and JDECO, and its execution would be highly desirable. Other options, such as a 400 kV connection to the Jordanian Samra 400 kV substation, have been assessed in the past but are more costly and more complex. The Jordanian substation has sufficient space for extensions by two 400 kV line bays, and there is also the possibility of extending the Samra Thermal Power Plant in Jordan, to supply additional energy if required.[2]

Since Palestinian power demand is not integrated into Jordanian power sector expansion plans, only surplus Jordanian power is available for export. Given the relatively small size of the Jordanian system, total power demand in the West Bank currently represents about one-third of Jordanian demand. The quantities available for export are determined on an hourly basis by the available capacity in Jordan as well as the evolving Jordanian load. Nevertheless, Jordan's National Electric Power Company has been responding positively to requests for firm power export from Jordan to the West Bank. In a recent visit to Amman, the Palestinian minister of energy agreed with the Jordanian counterparts to accelerate efforts to upgrade the existing connection inside Jericho from 33 kV to 132 kV.[3]

Jordan's successful transformation of its energy sector has increased its capability to export power to the West Bank. As recently as 2010-2015, Jordan faced an electricity supply crisis due to a shortage of natural gas in Egypt that led to the curtailment of Egyptian fuel and power imports, and forced the country to switch its plants over to Heavy Fuel Oil with serious financial consequences. This situation has largely been turned around by the installation of an FSRU at Aqaba allowing the import of LNG so that thermal plants could revert to running on natural gas. The recent signature of a Gas Sales Agreement GSA) with the US-based Noble Energy for gas from Israel's Tamar and Leviathan fields, will allow Jordan to displace part of its LNG imports with natural gas reducing the cost of power generation. While Jordan was also interested in exploring imports of Palestinian gas from Gaza Marine, it remains unclear when such gas may become available. As a result of these measures, Jordan has restored its reserve margin to the prudent 10-15 percent range. In addition, the country has 1,300 MW of renewable energy in the pipeline, which due to their variable nature are not counting towards the reserve margin. Hence, Jordan is likely to enjoy electricity surpluses in the medium term and would be well positioned to increase electricity exports to the West Bank.

A key issue driving the decision of how much to rely on Jordanian imports is their relative cost. Historically, the cost of electricity imports from Jordan to the West Bank, through JDECO, have been based on a special import tariff averaging NIS 0.51–0.55 (US$0.14–0.15) per kilowatt hour (kWh), which is significantly more expensive than the Israeli import tariff averaging NIS 0.33–0.40 (US$0.09–0.11) per kWh. JDECO purchases power from Israeli Electric Corporation (IEC) on a time-of-use basis, with different costs based on the time of day and season. At the same time, JDECO arbitrages IEC costs against Jordan time-of-use rates, which are made up of a capacity charge component and a day-versus-night tariff rate. Typically, during fall and spring, when Palestinian loads are smaller, JDECO buys exclusively from IEC, whose rates are much lower than Jordan's. However, during summer and winter, when Palestinian loads are high and IEC tariffs increase (see figure I-5.1), JDECO may purchase power from Jordan, as tariffs rates are within 10–15 percent difference. It should be noted that the Palestinian Authority pays back to JDECO the difference in price between IEC and Jordanian tariff rates, as JDECO is obliged to follow PERC's unified tariff, which is set using the IEC price only. A fundamental reason for the cost differential between Israeli and Jordanian power lies in the fact that Israeli power generation is increasingly based on relatively low-cost domestic gas, while that in Jordan it is based on significantly more expensive imports of LNG. This differential will come down as Jordan starts to rely on Israeli imports of natural gas, although it is unlikely to disappear entirely.

Figure I-5.1: IEC Time-of-Use High Voltage Tariff versus Jordan Average Annual Tariff



Source: Information provided by Israeli Electric Corporation and Palestinian Electricity Regulatory Council.
Note: TOU = time-of-use.
*IEC time-of-use high voltage tariff set as of September 13, 2015.
**Jordan 2015 annual average tariff.

Increasing energy imports from Jordan is key to diversifying energy sources through regional trade. Jordan is willing to act as a transit country for Palestinian trade with third parties and already has a well-established wheeling tariff and associated regulations. Strengthening connection with the Jordanian grid would allow access to Egyptian power supply as well as the eight-country Arab regional grid comprised of Egypt, Iraq, Jordan, Syria, Turkey, Libya, Lebanon, and the West Bank and Gaza. In terms of natural gas, as noted, an approximately60-kilometer branch from the Arab Gas Pipeline from Jordan into the West Bank would allow export of gas for the Palestinian energy sector. This would require agreement from the four nations (Egypt, Jordan, Lebanon, and Syria) that are members of the Arab Gas Pipeline.

EGYPT

Gaza imports 20–30 MW of power from Egypt to the Gaza Strip during a limited number of hours per day. This restricted service is frequently interrupted due to lack of maintenance of the lines and security concerns in the Sinai Peninsula. In addition, the electricity supplied is of poor quality, with voltage and frequency deviations causing damage to sensitive electronic equipment, such as magnetic resonance imaging machines at hospitals. Egypt provides 14 percent of Gaza's energy supply through three feeder lines from the Al Arish power plant in Northern Sinai at an average tariff of NIS 0.27 (US$0.07) per kWh, almost 40 percent lower than the Israeli import price. Unlike all other cross-border electricity transactions with Egypt, which have the Egyptian Electricity Transportation Company as the contractual party, the export of power to Gaza is managed through an agreement with the local Canal Distribution Company in Sinai. The total monthly cost of Egyptian power imports is NIS 3.7 million (US$1 million), which is entirely paid by the League of Arab States.

Increasing connection capacity from Egypt into Gaza is a technically feasible option. It would have minimal impact on the Egyptian power system, because current exports represent only 0.1 percent of total current consumption in Egypt. (Indeed, total electricity demand in the West Bank and Gaza is no more than 2–3 percent of Egyptian demand.) The construction of a 220-kV transmission line from Egypt into Gaza has been considered in the past. The Islamic Development Bank had agreed to finance two 22-kV feeders from Egypt to Gaza, which would have increased the import capacity to 60 MW, but the project was put on hold.

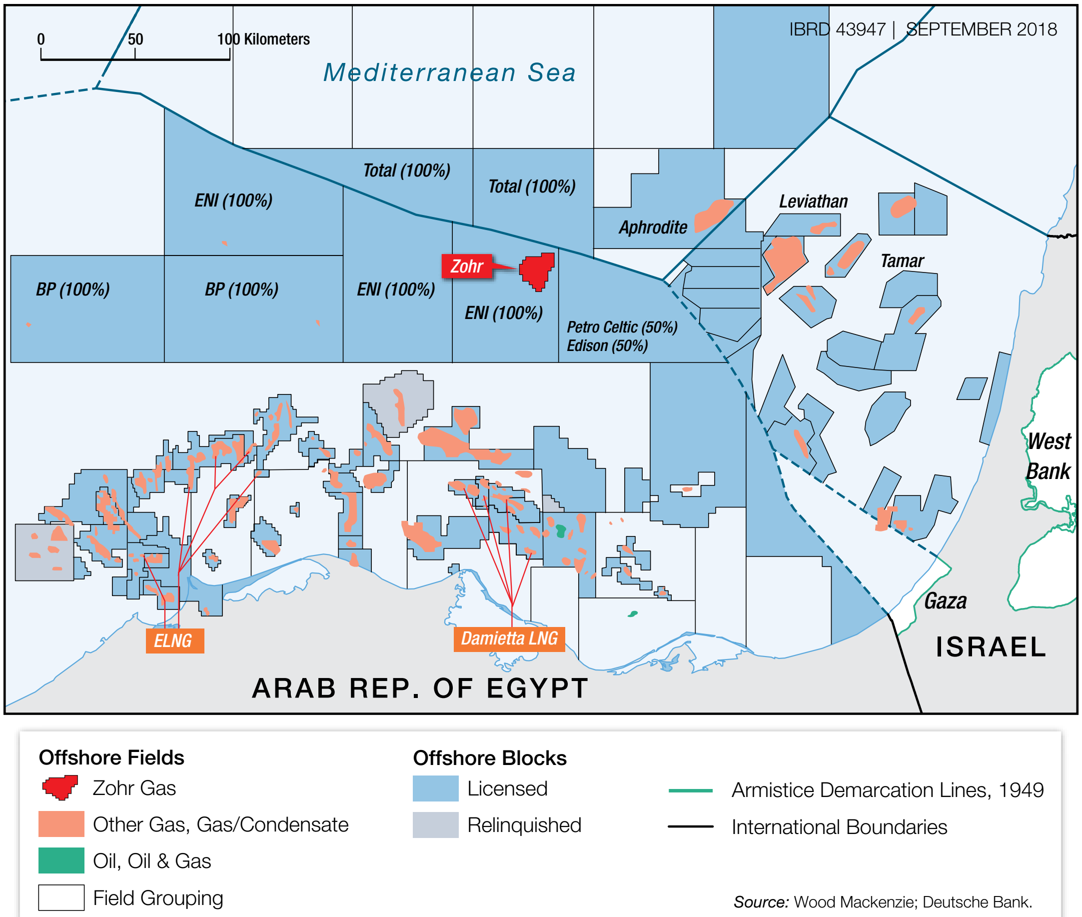
Egypt has successfully turned around its recent power supply crisis and is heading for a substantial electricity surplus. A shortage of domestic gas supply led to a serious power supply crisis in Egypt during the summer of 2014, resulting in rolling blackouts and social unrest. Since then, the government has taken decisive measures to expand electricity supply through contracting emergency plants, establishing three new floating LNG import terminals at Ain Sokhna to compensate for the shortage of domestic gas, and contracting the development of over 18 gigawatts (GW) of new thermal generation capacity, most notably through a large bilateral deal with Siemens of Germany for the development of a new generation of efficient CCGT plants. As a result, Egypt's fossil-fuel generation capacity is expected to double between 2015 and 2021, even as some 4 GW of new renewable energy capacity also come online. Demand is unlikely to keep up with this rapid growth, so that, in the absence of major capacity retirements, the average capacity utilization of fossil power plants will fall from 54 percent in 2015 to 41 percent in 2021 (see table I-5.1 and appendix E, table E.1 for additional detail). As a result, Egypt is moving from a 5 GW power deficit in 2014 to potentially a substantial power surplus by 2021, opening up the possibility of significantly expanding power exports and other domestic uses of electricity.

TABLE I-5.1: PROJECTED FOSSIL FUEL SUPPLY SITUATION IN THE EGYPTIAN POWER MARKET

	UNIT	2015	2016	2017	2018	2019	2020	2021
Capacity utilization factor	%	54	55	52	44	40	41	41
Marginal economic cost	US$ per kWh	0.04	0.03	0.04	0.05	0.05	0.06	0.06
Electricity supply	'000s GWh	161.9	171.7	178.6	188.6	199.1	210.2	223.2
Generation capacity	GW	21.3	22.3	25.9	33.6	39.6	41.2	44.8

Note: kWh = kilowatt hour; GWh = gigawatt hour; GW = gigawatt.

Map I-5.1: Zohr Gas Discovery and Surrounding Infrastructure



Source: Wood Mackenzie; Deutsche Bank.

Egypt's declining domestic gas production received a boost from the discovery of the Zohr field in 2015. Th-s offshore deep water field could hold a potential of 30 trillion cubic feet (tcf) of lean gas, making it the largest gas discovery in Egypt and one of the largest globally over the past decade. Assuming that 75 percent of the gas can be recovered, the field would add around 22 tcf, or 34 percent to Egypt's natural gas reserves, equivalent to about 12 years of current natural gas consumption. ENI's announced development plan envisages the start of production by the end of 2017, just two years after the discovery, with a progressive ramp up to a volume of about 2.7 billion cubic feet of gas per day by 2019. This discovery promises to reverse the fortunes of Egypt's gas sector, which had been in long-term decline, switching from exporting to importing status in 2015. This was due to an unfavorable energy-pricing regime, mounting arrears to international oil and gas companies, and social unrest following the Arab Spring. An ambitious policy reform agenda has helped to restore private-sector confidence and underpinned the current development of the Zohr field. Due to its strategic location close to the boundary of Egyptian, Cypriot, and Israeli water, and the availability of stranded LNG export facilities in Egypt, the Zohr field also has the potential to become a gas hub for LNG export from the region (see map I-5.1).

The cost of Egyptian electricity imports compares favorably with those of Israel. Domestic electricity tariffs in Egypt, at an average level of NIS 0.08 (US$0.02) per kWh, compare favorably with Israel, although they are distorted by significant subsidies, both to the power sector and the upstream fuels sector, which are currently in the process of being unraveled. The current cost recovery benchmark tariff is in the order of NIS 0.15 (US$0.04) per kWh. Historic exports to Gaza have also been priced at a favorable rate of NIS 0.27 (US$0.07) per kWh.

IMPLICATIONS FOR THE WEST BANK AND GAZA

These recent developments in the electricity sectors of neighboring Jordan and Egypt have significant implications for the future energy plans of the West Bank and Gaza.

Jordan and Egypt have recently overcome major, related power supply crises and are well on their way to having significant power surpluses. The recent electricity supply crisis in Egypt, due to declining availability of domestic gas, triggered a second crisis in Jordan, as Egyptian imports to that country had to be curtailed. Both countries have acted decisively to address their respective crises and are emerging with significantly expanded power-generation capacity and greatly enhanced energy security. Both countries are beginning to face the prospect of electricity surpluses, a modest surplus in Jordan of the order of 100s of MW and a much more substantial surplus in Egypt of the order of 1,000s of MW. As a result, both countries will have power available for export during the coming years, which would greatly help in the diversification efforts of the West Bank and Gaza.

From an economic standpoint, power imports from Egypt look more attractive than those from Jordan. The characteristics of potential power imports from Jordan and Egypt look quite different. Egyptian power looks to be lower cost than Israeli power, while Jordanian power looks to be higher cost than Israeli power. Since all three countries are heavily dependent on natural gas, this difference largely boils down to the cost of gas. In Egypt, domestic gas has historically been low cost, as the gas reserves are in shallow waters. In Israel, gas prices are higher as the gas reserves are in deeper waters. In Jordan, gas prices are the highest, as they do not have domestic gas supply and rely on more expensive LNG imports.

From a technical standpoint, the relative sizes of the different power systems also facilitate reliance on Egypt. Another important difference lies in the scale of the two neighbors' power sectors. The Egyptian sector is more than 10 times larger than the Jordanian one—Palestinian electricity demand represents more than 30 percent of Jordanian demand but less than 3 percent of Egyptian demand. This has important implications for energy planning. Any significant increase in imports from Jordan would eventually suggest the need for closer coordination between the two countries on energy planning. Imports from Egypt could be substantially increased without any real impact on the Egyptian system.

From a political and security standpoint, however, power imports from Jordan may be more feasible than those from Egypt. Despite the technical and economic advantages of Egyptian power, cross-border power cooperation with Jordan is significantly more advanced for political reasons. For a number of reasons, ranging from political upheaval and security concerns in the Sinai to the recent curtailment of power exports to Jordan, Egypt's reputation as a reliable source of electricity has been prejudiced. At the same time, political relations between Egypt and Gaza have been increasingly strained. On the other hand, political relations with Jordan remain strong and constructive dialogue has already been established.

Further upgrading of electricity imports from Jordan will require approvals from Israel over access to Area C. Any expansion of or addition to the current cross-border power line to Jordan traverses Area C of the West Bank and as a result will require Israeli approval, even for the upgrade of the existing lines.

NOTES

1 This is described in "Palestinians Plug Jericho into Jordan's Power Grid," Reuters, February 15, 2008, http://www.reuters.com/article/us-palestinians-israel-electricity/palestinians-plug-jericho-into-jordans-power-grid-idUSL2563001520080225.

2 For more on this see Palestinian Energy Authority and Norconsult. 2008. *Interconnection of the Electrical Networks of Egypt—Gaza Strip and Jordan-West Ban*. Sandvika, Norway: Norconsult.

3 More information can be found in World Bank. 2016. "Aide Memoire." Washington, DC: World Bank.

CHAPTER 6

Developing Domestic Renewable Power Generation

THE CURRENT CONTEXT

Renewable energy represents the only truly independent form of power supply that does not rely on imports of electricity or fuel. Currently, over 96 percent of Palestinian energy supply is dependent on Israel in terms of either direct electricity imports or fuel imports for the Gaza Power Plant (GPP). In the future, there are plans to increase domestic gas-fired generation capacity. However, unless the Gaza Marine field is developed—which is difficult, given the complex geopolitical context—the fuel for these power plants would also have to be imported from Israel. Even if Gaza Marine were to be developed, the import of the fuel would likely still entail reliance on Israeli gas transportation infrastructure. Renewable energy, particularly solar, is the only source that can be independently produced on Palestinian soil.

As the cost of solar energy continues to decline, the option looks increasingly attractive for the West Bank and Gaza. As shown in figure I-6.1, the cost of rooftop photovoltaics and utility-scale solar have dropped more than 80 percent since 2010.[1] [1] In addition, neighboring Jordan has received bids as low as NIS 0.22 (US$0.06) per kilowatt hour (kWh), which is almost half the price of Israeli Electric Corporation (IEC) imports. Nevertheless, care should be taken in comparing simplistic unit costs between firm sources of energy, like IEC imports, and variable sources, like solar generation. In addition, the political and economic climate in Jordan are significantly better than in the West Bank and Gaza, making it a more conducive environment for investment and private-sector involvement. Nevertheless, the West Bank and Gaza are located in a region rich with the sun's energy. With 3,000 sunshine hours per year and global horizontal irradiance over 2,000 kilowatt-hours per meter squared, the West Bank and Gaza rank among the world's top locations for construction of solar systems. Solar energy represents one of the few untapped supply options for the West Bank and Gaza, in a context where negotiations with neighboring countries on increasing power supply options have proven difficult to advance.

Figure I-6.1: Recent and Projected Declines in the Unit Cost of Renewable Energy

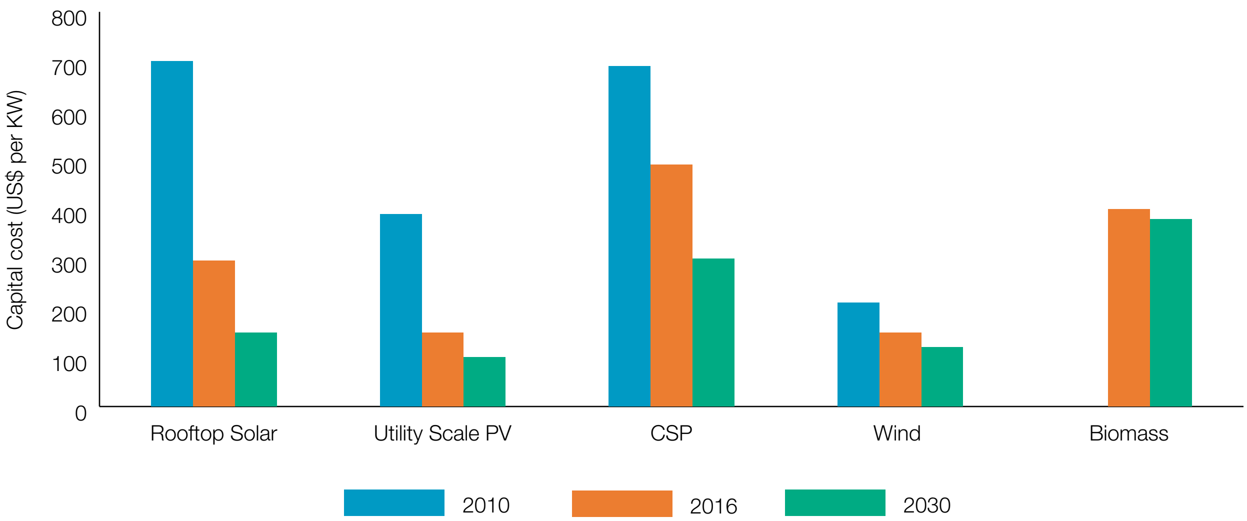


TABLE I-6.1: PROGRESS TOWARD THE ACHIEVEMENT OF PENRA'S RENEWABLE ENERGY TARGETS

PENRA'S RENEWABLE ENERGY TARGETS (SET IN 2012)		
	2020 TARGET (MW)	ACHIEVED BY 2017 (MW)
Rooftop Solar	25	1.5
Utility-scale PV and CSP	40	16
Wind	44	0
Biogas (animal and landfill)	21	0.5
Total	130	18

Note: PENRA = Palestinian Energy and Natural Resources Authority; MW = megawatt; PV = photovoltaic; CSP = concentrated solar power.

Nevertheless, it is proving challenging to kickstart renewable energy investment in the Palestinian context. The Palestinian Energy and Natural Resources Authority's (PENRA's) renewable energy targets, set in 2012, aim to generate 130 megawatts (MW) of power supply from domestic renewable resources by 2020. As of March 2017, less than 15 percent of that target had been achieved (see table I-6.1). After a slow start, interest in renewables has noticeably increased in the past three to four years, following the cabinet adoption of the renewable energy strategy in 2012 and the promulgation of the Palestinian Renewable Energy Laws released in 2015. This young sector has faced two main challenges to date. They include an inability to secure a power purchase agreement with a bankable off-taker, and there is a lack of available transmission infrastructure for power evacuation. Investors are deterred by the context that, given the current circumstances, could result in significant construction delays and high risk of payment default.

If these obstacles were addressed, the potential for renewable energy development in the West Bank and Gaza could go far beyond current policy targets. In fact, based on a survey of the available potential, the existing renewable energy target could be increased by more than 30 times, as highlighted in table I-6.2, for a total of 4,246 MW. (See appendix F, tables F.1 through F.5 for full calculations and assumptions). However, there are a number of important points to note. First, about 96 percent of the identified potential is in the West Bank. Only 165 MW of potential have been identified for Gaza, and this is almost exclusively in the form of rooftop solar, due to extreme land constraints and vertical patterns of urbanization. Second, about 83 percent of the potential identified for the West Bank is located in Area C (see appendix G, map G.3 for map and explanation of areas A, B and C). However, obtaining construction permits in Area C is extremely difficult, with only 3.5 percent of construction permits submitted by Palestinians to the Israeli Civil Administration to build in Area C having been approved in 2015. Again, due to land constraints—less severe for the West Bank than Gaza but nonetheless real—the total renewable potential of Areas A and B amounts to just 707 MW, of which over 75 percent is in the form of rooftop solar. The larger prevalence of houses in the West Bank, as well as the larger population, makes the rooftop potential much larger than for Gaza. Third, as much as 98 percent of renewable energy potential in the West Bank and Gaza takes the form of solar, due to limited suitability for wind or availability of biomass.

Wind faces land limitations similar to utility-scale PV and needs to be firmed up due to its intermittent nature. Because of safety concerns, wind farms cannot be built in densely populated urban centers. In Gaza, this means wind production is not possible. In addition, wind speeds are not sufficient in Gaza. In the West Bank, the densely populated Area A is not suitable for wind generation. On the other hand, similar to utility-scale PV, Area C is not accessible for construction. The limited sites in the West Bank with the right height, orientation, and wind speed are located close to the Israeli border, which presents a security concern to the Israeli side. Also, the intermittency of wind would have to be firmed up with additional power supply likely having to come from Israel.

Biogas plants are dispatchable and do not face land restrictions but are limited in terms of scalability. Small, distributed biogas digesters can be located close to their associated farms. The larger biogas power plants for landfills can be built on site. Power from biogas plants is dispatchable because gas

TABLE I-6.2: OVERVIEW OF RENEWABLE ENERGY POTENTIAL IN THE WEST BANK AND GAZA

POTENTIAL AVAILABLE RENEWABLE ENERGY CAPACITY (MW)				
	Utility-scale PV or CSP[a]			
	Areas A and B		Area C	Total
West Bank	103		3,374	3,477
Gaza	0			0
	Rooftop solar[b]			
	Residential	Public	Commercial	Total
West Bank	490	13	31	534
Gaza	136	8	19	163
	Wind[c] and biomass[d]			
	Wind Areas A, B, C	Biomass (animals)	Biomass (landfill)	Total
West Bank	45	7	18	70
Gaza	0	2	0	2
Total				
West Bank				4,081
Gaza				165
West Bank and Gaza				4,246

Note: MW = megawatt; PV = photovoltaic; CSP = concentrated solar power.
a Assumptions: According to PETL and PEC, 0.12 percent of Area A and B and 3 percent of Area C are available for solar installations. The land requirement is ~28 square meters (m2) per kilowatt peak (kWp), including space for control rooms and so forth.
b Assumptions: According to the Palestinian Central Bureau of Statics and the Palestinian Energy and Environmental Research Center, in the West Bank and Gaza there are over 400,000 residential, 2,500 public-sector, and 5,000 commercial sector rooftops. The rooftop areas range from 150–300 m2, and between 30–50 percent of the rooftops are available for solar installations. The rooftop space requirement is 9 m2 per KWp.
c Assumptions: In hilly regions of the West Bank, wind speeds are 4–8 meters per second for regions above 1,000 meters. The land requirement is ~210 to 330 m^2 per KWp.
d Assumptions: Three landfills in the West Bank (Jenin, Ramallah, and Hebron) each take in 800 tons of waste per day and produce 41,800 m3 of biogas, which can be converted to 251 megawatt hours (MWh) per day. For animal waste, assuming approximately 172 animal digesters making a total of 750 MWh per day.

output is constant, and an operator can choose when to generate power. This eliminates the need for firming up arrangements through backup generation. Biogas generation will decline over time but can be considered relatively constant until 2030. Although biogas is an excellent supply option, it is limited in scale and cannot be scaled up.

By 2030, rooftop solar and utility-scale photovoltaic (PV) are expected to have the lowest combined capital expenditure as well as fixed and variable operating and maintenance costs. The 2016 and forecast 2030 capital costs, as well as fixed and variable operation and maintenance costs for these supply options, are shown in table I-6.3.[2] [2] It should be noted that these figures represent the U.S. solar market and could be higher in the West Bank and Gaza to compensate for the higher risk environment. In addition, cost comparisons between PV and concentrated solar power (CSP) technologies are complicated by the fact that CSP provides some degree of storage and hence greater flexibility of use.

There is considerable potential to use rooftop solar as an electricity safety net for institutions fulfilling critical humanitarian roles, particularly in Gaza. Box I-6.1 describes how health facilities in Gaza are benefiting from a switch away from backup diesel to rooftop solar generation.

TABLE I-6.3: PROJECTED COST OF ALTERNATIVE RENEWABLE ENERGY TECHNOLOGIES IN THE WEST BANK AND GAZA BY 2030

	ROOFTOP SOLAR	UTILITY-SCALE PV	CSP	WIND	BIOMASS
	2016				
Capital costs (US$ per kW)	2,930	1,600	4,800	1,580	3,984
Fixed O&M (US$ per kW per year)	17	15	63	51	107
Variable O&M (US$ per MWh)	0	0	4	0	5
	2030				
Capital costs (US$ per kW)	1,500	1,000	3,000	1,290	3,750
Fixed O&M (US$ per kW per year)	10	8	40	49	107
Variable O&M (US$ per MWh)	0	0	4	0	5

Note: MW = megawatt; PV = photovoltaic; CSP = concentrated solar power; kW = kilowatt; MWh = megawatt hour; O&M = Operation and maintenance.

Box I-6.1: Contribution of Rooftop Solar to meet Critical Energy Needs in Gaza's Health Facilities

The United Nations (UN) has been delivering emergency fuel supply to a subset of critical health and water and sewage facilities in Gaza since 2013. The available power supply to Gaza is only enough to meet half the demand, and the available power is constantly fluctuating due to frequent unit and line outages. Between 2015 and 2016, Gaza Power Plant (GPP) was off-line on average 23 days per year, and a subset of Egyptian and Israeli import lines were down for an average of 6 and 4 days, respectively, per month. As a result, since December 2013, the UN has coordinated emergency donations of fuel supplies for generators of critical infrastructure in Gaza to ensure the population continues to have access to health, water, and sanitation facilities. As of April 2017, the UN supplies this emergency fuel to 186 facilities, of which 32 are in the health sector, 124 in water and sanitation, and 30 in solid waste management. The UN Office for the Coordination of Humanitarian Affairs (OCHA) takes on the role of coordination and prioritization of fuel needs with sectors in Gaza, while UN Relief and Works Agency (UNRWA) takes charge of purchase, delivery and distribution of fuel.

As the power situation in Gaza deteriorates, the need for additional emergency fuel donations for critical infrastructure increases, while donors are backing away from providing additional funding. In the best-case scenario, where GPP is running at 60 MW, health facilities need 450,000 liters of fuel per month, water and sewage facilities need 200,000 liters per month, and solid waste collection needs 150,000 liters per month. In total, this costs over NIS 22 million (US$6 million) per year, which includes a UN tax exemption on the cost of fuel, without which the cost would be much higher. If GPP is not running, health facilities need 650,000 liters of fuel per month, WASH facilities need 400,000 liters per month, and solid waste collection needs 200,000 liters per month. In total, this costs NIS 37 million (US$10 million) per year. Traditionally, Islamic Development Bank, Qatar, Turkey, and Japan have been the biggest donors of funds for emergency fuel supplies to Gaza. However, as the situation continues to deteriorate, donors are finding it increasingly difficult to contribute to such an expensive and unsustainable solution.

Box I-6.1: Contribution of Rooftop Solar to meet Critical Energy Needs in Gaza's Health Facilities *(continued)*

Many donors are considering donation of rooftop solar systems for critical departments in hospitals as an alternative to providing fuel for generators. Since the 2014 war in Gaza, which saw extensive damage to GPP and the Egyptian and Israeli import lines, the efforts to harness the abundant energy of the sun, through distributed rooftop solar systems, have increased 10-fold in the Gaza Strip.[a] This is especially true for critical infrastructure such as hospitals, where donors are substituting the need to provide emergency fuels for generators with installation of sustainable solar systems for critical units or departments at a fraction of the cost. As of May 2017, approximately 306 kW of rooftop solar systems have been, or are being installed on health facilities in Gaza at a total cost of approximately NIS 5.5 million (US$1.5 million). Table F.6 in appendix F contains a full breakdown of the completed and ongoing installations, including the names of health facilities benefiting from the projects and the names of donors providing the funding.

There is significant additional need for installation of rooftop solar systems in Gaza, and more donors should consider this approach as an alternative to providing fuel donations. Rooftops of hospitals in Gaza are large, flat surfaces ideal for solar installations. Although the area will not be enough to supply solar energy to the entire hospital, the existing rooftop space should be maximized through solar installations before spending extremely high sums on diesel fuel for generators. According to the Ministry of Health (MoH) and the World Health Organization (WHO), an additional 1 MW of rooftop solar systems can be installed across 34 critical units within 10 MoH hospitals in Gaza, with a total expected cost of approximately NIS 14.5 million (US$4 million). Table F.7 in appendix F provides a full breakdown of the hospitals and critical units in need of solar systems. A similar analysis should be carried out for the WASH sector in Gaza, where a subset of energy needs could also be met through solar energy.

[a] According to PENRA Gaza, between 2012 and 2014, only 310 kilowatt peak (kWp) of large-scale rooftop solar systems were installed. However, post-2014, over 3,500 kWp have been or are being installed

IMPLICATIONS FOR THE WEST BANK AND GAZA

These recent developments in the renewable energy market have significant implications for the future energy plans of the West Bank and Gaza.

The Palestinian Electricity Transmission Company (PETL) is the key enabler of renewable energy development, particularly in the West Bank. PETL plays two critical roles in renewable energy development: off-taker of power and provider of transmission infrastructure. At present, PETL has no track record in either of these roles. It is therefore pressing for PETL to become financially sustainable and establish a track record as a reputable off-taker. It is also important to ensure that PETL has the capability to meet the transmission requirements of renewable energy generation and/or to negotiate appropriate transmission arrangements with IEC.

The financial credibility of PETL is ultimately premised on the creditworthiness of the distribution companies (DISCOs). Ultimately, PETL is largely a financial middle man between generators and distributors. Providing credit enhancements for PETL cannot be seen as a reliable solution until the real underlying financial issues are resolved at the level of the DISCOs and municipality and village councils. That involves tackling pricing and operational performance at the utility level, as well as strengthening municipal finances to avoid the diversion of revenues from the electricity sector into municipal budgets. As such, a cabinet decision has enforced DISCOs and municipality and village councils to establish escrow accounts that ring-fence the electricity bill payments to ensure they are used only for the payment of suppliers.

Land availability is a major constraint for developing utility-scale solar energy production. Due to the small size and high population density of Gaza, the potential for utility-scale solar is negligible. In the West Bank, Areas A and B, which make up 40 percent of the total land area, contain all Palestinian towns and industries, leaving little space for land-intensive solar generation, but providing more rooftop space for PV than in Gaza. According to PETL and the Palestinian Energy and Environmental Research Center, based on currently submitted projects, approximately 0.12 percent of Areas A and B are available and suitable for solar production, with maximum potential capacity of 103 MW. Area C, which is sparsely developed, has much larger tracts of desert land potentially suitable for solar generation. However, this is outside the control of the Palestinian Authority, and permits for construction are rarely granted there.

Access to Area C would have a huge impact on the ability to develop domestic renewable energy generation for the West Bank. If just 3 percent of the land in Area C was used for utility-scale solar production, over 3,000 MW could be built. Area C, which makes up 60 percent of the total land area of the West Bank is made up of vast empty spaces. The lack of access to Area C is a significant lost opportunity for independence, diversification, and energy security for the Palestinian energy sector.

Rooftop solar systems increase resilience and energy security in a context prone to armed conflict. Of all supply options under consideration, rooftop solar holds the greatest potential, as it is least tied to the geopolitics of the region. Land restrictions are not a factor and construction permits are not required. There is no need to enter into long-term power purchase agreements with an off-taker or to evacuate the power generated through a transmission grid. In terms of construction time, it is the fastest and easiest to build, and since there is no need for imported fuels, the system reduces import dependency. Due to their small distributed nature, rooftop solar systems are the most secure power supply option in case of armed conflict, as experience has shown that large centralized generation systems have repeatedly become damaged during past conflicts. In that sense, rooftop solar can be regarded as an electricity safety net that allows the most basic needs to be met under a wide range of possible scenarios

NOTES

1 See the National Renewable Energy Laboratory (NREL) 2016 annual technology baseline. Note that these figures represent the U.S. solar sector. In the West Bank and Gaza, costs could be higher to compensate for the high-risk environment.
2 National Renewable Energy Laboratory (NREL) 2016 annual technology baseline.

CHAPTER 7

Developing Transmission Infrastructure

THE CURRENT CONTEXT

The West Bank and Gaza are highly dependent on energy imports from neighboring countries. The West Bank has over 250 low- and medium-voltage connection points with Israel, and 1 connection point with Jordan, which provide 99 percent and 1 percent of total energy supply to the West Bank, respectively. Gaza has 10 connection points with Israel, 3 with Egypt, and 1 with the Gaza Power Plant (GPP), which provide 64 percent, 13 percent, and 23 percent of Gaza's energy supply, respectively. Map G.1 in appendix G is a geographical representation of the connection points. All connection points in Gaza, and most in the West Bank, are fully saturated, which leads to power cuts during peak winter and summer loads. As the electricity demand continues to grow, the situation is bound to deteriorate unless the capacity of import lines is expanded.

To increase diversification of supply and relieve the pressure on the saturated interconnections, additional infrastructure needs to be built. Plans for improved power supply for the West Bank are more advanced than for Gaza. According to the Palestinian Energy Authority's draft Energy Sector Strategy 2017–2022, expansion plans for the West Bank include the following:

1. Four new high voltage substations (see map G.2 in appendix G for location and service area of new substations) providing an additional 550 megawatts (MW) of import capacity from Israeli Electric Corporation (IEC) with expected in-service dates ranging from 2017 to 2019
2. Jenin Power Plant (JPP), providing additional capacity of 200–450 MW with expected service date of 2020
3. Hebron Power Plant, providing additional capacity of 120 MW with planned service date of 2022.

Expansion plans for Gaza are still in the discussion phase and include (i) a high-voltage 161 kV power line from IEC with import capacity of 100–150 MW and (ii) and upgrade of GPP to operate on natural gas coupled, with expansion of the capacity up to 560 MW. All expansion plans, for the West Bank and especially for Gaza are heavily tied to the political economy of the context and concerns over risk of nonpayment.

In the West Bank, the energization of the new high-voltage substations under the Palestinian Electricity Transmission Company's (PETL's) management will start a process of consolidation of the existing connection points. This would streamline operations by reducing the large number of direct bilateral low- and medium-voltage connection points between Palestinian distribution companies (DISCOs) and municipalities and village councils (MVCs). Instead, IEC would sell power to PETL at higher voltage through the substations, and PETL would in turn sell the power to DISCOs and MVCs. This would increase billing transparency and allow PETL to improve the sector's bookkeeping by having better control of the billing and payment cycles. Power transmission at higher voltages would also reduce losses, enabling PETL and DISCOs to bill for a larger portion of the purchased power, thereby improving cost recovery. In addition, IEC's bulk supply tariff at higher voltage is at least 10 percent lower than at the low- and medium-voltage levels. Finally, the substations would allow desperately needed additional power to be supplied to the West Bank, which would be instrumental in avoiding civil unrest and mass protests observed during past winter and summer peak load conditions, which stemmed from power cuts due to shortages in power supply.

The West Bank does not have its own transmission backbone to evacuate domestic generation. Currently, Palestinian load centers are passive absorbers of electricity. Their power comes from several low- and medium-voltage distribution networks managed by Palestinian DISCOs. These Palestinian distribution networks are in turn fed by Israeli high-voltage transmission networks that act as electron highways routing large volumes of power over large distances from point of generation to point of distribution.

As the West Bank develops its own domestic power-generation capacity, one option for moving generated power to its load centers is to wheel through the Israeli grid. Wheeling is a mechanism by which power generated in the West Bank is evacuated out into the Israeli network and injected back into the West Bank at a different location closer to the Palestinian load centers. Wheeling charges are set by the Israeli regulator, Public Utility Authority (PUA), with a full breakdown provided in table I-7.1. This figure shows that the time-of-use (TOU) costs are lowest if only the Israeli transmission network is used and highest if both the transmission and distribution network are used. (See appendix C, table C.7 for definition of TOU periods). Table I-7.2 provides a breakdown of the consumption patterns in the West Bank, showing that the shoulder hours in spring and fall make up the largest percentage of consumption, at 26 percent, and on-peak hours in winter or summer make up the smallest percentage of consumption, at 3 percent each. Average wheeling costs, shown in table I-7.3, are derived by cross multiplying the costs in table I-7.1 with the consumption patterns in table I-7.2. Table I-7.3 shows that, for every kilowatt hour (kWh) of Palestinian energy that needs to be moved through the Israeli grid, the Palestinian side would need to pay between NIS 0.018–0.050 (US$0.005–0.013) per kWh, equivalent to a 5–10 percent mark-up over the IEC import tariff. In addition to these relatively high wheeling costs, the Israeli transmission network acts as the gatekeeper for the flow of Palestinian electricity, which diminishes the control and flexibility of Palestinian operators.

TABLE I-7.1: ISRAELI ELECTRIC CORPORATION WHEELING TARIFFS

NIS AGOROT PER KWH, AS OF SEPTEMBER 13, 2015

SEASON	TOU BLOCK	TRANSMISSION TARIFF *	TRANSMISSION AND DISTRIBUTION TARIFF**	DISTRIBUTION TARIFF***
Winter	Off peak	0.89	3.46	2.55
	Shoulder	1.10	3.89	2.78
	Peak	2.8	7.22	4.38
Spring/Fall	Off peak	0.81	3.22	2.41
	Shoulder	1.36	4.17	2.80
	Peak	1.79	4.82	3.01
Summer	Off peak	1.42	4.20	2.77
	Shoulder	2.60	6.32	3.68
	Peak	6.12	12.13	5.90

Source: Information provided by Israel PUA.
Note: Ultra-high voltage = 400 kV and 161 kV; high voltage = 22 kV and 33 kV.
TOU = time of use.
* Ultra-high voltage producer selling to ultra-high voltage consumer
** Ultra-high voltage producer selling to "far away" high voltage consumer
*** Ultra-high voltage producer selling to "close by" high voltage consumer

TABLE I-7.2: WEST BANK ANNUAL CONSUMPTION BY TIME OF USE

WINTER			SPRING/FALL			SUMMER		
OFF PEAK	SHOULDER	ON PEAK	OFF PEAK	SHOULDER	ON PEAK	OFF PEAK	SHOULDER	ON PEAK
3%	16%	9%	11%	26%	20%	3%	7%	5%

Source: IEC load curve for JDECO consumption, 2015
Note: The data comes from IEC and represents only sales to JDECO, which covers approximately 50 percent of the West Bank. The figures here assume similar consumption patterns in all of the West Bank.

TABLE I-7.3: ANNUAL AVERAGE WHEELING TARIFFS

	TRANSMISSION TARIFF	TRANSMISSION AND DISTRIBUTION TARIFF	DISTRIBUTION TARIFF
Agorot per kWh	1.8	5.0	3.1
U.S. cents per kWh	0.5	1.3	0.8

Source: World Bank calculations.
Note: kWh = kilowatt hour.

An alternative option is to construct a Palestinian backbone by connecting the new high-voltage substations through a high-voltage transmission line. This would allow generated power to be routed directly to Palestinian load centers through this backbone, providing greater flexibility and autonomy to Palestinian operators. Although operationally more favorable, this option faces significant obstacles, as Israeli approval and permits would be required for those sizeable sections of the backbone that would need to be built cross Area C. A more detailed comparison of the financial impacts of wheeling versus building a backbone is provided in Part II.

Building a transmission backbone in the West Bank is logistically and operationally complex. The land in the West Bank is divided into islands, called Areas A and B, that are surrounded by Area C (see map in map G.3 in appendix G). Areas A and B, which combined make up 40 percent of the West Bank, are under Palestinian or joint Palestinian and Israeli civil control, respectively, so construction permits can be obtained more easily. Area C is entirely under Israeli control and construction permits are extremely difficult to obtain. Building a transmission backbone would require constructing large and contiguous infrastructure traversing Areas A, B, and C, which would likely face significant delays. In addition, neighboring countries would have to provide approvals for large connections to their system, which may affect their own grid stability. Finally, if the transmission backbone is built, all sides must work together constantly to create supply-demand balance in the connected grids, which requires excellent cooperation at all times. For this to happen, PETL would need to develop the capacity to play the role of a proper transmission system operator.

Many other preconditions need to be met before it makes sense to consider the development of a transmission backbone. Before a transmission backbone is built, a series of phases must be passed to create the right environment. First, the substations must be energized, which would allow PETL to become operational. Next, PETL must work with DISCOs to reduce financial leakages, in order to create strong payment discipline along the electricity supply chain. This would improve the creditworthiness of PETL and make it possible for it to sign power purchase agreements (PPAs) with independent power producers, thereby increasing domestic generation capacity. As domestic generation increases, in the initial years, wheeling could be a viable option as PETL becomes financially and operational stable and capable. Only at this point, once the foundations for a financially secure energy sector have been laid, would it be time to consider the construction of a transmission backbone to enhance energy sector independence.

A swap mechanism could be an interesting third option to consider. In addition to the options of wheeling through the Israeli grid or building a transmission backbone in the West Bank, the Palestinian Authority could negotiate a swap mechanism with Israel, in which power generated in the West Bank is exported to Israel and Israel agrees to provide the same quantity of power at a different location back to the West Bank. The details need to be sorted between the two sides, but this would provide a convenient middle ground to avoid having to build infrastructure in Area C or having to pay a constant per kWh charge to use the Israeli network.

In Gaza, Palestinian Authority concerns over nonpayment have impeded development of additional IEC supply through a 161 kV transmission line from Israel. Additional power supply to Gaza is desperately needed as the existing import feeder lines have been fully saturated for quite some time. Additional power supply from IEC through a 161 kV transmission line has been on hold for over a decade, but recently Israeli authorities gave the green light for its construction. Since the Palestinian Authority pays for the entirety of the power that Gaza receives from IEC through clearance revenues and the net lending process, they are concerned about how the additional power from IEC to Gaza will be paid for. This is especially true given the fact that donor contributions to the Palestinian Authority's budget support have fallen from 32 percent of gross domestic product in 2008 to under 6 percent in 2016.

Building a transmission backbone in Gaza makes more sense than wheeling domestically generated power supply through Israel. Given the small size of the Gaza Strip, and the fact that there are no land restriction and permitting issues such as Area C in the West Bank, if domestic generation is ramped up in the future in Gaza, it makes more sense to create a domestic backbone then to export the power into the Israeli grid for wheeling and reinjection. Between the West Bank and Gaza, the total investment costs for building the full domestic transmission and distribution infrastructure, including the transmission backbone but assuming no wheeling or swaps, are given in table I-7.4.

TABLE I-7.4: SUMMARY OF TRANSMISSION AND DISTRIBUTION INVESTMENT COSTS (US$ MILLIONS)

	GAZA	WEST BANK	WEST BANK AND GAZA
Transmission backbone	33[a]	72[b]	105
Transmission to evacuate renewable energy projects in Area C	-	44[c]	44
Regional interconnectors	32[d]	20[e]	52
Distribution	60[f]	52[g]	112
Total	124	188	312

[a] 2 x 161/33 substations, overhead 161 kilovolt (kV) line; 26 kilometers (km).
[b] 2 x 161/33 substations, overhead 161 kV line; 117 km plus a national control center.
[c] 3 x 161/33 substations, overhead 161 kV line; 72 km.
[d] 2 x 161/33 substations, overhead 161 kV line; 20 km.
[e] 1 x 161/33 substations, overhead 161 kV line; 26 km.
[f] For Gaza-North, rehabilitation of the distribution grid (224 km) and extension of the grid (200 km). For Gaza- South, rehabilitation of the distribution grid (74.7 km) and extension of the grid (200 km).
[g] For West Bank-North, adaptation of the distribution grid to support new connection points (200 km) and extensions around JPP (100 km). For West Bank-Central, adaptation of the distribution grid to support new connection points (200 km) and extensions for supporting Area C and extension of connection with Jordan (100 km plus 100 km). For West Bank-South, adaptation of the distribution grid to support new connection points and extensions to support the development of gas for West Bank-South.

IMPLICATIONS FOR THE WEST BANK AND GAZA

The development of transmission infrastructure in the West Bank and Gaza have the following implications for the Palestinian energy sector.

PETL must start operating on a commercial basis and take ownership for fixing the gaps in the revenue cycle as its first priority. Financial independence will lead to energy independence, but the reverse is not possible. Supplier concerns over nonpayment undermine any potential for upgrade and expansion in the energy sector. PETL has two roles: that of a single buyer and bookkeeper and that of a transmission system operator. In order to enable the right environment for building large-scale infrastructure, including transmission, PETL must excel in its role as the single buyer and bookkeeper first before becoming a transmission system operator, and it can take on this role even before the substations are energized or a PPA with IEC is signed.

In parallel, while PETL is negotiating with IEC on the main PPA and the energization of the substations, it can focus on strengthening its operational capacity as the energy sector's bookkeeper. As the negotiations continue, PETL should focus on three issues in the short term. First, PETL should prepare and open negotiations on power service agreements (PSA) with the DISCOs and MVCs to set the terms of power sales to, and collections from, electricity distributors in the West Bank. Progress can be achieved on draft PSAs while the main PPA is still being negotiated. Once the PPA is signed, the PSAs can be completed with final clauses, saving a significant amount of time. Second, a billing and collection system must be set up for PETL, allowing it to receive invoices from IEC, send bills to distributors, collect payments from distributors, and pay back IEC for the purchased electricity. USAID is currently supporting PETL to design the software and mechanism for billing and collections. In addition, PETL is working with IEC to ensure that the company receives the bills directly instead of through the Palestinian distributors. Finally, PETL should collaborate with the Palestinian Electricity Regulatory Council in the preparation of its sale tariff to the distributors. With these mechanisms in place, PETL could accelerate its progress toward fulfilling its role and responsibilities under the PPA and reducing its reliance on donor assistance for its operational costs. PETL's staffing plan needs to be adjusted according to the company's projections on revenues collected from distributors.

As domestic generation develops, Israeli and Palestinian sides will have to work together to determine how best to evacuate the power. In the short term, the two sides will need to negotiate favorable wheeling charges or swap mechanisms to ensure that power supply expansion keeps pace with demand growth. In the mid- to longer term, as the Palestinian energy sector becomes more stable and bankable, the two sides can work together to build a long-term vision of establishing a high-voltage transmission network. Given the inherently interwoven nature of the Israeli and Palestinian energy sectors, with or without a Palestinian transmission network, both sides must cooperate closely to ensure grid stability.

If the Palestinian energy sector is to become a major client for wheeling power back through the Israeli grid, then the tariff structure for wheeling will need to be carefully considered, or alternatively a swap mechanism needs to be negotiated. At present, the wheeling charges that would apply to Palestinian electricity wheeling back through the Israeli grid look to be relatively high and represent a significant surcharge on the import tariff. The cost implications of using the Israeli grid for wheeling would need to be carefully understood and negotiated by both sides. A swap mechanism could be the most ideal solution if both sides can come to agreeable terms.

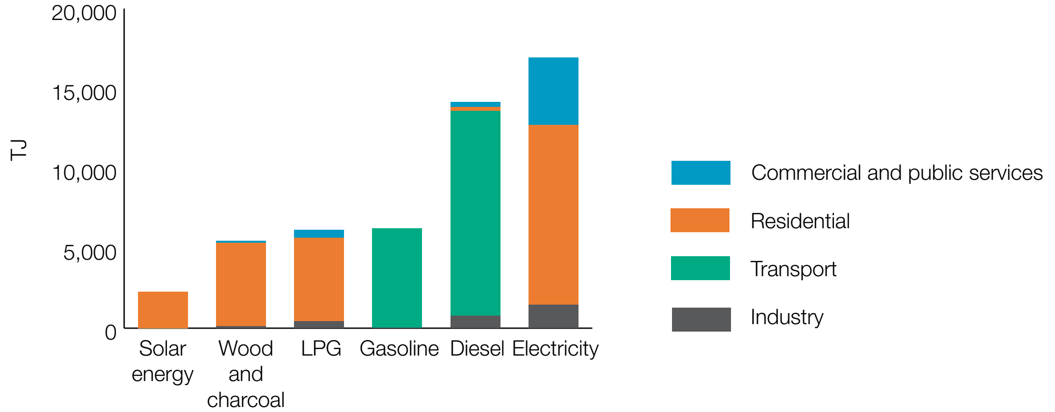
CHAPTER 8
Integrating Energy Efficiency

THE CURRENT CONTEXT

The Palestinian energy system is characterized by the complete dependence on imported energy products and the predominance of electricity in final energy consumption. Diesel and gasoline are used primarily in the transport sector, while all other sources of energy—including electricity—are primarily used by the residential sector (figure I-8.1).

The Palestinian National Energy Efficiency Action Plan (NEEAP) aims to reduce 384 gigawatt hours (GWh) of total energy demand by 2020, representing around 1 percent reduction per year (compared to 2010 levels). The action plan is mainly focused on electricity, because this energy type has the largest share in the Palestinian final energy mix (see table I-8.1).[1] The Palestinian Energy and Natural Resources Authority (PENRA), with the support of the French Development Agency (Agence Française de Développement, AFD) and the World Bank, has been actively spurring the implementation of the three-phased NEEAP for 2012–20. Phase I has been successfully achieved and Phase II is being implemented satisfactorily. PENRA's Energy Efficiency Unit has so far undertaken 250 energy audits across different sectors of the Palestinian economy, which have triggered the investments required to unlock the untapped energy efficiency potential. Phase III is expected to start in 2018.[2]

Figure I-8.1: Final Energy Consumption per Sector in the Palestinian Territories



Source: World Bank own elaboration based on PCBS data.
Note: LPG = liquid petroleum gas.

TABLE I-8.1: ENERGY EFFICIENCY TARGETS UNDER NEEAP 2012–2020 (GWH)

SECTOR	TARGETS			
	PHASE I (2012–14)	PHASE II (2015–17)	PHASE III (2018–20)	2020
Industrial	5	6	8	19
Buildings	38	130	195	363
Water pumping	-	1	1	2
Total (GWh)	43	137	204	384

Source: Information provided by Palestinian National Energy Efficiency Action Plan (NEEAP) and Palestinian Energy and Natural Resources Authority.
Note: GWh = gigawatt hour.

To further promote energy-efficiency investments, PENRA has drafted the ambitious National Energy Efficiency Action Plan for 2020–2030 with the support of the World Bank (figure I-8.2) . The proposed target is to reduce 5 percent of the forecast consumption during the 10-year period, a total savings of 5,000 GWh. This represents a large increase from the 384 GWh savings of the current NEEAP 2012–2020. The future action plan is also divided in three phases.

Phase I (2021–30) focuses on efficient appliances and industrial equipment (see figure I-8.3). This phase is designed as a follow-on of the current NEEAP 2012–2020, to expand and consolidate its achievements. This phase focuses on energy audits for the industrial and commercial sectors and financial incentives. The deployment of smart-meters and related information systems will allow consumers to have real-time and accurate information on consumption and associated costs. Consumption data will be collected, stored, and analyzed to provide useful guidance to replace inefficient products and improve industrial processes (sub-metering and energy audits are the key tools to be used). This phase will also pave the way to Phase III to ensure that smart-home appliances will be fully interoperable with metering systems.

Figure I-8.2.: Draft NEEAP 2020–2030 Implementation Strategy

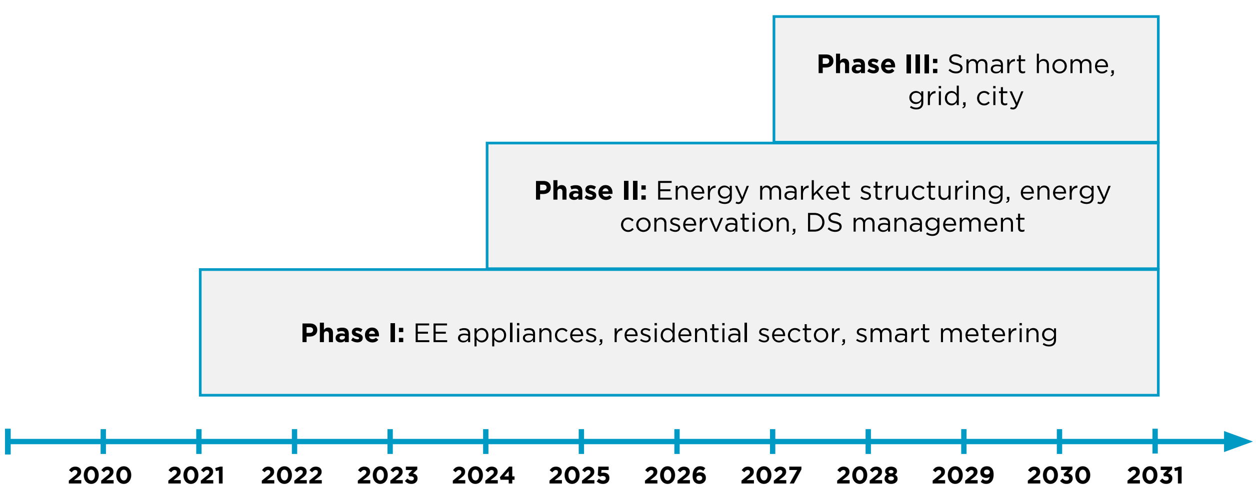
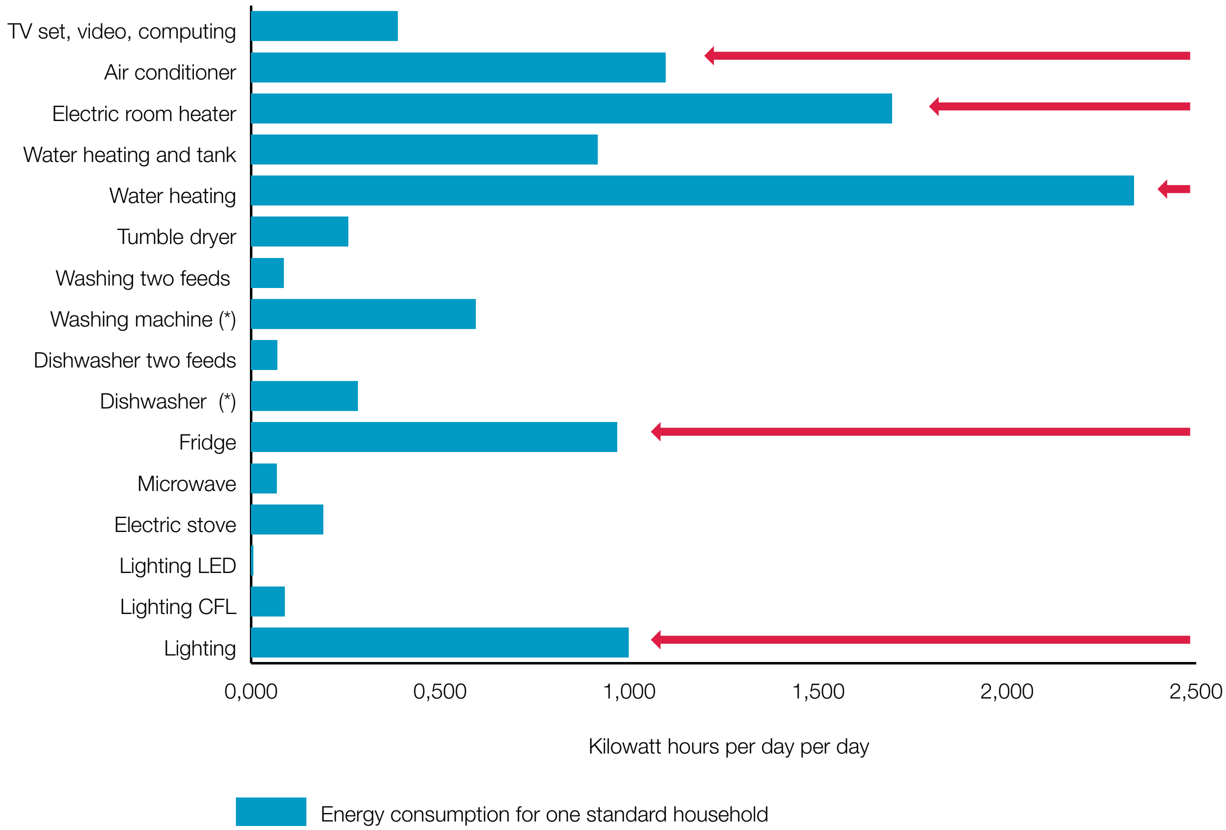


Figure I-8.3: Energy Efficiency Potential in the Residential Sector



Source: World Bank own elaboration based on Palestinian Central Bureau of Statics data for households energy 2015.

Phase II (2024–30) will focus on energy market structuring and thermal insulation of buildings. The opening of the national electricity market to competition could be considered in this phase. From an energy efficiency perspective, this reform would make new market-based services available, such as the possibility to remunerate clients reducing their consumption on demand. The rollout of smart-meters and the introduction of time-of-use tariffs would contribute to incentivize behavior change and reduce consumption during peak hours. Due to the large lead times of building renovations, thermal insulation of buildings should also be a priority activity during this phase. Following the design of specific minimum efficiency performance standards and building codes integrating nearly Zero Energy Building standards (nZEB), these would become mandatory for all public buildings and encouraged by financial incentives for the residential sector.[3] A building renovation strategy would also be drafted for the residential sector in order to improve thermal insulation of the existing building stock.

Phase III (2027–30) will focus on smart-homes, smart-buildings, and smart-grids. The simultaneous use of market-based services and smart-appliances would enable consumers to become active energy players. For instance, consumer's behavior could adjust to changes in electricity prices. Demand response actions to shift consumer's electricity usage during peak hours in response to time-based rates would avoid building new generation capacity.

The proposed energy efficiency actions have relatively modest investment costs and short payback periods. Table I-8.2 summarizes the proposed energy-efficiency actions with the expected savings during the 2020–30 timeframe, their total costs, and the cost-benefit ratio. When this ratio is less than the average retail electricity price, i.e., US$0.13 for residential, the corresponding investment may be recovered in less than 10 years.

TABLE I-8.2: ENERGY EFFICIENCY POTENTIAL DURING 2020–2030

ENERGY-EFFICIENCY ACTIONS	BENEFITS (GWH)	TOTAL COSTS (US$ MILLIONS)	COST-BENEFIT (US$-KWH)
Lighting: move to CFL standard	2,612	1.750	0.001
Lighting: move to LED standard	322	2.275	0.007
Introduction of more efficient fridges	127	4.375	0.035
Switch to gas for room heating	246	24.832	0.101
Electronic thermostats	222	10.177	0.046
Labelling and national campaign	1,270	3	0.002
Repairing of SWH	1,576	126	0.080
Smart-metering for all households	1,587	48	0.038
Sub-metering	317	4.812	0.015
Building thermal insulation	720	345	0.479
Labelling program	881	50	0.057

Source: PENRA, Palestinian National Energy Efficiency Action Plan for 2020 – 2030, draft March 2016.
Note: CFL = compact fluorescent light; LED = light-emitting diode.

IMPLICATIONS FOR THE WEST BANK AND GAZA

The development of energy-efficiency programs in the West Bank and Gaza have the following implications for the Palestinian energy sector.

Managing overall energy demand is a priority, but managing peak hour load will become increasingly important. Nowadays, electricity is bought from IEC at a high price, but IEC is in charge of managing the flexibility of the demand. In the future, PETL, acting as transmission system operator, could purchase "blocs" of electricity in bulk at a lower price but would have the responsibility to make daily forecasts and balance demand and generation in real time. If PETL has to develop the role of system operator in the future, a deep knowledge of energy consumption and its patterns would be key.

Among the proposed energy-efficiency actions, two may require a complex implementation program:

1. The first is the generalization of the smart-meters for the residential sector. This program aims to provide information to the consumers so that they will be in a position to better manage their consumption. These meters are the visible part of the iceberg. A sophisticated information system is simultaneously required from DISCOs to prepare energy audits per household, compare consumption profiles to detect nonefficient usages, recommend the replacement of appliances, and so forth. Home displays or equivalent devices (for example, mobile applications) will help the consumers relate their daily behaviors and the impacts on their consumption. Monthly billing information is not sufficient to create this link between usage and energy. The same program should help DISCOs improve their quality of service (detection of failures) and reduce technical and commercial losses. Smart-meters are not sufficient to do that. Internal processes have to be implemented to randomly check the consumption and detect unbalanced low voltage lines.

2. The second action is to promote a switch from electricity to gas (liquid petroleum gas and/or natural gas) for room heating. Electricity should be reserved to usages where there are no replacements (motors, electronics, and so forth). For consumers, the main argument in favor of electricity is the low cost of appliances. However, in the long term, the operational costs are much lower for gas. This switch cannot be initiated without a national strategy for gas so that the cost of the required infrastructures (transportation and storage of gas) will be shared among all stakeholders. The repair and further penetration of solar water heaters is part of this endeavor, since it would decrease the need to use nonrenewable energy.

NOTES

1 Electricity represents 33 percent of the final consumption of energy. Savings on diesel, the second energy most commonly used in the Palestinian territories, should also be considered in future assessments. Electricity is mainly used by the residential sector (more than 60 percent), whereas diesel is used almost exclusively in the transport sector.

2 The AFD has financed the required energy audit equipment and staff costs. Audits include 60 in the industrial, 120 in the public, 40 in the service, 10 in the agricultural, and 20 in the residential sectors

3 The concept of nZEB is an attempt to standardize the consumption of energy per square meter per year.

PART II

Decision Making

CHAPTER 9

Introduction and methodology

Attention now turns to the exploration of possible energy futures for the West Bank and Gaza, with the accent on enhanced energy security. However, energy security can itself be defined from a number of perspectives, each of them valid in its own way. First, there is the ability to reliably meet the entire demand for electricity, by minimizing supply interruptions and hence loss of load. Second, there is the resilience of the power system that comes from diversifying sources of power supply, including alternatives that are relatively robust in the context of different types of shocks. Third, there is the degree of independence of the power system, in terms of the extent to which electricity needs can be met from domestic production versus imports. It should be noted that only renewable energy provides full energy independence, in the sense that domestic generation with fossil fuels can be as, if not more, vulnerable to fuel supply interruptions as importing electricity. The analysis will consider all three of these dimensions of energy security, which can usefully be described as *reliability*, *resilience*, and *independence*. In practice, tradeoffs may exist between them.

Energy security cannot be considered in isolation from financial affordability. Increasing energy security often comes with a cost premium of some sort, as additional investments will likely be needed to achieve the requisite reserve margin, diversify sources of power, and/or expand domestic production. The benefits of energy security also need to be weighed-up against associated costs and the affordability of these costs for the power system as a whole. Affordability can be considered from two perspectives. The first is whether the retail tariffs needed to implement the energy security plan are affordable to customers. The second is whether any government subsidies needed to support the achievement of the energy security plan are fiscally affordable to government. Both are evaluated in this analysis.

There are therefore two steps involved in realizing a secure and affordable energy future for the West Bank and Gaza. The first is to conduct a power-sector planning exercise to evaluate the relative attractiveness of different electricity supply options. The second step is to evaluate the feasibility of financing the preferred power-sector planning choice.

ROBUST PLANNING MODEL

As a first step, a robust planning model is developed that is capable of incorporating the significant uncertainties of the Palestinian context into a traditional least cost power generation plan. Power-system planning is normally undertaken using models that select the least-cost sequence of generation options needed to meet electricity demand at some specified level of reliability, based on the assumption that all parameters are known with certainty. This approach does not appear realistic in the Palestinian context, where deep uncertainty is the norm. Four dimensions of uncertainty are explicitly considered for each generation option: (i) uncertainty in demand forecast, (ii) uncertainty in the evolving unit cost of different technologies over time, (iii) uncertainty in how soon particular supply options (that is, gas) will become available, and (iv) uncertainty due to outages and force majeure, such as conflict. Based on stakeholder consultation and expert opinion, plausible ranges for the uncertainties were defined.

By running the planning exercise many times in different states of the world, it becomes possible to identify the plan that is most robust over the largest number of possible futures. The model is run 100 times and each time a different draw is made from the probability distribution of all the uncertain parameters, resulting in a slightly different optimal least-cost plan (see figure II-9.1). At the end of the process, the 100 resulting plans are put side by side and used to construct a robust plan by starting with the supply option that is most frequently selected across the 100 least-cost plans,

Figure II-9.1: Illustration of Methodology for Determining the Robust Plan

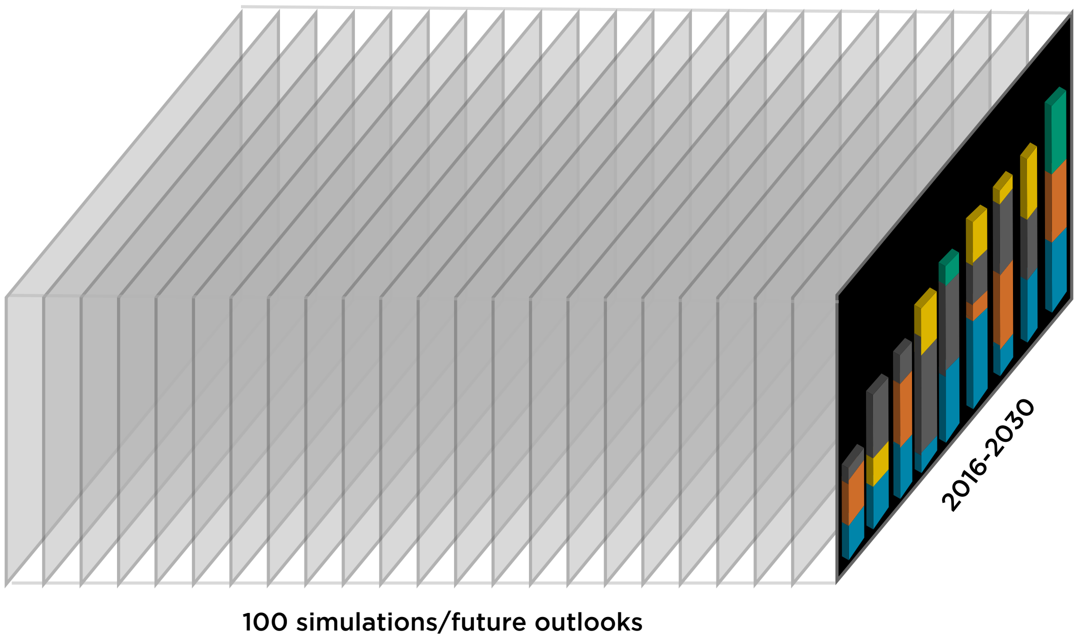


TABLE II-9.1: OVERVIEW OF ENERGY PLANNING SCENARIOS DEVELOPED WITH THE ROBUST PLANNING MODEL

SCENARIOS	CHARACTERIZATION	PURPOSE
Do Nothing	Electricity demand continues to grow without any proactive measures either to increase power imports or develop generation capacity.	This is the baseline against which other planning alternatives can be evaluated.
Planned Future	Future increases in electricity demand are met by projects that are already in the pipeline.	Evaluate the current thinking of the Palestinian Authority by analyzing the impact of (i) planned projects currently in the pipeline and (ii) PENRA's vision as stated in the most recent Palestinian National Authority Energy Sector Strategy of 2011–2013, as well as the draft Strategy for 2017–2022.
PENRA Vision	Future increases in electricity demand are met in such a way that by 2030 no single generation source accounts for more than 50 percent of energy needs, while providing the capacity to import 100 percent of energy needs as backup.	
Maximum Cooperation	Future increases in electricity demand are met primarily by increasing electricity imports.	Evaluate alternative futures at the extreme opposite ends of the independence spectrum to analyze the tradeoffs.
Maximum Independence	Future increases in electricity demand are met primarily by developing domestic generation options.	

Note: PENRA = Palestinian Energy and Natural Resources Authority.

and then adding the next most frequently selected, and so on, until demand is fully met. The model provides a detailed set of information regarding each selected energy future and can be constrained to meet certain policy objectives. Extensive details on the robust planning model and methodology, uncertainty variables and plausible ranges, and full model outcomes are provided in appendix 8.

The robust planning model is used to illustrate a number of different planning scenarios. The model will be used to explore five different types of planning scenarios each for the West Bank and Gaza (table II-9.1). It is important to stress that not all of the scenarios presented by the model are necessarily realistic, and some of them are used primarily to illustrate the implications of pursuing different approaches.

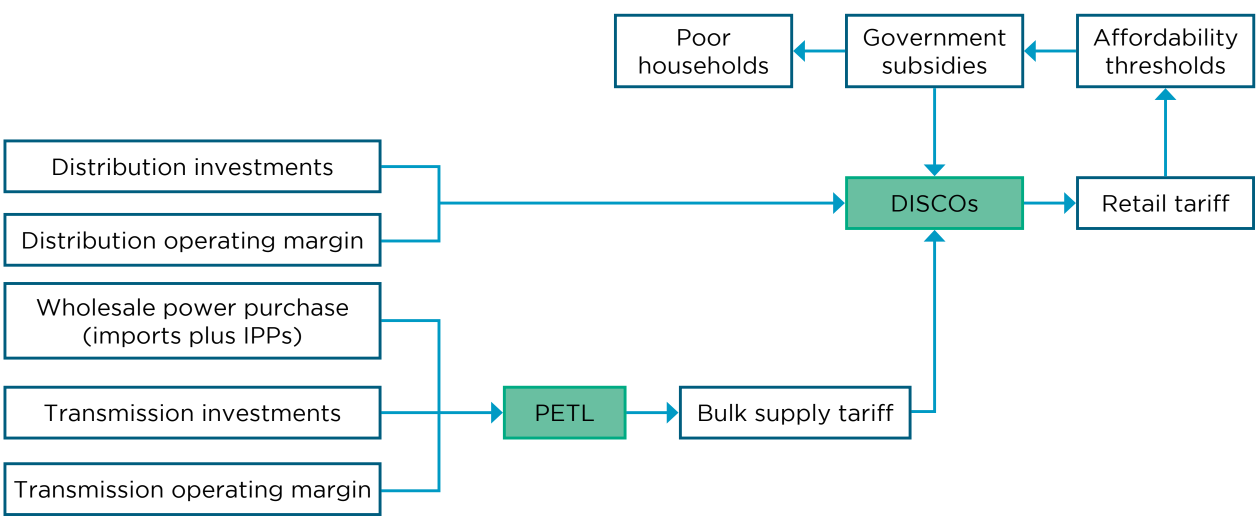
SECTOR FINANCIAL MODEL

A power sector financial model was developed to cover the entire Palestinian electricity sector. The model begins with the Palestinian Electricity Transmission Company (PETL) purchasing a "basket" of electricity from different producers at different wholesale costs under power purchase agreements, assuming no Palestinian public investment in generation (figure II-9.2). The pattern of purchases is determined by the output of the robust planning model (see figure II-9.3), which identifies the quantity and cost of each generation source. PETL then sells this electricity to distribution companies (DISCOs) at a *bulk supply tariff*, which will include a mark-up to cover PETL's own investment and overhead costs. DISCOs then sell this electricity to consumers at a *retail tariff*, which will include a mark-up to cover their own investment and overhead costs. The tariffs calculated in the financial model are *equilibrium tariffs* designed to offset and compensate for losses and low collection rates. This differs from the regulator's (Palestinian Electricity Regulatory Council, or PERC) tariff-setting methodology.

The retail tariff, consistent with financial equilibrium that is calculated by the model, differs somewhat from the regulatory tariff set by the regulator, PERC. First, PERC calculates a single unified tariff for all Palestinian distributors, based on averaging financial data submitted by a subset of the utilities—Jerusalem District Electricity Company and Northern Electricity Distribution Company. This means that while tariffs are set to cover costs on average, individual utilities may over- or under recover. The financial model instead calculates individual cost recovery tariffs for each utility each year. Second, PERC bases tariff calculations on the assumption of 100 percent revenue collection, so as not to pass on commercial inefficiencies to customers. The financial model allows efficiency improvement targets for 2030 to be built into the calculations so that performance improves gradually and is reflected in tariffs as soon as improvements take place. However, during the transition period, collection inefficiencies are passed on to customers.

Considerable efforts were made to collect the financial and operational data needed for the model. Numerous meetings were held with the Ministry of Finance, PETL, PERC, and all six DISCOs to support an extensive data-gathering exercise. The data collected include financial statements of DISCOs, as well as operational data such as purchase and sales, losses and collection rates, payment to suppliers (including through net lending), and more. In the case of the transmission system operator, PETL—a new institution with limited financial records—the company's business plan was used to estimate its anticipated cost structure.

Figure II-9.2: Flowchart Illustrating the Different Building Blocks of the Electricity Sector Financial Model

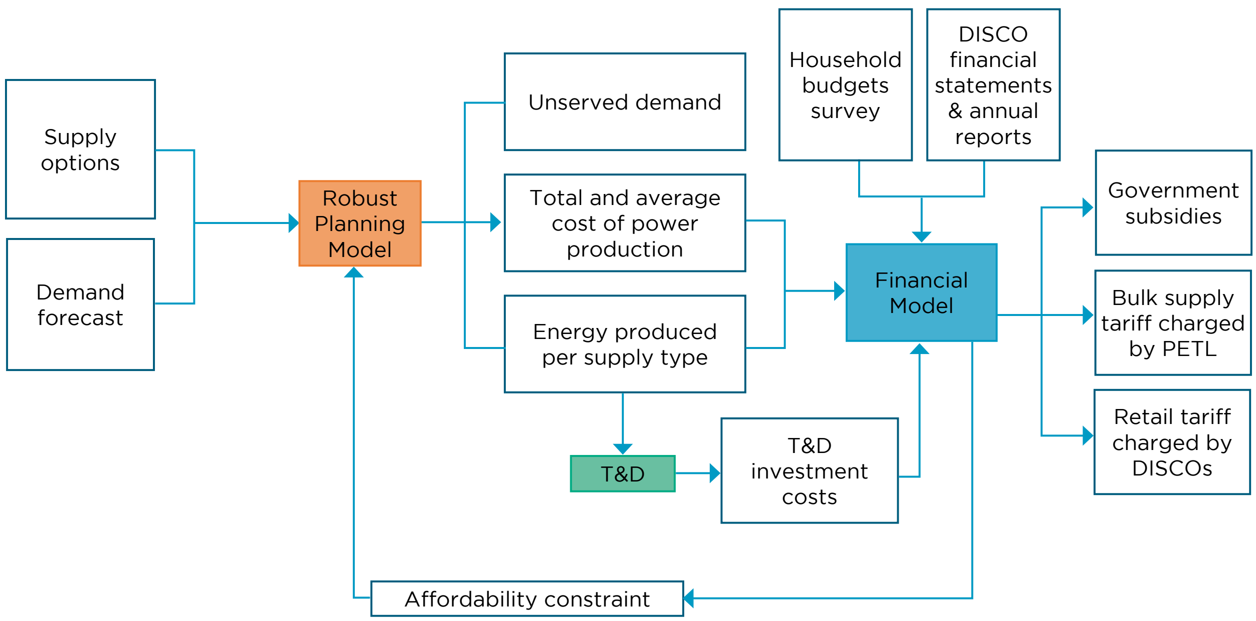


Note: DISCO = distribution company; IPP = independent power producer; PETL = Palestinian Electricity Transmission Company.

In addition, the consumer perspective was introduced into the financial model by incorporating an affordability limit on retail tariffs for the poorest households. To determine the affordability limits, the financial model draws upon the most recent Palestinian Expenditure and Consumption Survey, from 2011, which provides detailed information on household budgets, including electricity expenditure. The survey was used to understand the income distribution in the Palestinian territories, and in particular the budget available to the average household in each decile—or 10 percent—of the income distribution from poorest to richest.

According to the international literature, 5 percent of budget for a basic level of "subsistence consumption" is said to represent an affordability limit. In the Palestinian context, the subsistence consumption is set at 160 kilowatt hours (kWh) per month and corresponds to the first block of the retail tariff structure (see appendix A, table A.1). Considering the income distribution discussed previously, and the 5 percent affordability threshold, the model identifies (i) the maximum cost for the subsistence block of consumption so that even the poorest consumers can afford basic electricity supply, and (ii) the magnitude of subsidies required to make electricity services affordable to different income deciles. Such subsidies could either be channeled through distribution utilities as targeted bill reductions for poor households or through social welfare payments. In either case, a targeting mechanism would be needed to ensure that the poorest households can be identified. The West Bank and Gaza Cash Transfer Program could potentially be used as the targeting mechanism, since it contains a database of 115,000 households living under the poverty line in the West Bank and Gaza. The alternative to targeted subsidies, which is to keep tariffs low for all consumers, can also be modeled. While simpler to administer, it evidently entails a much higher subsidy bill.

Figure II-9.3: Flowchart Illustrating the links between the Robust Planning Model, Sector Financial Model, and the Transmission Costing Matrix



Note: DISCO = distribution company; PETL = Palestinian Electricity Transmission Company; T&D = transmission and distribution.

Bringing all the pieces together, the robust planning model and the sector financial model are designed to work together along with a transmission costing matrix as illustrated in figure II-9.3. The results of the robust planning model are fed into both the financial model and a transmission costing matrix, which is used to price out the cost of building additional transmission and distribution (T&D) infrastructure for the generation mix identified by the robust planning model. The T&D costs are then also fed into the financial model, which calculates the equilibrium tariffs and, comparing to affordability thresholds, also identifies subsidies required from the government to protect the poorest consumers. If outcomes are unacceptable, further iterations of the models are run to, for example, impose upper bounds on the cost of generation to improve overall affordability. Refer to appendix 9 for further details on the financial model methodology. Refer to appendix I, tables I.1–I.6 for full operational and financial data used in the financial model for each DISCO.

Finally, the macrofiscal impact of implementing the planned scenarios are also evaluated. Building on a new set of computable general equilibrium models developed separately for the West Bank and Gaza, it is possible to examine the macrofiscal impacts of the planning scenarios. The models are augmented to provide a more detailed characterization of the energy sector than might normally be the case, and the impact of the planning scenario is incorporated into the model simulation. This makes it possible to examine how the energy investments affect the overall growth domestic product growth trajectory, as well as the public finances.

CHAPTER 10

Analysis and Results for the West Bank

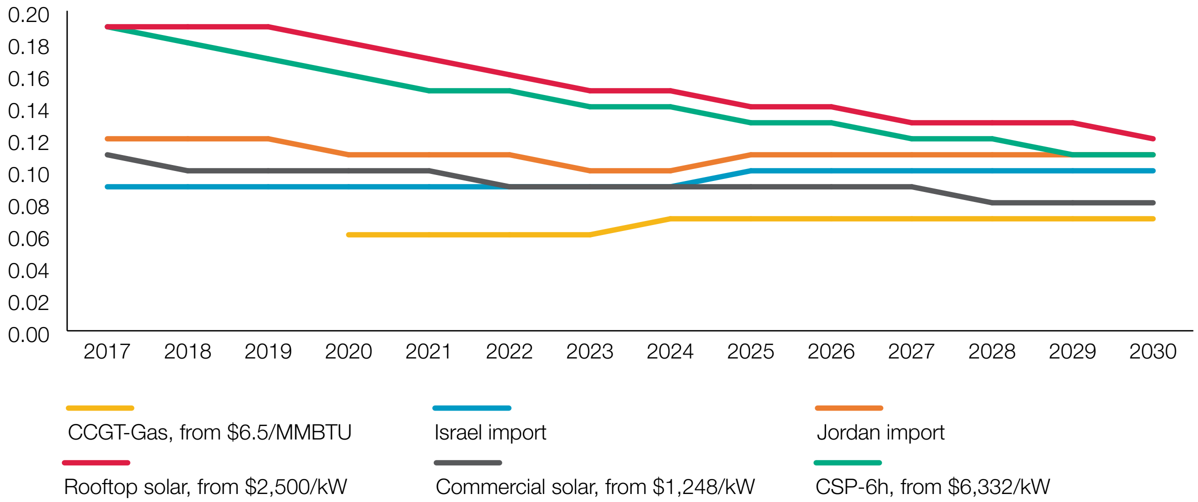
This chapter presents the results of the integrated planning and financial exercise for the West Bank.

PLANNING MODEL

The two key drivers of the planning scenarios are the relative cost of power supplied through different technologies and the range of uncertainties that affects each of them. Figure II-10.1 plots the so-called levelized cost of energy (LCOE), defined as total capital and operating costs across the lifetime of a power project averaged over the total electricity produced. While LCOE is a convenient device for making simple relative cost comparisons, it is important to recognize that it does not capture all relevant characteristics of each power source, such as its availability for dispatch and contribution to meeting peak loads. Table II-10.1 summarizes the different uncertainty parameters that characterize each of the power supply options, considering delays in availability, uncertainty of cost, as well as probabilities of interruption to supply. These are inevitably somewhat subjective and based on a combination of expert judgment and stakeholder consultation.

Domestic gas-fired power generation looks to compare favorably with Israeli imports, while projected declines in the cost of renewable energy bring these increasingly into parity. The LCOE analysis illustrates a wide dispersion in costs across different generation technologies, although for most sources there is convergence of costs over time toward the range of NIS 0.26–0.47 (US$0.07–0.13) per kilowatt hour (kWh) by 2030. Israeli imports, currently the dominant source of energy, and priced at just under NIS 0.37 (US$0.10) per kWh, set the relevant benchmark. At the beginning of the period, only gas-fired power generation comes in below the cost of Israel imports. While renewable energy starts out as more expensive than Israeli power imports, projected steep declines in unit costs bring solar photovoltaic (PV) into parity by the year 2022, and the cost differential for rooftop

Figure II-10.1: Time Trends of Levelized Cost of Energy for Different Supply Options in the West Bank



Note: CCGT = combined cycle gas turbine; CSP = concentrated solar power; kWh = kilowatt hour; MMBTU = million British thermal unit.

TABLE II-10.1: OVERVIEW OF UNCERTAINTY PARAMETERS FOR THE WEST BANK NORTH AND SOUTH PLANNING EXERCISE

	DIESEL	GAS: NORTH	GAS: SOUTH	ISRAEL	JORDAN
Availability range					
Earliest	2016	2021	2024	2020	2022
Latest	2016	2035	2035	2030	2035
Volume range					
Lowest	Unlimited	0.2 bcm	0.2 bcm	850 MW	30 MW
Highest	Unlimited	2.0 bcm	2.0 bcm	1400–1800 MW	100–200 MW
Price range					
Lowest	Known	$4.0/MMBTU	$4.0/MMBTU	Current	Indexed to oil
Highest	Known	$6.5/MMBTU	$7.5/MMBTU	$0.11/kWh	Indexed to oil
Outage duration range					
Minimum days	37	37	37	18	29
Maximum days	293	365	365	91	256
Other parameters					
Minimum availability	0.30	0.40	0.40	0.80	0.70
Probability of interruption	0.40	0.06	0.10	0.02	0.05

Note: bcm = billion cubic meters; MW = megawatt; MMBTU = million British thermal units.

solar and concentrated solar power is substantially eroded by 2030. Nevertheless, it is important to underscore that these do not represent firm energy in the way that Israeli power imports do. Power imports from Jordan are also expected to decline with time as cheaper Israeli gas begins flowing to Jordan by 2020. This will bring the cost of Jordanian power closer to Israeli power, although Jordanian power is expected to continue being offered at a premium to Israeli power unless Jordan's power generation portfolio moves away from being dominated by gas and toward cheaper renewables.

The modeling exercises also strives to capture some of the main features of the uncertain planning environment. Specific uncertainty ranges associated with each of the nonrenewable options are summarized in table II-10.1. With the exception of diesel, there is considerable uncertainty of when particular capacity expansions would come online, how large they would be, and at what price they would be offered. Probabilities of supply interruptions and their effect on availability of power from different sources and potential duration of outages are also captured. Based on the historical record, Israeli power imports come across as the least risky source of electricity and diesel as the riskiest.

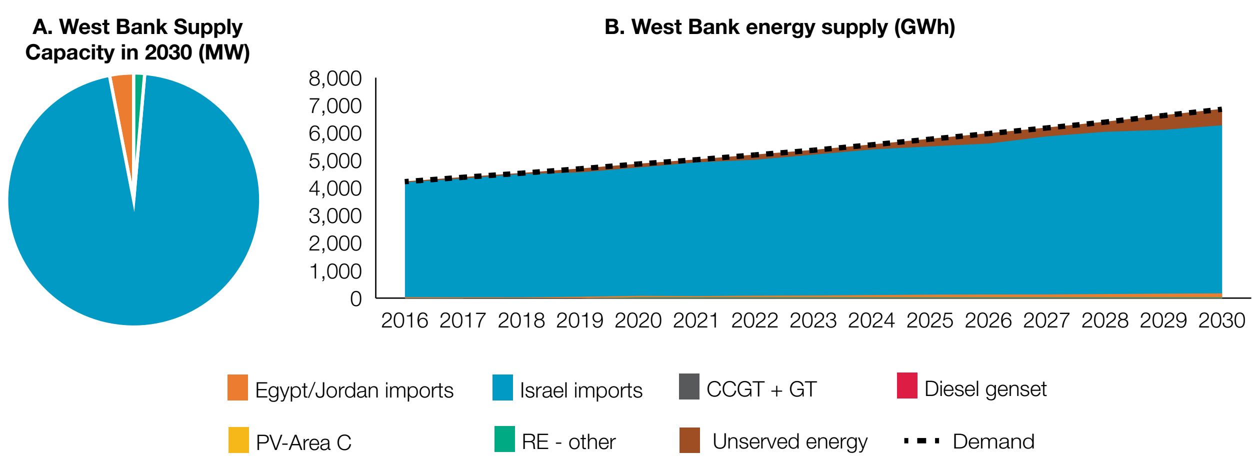
Against this backdrop, the results of five planning scenarios are considered. As noted above, these include a Do Nothing counterfactual, where not further investments are made in power infrastructure while demand continues to grow. This is compared with the impact of the current pipeline of investments, described as the Planned Future, as well as PENRA Vision for the longer term, which seeks to limit dependence on any single source of energy to 50 percent of demand while retaining the ability to import 100 percent of energy needs if required. For the purposes of illustration, two additional, more extreme scenarios are considered. Maximum Cooperation considers the possibility of continuing the West Bank's historically almost exclusive dependence on Israel for imported power, while scaling up the associated infrastructure to keep pace with mounting demand. Maximum Independence looks at the fullest extent of domestic power generation that could be developed in the West Bank under the most optimistic scenario.

Under the Do Nothing scenario, the West Bank becomes increasingly unable to meet its electricity demand (figure II-10.2). With the capacity for Israeli electricity imports capped at current levels of 890 megawatts (MW), and Jordanian imports capped at 20 MW, and in the absence of any new domestic generation capacity, the average cost of electricity remains at current level of NIS 0.36 (US$0.098) per kWh. However, the percentage of unserved demand rises steeply from small levels in 2016 to reach 9 percent in 2030, and averages 4 percent of total demand over the entire period. The associated economic losses are valued at NIS 9.5 billion (US$2.6 billion), equivalent to about 20 percent of the gross domestic product (GDP) of the West Bank in 2015. In the northern region of the West Bank, this shortage has already been felt as power shortages during the summer of 2016 that resulted in rolling blackouts culminating in street protests. This clearly represents an unacceptable trajectory.

Under the Planned Future scenario, a significant volume of investment brings about greater supply diversification with only minimal impacts on costs (figure II-10.3). The development of the Jenin and Hebron gas-fired CCGT plants, as well as the expansion of the renewable energy portfolio to reach the 130 MW target, call for capital expenditure of NIS 3.1 billion (US$850 million) and lead to significant diversification of the power mix, with domestic production providing 36 percent of energy needs by 2030. Relative to the Do Nothing scenario, this eliminates supply shortages while only raising the average cost of electricity very slightly to NIS 0.37 (US$0.101) per kWh. However, in terms of energy independence, little has changed, since both the electricity and gas—accounting for 96 percent of energy use—are imported from Israel.

Figure II-10.2: Results of "Do Nothing" Scenario for West Bank

Do Nothing: Demand continues to grow while power infrastructure is capped at 890MW of interconnectors with Israel and 20MW of interconnectors with Jordan



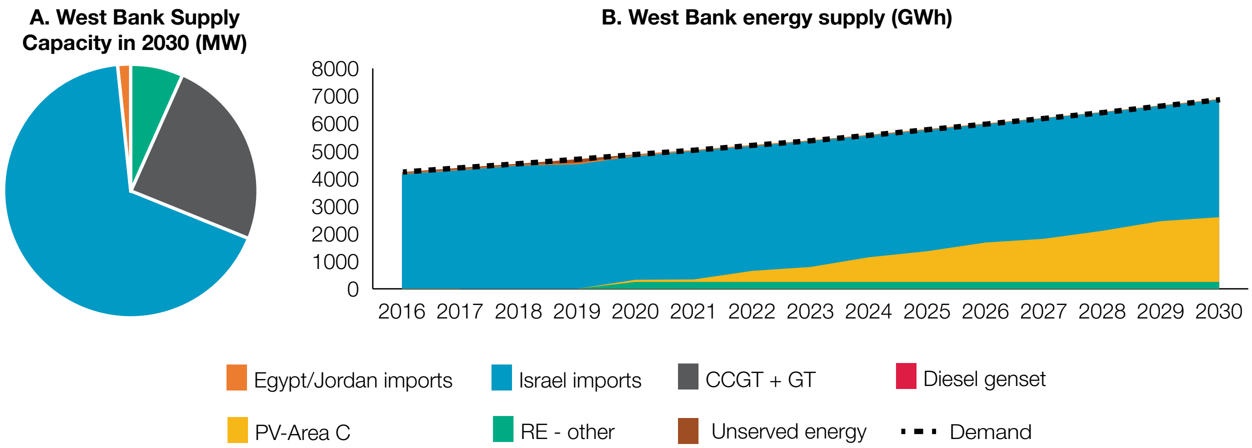
AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
9.79	0	9%	90%	0%	0.4%

Takeaway: Currently, power supply is not diversified and there will soon be power shortage in the West Bank.

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gas Turbine ; MW = megawatt; PV = photovoltaic; RE = renewable energy.

Figure II-10.3: Results of "Planned Future" Scenario

Planned Future: All PENRA's currently planned projects come online (four substations (540 MW), Jenin Power Plant (400 MW), Hebron Power Plant (120 MW)). Renewables target (130 MW



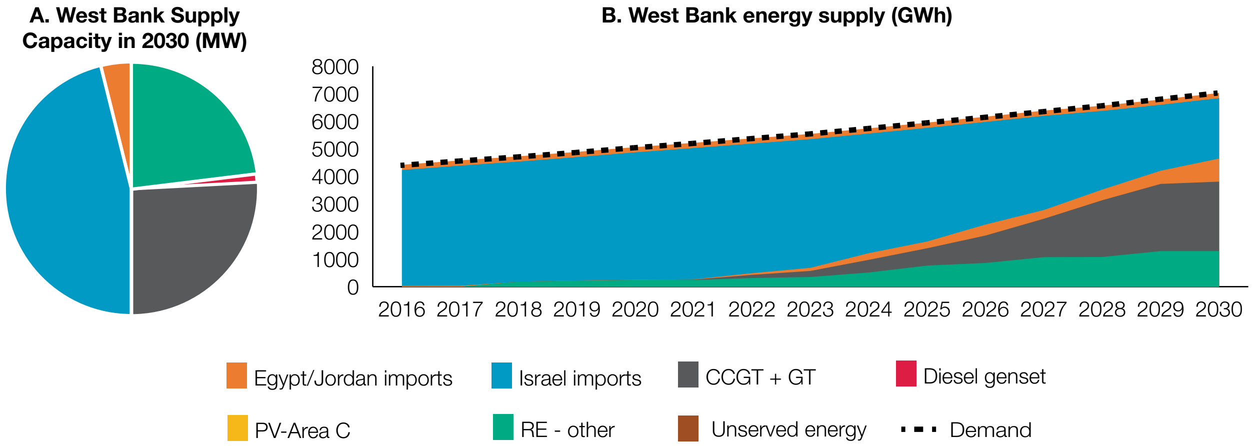
AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
10.06	850	0%	64%	32%	4%

Takeaway: There is no power shortage but still limited diversification as 96% of power and fuel is imported.

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gas Turbine; MW = megawatt; PV = photovoltaic; RE = renewable energy.

Figure II-10.4: Results of "PENRA Vision" Scenario

Planned Future: All PENRA's currently planned projects come online (four substations (540 MW), Jenin Power Plant (400 MW), Hebron Power Plant (120 MW)). Renewables target (130 MW



AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
10.16	2,133	0%	45%	37%	19%

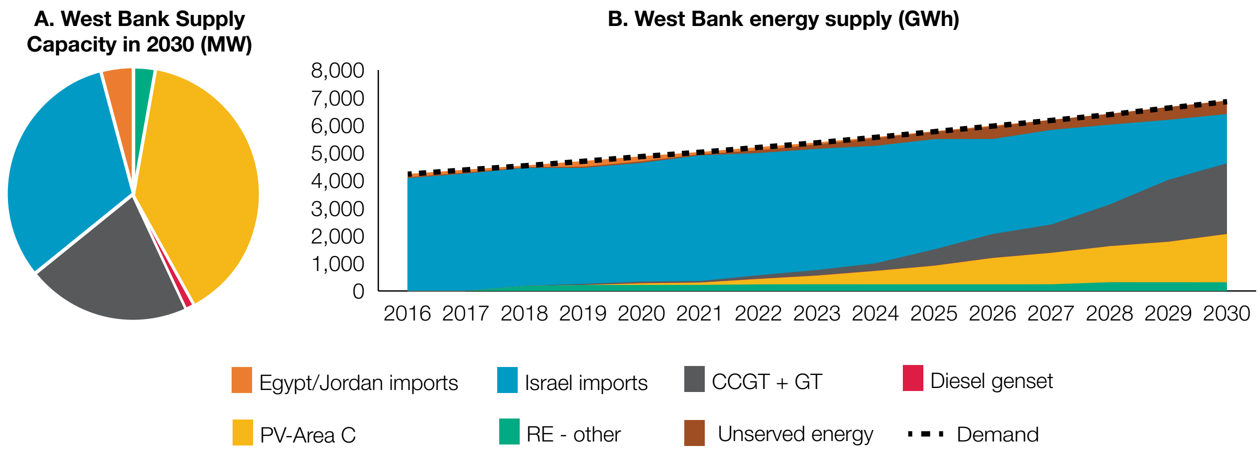
Takeaway: PENRA can achieve diversification vision w/o Area C but needs large RE scale up in Areas A, B and rooftop solar.

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gas Turbine ; MW = megawatt; PENRA = Palestinian Energy and Natural Resources Authority; PV = photovoltaic; RE = renewable energy.

But the only way to meet the full PENRA Vision of diversification is to invest much more heavily in solar PV, fully developing potential in Areas A and B (figure II-10.4). While the Planned Future scenario represents a substantial improvement on Do Nothing, it remains dependent on Israeli electricity and fuel imports to meet 96 percent of its energy needs. It does not meet PENRA's longer term diversification criterion that no source of electricity should account for more than 50 percent of demand. To meet this constraint, the model ramps up the proportion of renewable energy—essentially developing much of the potential in Areas A and B—and achieving, as a result, a much higher degree of diversification. Although these options are slightly more expensive on a per unit basis than Israeli imports, and the necessary capital expenditure more than doubles to reach NIS 7.7 billion (US$2.1 billion), the overall impact on the average cost of generation remains very modest, rising only to NIS 0.372 (US$0.102) per kWh. This scenario shows that PENRA's strategic vision can be achieved without access to Area C, by focusing on developing solar PV potential in Areas A and B and on rooftops.

Figure II-10.5: Results of "Maximum Independence" Scenario

Maximum Independence: Same goals as PENRA vision but with unlimited access to Area C



AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
9.88	2,284	0%	36%	34%	30%

Takeaway: If Area C was available, diversification would be more balanced and average cost of power would be lower

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gas Turbine ; MW = megawatt; PENRA = Palestinian Energy and Natural Resources Authority; PV = photovoltaic; RE = renewable energy.

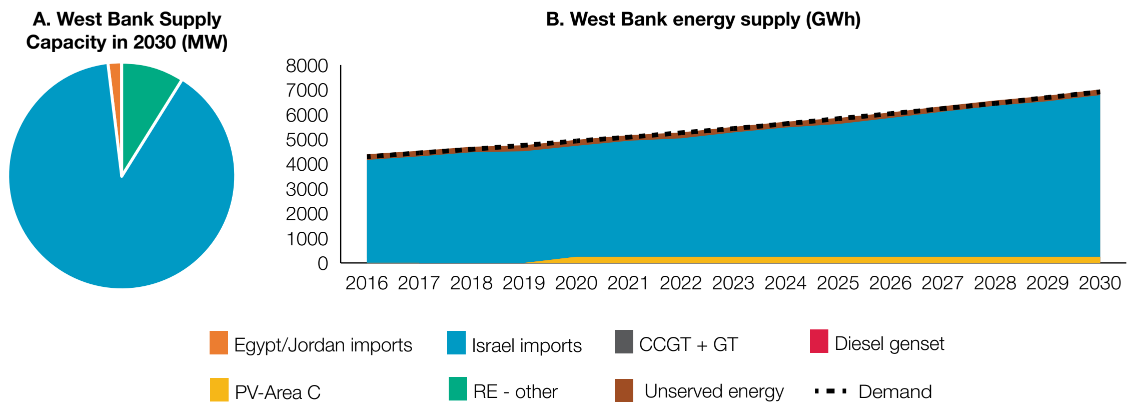
Relaxing the constraint on access to Area C significantly reduces import dependence and improves diversification even while slightly reducing costs (figure II-10.5). Even in the PENRA Vision, more diversified scenario, the West Bank would still be dependent on Israel for about 80 percent of its energy needs through electricity and fuel imports. The next scenario considers what is the Maximum Independence that could be achievable in power generation. This is done by relaxing the constraint on access to Area C, so that the model has a much larger renewable energy potential to draw upon. Under these conditions, it becomes economical to increase the renewable energy share from 19 to 30 percent, even as the average cost of generation falls slightly relative to the PENRA Vision, from NIS 0.372 (US$0.102) to NIS 0.361 (US$0.099), although capital expenditure requirements climb slightly to reach NIS 8 billion (US$2.2 billion).

Finally, it is helpful to contrast these increasingly diversified and independent scenarios with one of Maximum Cooperation (figure II-10.6). This essentially represents a continuation of the current strategy whereby the West Bank imports almost all of its electricity needs from Israel, with the Israeli interconnection capacity allowed to expand in tandem with growing demand and estimated to reach 1,430 MW by 2030. At the same time, the relatively modest current targets for renewable energy are met. This approach largely avoids any major capital expenditure on the Palestinian side and results in the preservation of the current average cost of NIS 0.36 ($0.098) per kWh. Diversification drops significantly relative to the other scenarios, as 96 percent of electricity would be imported. The inclusion of this alternative helps to clarify that the cost premium for supply diversification in the context of the West Bank is relatively small at between NIS 0.004–0.015 (US$0.001–0.004) per kWh, which represents a markup of less than 5 percent.

No single option performs better than others on all relevant dimensions, illustrating that tradeoffs must be made. Examining the five scenarios side by side helps to clarify their relative performance. Table II-10.2 compares various dimensions of performance, including the average cost of power generation, the total capital expenditure, the level of unserved demand in 2030, the continued reliance on electricity imports or fuel imports for generation, and the share of domestically generated renewable energy in the overall mix.

Figure II-10.6: Results of "Maximum Cooperation" Scenario

Maximum Cooperation: All additional power supply comes from IEC with import capacity expanded to 1,430MW by 2030



AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
9.78	174	1%	96%	0%	4%

Takeaway: Premium for diversified portfolio is 0.1-0.4 US cents/KWh more expensive than importing all power from IEC

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gas Turbine; IEC = Israeli Electric Corporation; MW = megawatt; PV = photovoltaic; RE = renewable energy.

TABLE II-10.2: COMPARISON OF RESULTS ACROSS THE FIVE SCENARIOS

	AVERAGE COST OF POWER (U.S. CENTS PER KWH)	CAPEX (US$ MILLIONS)	2030 UNSERVED DEMAND	2030 ELECTRICITY IMPORTS	2030 DOMESTIC GENERATION WITH IMPORTED FUEL	2030 DOMESTICALLY GENERATED RE
1. Do nothing	9.79	0	9%	90%	0%	0.4%
2. Planned future	10.06	850	0%	64%	32%	4%
3. PENRA vision	10.16	2,133	0%	45%	37%	19%
4. Maximum cooperation	9.88	2,284	0%	36%	34%	30%
5. Maximum independence	9.78	174	1%	96%	0%	4%

Note: The darker the shade of green the better the performance on that dimension, while the darker the shade of orange the worse the performance on that dimension.
Note: CAPEX = capital expenditure; kWh = kilowatt hour; RE = renewable energy.

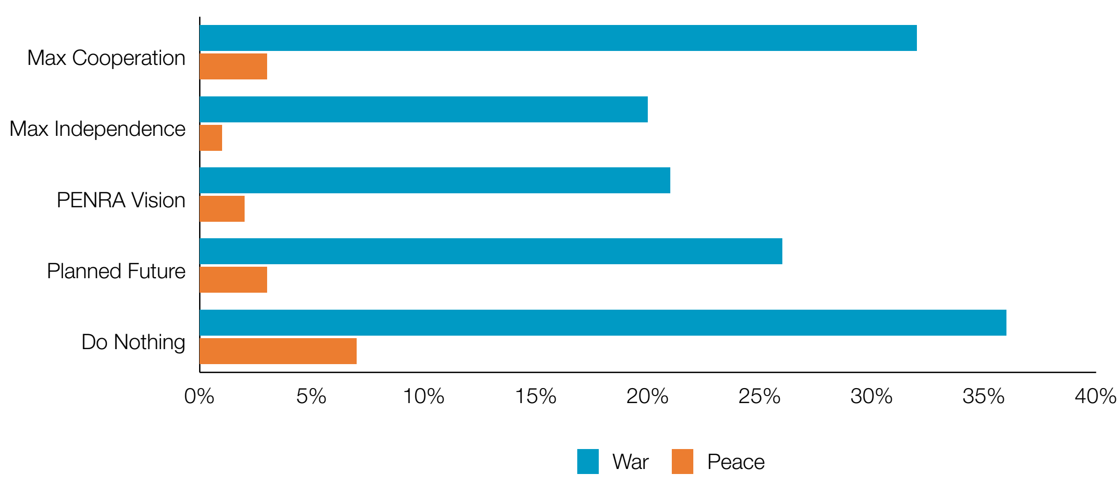
The scenarios with the highest share of domestic renewable energy look to be the most attractive, but they require raising large amounts of capital from the private sector. What is clear is that any alternative that achieves a significant shift in the level of diversification and energy independence entails raising private capital in excess of NIS 7.3 billion (US$2 billion) over the next decade. Given that private-sector investment in the Palestinian power sector is very much in its infancy, this is not a minor undertaking, and would require addressing the creditworthiness of the sector, which is currently the most significant constraint to attractive private capital.

While access to Area C would be desirable, significant diversification can already be achieved based on use of Areas A and B alone. The Maximum Independence scenario is based on unrestricted access to Area C, which is far from being the current situation and would pose major political challenges. Nevertheless, in the absence of access to Area C, PENRA's strategic vision, of limiting dependency on any one supply to less than 50 percent, could still be achieved by maximizing renewable energy installations in Areas A and B and on rooftops. This would be a desirable starting point and would still represent a major increase in ambition from current targets of 130 MW by 2020 to a target of 600 MW by 2030. Given that only 18 MW of solar PV have been achieved since the target was announced in 2012, this would be very challenging.

Given the potential substantial scale-up in solar energy, close coordination with the Israeli grid would be critical to preserve overall stability. Both the PENRA Vision and the Maximum Independence scenarios call for increasing the share of solar PV up to 20 or 30 percent. It is important to note that any scale-up in generation in the West Bank will raise significant grid stability and integration issues for the Israeli grid, which is also in the process of ramping up its share of variable renewable energy to meet its own national targets. Close collaboration and careful planning would be a prerequisite for any expansion plan involving an enhanced role for renewable energy. Finally, although the currently Planned Future projects are important for ensuring power-supply expansion keeps pace with demand growth, and significantly impact the reliability of supply, their impact on diversification and independence is still relatively small.

To put things in perspective, the cost differentials between alternative scenarios are small and almost all of them deliver a reliable supply. There is a difference of just 4 percent (or $0.004 per kWh) in the average cost of generation between the highest and lowest scenarios. Moreover, all scenarios except for Do Nothing essentially provide for a reliable supply of electricity.

Figure II-10.7: Resilience Stress Test across Scenarios in Terms of Percent Increase in Unserved Demand for the West Bank



Note: PENRA = Palestinian Energy and Natural Resources Authority.

Another way to compare the alternative scenarios is through a stress-testing process that examines how they perform under extreme conditions. In particular, the stress test looks at how the percentage of unserved energy rises for each scenario when conflict conditions are simulated.

The scenarios with a higher share of solar PV look to be the most resilient (figure II-10.7). As might be expected, the scenarios with higher solar PV shares have the lowest share of unserved energy, at around 20 percent compared with 25–35 percent for the others. This is because they are less susceptible to supply interruption or conflict damage.

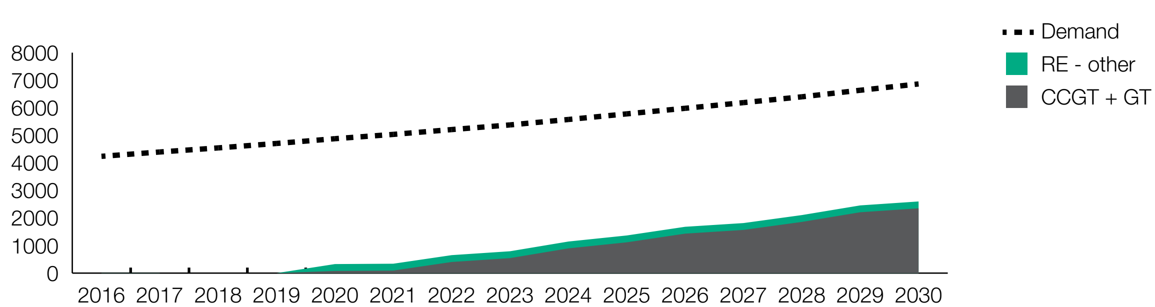
TRANSMISSION

Domestic power generation in the West Bank can be moved to Palestinian load centers either by wheeling through the Israeli network or by building a Palestinian transmission backbone. As domestic power generation in the West Bank increases, there is a need to evacuate electricity from the locations where it is produced to those where it will be consumed, as cost-effectively as possible. Two options exist. The first is to wheel the power out from the West Bank, through the Israeli network, and inject it back into the West Bank to the load centers. The second is to build an independent Palestinian transmission backbone capable of moving power at higher voltages over long distances within the West Bank. Under both scenarios, distribution infrastructure needs to be expanded and upgraded to accommodate the additional supply. Part I, chapter 7, provides background detail on wheeling tariffs and transmission and distribution (T&D) infrastructure capital costs.

By 2030, approximately 2,400 Gigawatt hours (GWh) of domestic generation will need to be wheeled through the IEC grid if PENRA's planned projects come online (figure II-10.8). In the following analysis, the cost of wheeling is compared to the cost of building a transmission backbone for the Planned Future scenario. It is expected that by 2030 up to 35 percent of demand will be met by domestic generation, in particular, through renewables and thermal generation, corresponding to approximately 2,400 GWh per year.

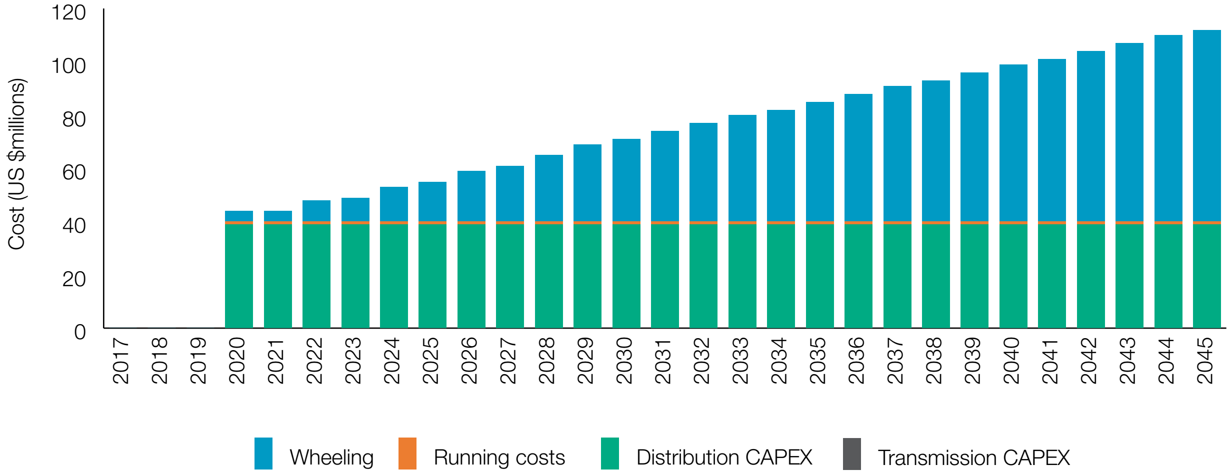
Due to the envisaged scale-up in the volume of domestically generated electricity, the recurring cost of wheeling charges rapidly increase year over year. Figures II-10.9 and II-10.10 show the need for NIS 146 million (US$40 million) investment in the Palestinian distribution network to absorb the additional generation that would come online under the Planned Future scenario. In terms of transmission, figure II-10.9 shows the scenario in which IEC's most expensive wheeling tariff is used, which, at NIS 0.05 (US$0.013) per kWh, allows the use of both the Israeli transmission and distribution networks. Figure II-10.10 shows the

Figure II-10.8: Domestic Generation, as Proportion of Total Demand, Needing to Be Wheeled through the Israeli Electric Corporation Grid under the "Planned Future" Scenario



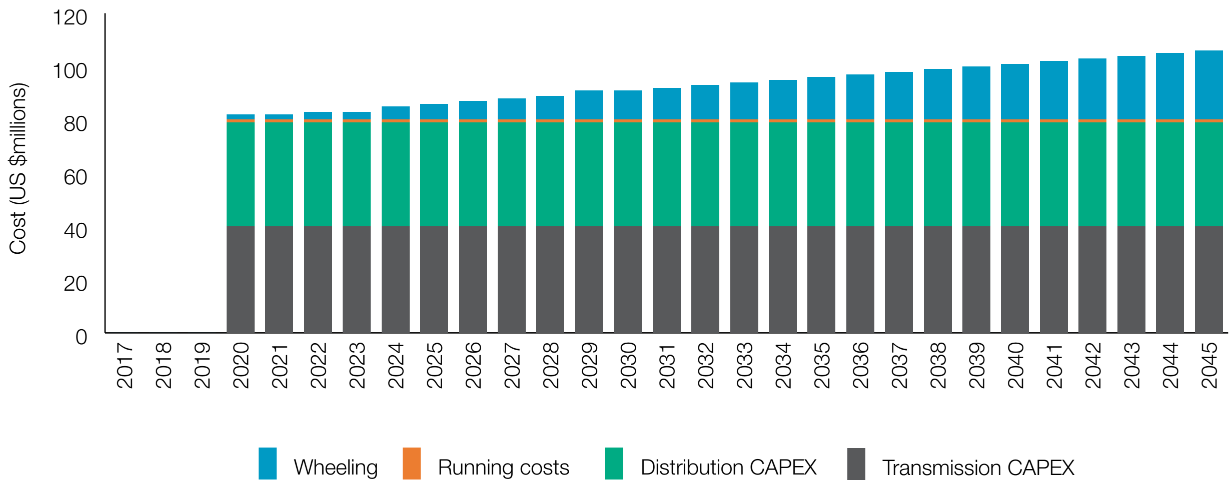
Note: CCGT = combined cycle gas turbine; RE = renewable energy.

Figure II-10.9: Cumulative Transmission and Distribution and Wheeling Costs under "Planned Future" Scenario if Highest Wheeling Charge Is Used



Note: CAPEX = capital expenditure.

Figure II-10.10: Cumulative Transmission and Distribution and Wheeling Costs Under "Planned Future" Scenario if Lowest Wheeling Charge Is Used



Note: CAPEX = capital expenditure.

scenario in which IEC's least expensive wheeling tariff is used, which, at NIS 0.02 (US$0.005) per kWh, allows the use of only the Israeli transmission network. In this case, additional substations would need to be built in the West Bank, beyond the existing four new high-voltage substations, to ensure that all power evacuated into Israel and received back into the West Bank travel only on the Israeli transmission grid. The cost for these additional substations is estimated at an additional NIS 146 million (US$40 million). If the higher wheeling tariff is used, by 2030 wheeling charges will reach over NIS 110 million (US$30 million) per year. If the lower wheeling tariff is used, by 2030 wheeling charges will be lower at approximately NIS 40 million (US$11 million) per year.

In the Palestinian backbone case, the exact investment requirements would reflect the composition of the selected investment plan (table II-10.3). Investment needs for distribution range from NIS 95 to NIS 190 million (US$26–52 million); those from transmission range NIS 172 to NIS 500 million (US$47–137 million). The projects with the largest impact on transmission investment requirements are the Jenin Power Plant and the development of solar PV in Area C, each at around NIS 164 million (US$45 million).

TABLE II-10.3: BREAKDOWN OF REQUIRED TRANSMISSION AND DISTRIBUTION INVESTMENTS AS ADDITIONAL SUPPLY COMES ONLINE IF A TRANSMISSION BACKBONE IS BUILT

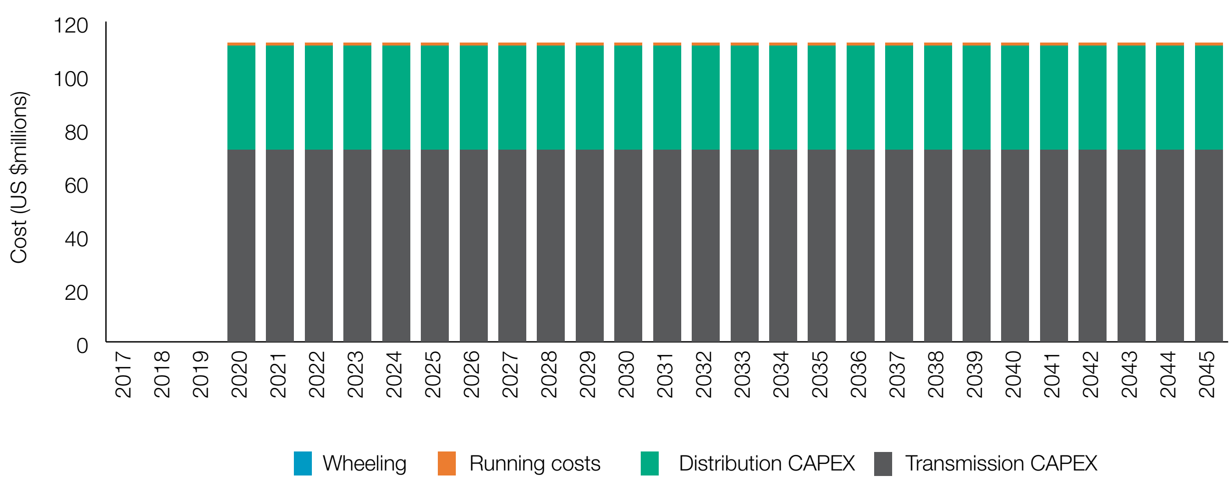
(US$)		FOUR HIGH-VOLTAGE SUBSTATIONS ENERGIZED	JPP COMES ONLINE	HPP COMES ONLINE	RENEWABLES ALLOWED IN AREA C	JORDANIAN CONNECTOR IS EXPANDED	TOTAL
West Bank	Trans.	0	47	25	44	20	137
West Bank	Dist.	26	7	7	7	7	52
Total	T&D	26	54	31	51	27	188

Note: JPP = Jenin Power Plant; HPP = Hebron Power Plant.

For the Planned Future scenario, the total required investment in T&D would be NIS 409 million (US$112 million). The components in figure II-10.11, which contribute to the Planned Future scenario, are the energization of the four new substations, plus Jenin Power Plant and Hebron Power Plant coming online. Combined, these additional supply options will need NIS 263 million (US$72 million) for transmission infrastructure, and NIS 146 million (US$40 million) for distribution infrastructure for a total investment of NIS 409 million (US$112 million). Regardless, it is not desirable to have variable costs that grow year after year and the transmission backbone would allow a fixed cap on expenditures. It is important to note that, whereas investments in generation would be pursued under a public-private partnership model, investments in T&D would necessarily take the form of public investment.

In the short term, PENRA must negotiate lower wheeling tariffs with IEC, and in the mid to long term, PENRA should build a transmission backbone to reduce costs—negotiating a swap mechanism could be an attractive third option. The cost of wheeling at the higher tariff breaks even with the cost of the backbone by 2045 and the cost of wheeling at the lower tariff breaks even with the cost of the backbone by 2052. By 2030, the transmission component of the retail tariff would be NIS 0.004 (US$0.001) per kWh if a backbone is built, NIS 0.007 (US$0.002) per kWh if the lower wheeling charge is used, and NIS 0.018 (US$0.005) per kWh if the higher wheeling charge is used (assuming amortization of all CAPEX to 25 years). This represents 0.7, 1.3, and 3.3 percent of the total expected retail tariff in 2030, respectively. Building a transmission backbone is more cost-effective than wheeling the power through Israel. simply because

Figure II-10.11: Cumulative Transmission and Distribution Investment for the "Planned Future" Scenario if a Transmission Backbone Is Built



Note: CAPEX = capital expenditure.

the costs are fixed and do not grow as domestic generation expands. If wheeling is to be used, at least in the initial years until a transmission backbone is built, the wheeling tariff should be extensively negotiated with IEC to bring down costs. A swap mechanism, in which power generated in the West Bank is evacuated to Israel, and swapped for power from Israel at a later time and injected back into the West Bank, can be an attractive alternative but requires extensive negotiations and collaboration on both sides.

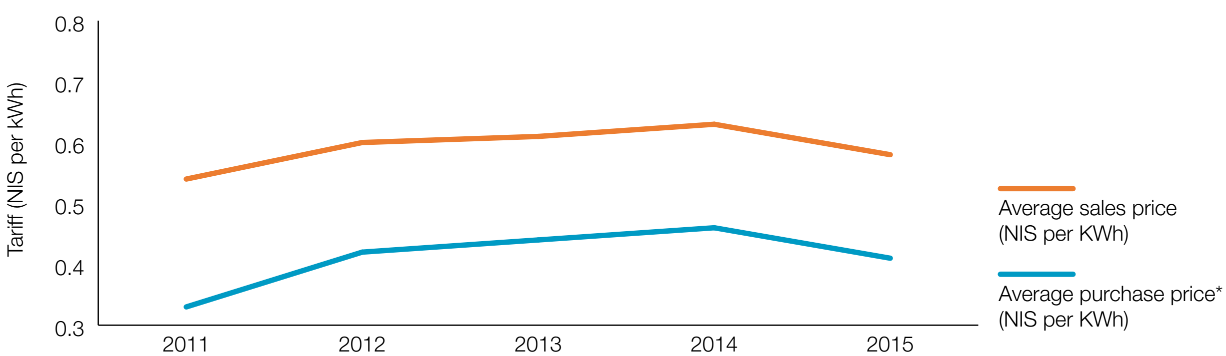
FINANCIAL MODEL

Attention now turns to the financial implications of implementing the planning scenarios described above. The key focus of attention is the financial equilibrium tariff and how it may need to evolve relative to historic practice.

Historically, the retail tariff in the West Bank has included an average 45 percent markup over the wholesale cost of IEC power (figure II-10.12). Retail tariffs in the West Bank are determined by the regulator, PERC, which allows a markup over the wholesale price of IEC power to cover the operating margin of the DISCOs, including the significant operational inefficiencies and overheads. For the period 2011–15, this markup has averaged 45 percent over and above the IEC tariff. (This is in contrast to Gaza, where PERC regulation has not been in force and retail tariffs have dropped below the weighted average cost of supply, which includes IEC imports and generation from GPP)

While there has been some improvement in the operating efficiency of the West Bank DISCOs, substantial variations remain across companies. In the West Bank, overall DISCO losses (including both technical and nontechnical losses) have been falling from around 26 percent in 2011 to 23 percent in 2015 (figure II-10.13). As of 2015, Southern Electricity Distribution Company (SELCO) had the highest losses, at 27 percent, followed by Jerusalem District Electricity Company (JDECO) at 24 percent, Hebron Electricity Distribution Company (HEPCO) at 20 percent, Northern Electricity Distribution Company (NEDCO) at 17 percent, and Tubas Electricity Distribution Company (TEDCO) at 16 percent. The overall DISCO collection rates have improved from 88 percent in 2011 to 91 percent in 2015. As of 2015, NEDCO, JDECO, and HEPCO, which combined make up over 92 percent of sales, had collection rates above 90 percent. while SELCO and TEDCO had collection rates above 75 percent. For the purposes of financial modeling, two possibilities are considered. The first is that the regulator will set ambitious but realistic efficiency targets for the DISCOs that will be met by 2030. The second is that there is no significant improvement in DISCO inefficiency.

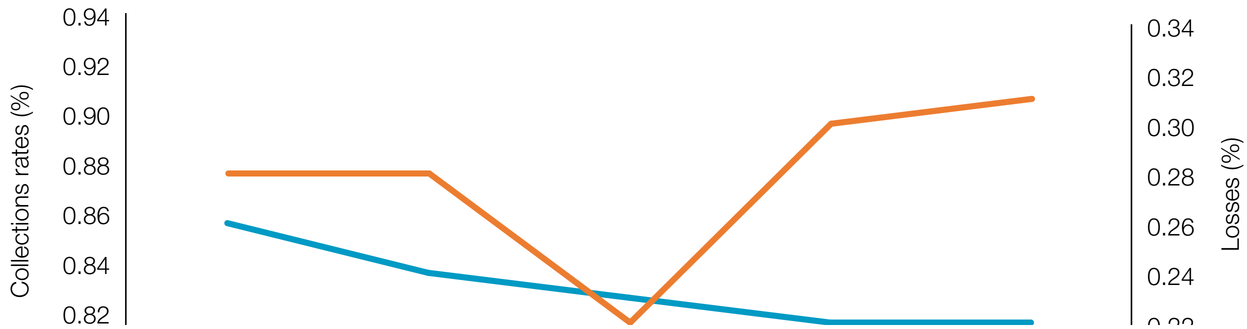
Figure II-10.12: In the West Bank, Retail Tariffs Have Followed the Cost of Israeli Electric Corporation Supply



	2011	2012	2013	2014	2015
Average purchase price* (NIS per KWh)	0.33	0.42	0.44	0.46	0.41
Average sales price (NIS per KWh)	0.54	0.60	0.61	0.63	0.58
Markup	65%	45%	39%	35%	41%

Note: kWh = kilowatt hour
Includes Israeli Electric Corporation and Jordan

Figure II-10.13: Time Trend for Distribution Losses and Revenue Collection Rates in the West Bank



	2011	2012	2013	2014	2015
Losses*	0.26	0.24	\0.23	0.22	0.22
Collection rates	0.88	0.88	0.82	0.90	0.91

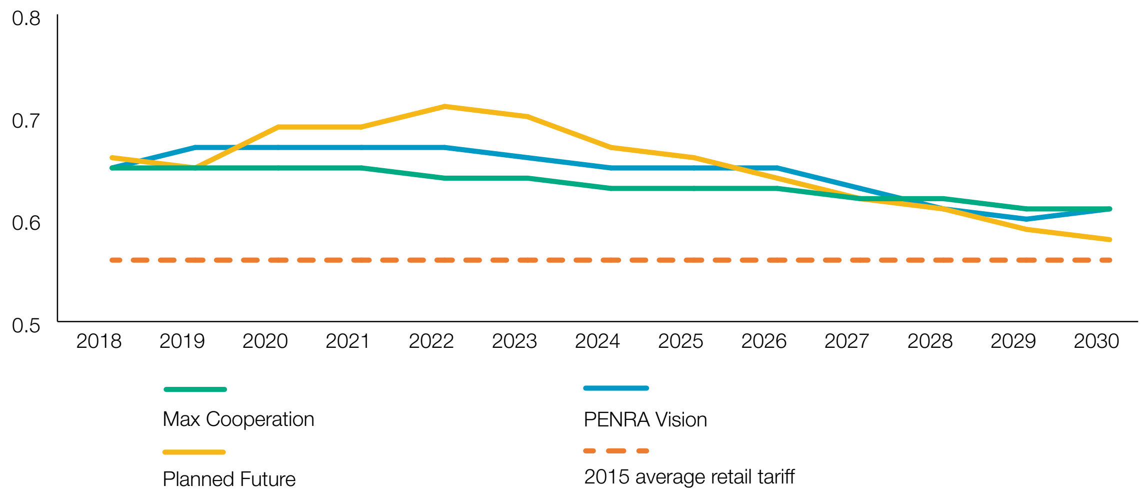
* Technical and non-technical losses

The financial modeling exercise is pursued for three of the planning scenarios that capture the full range of potential financial implications. In the West Bank, the PENRA Vision scenario was the most expensive, entailing an average generation cost of NIS 0.39 (US$0.102) per kWh, while the Maximum Cooperation scenario was the least expensive, entailing an average generation cost of NIS 0.37 (US$0.098) per kWh. The Planned Future represents the middle ground, with an average cost of NIS 0.42 (US$0.11) per kWh.

In the West Bank, the financial equilibrium tariffs do not vary significantly across scenarios, but all show a declining trend. The equilibrium tariff follows a narrow band for all three scenarios, reflecting the fact that the average cost of generation does not differ significantly across different planning scenarios in the West Bank (figure II-10.14). In all cases, the financial equilibrium tariff declines significantly by the end of the period, as DISCO efficiencies improve, technology costs drop (such as those for PV), and gas becomes available. For both the PENRA Vision and particularly for the Planned Future the financial equilibrium tariff rises in the medium term before an eventual decline, essentially because operational efficiency has not yet had time to improve to a point where it can more than compensate for higher generation costs. However, by 2027, it is expected that the Planned Future and PENRA Vision scenarios, which represent diversified portfolios with large amounts of solar and gas plants, will have lower costs than the Maximum Cooperation scenario, which represents pure imports from IEC. Despite the declining costs by 2030, the equilibrium tariff for all scenarios is higher than the 2015 retail tariff.

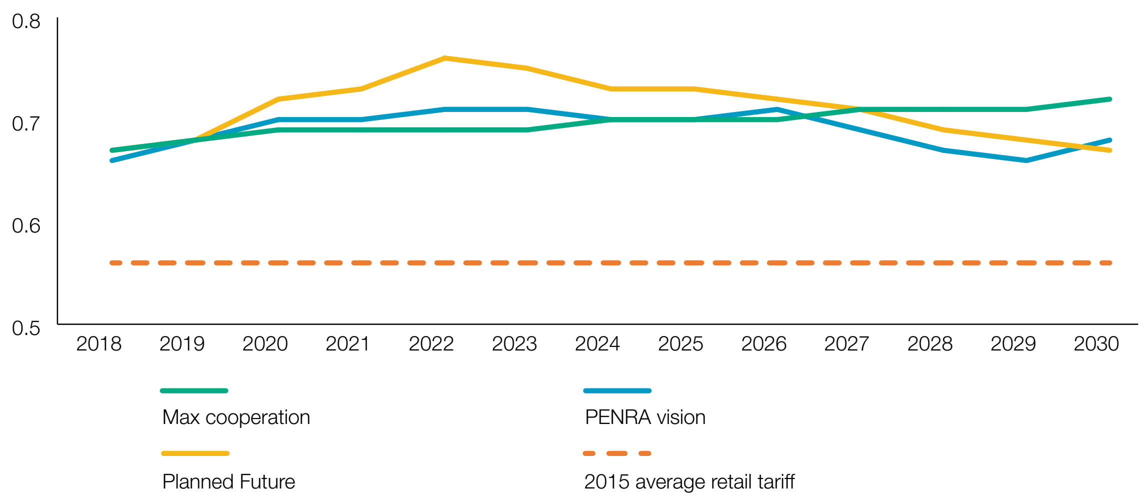
If DISCO performance is not improved by 2030, the equilibrium tariff for the PENRA Vision planning scenario will be NIS 0.07 (US$0.02) per kWh higher than otherwise. The equilibrium tariffs represented in figure II-10.14 assume that, by 2030, collection rates increase from current levels of 91 percent to 97 percent, distribution grid technical and nontechnical losses decline from current levels of 23 percent to 16 percent, transmission system losses are 2 percent, and DISCO operation and maintenance costs improve by 2 percent per year. Based on reports from the DISCOs, it is assumed that debt is currently financed at 3.5 percent, but would need to rise toward 7 percent by 2030. If these improvements are not achieved, the equilibrium tariff in 2030 will be NIS 0.66–0.71 (US$0.17–0.19) per kWh instead of NIS 0.58–0.61 (US$0.15–0.16) per kWh (figure II-10.15).

Figure II-10.14: West Bank Equilibrium Tariff Decline as Discos Performances Improve by 2030



Note: kWh = kilowatt hour.

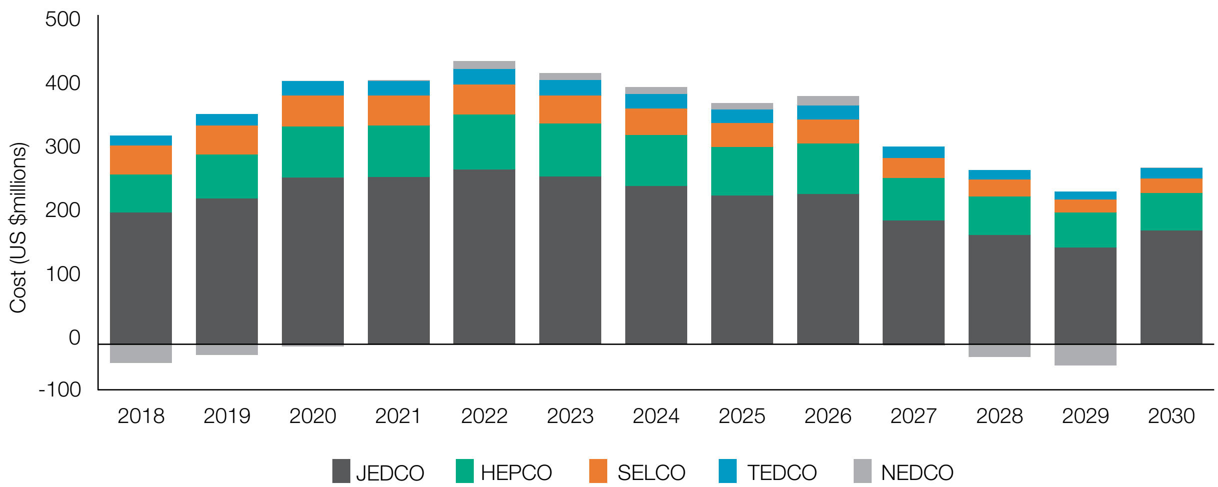
Figure II-10.15: West Bank Equilibrium Tariff Remains High if DISCO Performances Fail to Improve by 2030



Note: kWh = kilowatt hour.

Failure to adjust the unified tariff in the West Bank would result in massive average annual subsidy requirements to keep the DISCOs afloat (figure II-10.16). If the West Bank pursues the PENRA Vision scenario without making any compensating adjustments in retail tariffs, the subsidy required to keep the DISCOs afloat would begin at approximately NIS 300 (US$82) million in 2018, and increase to almost NIS 450 (US$123) million by 2022. In other words, in 2018, all DISCOs, except NEDCO, will lose NIS 0.10–0.35 (US$0.03–0.09) for every kWh they sell if the tariffs are not increased. JDECO, with the largest customer base, will require the largest subsidy from the government. NEDCO, which already has the best operational performance, does not require much in the way of subsidies and would be the only DISCO able to absorb the new generation cost without a raise in the unified tariff. These calculations assume that all DISCOs meet efficiency targets by 2030. If they do not, the required subsidy will be significantly higher.

Figure II-10.16: Subsidy Required to Sustain Financial Equilibrium of Discos in the Absence of Any Adjustment to the Current Unified Retail Tariff Based on the PENRA Vision Scenario, Assuming Efficiency Targets Are Achieved



Note: JEDCO = Jerusalem District Electricity Company; HEPCO = Hebron Electricity Distribution Company; SELCO = Southern Electricity Distribution Company; TEDCO = Tubas Electricity Distribution Company; NEDCO = Northern Electricity Distribution Company.

Alternatively, if subsidies are targeted purely to the poorest customers who face affordability limits, the overall subsidy bill drops substantially. According to the affordability thresholds in the West Bank, the bottom decile of the population can afford to pay up to NIS 0.41 (US$0.114) per kWh, while the second decile can afford to pay up to NIS 0.71 (US$0.197) per kWh (figure II-10.17). The analysis suggests that, as long as DISCOs meet their efficiency targets, tariffs should hardly rise beyond NIS 0.7 (US$0.19) per kWh, so that subsidies need only be channeled to the poorest 10 percent of the population. The subsidy required to cover the difference between the increased retail tariff and the affordability thresholds of these families would amount to no more than NIS 25 million (US$7 million) per year with over 60 percent going to JDECO consumers (figure II-10.18). As DISCO efficiencies improve, required subsidies are observed to decrease over time.

Figure II-10.17: Comparing the First and Second Decile Affordability Thresholds against Equilibrium Tariff for the PENRA Vision Scenario Assuming Efficiency Targets Are Reached

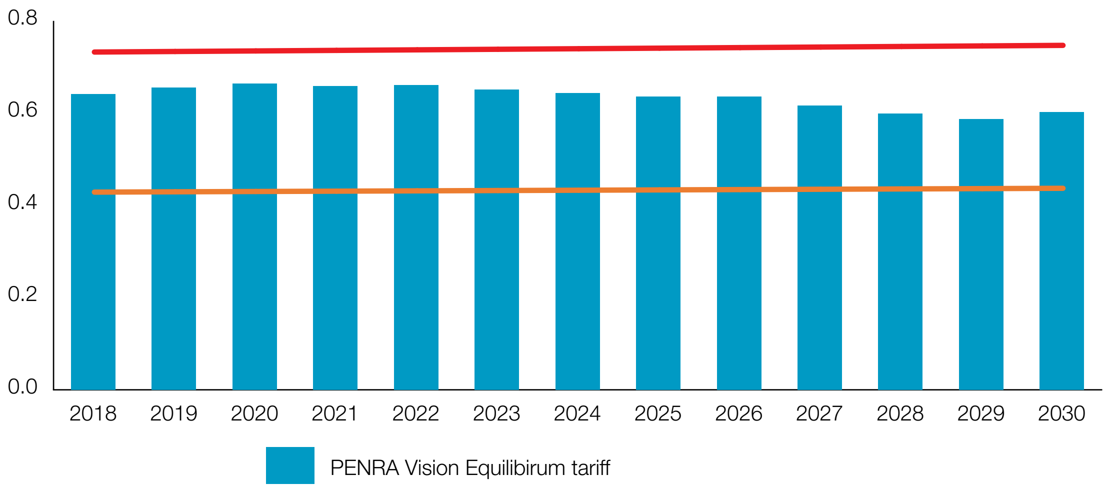
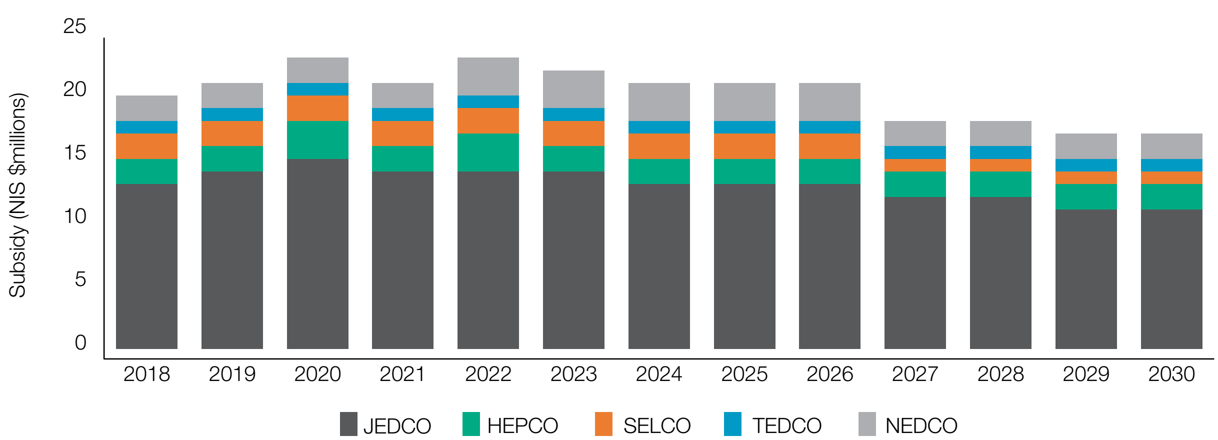


Figure II-10.18: Subsidy Required to Keep the Bills of the Bottom Decile of Households within the Corresponding Affordability Limits for the PENRA Vision Scenario Assuming Efficiency Targets Are Reached



MACRO FISCAL MODEL

A combined energy investment and reform package produces tangible macro fiscal benefits. To evaluate the fiscal and macroeconomic impact of PENRA's current projects in the pipeline, a computable general equilibrium (CGE) model is designed for the Planned Future scenario. For modeling purposes, this scenario is characterized by a steep expansion in domestic power generation accompanied by a fall in energy costs.

The CGE model predicts that the Planned Future scenario ensures electricity subsidies are fully eliminated and there is a boost in GDP growth and investment. From a fiscal perspective, the Planned Future scenario entails a dramatic reduction in electricity subsidies that are otherwise projected to escalate to 0.8 percent of GDP by 2025 under the Do Nothing scenario, to a net positive fiscal position of 0.9 percent of GDP by 2025 (table II-10.4). This makes a substantial contribution to the net government operating balance, estimated to be in slight surplus under the Planned Future versus a sizeable deficit under the Do Nothing scenario. The Planned Future scenario also delivers a significant boost to the growth rate of the economy, which would be 0.3 percentage points of GDP higher than otherwise for the entire decade (table II-10.5). The main sector to benefit from the energy turnaround is investment, which grows as much as 0.7 percentage points of GDP higher than otherwise, partly as a result of the increased fiscal space created by reducing electricity subsidies.

TABLE II-10.4: IMPACT OF THE "PLANNED FUTURE" ENERGY SCENARIO ON GOVERNMENT ACCOUNTS

AS % OF GDP	2016 BASELINE	2025	
		PLANNED FUTURE	DO NOTHING
Revenue	28.0	26.2	27.1
Expenditure	26.6	25.9	28.3
Of which Electricity subsidies	0.1	-0.9	0.8
Operational Balance	1.4	0.3	-1.2

TABLE II-10.5: IMPACT OF THE "PLANNED FUTURE" ENERGY SCENARIO ON MACROECONOMIC PERFORMANCE

AVERAGE ANNUAL GROWTH 2016–25	PLANNED FUTURE	DO NOTHING
GDP at market prices	2.7	2.4
Investment	2.3	1.6
Consumer price index	2.0	1.8

CHAPTER 11

Analysis and Results for Gaza

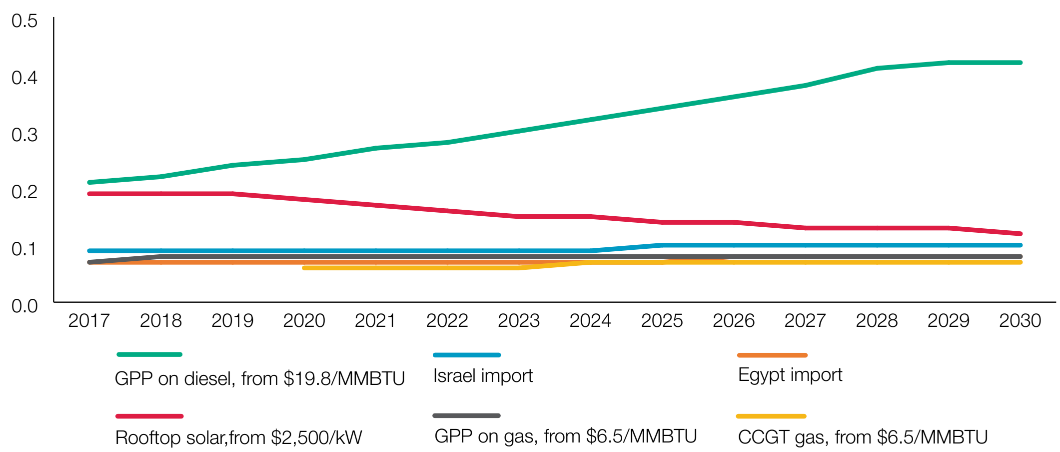
This chapter presents the results of the integrated planning and financial exercise for Gaza.

PLANNING MODEL

The two key drivers of the planning scenarios are the relative cost of power supplied through different technologies and the range of uncertainties that affects each of them. Figure II-11.1 plots the so-called levelized cost of energy (LCOE), defined as total capital and operating costs across the lifetime of a power project averaged over the total electricity produced. While LCOE is a convenient device for making simple relative cost comparisons, it is important to recognize that it does not capture all relevant characteristics of each power source, such as its availability for dispatch and contribution to meeting peak loads. Table II-11.1 summarizes the different uncertainty parameters that characterize each of the power supply options, considering delays in availability, uncertainty of cost, as well as probabilities of interruption to supply. These are inevitably somewhat subjective and based on a combination of expert judgment and stakeholder consultation.

Domestic power generation in Gaza is extremely costly, and will continue to be until the Gaza Power Plant (GPP) can be converted to gas and preferably to combined cycle technology (figure II-11.1). At present, the cost of diesel-fired generation at the GPP is over NIS 1.09 (US$0.30) per kilowatt hour (kWh) and projected to increase in line with the forecast trajectory of the global oil price. The only alternative domestic source of energy—rooftop solar—is also relatively expensive although projected to become cheaper over time in line with global trends, to reach around NIS 0.44 (US$0.12) per kWh by 2030. As of today, Israeli imports, at around NIS 0.37 (US$0.10) per kWh and Egyptian imports, at around NIS 0.27 (US$0.07) per kWh, are by far the most cost-effective source of energy available. However, eventual conversion of the GPP to natural gas, as well as possible conversion to more efficiency combined cycle gas turbine (CCGT) technology, would significantly bring down the costs of domestic generation.

Figure II-11.1: Time Trends of Levelized Cost of Energy for Different Supply Options in Gaza



Note: GPP = Gaza Power Plant; CCGT = combined cycle gas turbine; MMBTU = millions British thermal unit.

TABLE II-11.1: OVERVIEW OF UNCERTAINTY PARAMETERS FOR GAZA PLANNING EXERCISE

	DIESEL	GAS	ISRAEL	EGYPT
Availability range				
Earliest	2016	2022	2022	2021
Latest	2016	2035	2035	2035
Volume range				
Lowest	Unlimited	0.2 bcm	120 MW	10 MW
Highest	Unlimited	2.0 bcm	270 MW	70–150 MW
Price range				
Lowest	Known	$4.0 per MMBTU	Current	$0.08 per kWh
Highest	Known	$7.5 per MMBTU	$0.11 per kWh	$0.10 per kWh
Outage duration range				
Minimum days	37	37	18	29
Maximum days	365	365	91	182
Other parameters				
Minimum availability	0.30	0.30	0.80	0.60
Probability of interruption	0.15	0.15	0.02	0.20

Note: bcm = billion cubic meters; MMBTU = millions British thermal unit; MW = megawatt; kWh = kilowatt hour.

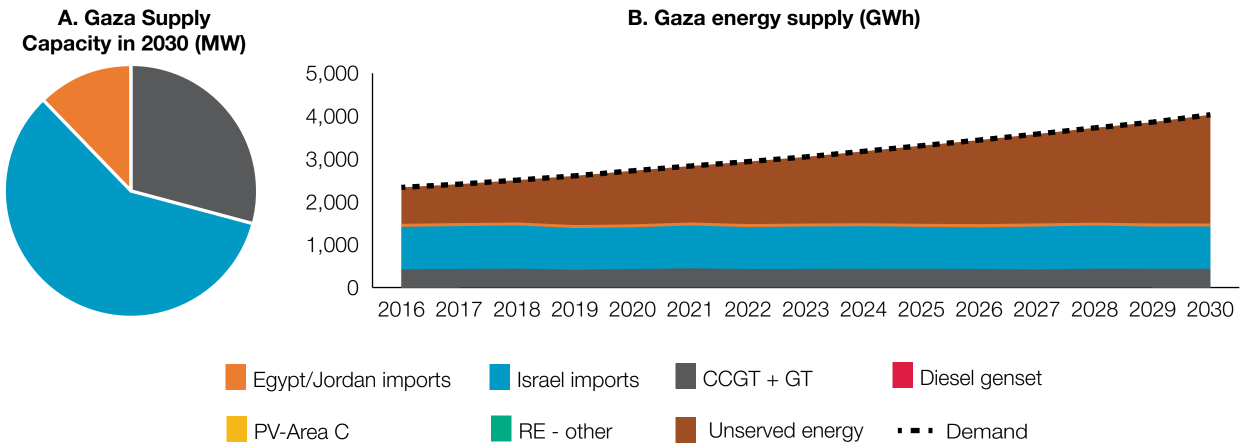
Due to the risky environment in Gaza, some of the lower cost power options are not necessarily the most secure (table II-11.1). The relative cost of alternative power generation options needs to be considered alongside their relative risk. A key issue to look at is the probability of a supply interruption at any given time. This indicates that both the diesel supply to the GPP and Egyptian imports have proved to be highly unreliable sources of electricity in the past. While gas supplies are not yet available, due to their nature as fuel imports, it is envisaged that these could be subject to similar levels of risk. Electricity imports from Israel, on the other hand, based on the historical record have proven to be more reliable and are therefore assigned a lower probability of interruption.

Against this backdrop, the results of the five planning scenarios are considered. These include a Do Nothing counterfactual, where no further investments are made in power infrastructure while demand continues to grow. This is compared with the impact of the current pipeline of investments, described as the Planned Future, as well as the PENRA Vision for the longer term, which seeks to limit dependence on any single source of energy to 50 percent of demand while retaining the ability to import 100 percent of energy needs if required. For the purposes of illustration, two additional—more extreme—scenarios are considered. Maximum Cooperation considers the possibility of Gaza following the power supply model that has so far characterized the West Bank, which is full dependence on Israeli imports to the extent of phasing out the GPP completely. Maximum Independence considers the opposite possibility of scaling-up the GPP to the point where it is capable of meeting the full extent of anticipated demand growth.

Under the Do Nothing scenario, Gaza's existing acute power shortages only become increasingly intolerable over time (figure II-11.2). The baseline for the planning exercise is a scenario in which no further power infrastructure is developed to support either increased domestic generation or expanded imports, but demand continues to grow in line with forecasts. Gaza is already unable to meet 50 percent of its demand, and under the Do Nothing scenario this situation continues to deteriorate dramatically, so that by 2030 over 60 percent of demand cannot be met,

Figure II-11.2: Results of "Do Nothing" Planning Scenario for Gaza

Do nothing: No additional power supply is brought online, and Gaza is limited to the following existing status: (i) 120 WM import capacity from IEC, (ii) 30 MW import capacity from Egypt, and (iii) the Gaza Power Plant (GPP) is running on diesel with 140MW capacity but limited to 60 MW due to fuel shortages.



AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
14.68	0	63%	26%	11%	0%

Takeaway: Under current conditions, unserved demand and power cuts will continue to increase in Gaza until 2030.

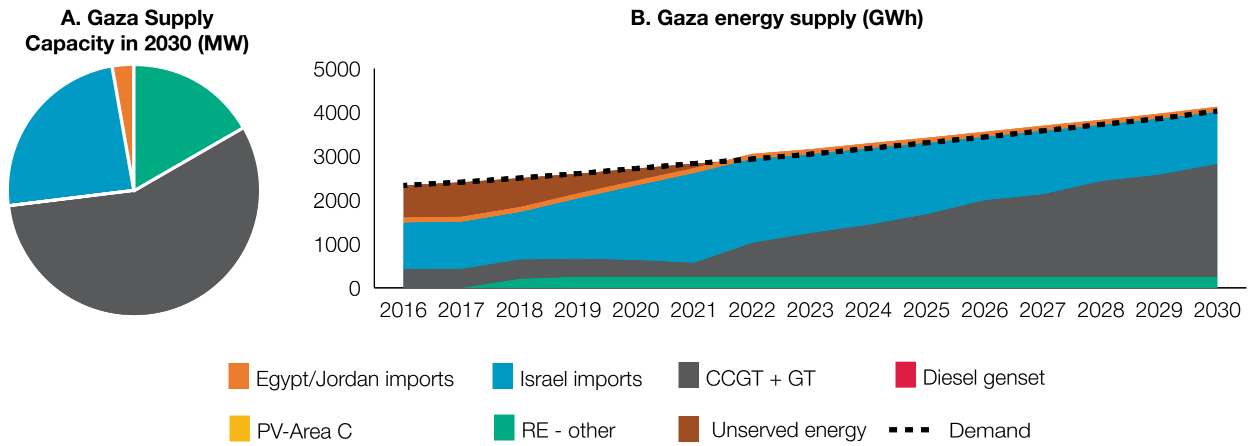
Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gast Turbine; IEC = Israeli Electric Corporation; MW = megawatt; PV = photovoltaic; RE = renewable energy.

which represents power cuts longer and more severe than those experienced today. At the same time, the cost of the limited power generation available is very high at almost NIS 0.55 (US$0.15) per kWh—about 50 percent higher than the equivalent scenario for the West Bank—and this is due to the high cost of running the GPP on diesel. And the GPP does not permit the achievement of energy independence. Due to the limited capacity and the constraints on diesel purchases, Gaza continues to rely on imports to meet 26 percent of its energy needs. Overall, the Do Nothing baseline scenario for Gaza paints a dire picture. Additional power supply is desperately needed, but the high cost of energy, coupled with consumers' low ability and willingness to pay, make it difficult to bring on additional supply.

Gaza's situation would improve significantly with the implementation of Planned Future projects, although the cost of energy would remain relatively high (figure II-11.3). In addition to the Palestinian Energy and Natural Resources Authority's (PENRA's) plans to energize a new 161 kilovolt (kV) line with the Israeli Electric Corporation (IEC) and substantially expand the capacity of the GPP to 560 megawatt (MW) while converting it to gas, this scenario incorporates the possibility of developing Gaza's full potential of 163 MW of solar photovoltaic (PV), mainly in the form of rooftop solar systems. The inclusion of the latter is not based on cost considerations, as rooftop solar remains relatively costly even through to the end of this period, but is rather motivated by considerations of resilience. Solar capacity of this kind could help to provide an electricity safety net capable of meeting the most basic needs during times of geopolitical tension that could potentially affect fuel or electricity imports. The implementation of this package would ensure that unserved demand could be eliminated by the early 2020s. However, implementing these projects would entail raising over NIS 3.7 billion (US$1 billion) of private financing, and the cost of electricity would remain relatively high at NIS 0.50 (US$0.134)

Figure II-11.3: Results of “Planned Future” Planning Scenario for Gaza

Planned Future: All PENRA’s current planned projects come online: (i) upgrade of GPP to run on natural gas and expand capacity up to 560 MW, (ii) and energization of the 161 kV power line to bring an additional 120 MW from IEC. In addition, we assume 163 MW of renewable energy (of which over 80% is rooftop solar) which is Gaza’s maximum potential capacity.



AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
13.39	1,035	0%	26%	68%	6%

Takeaway: Planned projects will meet Gaza’s unserved demand by 2030 but 94% of fuel and power will be imported.

Note: CAPEX = capital expenditure; GWh = gigawatt hour; IEC = Israeli Electric Corporation; GT = Gast Turbine; MW = megawatt; PV = photovoltaic; RE = renewable energy.

per kWh. Gaza would only be able to meet 6 percent of its energy needs on a fully self-sufficient basis through solar; however, this is the maximum amount feasible in any case.

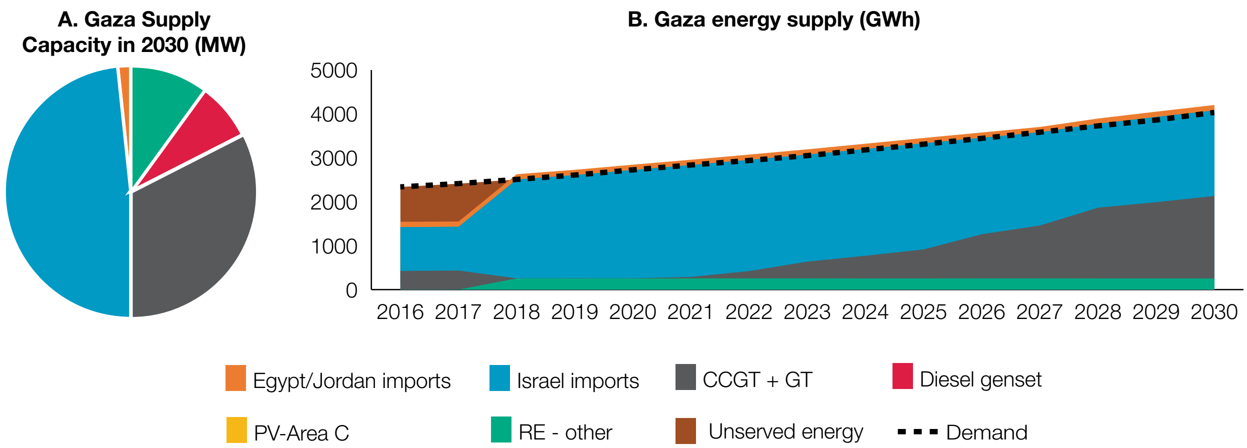
Achieving the PENRA Vision for the future, requires rebalancing from domestic thermal generation toward Israeli imports, thereby reducing the average cost of energy (figure II-11.4). The next scenario is based on the implementation of the PENRA Vision, according to which no source should contribute more than 50 percent of overall generation, while the import capacity should remain large enough to import all needed energy in case of emergency. Renewable energy potential continues to be tapped. The Planned Future scenario does not meet PENRA’s strategic vision, because it relies on the GPP for more than 50 percent of energy needs. The only viable way to achieve the requisite rebalancing is to scale back the GPP’s capacity and allow the Israeli connection to make up a larger proportion of the overall capacity. While this still requires capital expenditure in excess of NIS 3.7 billion (US$1 billion), the average cost of energy is slightly reduced by NIS 0.04 (US$0.011) per kWh to NIS 0.45 (US$0.12). Furthermore, unserved demand is more rapidly eliminated even before 2020. Both effects are due to the greater reliance of Israeli imports.

As a comparison to this balanced scenario, two more extreme scenarios are also considered here for illustrative purposes. One explores the option of maximizing cooperation on electricity imports with Israel, and the other the option of further developing domestic thermal generation to achieve Maximum Independence.

Under a strategy of Maximum Cooperation, Gaza achieves the lowest possible power generation costs, comparable to those currently enjoyed by the West Bank (figure II-11.5). Given the cost and security advantages of Israeli power imports over domestic thermal generation, the Maximum Cooperation scenario would call for shutting down the GPP and

Figure II-11.4: Results of "PENRA Vision" Planning Scenario for Gaza

PENRA Vision: "Dependency ratio on any one source should not exceed 50% in best conditions, with a possibility of importing all needs in case of emergency."



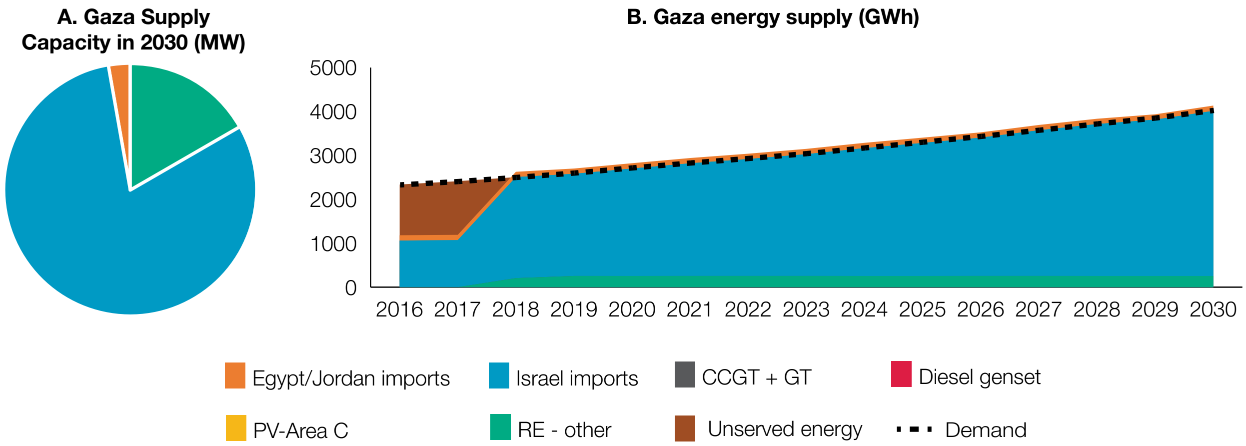
AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
12.30	1,066	0%	47%	46%	6%

Takeaway: Better diversification, which will reduce costs, requires IEC imports beyond the planned 161kV line.

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gast Turbine ; MW = megawatt; PV = photovoltaic; RE = renewable energy.

Figure II-11.5: Results of "Maximum Cooperation" Planning Scenario for Gaza

Maximum Cooperation: The Gaza Power Plant (GPP) is shut down and all electricity needs are imported from IEC with expanded interconnection capacity. The full 163 MW of solar potential is developed as a safety net.



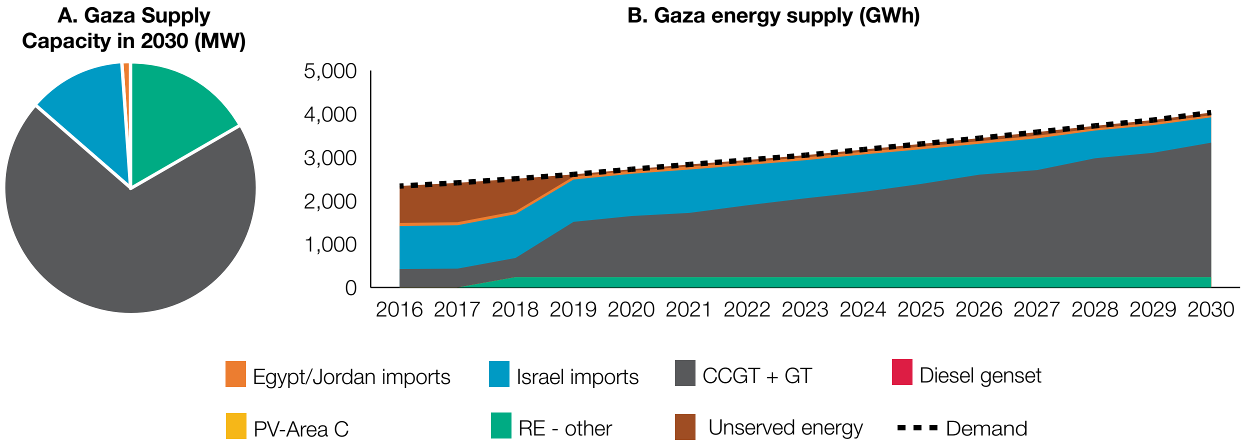
AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
10.37	385	0%	93%	0%	6%

Takeaway: Cost of power is 3UScents/KWh cheaper than the planned strategy which would help improve cost recovery.

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gast Turbine; IEC = Israeli Electric Corporation; MW = megawatt; PV = photovoltaic; RE = renewable energy.

Figure II-11.6: Results of "Maximum Independence" Planning Scenario for Gaza

Maximum independence: Meet all demand growth through further expansion of Gaza Power Plant up to 677 MW, while retaining existing 120 MW interconnection with IEC, and developing full 163 MW of solar PV potential (80% of rooftop)



AVG COST POWER (US CENTS/KWH)	CAPEX (US$ MILLION)	2030 UNSERVED DEMAND (%)	2030 ELECTRICITY IMPORTS (%)	2030 DOMESTIC GEN-IMPORTED FUEL (%)	2030 DOMESTIC GEN-RENEWABLES (%)
15.15	1,185	2%	9%	83%	6%

Takeaway: Relying purely on gas plants means, if gas is ever unavailable, diesel must be used, driving up costs significantly

Note: CAPEX = capital expenditure; GWh = gigawatt hour; GT = Gast Turbine; IEC = Israeli Electric Corporation; MW = megawatt; PV = photovoltaic; RE = renewable energy.

relying entirely on Israeli power imports. This entails expanding connection capacity with Israel from current levels of 120 MW toward 800 MW. The 163 MW of mainly rooftop solar are retained as an electricity safety net. In terms of operational installed capacity, this level of rooftop solar development would actually represent more than twice as much energy as what is offered by the GPP today, which is constrained to just 60 MW. However, in the absence of improved storage capacity, the hours of service available from solar power would be more restrictive. The capital expenditure associated with this option on the Palestinian side is much lower, at NIS 1.4 billion (US$0.39 billion). Significant investments would also be required on the Israeli side to enhance connection capacity, although these should be covered through the power export tariff. This approach also eliminates unserved demand relatively quickly, before 2020, and results in relatively low tariffs of NIS 0.38 (US$0.104) per kWh.

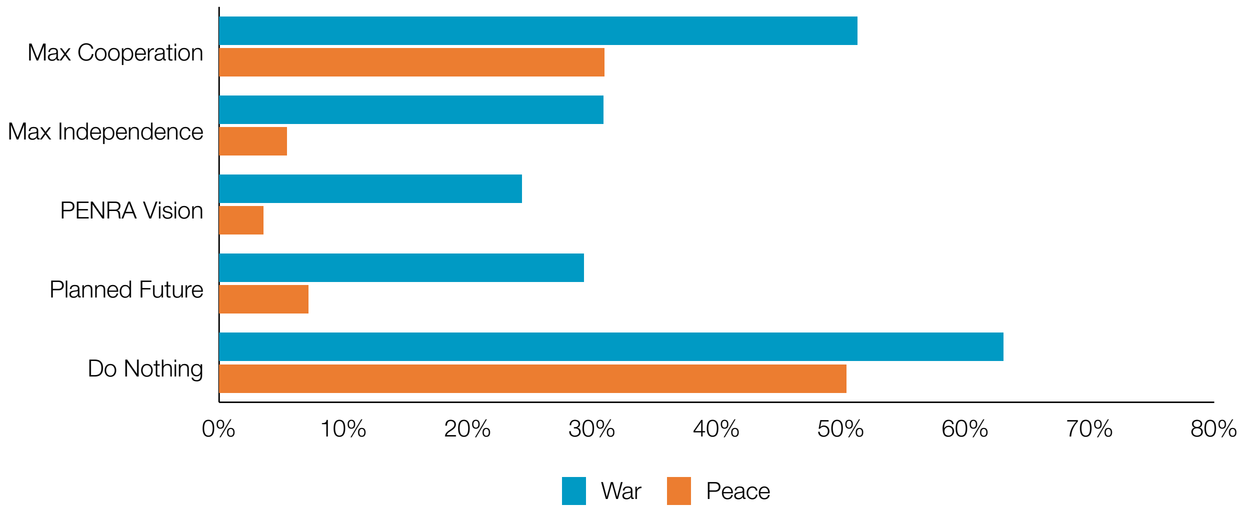
Under a strategy of Maximum Independence, a larger scale-up of the GPP is called for, and costs of power generation are at their highest (figure II-11.6). With Israeli imports capped at current levels of 120 MW, and renewable energy potential constrained to 163 MW, this scenario entails further expansion of the GPP until it is capable of meeting the entire demand. This entails significantly higher capital expenditure than any of the other scenarios, at around NIS 4.4 billion (US$1.2 billion). While unserved demand is eliminated by 2020, the average cost of generation is also higher than under any other scenario, at NIS 0.55 (US$0.152) per kWh. The reason for this—despite the relative cost-effectiveness of CCGT technology—is that high-cost diesel becomes the backup fuel for the gas plant anytime it experiences an outage; this is relatively often given the plant's operational history. Finally, this poorly diversified scenario is so heavily dependent on imported fuel that any impression of independence is largely illusory. It is possible that the performance of this scenario could be improved, if the GPP were able to run on Gaza Marine gas. However, even in this case, the gas would likely need to be transported via Israel or Egypt.

TABLE II-11.2: COMPARISON OF RESULTS ACROSS THE FIVE PLANNING SCENARIOS FOR GAZA

	AVERAGE COST POWER (U.S. CENTS PER KWH)	CAPEX (US$ MILLIONS)	2030 UNSERVED DEMAND	2030 ELECTRICITY IMPORTS	2030 DOMESTIC GENERATION WITH IMPORTED FUEL	2030 DOMESTICALLY GENERATED RE
1. Do nothing	14.68	0	63%	26%	11%	0%
2. Planned future	13.39	1,035	0%	26%	68%	6%
3. PENRA vision	12.30	1,066	0%	47%	46%	6%
4. Maximum cooperation	10.37	385	0%	93%	0%	6%
5. Maximum independence	15.15	1,185	2%	9%	83%	6%

Note: The darker the shade of green the better the performance on that dimension, while the darker the shade of orange the worse the performance on that dimension.
Note: CAPEX = capital expenditure; kWh = kilowatt hour; RE = renewable energy.

Figure II-11.7: Resilience Stress Test across Scenarios in Terms of Percent Increase in Unserved Demand for Gaza



Note: PENRA = Palestinian Energy and Natural Resources Authority.

No single option performs better than others on all relevant dimensions, illustrating that trade-offs must be made. Examining the five scenarios side by side helps to clarify their relative performance. Table II-11.2 compares various dimensions of performance, including the average cost of power generation, the total capital expenditure, the level of unserved demand in 2030, the continued reliance on electricity imports or fuel imports for generation, and the share of domestically generated renewable energy in the overall mix.

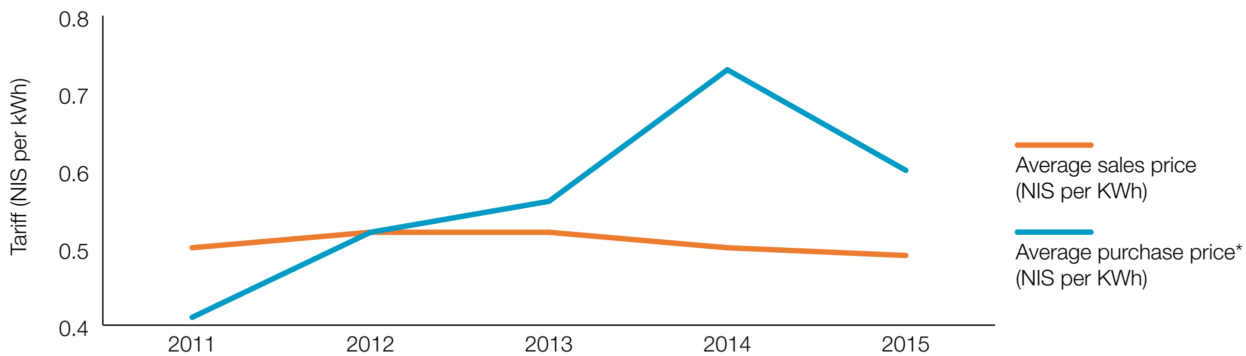
The key energy policy issue for Gaza is where to strike the right balance between Israeli imports and domestic gas-fired power generation. The first point to note is that the degree of true energy independence achievable in Gaza is, due to geographic circumstances, much lower than for the West Bank. Whereas the West Bank could potentially meet 20–30 percent of its energy needs from solar energy by 2030 (depending on access to Area C), Gaza is only able to meet at most 6 percent of electricity demand from solar energy by 2030, even after exploiting the full extent of its renewable energy potential. Moreover, given the low historical reliability of Egyptian power imports, Gaza's only two realistic power supply options are Israeli imports and an expanded GPP suitably converted to fire on gas. Energy policy for Gaza therefore boils down to striking the right balance between these two limited options. A simple cost comparison between the two suggests a slight advantage for the GPP once converted to gas. However, the relative ranking of these two options changes when risk factors are considered. On the one hand, Israeli power imports have had a reliable historical track record. On the other hand, the GPP would never be able to rely on gas entirely sourced and transported within the Palestinian territories and would be forced to run on expensive diesel whenever gas supplies were to fail. Running the GPP on diesel, as at present, is a highly unattractive option, which should be avoided as much as possible. Indeed, the investment differential between Maximum Cooperation and Maximum Independence is as much as NIS 2.9 billion (US$0.8 billion) while the average cost differential is as much as NIS 0.175 (US $0.048).

The recommendation is, therefore, not only to pursue the energization of the existing 161 kV line, but also to explore the possibility of additional connection capacity with IEC, even as efforts to import gas to Gaza continue. Finally, the development of Gaza's limited solar potential looks to be a worthwhile investment that provides a basic electricity safety net more effectively and efficiently than is currently being achieved with the GPP.

TABLE II-11.3: OVERVIEW OF TRANSMISSION AND DISTRIBUTION INVESTMENT REQUIREMENTS FOR GAZA

(US$)		GPP UPGRADED AND EXPANDED OR ADDITIONAL SUPPLY FROM IEC COMES TO GAZA	EGYPTIAN INTERCONNECTOR IS EXPANDED	TOTAL
WB	Trans.	33	32	65
WB	Dist.	47	13	60
Total	T&D	80	45	125

Figure II-11.8: In Gaza, Retail Sales Tariffs Have Remained Flat as Cost of Power from Israel and Gaza Power Plant Has Increased



	2011	2012	2013	2014	2015
Average purchase price* (NIS per kWh)	0.41	0.52	0.56	0.73	0.60
Average sales price (NIS per kWh)	0.50	0.52	0.52	0.50	0.49
Markup/discount	23%	1%	-7%	-47%	-22%

Note: kWh = kilowatt hour.
Includes Israeli Electric Corporation and Gaza Power Plant.

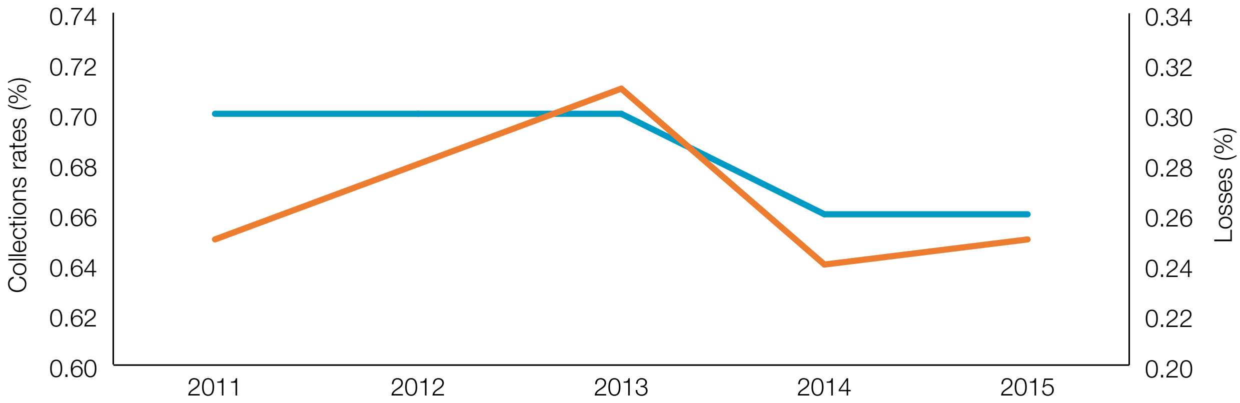
Another way to compare the alternative scenarios is through a stress-testing process that examines how they perform under extreme conditions. In particular, the stress test looks at how the percentage of unserved energy rises for each scenario when conflict conditions are simulated.

The Planned Future and PENRA Vision scenarios are the ones that perform the best under conflict conditions (figure II-11.7). Under these scenarios the unserved demand during wartime would increase to 24–29 percent, even slightly outperforming the Maximum Independence scenario, and far outperforming the Maximum Cooperation scenario that could lead to as much as 50 percent of unserved energy during a conflict period.

TRANSMISSION

The specific situation of Gaza points to the need to develop domestic transmission infrastructure as opposed to wheeling via the Israeli network. With respect to transmission options, Gaza's situation is quite different to that of the West Bank. Given Gaza's

Figure II-11.9: Time Trend for Distribution Losses and Collection Efficiency in Gaza



	2011	2012	2013	2014	2015
Losses*	30%	30%	30%	26%	26%
Collection Rates	65%	68%	71%	64%	65%

* Includes technical and nontechnical.

small territory and compact settlement patterns, its absence of land-use restrictions, and the relatively limited existing connection capacity with Israel, the option of wheeling power within Gaza via the Israeli network does not appear to be relevant. Attention, therefore, focuses on the need to develop domestic transmission and distribution infrastructure for power transportation purposes.

Capital expenditure requirements for transmission and distribution in Gaza range from NIS 292 million to NIS 456 million (US$80 million–125 million) (table II-11.3). Given the need to substantially expand the amount of power flowing through the Gaza network to meet growing demands, an investment of NIS 120 million (US$33 million) in an internal transmission backbone and a further NIS 172 million (US$47 million) for supporting distribution network enforcements would be needed in any case, whether the additional power was coming from IEC, the GPP, or some combination of the two. Although the planning scenarios did not end up including increased imports from Egypt, it is important to note that the pursuit of this option would entail a different set of investments in transmission and distribution, amounting to a total of NIS 164 million (US$45 million). It is important to note that, whereas investments in generation would be pursued under a public-private partnership model, investments in transmission and distribution would necessarily take the form of public investment.

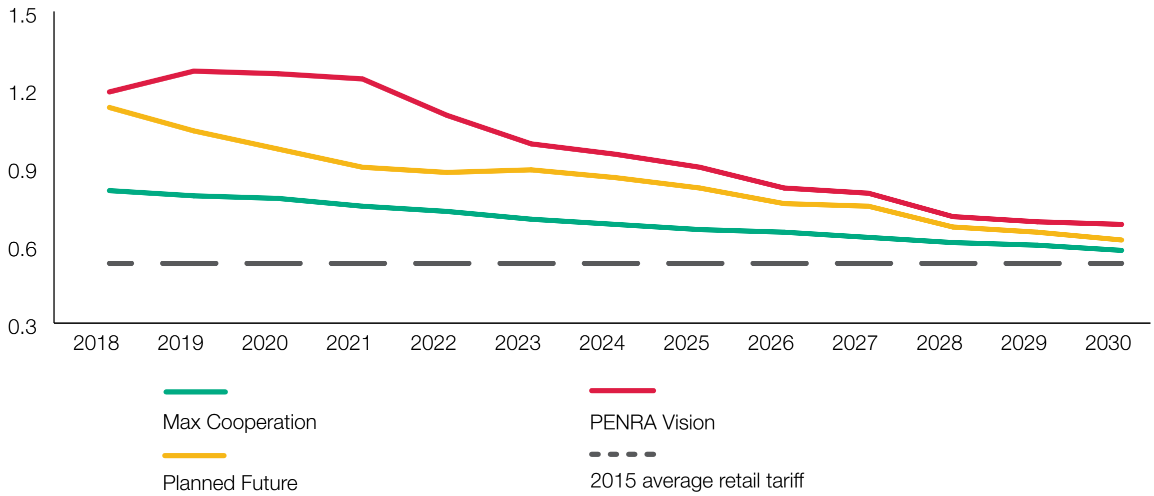
FINANCIAL MODEL

Attention now turns to the financial implications of implementing the planning scenarios. The key focus of attention will be the financial equilibrium tariff and how it may need to evolve relative to historic practice.

The Gaza Electricity Distribution Company (GEDCO) currently sells power to consumers at a cost lower than its own average purchase price from IEC and GPP (figure II-11.8). Gaza's retail power tariffs have been fixed at NIS 0.50 (US$0.14) per kWh for the past decade, even as the weighted average cost of purchasing power both from Israel and GPP has risen toward NIS 0.60–0.70 (US$0.17–0.19) per kWh. The implication is that GEDCO is selling power to customers at a discount over its own power purchase price, and that's not even considering the utility's own distribution operating margin.

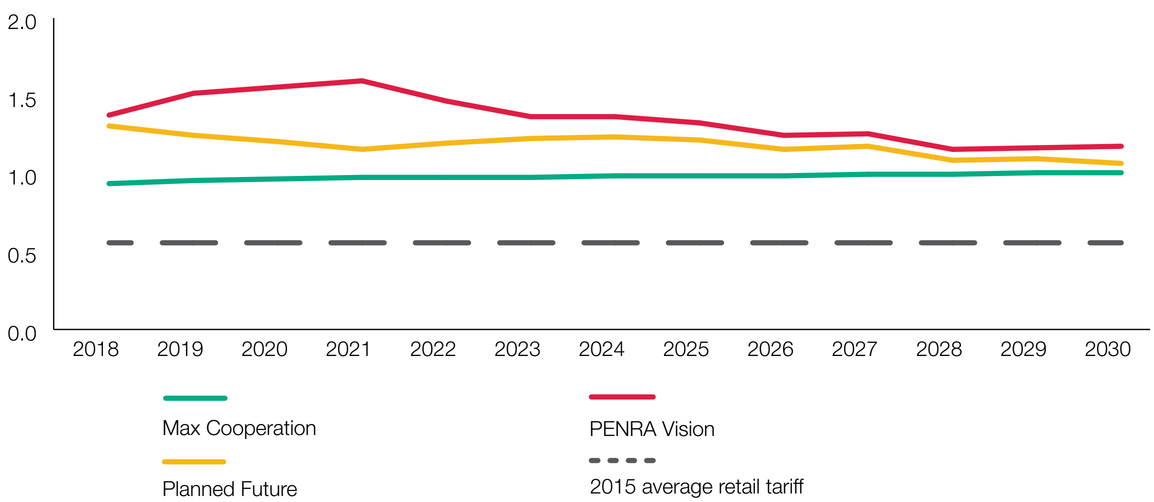
Moreover, GEDCO's operating performance is by far the worst of any of the Palestinian distribution utilities (figure II-11.9). While GEDCO's distribution losses (including both technical and nontechnical losses) have been falling somewhat from around 30 percent in 2011 to 26 percent in 2015, they remain high relative to other Palestinian utilities and are more than twice as high as what would be considered good practice internationally. GEDCO's collection ratio, which stands at around 65 percent (despite a

Figure II-11.10: Projected Financial Equilibrium Tariff for GEDCO under Different Planning Scenarios and Improved Operational Efficiency Assumptions



s*Note:* kWh = kilowatt hour.

Figure II-11.11: Projected Financial Equilibrium Tariff for GEDCO under Different Planning Scenarios and Static Operational Efficiency Assumptions

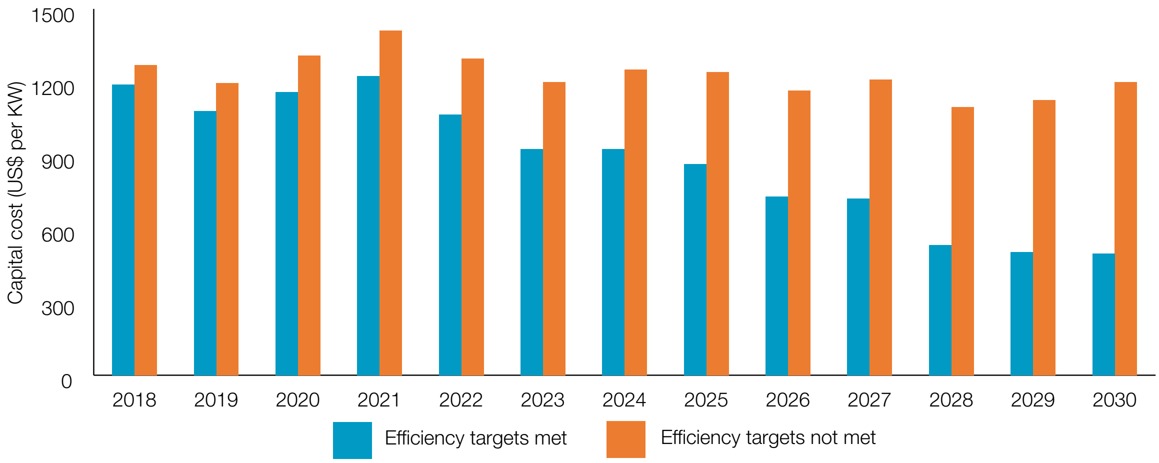


Note: kWh = kilowatt hour.

recent spurt), is extremely low and represents a huge financial drain on the company. This poor performance is partly explained by high levels of unemployment and poverty in Gaza due to the conflict situation, as well as limited willingness to pay from consumers that are subject to continuous rolling blackouts.

The financial modeling exercise is pursued for three of the planning scenarios that capture the full range of potential financial implications. In the case of Gaza, the Maximum Independence and PENRA Vision scenarios were the most expensive, entailing an average generation cost of approximately NIS 0.54 (US$0.15) per kWh, while the Maximum Cooperation scenario was the least expensive, entailing an average generation cost of (NIS 0.36) US$0.10 per kWh. The Planned Future represents the middle ground, with an average cost of just over (NIS 0.51) US$0.13 per kWh.

Figure II-11.12: Subsidy Requirement to Maintain Financial Equilibrium of GEDCO under Planned Investment Scenario if Retail Tariffs Are Not Adjusted under "PENRA Vision" Scenario



The financial equilibrium tariffs tend to converge across scenarios by 2030, but there are huge differences during the earlier years of the transition (figure II-11.10). While planning scenarios were compared in terms of their average cost of generation, in practice the cost of generation varies annually throughout the planning period. In practice, across all scenarios, the cost of generation declines toward the end of the planning scenario, as GEDCO is able to switch toward lower cost technologies, such as CCGT, and benefit from declining cost trends for solar PV. The PENRA Vision scenario entails a particular cost "hump" in the early years, as GEDCO has to increase reliance on diesel to meet demands until the gas conversion for the GPP comes on stream. The financial equilibrium tariff converges across all scenarios towards NIS 0.50–0.60 (US$0.14–0.17) per kWh by 2030, which is just slightly above the current tariff. However, in the early years, the tariff differences can be very large, ranging from NIS 1.20 (US$0.33) per kWh for the "PENRA Vision" scenario to NIS 0.70 (US$0.19) per kWh for the Maximum Cooperation scenario.

The financial equilibrium tariffs for GEDCO are hugely sensitive to assumptions about improvements in operational performance, making this a critical area of action. The financial equilibrium tariffs presented in figure II-11.11 are based on an important additional assumption that GEDCO's financial performance would improve substantially over time to meet more reasonable standards (if not yet full international best practice). In particular, it is assumed that collections can be increased from the current levels of 65 percent to 97 percent, while distribution losses fall from the current level of 26 percent to 16 percent. In addition, transmission losses are set at 2 percent, and there is an assumption that operations and maintenance costs could be trimmed by 2 percent annually. Based on reports from the DISCOs, it is assumed that debt is currently financed at 3.5 percent, but would probably need to rise toward 7 percent by 2030. Without these improvements, the financial equilibrium tariff to which all scenarios converge by 2030 rises substantially from NIS 0.50–0.70 (US$0.14–0.19) per kWh to NIS 0.90–1.10 (US$0.25–0.30) per kWh. Moreover, during the transition years, the financial equilibrium tariff gets as high as NIS 0.90–1.50 (US$0.25–0.42) per kWh.

Failure to adjust GEDCO tariffs would result in massive average annual subsidy requirements to keep GEDCO afloat (figure II-11.12). For the PENRA Vision scenario, the subsidy requirements are estimated at NIS 1,100

Figure II-11.13: Comparing the First Five Affordability Deciles against Equilibrium Tariff for the PENRA Vision Scenario, Assuming Efficiency Targets Are Met by 2030

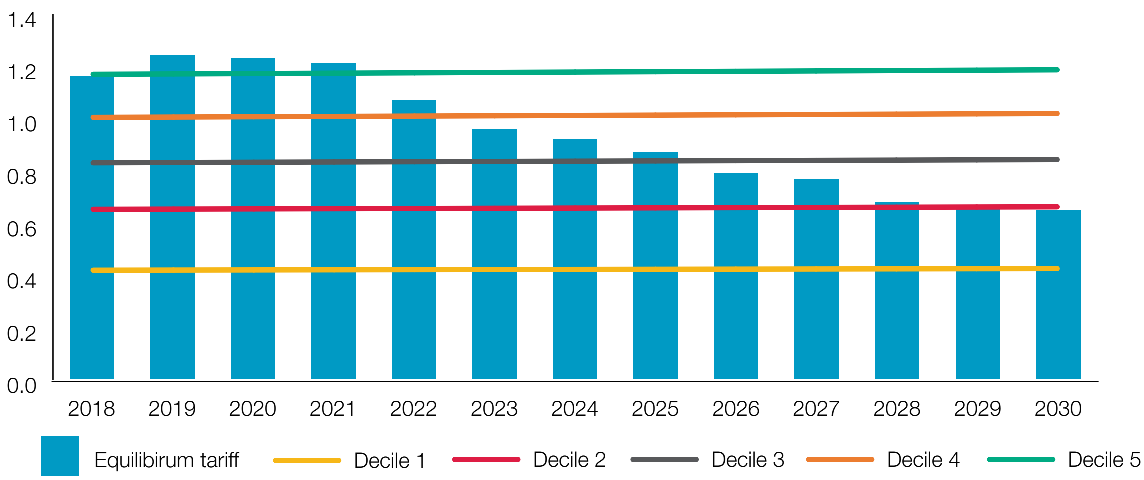
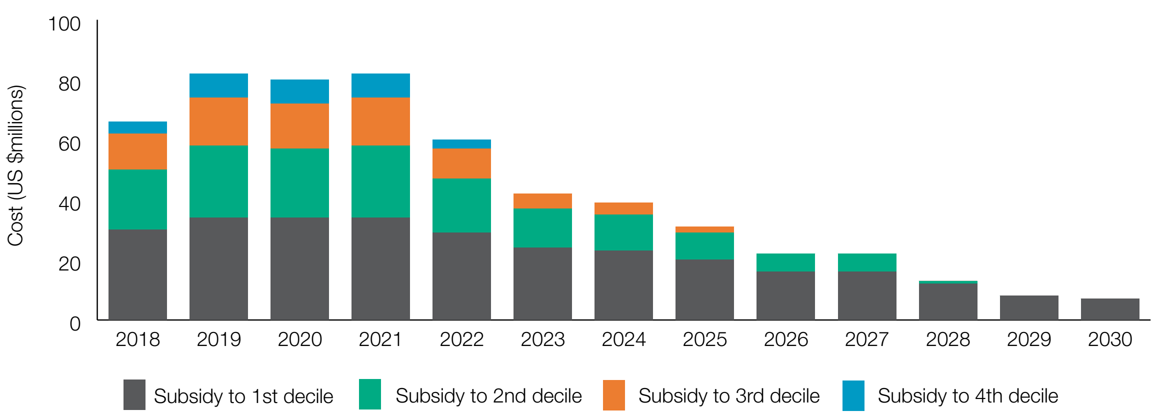


Figure II-11.14: Subsidy Requirement to Maintain Affordability of GEDCO's Tariffs to the Poorest Households under the "PENRA Vision" Scenario, Assuming Efficiency Targets Are Met



million–1,200 million (US$300 million–330 million) during the early years of the transition, although they decline as efficiency targets are reached. Another way of stating this is that if new power projects are taken on without performing tariff adjustments, GEDCO could be expected to lose an average of NIS 0.47 (US$0.13) on every kWh sold over the entire time horizon until 2030. with the losses in the initial five years being up to NIS 0.8 (US$0.22) per kWh. These subsidies assume that GEDCO meets the desired efficiency targets by 2030. If this expectation is not fulfilled, then the annual subsidy requirements would increase by, on average, a further NIS 308 million (US$81 million) per year over the time horizon until 2030.

An alternative approach is to allow GEDCO's tariffs to adjust to the evolving financial equilibrium tariff, while providing a social safety net to safeguard affordability to the poorest. The fiscal costs of keeping GEDCO's tariffs constant would clearly be prohibitive. At the same time, increasing tariffs beyond their already relatively high level could create affordability problems among Gaza's impoverished population. The affordability analysis conducted for this study suggests that the affordable tariff limit will be NIS 0.42 (US$0.11) per kWh in 2018 for the bottom decile of the population, NIS 0.65 (US$0.18) per kWh for the second decile, NIS 0.83 (US$0.23) per kWh for the third, NIS 1.0 (US$0.27) per kWh for the fourth, and NIS 1.17 (US$0.32) per kWh for the fifth decile

TABLE II-11.4: IMPACT OF THE "PLANNED FUTURE" ENERGY SCENARIO ON GOVERNMENT ACCOUNTS

AS % OF GDP	2016 BASELINE	2025	
		PLANNED FUTURE	DO NOTHING
Revenue	44.1	44.4	47.3
Expenditure	47.1	40.5	48.6
Of which electricity subsidies	4.7	0.9	6.0
Operational balance	-3.0	3.9	-1.3

TABLE II-11.5: IMPACT OF THE "PLANNED FUTURE" ENERGY SCENARIO ON MACROECONOMIC PERFORMANCE

AVERAGE ANNUAL GROWTH 2016–25	PLANNED FUTURE	DO NOTHING
GDP at market prices	4.6	4.1
Investment	8.9	5.2
Consumer price index	1.5	1.5

of the population (figure II-11.13). A targeted subsidy designed to keep electricity bills affordable for the poor as tariffs adjust to meet financial equilibrium would have a much lower fiscal cost, estimated starting at less than NIS 70 million (US$19 million) per year, increasing to NIS 80 million (US$22 million) per year in the subsequent years, then dropping to less than NIS 10 million (US$3 million) per year by 2030, as costs come down and target efficiencies are reached (figure II-11.14).

MACRO FISCAL MODEL

A combined energy investment and reform package produces tangible macro fiscal benefits. To evaluate the fiscal and macroeconomic impact of PENRA's current projects in the pipeline, a computable general equilibrium (CGE) model is designed for the Planned Future scenario described above. For modeling purposes, this scenario is characterized by a steep expansion in domestic power generation accompanied by a fall in energy costs.

The CGE model predicts that the Planned Future scenario ensures electricity subsidies are fully eliminated and there is a boost in GDP growth and investment. From a fiscal perspective, the Planned Future scenario entails a dramatic reduction in electricity subsidies that are otherwise projected to escalate to 6.0 percent of GDP by 2025 under the Do Nothing scenario, to a much lower level of 0.9 percent of GDP by 2025 (table II-11.4). This makes a substantial contribution to the net government operating balance estimated to be in substantial surplus under the Planned Future versus a sizeable deficit under the Do Nothing scenario. The Planned Future scenario also delivers a significant boost to the growth rate of the economy, which would be 0.5 percentage points of GDP higher than otherwise for the entire decade (table II-11.5). The main sector to benefit from the energy turnaround is investment, which grows as much as 3.7 percentage points of GDP higher than otherwise, partly as a result of the increased fiscal space created by reducing electricity subsidies.

PART III

Conclusions and Recommendations

CHAPTER 12

A Four-Phase Road Map to Improved Energy Security in the West Bank and Gaza

This concluding chapter brings together all of the analysis in the report to define a sequenced and prioritized roadmap of recommendations for the Palestinian electricity sector. The starting point for the road map is to strengthen the Palestinian Electricity Transmission Company's (PETL's) operational capacity and financial sustainability. While an important interim agreement was signed in July 2017, PETL is still negotiating with the Israeli Electric Corporation about (i) a power purchase agreement (PPA), (ii) the energization of several high-voltage substations, and (iii) the transfer of connection points from distribution companies (DISCOs) and municipality and village councils to PETL. In parallel, PETL should focus on (i) negotiating the power supply agreements with Palestinian distributors, (ii) putting in place billing and collection systems to sell power to, and collect payments from, Palestinian distributors, and (iii) providing advice to the Palestinian Electricity Regulatory Council (PERC) for the calculation of a tariff for selling power to the distributors. With these mechanisms in place, PETL could accelerate its progress toward fulfilling its role and responsibilities under the PPA and reduce its reliance on donor assistance for operational costs. Once these immediate measures are in place, the question becomes what needs to be done next to begin to move toward the vision of improved energy security in the Palestinian territories. The analysis suggests that there is a certain sequence in which measures will need to be taken. Four distinct phases are identified.

PHASE 1: IMPROVE SECTOR CREDITWORTHINESS

The first phase needs to focus on what is by far the highest priority issue in the Palestinian electricity sector today: namely, the issue of financial creditworthiness. Progress on all other aspects of the Palestinian energy sector depend on greater creditworthiness. Without improved creditworthiness, the sector cannot sign new power import deals or close PPAs with independent power producers for increased domestic power-generation projects; as recent experience with renewable energy development has illustrated. Creditworthiness is equally important to allow the import of natural gas into the Palestinian territories, whether through gas purchase agreements with Israel or ultimately a contract to develop Palestinian gas from the Gaza Marine field. None of these ventures can get off the ground unless the Palestinian electricity sector becomes a credible off-taker.

There are several distinct components that will need to be tackled if creditworthiness is to be improved.

First, replace generation from the Gaza Power Plant (GPP) with increasing electricity imports from Israel to provide considerable relief until a conversion to gas can be undertaken. The cost of diesel-fired generation at GPP is exceptionally high, at approximately US$0.30 per kilowatt hour (kWh), even at current low oil prices. This is approximately three times the cost of power imports from Israel, which also provides a much more reliable level of supply. Until GPP is ready for the switch over to gas-fired generation that would slash costs to US$0.068 per kWh, it would be desirable to substitute domestic diesel-fired power generation with Israeli power imports, taking advantage of the new 161 kV line that is in an advanced stage of planning. Even considering the need to continue to pay capacity charges of US$0.026 per kWh to GPP, every reduction of one kWh in diesel-fired power generation would be sufficient to buy two kWh of Israeli imports. Such a move would simultaneously reduce costs and improve quantity and reliability of supply, and thereby increase prospects for improved recovery of costs through tariff revenues.

Second, accelerate improvements in the operational and commercial performance of Palestinian DISCOs. Cost-recovery tariffs could be significantly reduced over time if the operational and commercial performance of the Palestinian DISCOs could be improved to reasonable regional benchmark levels. For the utilities in the West Bank, improved operational performance would take US$0.03 per kWh off the financial equilibrium tariff, while in Gaza improving operational performance is worth as much as US$0.11 per kWh. Achieving further improvements can build on some recent successes with the introduction of prepaid and smart meters that helped to raise revenue collection rates to 85 percent on average across the utilities. Further improvements in revenue collection are required, particularly for weak performers such as Gaza Electricity Distribution Company and Southern Electricity Distribution Company. Moreover, across the board, attention needs to turn toward improving network losses which remain abnormally high despite all efforts. In this regard, it is recommended to establish a revenue protection program to permanently measure and bill every kWh sold to the largest DISCO customers with state-of-the-art technology.

Third, create securitization mechanisms to ensure that Palestinian DISCO revenues are not diverted to other municipal projects. Due to the lack of a subnational financing framework in the West Bank and Gaza, DISCO revenues remain vulnerable to diversion into municipal budgets. The long-term solution to this problem, which is to strengthen the basis of subnational public finance, is important for broader development reasons that go well beyond the energy sector. However, this will likely take some time to achieve. Hence the importance of finding interim mechanisms to securitize the revenues needed for the DISCOs to meet the costs of wholesale power purchase. This could take the form of a payment prioritization hierarchy, combined with an escrow account that requires revenues to be deposited to cover a certain advance period of wholesale power purchases before these can be supplied. The issue of securitization of revenues is particularly critical in Gaza, and would be an essential component of any moves to substitute increased Israeli power imports for domestic diesel-fired power generation.

Fourth, ensure that all Palestinian DISCOs move toward cost recovery. Not all Palestinian DISCOs are charging cost recovery tariffs today. Only two Palestinian utilities, Jerusalem District Electricity Company and Northern Electricity Distribution Company, make formal tariff submissions to PERC. The resulting uniform tariff that is applied across all Palestinian utilities in the West Bank is estimated to under recover costs for all but Northern Electricity Distribution Company. Moreover, PERC's practice of not passing through collection inefficiencies to the retail tariff, while defensible from the standpoint of consumers, further weakens the financial solidity of the sector. In addition, Gaza Electricity Distribution Company does not follow PERC tariff guidelines and has not adjusted its electricity tariff for a decade, currently charging a retail tariff that is US$0.03–0.05 per kWh lower than the wholesale purchase price of electricity, without considering the costs of power distribution. The higher costs of electricity production in Gaza, combined with the sensitive social context, suggest that efforts to improve cost recovery in Gaza would need to be preceded by measures to both reduce costs and improve the availability of power supply, such as the switching of diesel-fired power generation for Israeli imports.

Fifth, build the capacity of PETL to play its envisaged role in the sector. In the new sector architecture, PETL has been assigned a dual role of transmission system operator and single buyer and central bookkeeper of the electricity sector. However, its start of operations has been delayed pending the closure of a long-term PPA with Israel and the energization of the high-voltage substations. The signing of an interim agreement with Israel to energize the Jenin high-voltage substation alone was the first step toward PETL's financial and operational sustainability, and this was completed on July 10, 2017 after extensive negotiations. PETL is now able to resell the discounted power to DISCOs in the north of the West Bank at a slight markup, allowing them to obtain revenues. The next step is the signing of the main long-term PPA for all substations. In the meantime, PETL should make further progress toward its goal of being the single buyer, by ensuring that all wholesale power purchases are undertaken through its intermediation in order to improve transparency and discipline of the sector.

PHASE 2: ADVANCE PARALLEL "NO REGRETS" MEASURES

While the absolute priority is to improve the creditworthiness of the electricity sector, there are several other no regrets measures that can advance in parallel during a second phase. Even after decisive steps are taken to address the issue of creditworthiness, time will be needed for a payment record to be established and a reputation to be built. During this period of consolidation, it would be helpful to accelerate measures that will facilitate the development of other power supply options that will become feasible once the issue of creditworthiness has been adequately addressed.

First, create the infrastructure needed to support the import of natural gas into the Palestinian territories. All the planning analysis confirms the strategic role that natural gas-fired power generation can play in the electricity mix for both the West Bank and Gaza, as well as its relatively attractive cost. The first step in making this possible is to construct the relatively modest pipeline extensions needed to make possible the import of gas from the Israeli system. These will create the platform for credible negotiations for gas supply agreements and ultimately the construction of a new gas-fired plant, or the conversion to gas in the case of Gaza. The Gas-for-Gaza Project led by the Office of the Quartet has focused its efforts in removing key obstacles for the construction of a gas pipeline from Israel to the GPP.

Second, pursue an aggressive program to promote the uptake of rooftop solar photovoltaics (PV). Unlike grid-based solar power, rooftop solar PV is highly decentralized and is not contingent on progress toward sector creditworthiness and the capacity of PETL. Moreover, it has been shown that rooftop solar PV can play a valuable role as an electricity safety net to increase the resilience of the Palestinian electricity system and ensure that critical humanitarian needs can be met. This is particularly true in the case of Gaza, where the World Bank will support a pilot rooftop solar PV project to reduce the high upfront capital expenditures for the customers and test the sustainability of a revolving fund model. In parallel, the French Development Agency is planning to launch a project-based on a financial intermediary model to support the scaling up of renewable energies.

Third, complete the domestic transmission backbone in Gaza. Domestic transmission constraints are already an issue in Gaza, and these will only become more severe as efforts to increase the supply of power bear fruit. It is therefore important to ensure that the modest transmission and distribution upgrades required are completed in a timely fashion, and certainly well ahead of any future expansion of GPP. The Gaza Electricity Network Rehabilitation Project, financed by the World Bank, has constructed or rehabilitated more than 250 kilometers of transmission and distribution lines in the Gaza Strip affected by past conflicts. But more needs to the done. Additional feasibility studies for the transmission and distribution lines to deliver the power to the end-consumer will, however, be required.

Fourth, improve the enabling environment for independent power projects. While the financial creditworthiness of the sector is the single largest impediment to the implementation of independent power projects, there are several other simple measures that could be taken to improve the quality of the enabling environment, and which could be handled through secondary legislation or executive regulations that develop broad provisions in the existing sector legislation. These include further clarifying the provisions for licensing new generators and the provisions associated with connection to the grid. The roles of PERC and PETL in this process also need to be further spelled out.

Fifth, establish a risk-mitigation mechanism to support the next generation of Palestinian independent power projects. Risk mitigation is no substitute for addressing the fundamental underlying creditworthiness issues in the sector, and it does not make sense to move ahead with risk mitigation until the Palestinian Authority has demonstrated a sustained and credible commitment to improving the financial standing of the sector. Nevertheless, once this has taken place, risk mitigation may play a valuable role in getting the next generation of Palestinian independent power projects off the ground. It would therefore be valuable to work with donors to develop a suitable mechanism for risk mitigation, evaluating the relevance of a range of financial instruments such as guarantees, first loss, blended finance, and viability gap finance.

PHASE 3: IMPLEMENT FIRST WAVE OF INDEPENDENT POWER PROJECTS

In a third phase, it will become possible to make progress with a major wave of Palestinian independent power projects. These will build on the critical foundational elements already tackled under the first two phases. It makes sense to begin with those projects that look to be the most tractable from a technical and political perspective, which suggests focusing on developing combined cycle gas turbine (CCGT) capacity and utility-scale solar PV in Areas A and B.

First, convert GPP to CCGT gas-fired technology as the most urgent of the domestic power-generation projects. Conversion of GPP to CCGT gas-fired technology once a gas pipeline comes on stream would save between US$45 million and US$62 million annually in fuel bills and provide Gaza with a cost-effective domestic source of power generation.

Second, proceed with the construction of a new CCGT gas-fired plant initially in Jenin, and eventually in Hebron. Once the gas transportation infrastructure is in place, and some improvements to the sector environment have been achieved, the implementation of the Jenin CCGT plant should be relatively straightforward. Guarantee products might be required to reduce the risk of nonpayment by the off-taker. Two important issues need to be addressed in the project design. One is the arrangements for selling any surplus energy back into the Israeli grid. The other is to ensure that the terms of a future gas supply agreement are sufficiently flexible to allow for an eventual switch of supply from the Gaza Marine gas field, should this prove to be desirable.

Third, embrace a more ambitious target for utility-scale solar PV farms in Areas A and B. As noted in the planning analysis, it looks feasible to develop over 600 MW of solar PV capacity in the West Bank based on potential in Areas A and B as well as rooftop. This goes far beyond the current target of 130 MW by 2020. With the improvements in the enabling environment in place, as well as the establishment of risk-mitigation mechanisms, it should become feasible to scale-up and accelerate efforts to develop this solar potential.

Fourth, establish suitable wheeling arrangements with Israel. As the volume of domestic power generation in the West Bank ramps up, there will be increasing need to move power away from generation plants toward Palestinian load centers. At present, this can be done only by wheeling power back through the Israeli grid and reimporting into the West Bank at another location. The analysis suggests that wheeling charges are relatively costly, particularly if low-voltage networks need to be used. It will therefore be important to ensure that the number of substations in the West Bank increases in such a way as to keep pace with the expansion of domestic supply. It would also be important to have dialogue with the Israeli regulator, Public Utility Authority, regarding the charges for wheeling, and to explore any possible alternative arrangements (such as power swaps) that may help to contain costs.

Fifth, engage in dialogue over the use of Area C for the development of Palestinian power infrastructure and renewable energy generation. The planning analysis highlights the economic value of Area C, both as a location for grid-based solar generation and as the conduit for any future Palestinian electricity transmission infrastructure. While there is much that still needs to be done before the issue of Area C becomes a binding constraint, the political complexity of the issue suggests that it may be helpful to begin a dialogue process that over time can help to clarify the modalities for making use of Area C. A related question is the need to coordinate Palestinian plans to ramp up renewable energy generation with those that also exist on the Israeli side, in order to ensure that challenges related to grid stability and the integration of intermittent sources can be adequately handled to the benefit of both sides.

PHASE 4: IMPLEMENT TRANSFORMATIONAL PROJECTS

The fourth and final phase would build on earlier success to tackle the more challenging, and potentially transformational, projects needed to complete the Palestinian energy vision. These include the construction of solar generation and transmission backbone infrastructure in Area C, as well as the development of the Gaza Marine gas field.

First, develop a Palestinian transmission backbone in the West Bank. The analysis has shown that as domestic Palestinian power generation ramps up, the cost of wheeling charges back through the Israeli grid rapidly become quite significant. A more economic option in the long term would be to construct a Palestinian transmission backbone.

Second, develop utility-scale solar PV and concentrated solar power projects in Area C of the West Bank. If a successful track record of solar farm development can be established on the more limited land endowments of Areas A and B, and suitable transmission backbone infrastructure can be put in place across Area C, the West Bank would be ready to benefit from larger scale solar development in Area C. This would entail both solar PV and concentrated solar power technologies.

Third, move ahead with the development of the Gaza Marine gas field. As noted, the development of the Gaza Marine gas field is critically dependent on having

TABLE III-5.1: INDICATIVE INVESTMENT NEEDS ASSOCIATED WITH THE PALESTINIAN ENERGY AGENDA (US$ MILLIONS)

	WEST BANK		GAZA		WEST BANK AND GAZA	
	PUBLIC	PRIVATE	PUBLIC	PRIVATE	PUBLIC	PRIVATE
Phase One	-	-	-	-	-	-
Phase Two	7[a]	800–1,100[b]	135[c]	240–320[d]	142	1,040–1,420
Phase Three		930[e]		900–990[f]	-	1,830–1,920
Phase Four	188[g]	375–500[h]	-	250–1,200[i]	188	620–1,700
Total	195	2,105–2,530	135	1,390–2,510	330	3,495–5,040

[a] Includes natural gas pipeline of 15 kilometers (km) for Jenin Power Plant (JPP).
[b] Includes 530 megawatt (MW) of rooftop in the West Bank, assuming cost of US$1,500–2,000 per kilowatt peak (kWp).
[c] Includes natural gas pipeline of maximum 20 km (section inside Gaza only) and upgraded transmission and distribution network capable of absorbing power from expanded Gaza Power Plant, Israeli Electric Corporation, and Egyptian supply options.
[d] Includes 160 MW of rooftop in the West Bank, assuming cost of US$1,500–2,000 per kWp.
[e] Includes JPP at 400 MW and Hebron Power Plant (HPP) at 120 MW, as well as 130 MW of renewable energy in Areas A and B.
[f] Includes GPP upgrade to 560 MW on natural gas in Gaza.
[g] Includes the West Bank transmission backbone and distribution grid upgrade assuming four new substations are active, JPP and HPP are online, access to area C is granted, and Jordanian connector is expanded.
h Includes 500 MW of utility-scale solar in Area C, assuming cost of US$750–1,000 per Watt-peak.
[i] Estimate of costs for development of Gaza Marine gas field.

a creditworthy off-taker to sign the gas purchase deal. Given the abundance of gas discoveries in the eastern Mediterranean and the relatively small nature of the field, the development of this field will likely need to be underwritten by a significant Palestinian demand for gas. For all the reasons described, this demand will take time to develop and would be achieved only once significant gas-fired power generation was on-stream and establishing a solid gas purchase payment record in both the West Bank and Gaza. That would be a suitable juncture at which to sign a bankable deal for the development of the field, allowing the Palestinian gas-fired plants to switch gradually from Israeli to Palestinian gas as the new field starts to become productive. Given the relatively small volume of Palestinian demand, it may make sense to consider the options for Gaza Marine development that require the least infrastructure development—by making use of stranded infrastructure from the Israeli Mari B field—thereby making the field economic at lower levels of throughput. Seen from this perspective, the primary value of the Gaza Marine field to the Palestinian economy lies not so much as a supply of gas, which is in any case abundantly available in the region, nor even as a source of energy security, since Palestinian gas would inevitably need to be transported through Israeli infrastructure. Rather it is an eventual source of fiscal revenues for the Palestinian Authority, estimated at US2.7 billion over 25 years.

CONCLUDING REMARKS

The implementation of this road map would require private investment of the order of NIS 13 billion to NIS 18 billion (US$3 billion to US$5 billion) complemented by public investment of around NIS 1 billion (US$0.3 billion). Table III-5.1 clarifies the indicative investment needs that would be required during each phase of the road map in the West Bank and Gaza. Of the total investment requirements of NIS 14 billion to NIS 20 billion (US$3.8 billion to US$5.4 billion), over 90 percent corresponds to the private sector, between 50 and 75 percent to the West Bank.

Progress in many of the areas identified will require continued and even deepened cooperation with Israeli institutions (table III-5.2). In every phase of the road map, progress depends on coordinated measures being taken on both the Palestinian and Israeli sides. Close coordination will be needed on both sides throughout the implementation process.

In conclusion, the analysis presented in this report has allowed numerous elements of a Palestinian energy vision to come into focus. It has also clarified what are the most immediate steps that need to be taken in support of that vision.

TABLE III-5.2: SUMMARY OVERVIEW OF THE PROPOSED ROAD MAP FOR PALESTINIAN ENERGY SECURITY

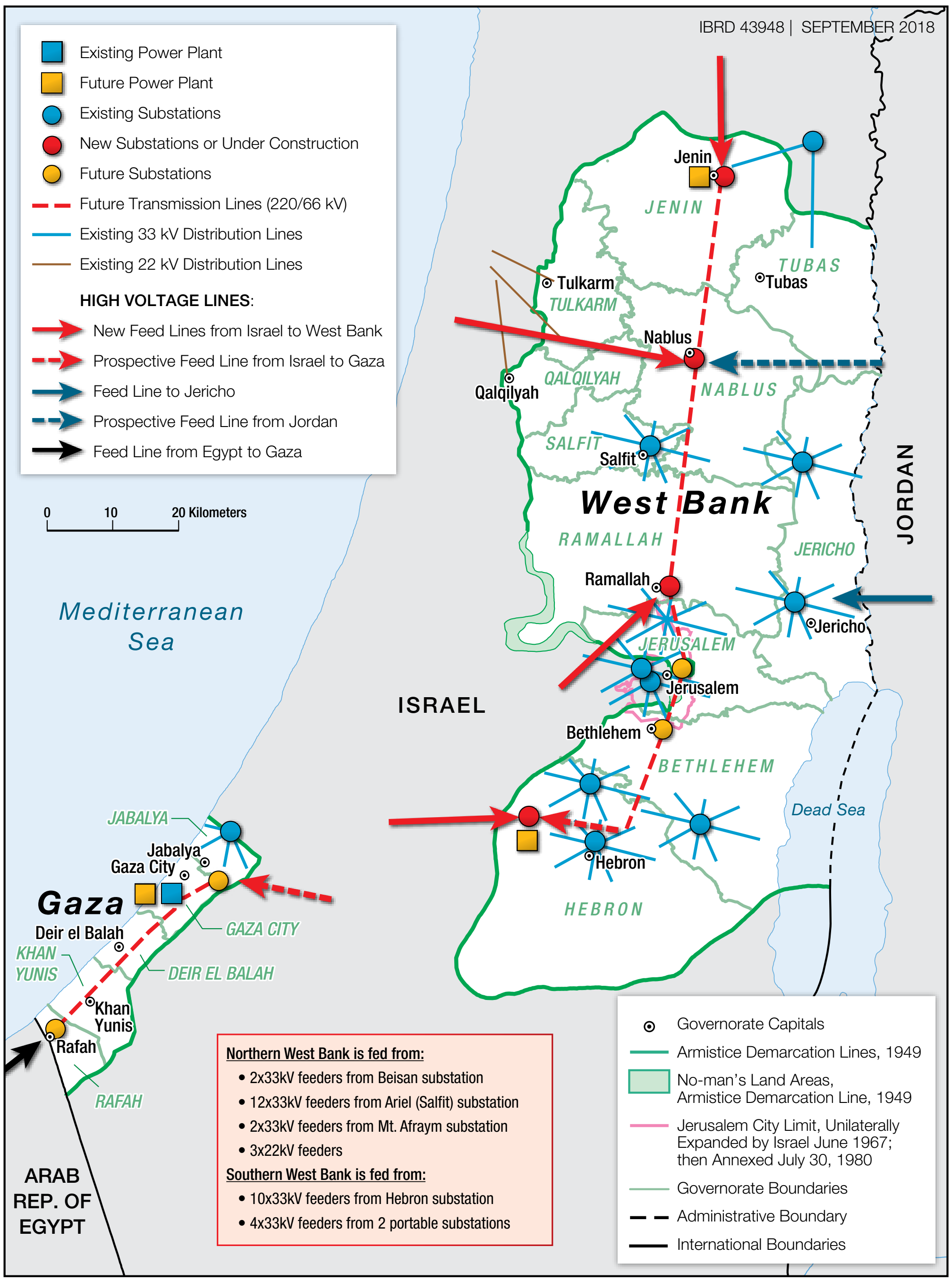
PHASE 1: IMPROVE SECTOR CREDITWORTHINESS	PHASE 2: ADVANCE PARALLEL NO REGRETS MEASURES
Substitute Israeli imports for diesel-fired generation in Gaza	**Create infrastructure for import of natural gas**
P : Gradually ramp down GPP and use the savings to buy additional IEC supply until GPP can be converted to gas. **I** : Provide additional power to Gaza through 161kV.	**P**, **I** : Construct natural gas pipelines for West Bank and Gaza paving the way for construction of new/upgraded power plants.
Improve operational and commercial efficiency	**Improve enabling environment for IPPs**
P : Continue improvement of DISCO performance by reducing losses, increasing collection rates and bringing down overhead costs. One mechanism can be through a revenue protection program aiming to permanently measure and bill every KWh sold largest DISCO consumers.	**P** : Update and improve legislation and licensing provisions that would help IPPs enter the market and also clarify roles and responsibilities of PERC and PETL in this environment.
Securitize payments of wholesale electricity	**Promote uptake of rooftop solar PV**
P : Strengthen sub national public finance to avoid diversion of electricity bill collections to municipal budgets and set up escrow accounts both in Gaza and West Bank to ring fence collections.	**P** : Set aggressive targets for 160MW of rooftop PV in Gaza and 530MW in West Bank.
Adjust tariffs to better reflect cost recovery	**Develop transmission backbone in Gaza**
P : Reexamine the retail tariffs and increase rates to allow better cost recovery by DISCOs.	**P** : Upgrade T&D network to allow increase in power supply and reduction in losses.
Build the capacity of PETL to play its role	**Design a risk mitigation mechanism for IPPs**
P : PETL to streamline billing to and payments from DISCOs while in parallel pushing to energize the new substations and sign the PPA with IEC. **I** : Sign bulk supply PPA and energize new substations.	**P**, **D** : After creditworthiness issues from Phase I have been improved, develop financial risk mitigation instruments such as guarantee mechanisms.

PHASE 3: IMPLEMENT FIRST WAVE OF IPPS	PHASE 4: IMPLEMENT TRANSFORMATIONAL PROJECTS
Convert GPP to CCGT gas-fired technology	**Develop grid-scale solar PV/CSP farms in Area C**
P : Complete conversion and upgrade of GPP ensuring flexible gas supply agreement to allow switch to Gaza Marine. **I** : Enter into gas supply agreement for GPP.	**P** : Begin development of renewables in Area C only after a successful track record of renewable development in Areas A and B. **I** : Provide permits for construction in Area C.
Construct new CCGT plant at Jenin, then Hebron	**Develop transmission backbone in the West Bank**
P : Complete JPP and HPP construction with flexible gas supply agreement to allow switch to Gaza Marine. Build additional substations to keep pace with increased domestic generation. **I** : Enter into gas supply agreement for JPP and HPP.	**P** : Begin development of a transmission backbone, considering also the possibility of negotiating a swap mechanism that eliminates the need for wheeling or building of infrastructure. **I** : Provide permits for construction in Area C and/or provide swap alternatives to building a backbone.
Increase renewable energy targets	**Develop Gaza Marine Gas Field**
P : Increase renewable energy targets to 600MW in West Bank and 160MW in Gaza by 2030 (includes rooftop solar) but only after the right enabling environment has been established from Phase I.	**P** : Develop Gaza Marine with least amount of infrastructure development to keep costs low. **I** : Allow permission to use existing Israeli infrastructure for evacuation of Gaza Marine.
Establish wheeling arrangements with IEC	
P, **I** : Negotiate lower wheeling tariffs and/or swap arrangements until a transmission backbone is built	
Engage in dialogue over use of Area C	
P, **I** : Coordinate on Area C access and permitting issues as well as grid stability and regional integration for supply expansion and transmission infrastructure.	

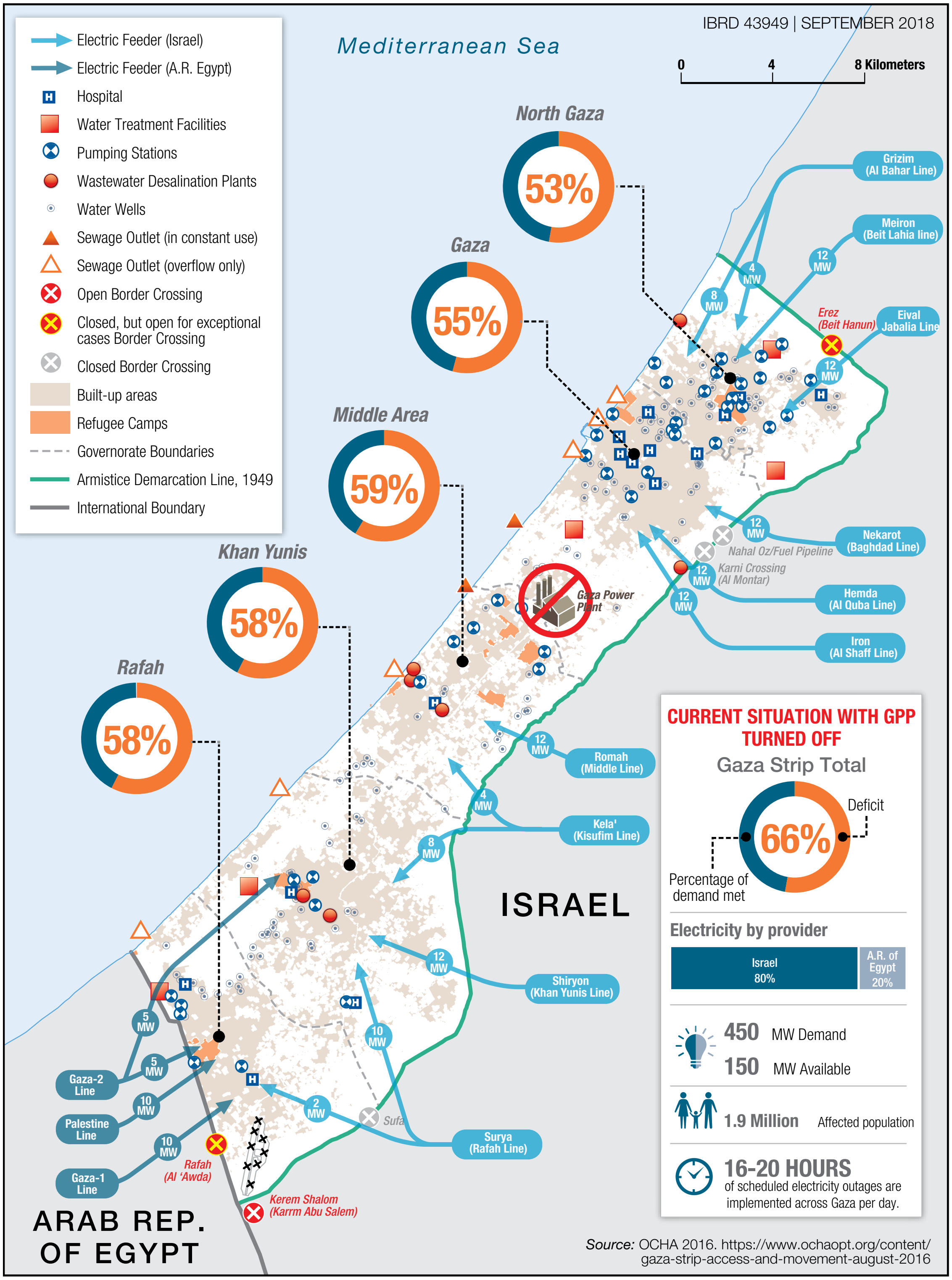
Appendix

APPENDIX A:
The Palestinian Electricity Sector

Map A.1: Electricity Supply System in the West Bank and Gaza



Map A.2: Power Supply to Gaza



Source: OCHA 2016. https://www.ochaopt.org/content/gaza-strip-access-and-movement-august-2016

TABLE A.1: PERC FLAT TARIFF STRUCTURE

SEGMENTS	2011	2012	2014	FEB ‘15	SEPT ‘15
Residential (postpaid): All West Bank except Jericho and Jordan Valley [NIS per kWh]					
1–160 kWh per month	1–100 kWh per month: 0.4085	0.465	0.490	0.441	0.437
161–250 kWh per month	101–200 kWh per month: 0.4546	0.510	0.528	0.475	0.471
251–400 kWh per month	Above 200kWh per month: 0.4795	0.590	0.635	0.572	0.543
401–600 kWh per month		0.620	0.665	0.600	0.581
Above 600 kWh		0.690	0.735	0.662	0.642
Fixed fees per day	0.333	0.333	0.333	0.333	0.333
Residential (prepaid): All West Bank except Jericho and Jordan Valley [NIS per kWh]					
Flat Rate (no segments)	0.467	0.520	0.565	0.500	0.475
Fixed fees per day	0	0	0	0	0
Residential (postpaid): Only Jericho and Jordan Valley [NIS per kWh]					
1- 500 kWh per month	NA	0.480	NA	0.450	0.428
Above 500 kWh per month	NA	0.520	NA	0.490	0.466
Residential (prepaid): Only Jericho and Jordan Valley [NIS per kWh]					
Flat rate (no segments)	NA	0.520	NA	0.475	0.451
Commercial (postpaid): Single and three-phase [NIS per kWh]					
Flat rate (no segments)	0.518	0.630	0.667	0.614	0.596
Fixed fees per day	0.667	0.667	0.667	0.667	0.667
Commercial (prepaid): Single and three-phase [NIS per kWh]					
Flat Rate (no segments)	0.508	0.600	0.637	0.586	0.568
Fixed fees per day	0.34	0	0	0	0
Industrial (low voltage): Less than 60 MWh consumption per month [NIS per kWh]					
Flat rate (no segments)	0.428	0.500	0.537	0.500	0.485
Fixed fees per day	1	1	1	1	1
Industrial (medium voltage: 6.6, 11, 33kV) [NIS per kWh]					
Flat rate (no segments)	0.399	0.450	0.487	0.440	0.414
Fixed fees per day	4	4	4	4	4
Industrial 2 (marble and stone) [NIS per kWh]					
Flat rate (no segments)	NA	NA	NA	0.54	0.5238
Water pump [NIS per kWh]					
Flat rate (no segments)	0.467	0.500	0.537	0.485	0.460
Fixed fees per day	1	1	1	1	1
Agriculture [NIS per kWh]					
Flat Rate (no segments)	0.409	0.460	0.497	0.448	0.440
Fixed fees per day	0.333	0.333	0.333	0.333	0.333
Street lights [NIS per kWh]					
Flat rate	0.407	0.466	0.503	0.453	0.450
Fixed fees per day	0.333	0.333	0.333	0.333	0.333
Temporary service (postpaid) [NIS per kWh]					
Flat rate	0.683	0.800	0.837	0.754	0.754
Fixed fees per day	0.667	0.667	0.667	0.667	0.667
Temporary service (prepaid) [NIS per kWh]					
Flat rate	0.683	0.800	0.837	0.754	0.754
Fixed fees per day	0.34	0.34	0.34	0	0

Note: The flat tariff is applied to residential, commercial, and industrial customers consuming less than 60 MWh per month.

TABLE A.2: PERC TIME OF USE (TOU) TARIFF STRUCTURE (NIS PER KWH)

LOW VOLTAGE (NIS PER KWH)

SEASON	TOU TARIFF CATEGORY	2015 ISRAEL TARIFF	2011 PA TARIFF	2012 PA TARIFF	FEB 2015 PA TARIFF	SEPT 2015 PA TARIFF
Winter	Rate-A (off-peak)	0.3802	0.3055	0.4364	0.4283	0.4010
	Rate-B (mid-peak)	0.6035	0.5648	0.7541	0.6798	0.6263
	Rate-C (peak)	1.0052	0.9774	1.2859	1.1323	1.0283
Spring and autumn	Rate-A (off-peak)	0.3304	0.2697	0.3826	0.3722	0.3602
	Rate-B (mid-peak)	0.409	0.3408	0.4776	0.4607	0.4400
	Rate-C (peak)	0.503	0.4259	0.5914	0.5666	0.5303
Summer	Rate-A (off-peak)	0.3441	0.2756	0.3955	0.3876	0.3767
	Rate-B (mid-peak)	0.4964	0.4453	0.6026	0.5591	0.5408
	Rate-C (peak)	1.1466	1.0792	1.4105	1.2915	1.1894

MEDIUM VOLTAGE (NIS PER KWH)

SEASON	TOU TARIFF CATEGORY	TARIFF ISL 2015 [6]	2011 PA TARIFF [4]	2012 PA TARIFF [3]	FEB 2015 PA TARIFF [2]	SEPT 2015 PA TARIFF [1]
Winter	Rate-A (off-peak)	0.3014	0.2684	0.3642	0.3395	0.3149
	Rate-B (mid-peak)	0.513	0.5165	0.6667	0.5778	0.5285
	Rate-C (peak)	0.8796	0.8963	1.1583	0.9908	0.8939
Spring and autumn	Rate-A (off-peak)	0.2556	0.2355	0.3147	0.2879	0.2780
	Rate-B (mid-peak)	0.3259	0.2996	0.4007	0.3671	0.3491
	Rate-C (peak)	0.4141	0.3795	0.5078	0.4664	0.4336
summer	Rate-A (off-peak)	0.2639	0.2367	0.3220	0.2973	0.2886
	Rate-B (mid-peak)	0.3997	0.3905	0.5108	0.4502	0.4349
	Rate-C (peak)	0.9993	0.9772	1.2627	1.1256	1.0305

Note: The TOU tariff is applied to Industrial customers consuming less than 60 MWh per month.

TABLE A.3: JDECO BALANCE SHEETS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014	2015
Current assets					
Accounts receivable	511,543,102	592,638,906	759,513,337	912,051,741	994,313,285
Cash and cash equivalents	66,731,355	78,507,761	89,072,998	81,999,095	76,013,661
Asset inventory in warehouse	50,328,765	32,279,908	41,059,610	46,348,215	45,437,813
Work under implementation	147,115,720	236,841,628	NA	NA	NA
Other current assets	3,493,216	7,661,401	18,406,544	15,083,321	10,010,723
Total current assets	779,212,158	947,929,604	908,052,489	1,055,482,372	1,125,775,482
Noncurrent assets					
Property plant and equipment	327,291,487	361,827,870	415,044,614	627,740,662	715,900,801
Projects under construction	NA	NA	257,407,020	108,497,147	128,373,720
Intangible assets	50,000	50,000	50,000	50,000	50,000
Other noncurrent assets	7,130,789	22,717,324	32,248,657	43,470,784	46,554,248
Total noncurrent assets	334,472,276	384,595,194	704,750,291	779,758,593	890,878,769
Total assets	1,113,684,434	1,332,524,798	1,612,802,780	1,835,240,965	2,016,654,251
Current liabilities					
Accounts payable	285,831,913	441,908,286	881,953,033	1,027,225,379	1,255,331,424
Other current liabilities	115,593,048	116,281,908	132,567,633	139,247,227	143,390,312
Total current liabilities	401,424,961	558,190,194	1,014,520,666	1,166,472,606	1,398,721,736
Noncurrent liabilities					
Long term loans	192,511,116	152,496,471	117,087,630	92,051,231	68,657,070
Provision for end of service	67,999,128	68,395,500	86,197,324	81,978,304	89,250,091
Deferred revenue	127,381,058	179,957,470	114,982,955	118,558,214	130,182,770
Other allocation reserves	3,586,600	3,586,600	3,586,600	3,586,600	5,086,600
Total noncurrent liabilities	391,477,902	404,436,041	321,854,509	296,174,349	293,176,531
Equity					
Paid up capital	178,875,000	178,875,000	178,875,000	178,875,000	178,875,000
Treasury shares	-3,879,311	-7,666,691	-1,486,709	-3,622,230	-3,622,230
Statutory reserve	9,187,500	9,187,500	9,187,500	9,187,500	9,187,500
Revaluation reserve	86,962,931	69,570,345	53,716,168	33,576,949	67,683,536
Retained earnings	49,635,451	119,932,409	36,135,646	154,576,791	72,632,178
Total equity	320,781,571	369,898,563	276,427,605	372,594,010	324,755,984
Total liabilities and equity	1,113,684,434	1,332,524,798	1,612,802,780	1,835,240,965	2,016,654,251

Source: 2011–15 JDECO annual reports (all years audited by Price Waterhouse Coopers (PWC).

TABLE A.4: JDECO INCOME STATEMENTS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014	2015
Operating income					
Electricity sales (billed)	694,862,965	875,140,233	888,860,424	950,714,795	949,052,263
Purchased electricity	-562,555,632	-800,261,437	-831,806,133	-886,356,917	-871,483,182
Gross Profit from sales	132,307,333	74,878,796	57,054,291	64,357,878	77,569,081
Subscriber's contribution to extension of services	35,149,206	22,703,391	68,183,242	54,921,120	55,149,003
Revenue from services	9,828,978	7,166,019	9,646,416	11,571,609	10,182,591
Total operating income	177,285,517	104,748,206	134,883,949	130,850,607	142,900,675
Operating expenses					
General and administrative expenses	-145,790,757	-148,425,865	-162,865,171	-171,517,383	-187,635,103
Depreciation expenses	-23,871,283	-21,160,451	-19,752,101	-29,677,585	-36,690,360
Provision for doubtful receivables	NA	NA	-2,378,492	-2,245,586	-4,000,000
Provision for obsolete or damaged goods	NA	NA	-1,508,245	-1,508,245	-1,815,124
Total operating expenses	-169,662,040	-169,586,316	-186,504,009	-204,948,799	-230,140,587
Net Income or losses before other income and expenses	7,623,477	-64,838,110	-51,620,060	-74,098,192	-87,239,912
Financing expenses	-21,769,450	-33,838,017	-28,076,247	15,225,873	10,827,836
Other income	8,993,026	27,270,860	4,725,648	5,217,910	2,191,500
Annual income or loss before income tax	-5,152,947	-71,405,267	-74,970,659	-53,654,409	-74,220,576
Income tax expense	-2,589,440	0	0	-2,791,446	-7,658,068
Annual income or loss	-7,742,387	-71,405,267	-74,970,659	-56,445,855	-81,878,644

Source: 2011–15 JDECO annual reports (all years audited by PWC).

TABLE A.5: SELCO BALANCE SHEETS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014	2015
Current assets					
Cash and cash equivalents	3,183,063	9,114,211	5,435,813	16,670,961	11,389,588
Checks under collection	4,381,660	6,607,877	5,379,639	2,308,503	4,388,066
Stakeholders net receivables	128,539,580	142,283,171	158,385,189	205,881,442	218,715,066
Inventories	42,268,623	38,112,171	30,555,028	33,265,776	27,559,593
Prepaid payments and debit balances	4,403,698	5,548,385	9,511,609	13,917,083	23,312,365
Total current assets	182,776,624	201,665,815	209,267,278	272,043,765	285,364,678
Noncurrent Assets					
Beit Ummar Municipality	6,892,635	6,892,635	6,892,635	6,892,635	6,892,635
Net fixed assets	86,856,645	107,515,454	107,259,124	108,602,044	138,986,851
Work-in-progress	13,109,462	526,611	4,385,403	9,405,428	0
Other	0	0	0	1,602,317	3,382,006
Total noncurrent assets	106,858,742	114,934,700	118,537,162	126,502,424	149,261,492
Total assets	289,635,366	316,600,515	327,804,440	398,546,189	434,626,170
Current liabilities					
Accounts payable	11,928,801	5,054,300	15,598,036	16,196,681	37,843,068
Other current liabilities	7,671,467	10,503,416	11,557,674	17,974,835	18,323,477
Total current liabilities	19,600,268	15,557,716	27,155,710	34,171,516	56,166,545
Long-term liabilities					
Long-term loans	78,142,027	84,069,134	82,815,894	83,084,752	83,015,967
Severance allowances	2,817,115	3,334,956	4,695,549	4,646,758	5,563,625
Ministry of Finance	179,409,815	223,048,447	257,816,215	325,136,253	333,309,386
Total long-term liabilities	260,368,957	310,452,537	345,327,658	412,867,763	421,888,978
Total liabilities	279,969,225	326,010,253	372,483,368	447,039,279	478,055,523
Equities					
Paid-in capital	44,250	44,250	44,250	44,250	44,250
Statutory reserve	44,250	44,250	44,250	44,250	44,250
Voluntary reserve	1,869,495	1,869,495	1,869,495	1,869,495	1,869,495
Stakeholders receivables	-31,065,858	-40,474,211	-57,391,364	-46,594,927	-61,433,602
Shareholders current account	41,522,376	41,522,376	41,522,376	41,522,376	41,522,376
Accumulative (loss) – Statement B	-2,748,372	-12,416,014	-30,767,935	-45,378,534	-25,476,122
Net equities	9,666,141	-9,409,854	-44,678,928	-48,493,090	-43,429,353
Total liabilities and equities	289,635,366	316,600,399	327,804,440	398,546,189	434,626,170

Source: SELCO financial statements, 2011–13 audited by Talal Abu Gazaleh, but 2014–15 draft or unaudited. form.

TABLE A.6: SELCO INCOME STATEMENTS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014	2015
Revenues					
Electricity sales plus discount	48,333,776	55,906,513	53,766,667	76,048,100	67,230,123
Electricity purchase	-42,969,409	-54,065,475	-52,664,853	-70,714,130	-48,869,845
Operating expenses (wages, rents, salaries, maintenance)	-4,024,643	-5,046,172	-8,078,247	-8,251,986	-11,083,814
Installation services revenues	1,537,144	2,743,024	2,442,701	2,178,763	867,314
Other operating revenues	3,424,981	1,205,492	1,293,851	1,171,357	4,758,443
Total profit (loss)	6,301,849	743,382	-3,239,881	432,104	12,902,221
Contributions in kind	131,826	300,269	-	623,738	4,021,210
Currency differential	-3,588,404	862,298	2,585,184	-39,483	-249,711
Total profit (loss) before administrative and general expenses	2,845,271	1,905,949	-654,697	1,016,359	16,673,720
Expenses					
Administrative, general, and operating expenses	-4,009,067	-4,216,934	-10,058,292	-6,555,902	-7,412,130
Other expenses	2,180,286	1,566,260	1,914,811	347,531	6,909,898
Allowance	-4,928,673	-5,493,227	-6,801,094	-7,145,739	-7,115,438
Financing costs	-1,574,845	-2,233,066	-2,387,574	-1,933,661	-3,185,965
The provision for doubtful debts	-502,135	-1,196,624	-340,034	-339,187	-222,797
Total expenses	-8,834,434	-11,573,591	-17,672,183	-15,626,958	-11,026,432
Net income or loss of the year	-5,989,163	-9,667,642	-18,326,880	-14,610,599	5,647,288
Accumulative (loss) at the beginning of the year	2,225,724	-2,748,372	-12,416,014	-30,767,935	-45,378,534
Prior-years' adjustments	-19,203	-	-25,041	0	14,255,124
Net accumulative (loss) at the end of the year – Statement A	-3,782,642	-12,416,014	-30,767,935	-45,378,534	-25,476,122

Source: SELCO financial statements, 2011–13 audited by Talal Abu Gazaleh, but 2014–15 in draft or unaudited form.

TABLE A.7: HEPCO BALANCE SHEETS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014	2015
Current assets					
Cash and cash equivalent	10,542,073	13,424,893	13,090,423	2,947,436	5,782,708
Checks under collection–short term	5,510,679	6,152,219	7,967,833	9,876,538	9,387,145
Accounts receivables–net	294,580,488	339,491,140	401,093,998	389,259,352	382,332,268
Inventory	28,680,295	39,868,393	30,765,489	30,762,287	29,994,661
Other current assets	3,073,656	357618	1,321,385	8,942,093	5,902,513
Hebron municipality current account	133,858,383	153,102,568	187,741,096	225,874,663	270,649,990
Total current assets	476,245,574	552,396,831	641,980,224	667,662,369	704,049,285
Long-term assets					
Checks under collection–long term	1,423,064	1,364,601	3,007,089	6,761,154	11,181,157
Work in process	0	10537049	19,480,450	2,776,993	7,290,115
Properties, fixed assets NBV	128,520,429	127,103,039	126,096,754	142,789,491	137,973,496
Concession rights	30,444,000	30,444,000	30,444,000	30,444,000	30,444,000
Total long-term assets	160,387,493	169,448,689	179,028,293	182,771,638	186,888,768
Total assets	636,633,067	721,845,520	821,008,517	850,434,007	890,938,053
Liabilities and owner's equity					
Current liabilities					
World Bank loan–short term	661,915	686,135	1,029,203	1,805,633	3,419,999
Accounts payable plus outstanding	466,273,583	555,898,298	650,710,732	626,763,044	651,371,638
Unearned revenue	4,526,352	5,960,690	1,705,579	10,422,151	11,022,622
Other current liabilities	1,559,105	3,785,656	3,467,256	2,035,616	11898610
Total current liabilities	473,020,955	566,330,779	656,912,770	641,026,444	677,712,869
Long-term liabilities					
Employees end of service benefit	3,596,685	4,364,141	5,248,868	5,163,790	7,014,518
World Bank loan–long term	9,381,319	8,640,322	8,299,574	7,181,005	6,450,622
Deferred revenues–grants and in-kind	6,822,433	10,334,784	20,864,471	23,974,775	25,285,153
Total long-term liabilities	19,800,437	23,339,247	34,412,913	36,319,570	38,750,293
Total liabilities	492,821,392	589,670,026	691,325,683	677,346,014	716,463,162
Owner's equity Hebron municipality					
paid in capital	152,745,000	152,745,000	152,745,000	152,745,000	152,745,000
Prior period adjustments–VAT Reconciliation				-4,303,468	NA
Prior period adjustments	-8,933,325	-20,569,506	-2,062,166	-8,339,560	-5,448,532
Prior period adjustments–MoF reconciliation				41,222,720	41,222,720
Accumulated losses				-8,236,760	-14,044,297
Total owner's equity	143,811,675	132,175,494	129,682,834	173,087,932	174,474,891
Total liabilities and owner's equity	636,633,067	721,845,520	821,008,517	850,433,946	890,938,053

Source: HEPCO annual reports (financial statements not audited)

TABLE A.8: HEPCO INCOME STATEMENTS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2,014	2015
Revenues					
Electricity sales	144,250,785	159,362,877	171,194,239	179,775,466	183,560,826
Add: Tariff differences	9,352,890	21,979,208	9,700,234	9,854,794	9,612,348
Add: Fixed charges	NA	NA	NA	2,991,710	NA
Deduct: Cost of electricity purchased	-136,354,132	-159,809,793	-170,222,657	-175,900,386	-163,700,004
Gross profit	17,249,543	21,532,292	10,671,816	16,721,584	29,473,170
Other income					
Customer participations	4,247,980	1,596,640	2,165,075	2,640,750	6,896,943
Other operating revenues	8,704,419	10,570,952	13,004,102	11,546,126	7,922,121
Accrued of deferred revenues	758,048	583,833	600,000	795,173	800,000
Total other income	13,710,447	12,751,425	15,769,177	14,982,049	15,619,064
Total operating income	30,959,990	34,283,717	26,440,993	31,703,633	45,092,234
Expenses					
Operating expenses	-1,476,263	-3,067,033	-2,841,731	-1,829,166	-2,722,492
General and administrative expenses	-1,366,052	-1,878,389	-2,706,498	-1,469,510	-1,346,796
Payroll expenses	-10,037,633	-12,013,416	-12,983,957	-11,912,764	-12,358,333
Depreciation	-9,002,162	-8,797,369	-9,207,810	-10,251,450	-9,762,652
Community Municipality of Hebron contributions	NA	-231,614	-178,414	NA	-853,424
Loan interest expense	-105,696	NA	NA	NA	-195,000
World Bank loan	NA	NA	NA	-170,000	NA
Currency differential loss	-539,704	-120,016	-15,243	-100,000	-100,000
Bad debt expenses or doubtful receivables	-1,000,000	-11,472,400	-1,000,000	-3,000,000	-6,000,000
Net book value of assets disposed	NA	NA	NA	NA	-1,000,000
Other	NA	NA	NA	-927,688	NA
Total operating expenses	-23,527,510	-37,580,237	-28,933,653	-29,660,578	-34,338,697
Net income	7,432,480	-3,296,520	-2,492,660	2,043,055	10,753,537

Source: HEPCO annual reports (financial statements not audited).

TABLE A.9: GEDCO BALANCE SHEET (IN NIS EXCLUDING VAT)

	2014	2015
Assets		
Current assets		
Cash and cash equivalents	6,389,609	2,197,965
Customers' receivables	3,545,123,306	3,743,707,146
Materials and supplies in warehouses	14,635,146	24,182,036
Partners current accounts (municipalities)	370,615,454	399,610,375
Receivables and other current assets	14,697,288	35,880,987
Total current assets	3,951,460,803	4,205,578,509
Noncurrent Assets		
Financial assets at fair value	413,478	484,398
Property, plant, and equipment, net	116,354,190	122,062,881
Projects in progress	4,374,270	10,707,531
Total noncurrent assets	121,141,938	133,254,810
Total assets	4,072,602,741	4,338,833,319
Liabilities and shareholders' equity		
Current liabilities		
Payables and other liabilities	103,218,121	128,883,852
Banks overdraft	0	13,195,769
Total current liabilities	103,218,121	142,079,621
Noncurrent liabilities		
Palestinian National Authority (PNA)	3,978,060,454	4,208,767,055
Canal Company for Electricity Distribution (Egypt)	100,122,920	151,475,280
Deferred revenues	80,043,837	97,539,206
Sundry provisions	59,569,735	61,649,421
Total noncurrent liabilities	4,217,796,946	4,519,430,962
Total liabilities	4,321,015,067	4,661,510,583
Shareholders' equity		
In-kind capital (electricity distribution network)	149,280,948	149,280,948
Revaluation reserve–electricity network	50,011,980	50,0 11,980
Cumulative change in fair value	6,030	76,950
Deferred losses	-1,156,470,721	-447,711,284
This year loss or profit–exhibit (B)	708,759,437	-74,335,858
Net shareholders' equity	-248,412,326	-322,677,264
Total liabilities and shareholders' equity	4,072 1 602,741	4,338,833,319

Source: GEDCO financial statements (unaudited).

TABLE A.10: GEDCO INCOME STATEMENT (IN NIS EXCLUDING VAT)

	2014	2015
Operating revenues from billed sales	509,181,596	517,553,841
Cost of Sale		
Cost of energy sold	-383,614,843	-406,186,153
Energy lost (not billed)	-127,853,756	-126,671,379
Operating expenses	-3,299,263	-5,540,937
Total cost of sale	-514,767,862	-538,398,469
Gross profit	-5,586,266	-20,844,628
Deduct		
Depreciation of electricity network	-12,500,915	-13,152,821
Staff costs	-40,490,490	-44,020,905
General and administrative expenses	-13,817,427	-13,678,708
Losses aggression	-35,188,472	-18,726
	-101,997,304	-70,871,160
Add		
Realized grants and cash donations	1,507,955	1,191,189
Realized grants and in-kind donations	17,707,847	5,535,508
Other revenues	2,882,112	3,823,384
	22,097,914	10,550,081
Loss for the year from activities	-85,485,656	-81,165,707
Other items		
Prior years' adjustments	794,245,093	6,829,849
Total other items	794,245,093	6,829,849
This year loss or profit–exhibit (A)	708,759,437	-74,335,858

Source: GEDCO financial statements (unaudited).

TABLE A.11: NEDCO BALANCE SHEETS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014
Current assets				
Accounts receivable	48,714,506	97,809,318	142,280,736	128,961,956
Cash on hand at banks	11,223,360	24,619,157	23,092,885	23,137,898
Dues from municipal and village councils	NA	56,036,239	80,236,793	70,964,603
Other current assets	52,200,611	22,194,384	37,580,642	19,153,316
Total current assets	112,138,477	200,659,098	283,191,056	242,217,773
Noncurrent assets				
Property and equipment	230,296,617	253,445,831	258,628,054	261,864,378
Projects under construction	NA	1,037,694	691,256	3,331,636
Stock items	NA	22,683,775	28,566,280	25,916,981
Total noncurrent assets	230,296,617	277,167,300	287,885,590	291,112,995
Total assets	342,435,094	477,826,398	571,076,646	533,330,768
Current liabilities				
Accounts payable	31,620,495	18,117,173	64,573,004	70,652,834
Other current liabilities	76,439,237	185,617,359	219,583,341	170,255,539
Total current liabilities	108,059,732	203,734,532	284,156,345	240,908,373
Noncurrent liabilities				
Provision for end of service	1,230,496	2,641,153	4,188,232	6,109,462
Deferred earnings	NA	33,786,138	37,921,059	39,528,711
Other noncurrent liabilities	300,700	NA	NA	NA
Total noncurrent liabilities	1,531,196	36,427,291	42,109,291	45,638,173
Equity				
Paid-up capital	15,251,594	17,231,440	17,231,440	17,231,440
Shareholder accounts	204,698,552	208,832,878	208,932,490	209,415,550
Statutory reserve	1,289,402	2,191,547	2,896,229	3,766,961
Optional reserve	1,289,402	2,191,547	2,896,229	3,766,961
Retained earnings	10,315,216	7,217,163	12,854,622	12,603,310
Total equity	232,844,166	237,664,575	244,811,010	246,784,222
Total liabilities and equity	342,435,094	477,826,398	571,076,646	533,330,768

Source: NEDCO financial statements audited by Ernst and Young (2015 financial statements not available).

TABLE A.12: NEDCO INCOME STATEMENTS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014
Operating income				
Electricity sales (billed) plus subscriptions plus services, etc.	188,881,771	225,555,641	254,389,364	260,922,894
Electricity purchases plus salaries and wages plus depreciation	-178,567,444	-199,879,476	-229,675,461	-249,814,659
Gross profit per operating Income	10,314,327	25,676,165	24,713,903	11,108,235
Operating expenses				
General and administrative expenses	-10,119,348	-17,066,283	-12,359,573	-12,741,808
Depreciation	-723,176	-1,889,580	-1,697,289	-1,508,697
Provision for doubtful receivables	-795,182	1,269,174	-792,774	-5,422,052
Other expenses	-300,700	NA	NA	NA
Total operating expenses	-11,938,406	-17,686,689	-14,849,636	-19,672,557
Net income or losses before other income and expenses	-1,624,079	7,989,476	9,864,267	-8,564,322
Revenue settlement with MoF	0	0	0	24,865,770
Grant from PENRA	1,804,535	NA	NA	NA
Other income	310,568	2,916,473	1,878,699	-841,050
Annual profit before income taxes	491,024	10,905,949	11,742,966	15,460,398
Income tax expenses	-399,893	-1,884,496	-4,696,143	-6,753,083
Annual profit after income tax	91,131	9,021,453	7,046,823	8,707,315

Source: NEDCO financial statements audited by Ernst and Young (2015 financial statements not available).

TABLE A.13: TEDCO BALANCE SHEETS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014	2015
Current assets					
Cash in bank	4,569,288	5,633,391	6,586,378	35,731,934	3,670,399
Checks	0	1,016,042	1,152,079	1,842,673	3,021,252
Accounts receivable	18,974,046	22,267,521	25,261,915	33,723,803	40,106,657
Other receivables	3,980,653	7,003,961	16,088,166	27,497,055	14,732,989
Accessories and spare parts in warehouse	809,865	1,535,601	1,488,859	1,669,365	1,959,394
Prepaid expenses	141,785	164,227	166,001	225,038	186,853
Total current assets	28,475,637	37,620,743	50,743,398	100,689,868	63,677,544
Fixed assets	20,849,458	22,975,233	24,146,557	25,764,776	28,768,289
Fixed asset consumption	-6,723,629	-7,846,018	-9,030,484	-10,132,413	-11,451,747
Net fixed assets	14,125,829	15,129,215	15,116,073	15,632,363	17,316,542
Total assets	42,601,466	52,749,958	65,859,471	116,322,231	80,994,086
Liabilities and equity					
Accounts payable	11,608,119	30,917,332	43,164,091	92,984,000	55,848,851
Other payables	9,498,750	0	1,712,992	1,931,121	0
Due payments	7,133	1,202,011	41,373	5,500	9,500
Income tax provision	65,103	65,103	65,103	65,103	572,664
Other provisions	524,622	755,152	956,586	1,237,181	1,611,351
Total liabilities	21,703,727	32,939,598	45,940,145	96,222,905	58,042,366
Capital	15,361,808	15,361,808	15,361,808	15,361,808	15,361,808
Capital reserve	5,374,958	5,374,958	5,374,958	5,374,958	5,374,958
Legal per statutory reserve	481,660	481,660	481,660	510,557	795,796
Earning from previous years	663,091	0	0	0	0
Losses	0	-320,687	-1,408,066	-1,309,997	-1,147,997
Net loss for the year	-983,778	-1,087,379	108,966	162,000	2,567,155
Total equity	20,897,739	19,810,360	19,919,326	20,099,326	22,951,720
Total liabilities and equity	42,601,466	52,749,958	65,859,471	116,322,231	80,994,086

Source: TEDCO financial statements audited by Jamal Abu Farha.

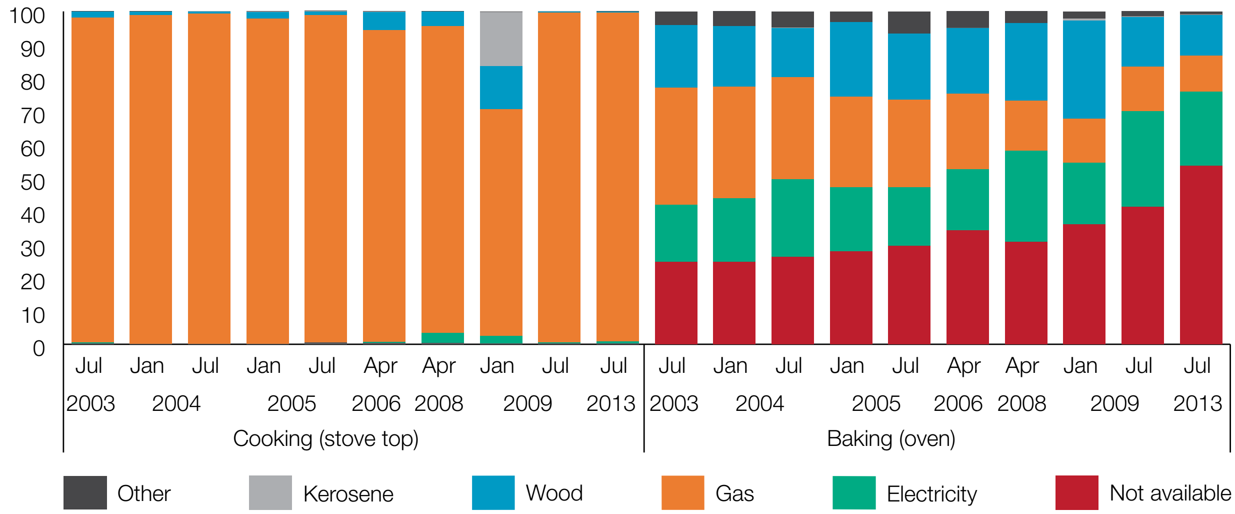
TABLE A.14: TEDCO INCOME STATEMENTS (IN NIS EXCLUDING VAT)

	2011	2012	2013	2014	2015
Revenues					
Electricity sales–prepaid			17,539,822	20,048,480	21,065,333
Electricity sales–mechanical counters	29,751,149	34,608,924	7,916,514	11,280,770	10,736,612
Electricity sales–medium voltage			12,124,651	13,012,333	13,374,891
Electricity sales–street lighting			1,135,804	1,228,366	1,045,340
Electricity purchases	-26,771,696	-33,147,964	-38,208,786	-44,740,672	-42,342,607
Gross profit electricity sales	2,979,453	1,460,960	508,005	829,277	3,879,569
Other revenues					
Revenue from miscellaneous services	0	2,163,512	1,696,691	3,118,616	3,610,845
Government support for electricity production (subsidy)	0	0	2,976,902	2,472,444	2,821,416
Income from transformer maintenance center	346,075	825,730	801,657	773,759	1,206,323
Total other revenues	346,075	2,989,242	5,475,250	6,364,819	7,638,584
Expenses					
Operating expenses	-2,781,780	-3,159,127	-3,210,182	-3,985,514	-4,801,092
General and administrative expenses	-887,262	-1,768,156	-1,906,374	-2,305,516	-2,561,213
Transformer main center expenses	-640,264	-610,298	-757,733	-723,066	-730,790
Total expenses	-4,309,306	-5,537,581	-5,874,289	-7,014,096	-8,093,095
Net profit from transformer maintenance center	-294,189	215,432	43,924	50,693	475,533
Total profit from electricity sales (not including transfer maintenance center)	-689,589	-1,302,811	65,042	129,307	2,949,525
Total net profit (including transfer maintenance center)	-983,778	-1,087,379	108,966	180,000	3,425,058
Income tax	0	0	16,345	38,000	572,664
Statutory reserve–10%	0	0	10,897	18,000	285,239
Net profit after taxes and reserves	0	0	81,724	124,000	2,567,155

Source: TEDCO financial statements audited by Jamal Abu Farha.

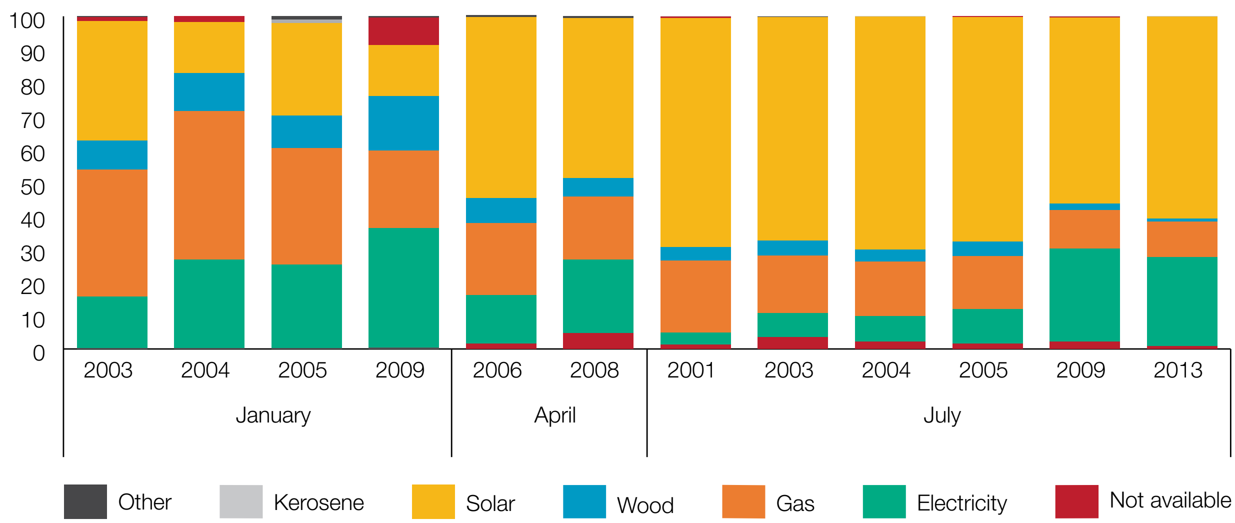
APPENDIX B:
Electricity Demand

Figure B.1: Shifting Patterns of Energy Usage for Cooking and Baking (percentage of households)



Source: Palestinian Central Bureau of Statics (PCBS,) Household Energy Surveys, 2003–13.

Figure B.2: Shifting Patterns of Energy Usage for Water Heating (percentage of households)



Source: PCBS, Household Energy Surveys, 2001–13.

TABLE B.1: ELECTRICITY CONSUMPTION REGRESSION MODEL RESULTS FOR THE SUMMER SEASON

INDEPENDENT VARIABLE	OBSERVATIONS	R-SQUARE	
Household grid electricity consumption, July	14,001	0.16	
VARIABLE	**COEFFICIENT**	**STANDARD ERROR**	**T-STATISTIC**
Gaza region dummy	191.9	28.8	6.7
North West Bank region dummy	183.8	28.1	6.5
Mid West Bank region dummy	344.3	28.8	12.0
South West Bank region dummy	211.1	28.6	7.4
Ownership of electric air conditioner	108.5	9.8	11.1
Ownership of electric fan	53.6	14.8	3.6
Ownership of solar heater	27.7	4.1	6.7
Main cooking fuel is electricity	10.9	38.5	0.3
Main baking fuel is electricity	-2.3	3.9	-0.6
Main water heating fuel is electricity	41.7	6.0	7.0
Ownership of electric generator	-20.0	13.5	-1.5

TABLE B.2: ELECTRICITY CONSUMPTION REGRESSION MODEL RESULTS FOR THE WINTER SEASON

INDEPENDENT VARIABLE	OBSERVATIONS	R-SQUARE	
Household grid electricity consumption, January	6,733	0.20	
VARIABLE	**COEFFICIENT**	**STANDARD ERROR**	**T-STATISTIC**
Gaza region dummy	239.4	22.5	10.6
North West Bank region dummy	217.7	23.5	9.3
Mid West Bank region dummy	329.8	24.9	13.2
South West Bank region dummy	268.7	23.5	11.4
Ownership of electrical heater	51.3	4.9	10.5
Ownership of solar water heater	26.4	3.5	7.6
Main cooking fuel is electricity	9.8	21.6	0.5
Main baking fuel is electricity	4.8	5.4	0.9
Main water heating fuel is electricity	67.5	5.2	13.1
Ownership of electric generator	-45.9	10.9	-4.2

TABLE B.3: EXISTING AND FORECAST ELECTRICITY NEEDS OF THE WATER AND WASTEWATER SECTOR IN GAZA

WATER/WASTEWATER FACILITY	2014	2017	2018	2020	2025	2030	2035
North Gaza WWTP (NGEST) component							
Terminal pumping station	2	1	1	2	2	3	3
Waste water treatment plant	2	2	2	3	4	5	5
Recovery and reuse scheme phase 1		2	2	3	3	4	5
Recovery and reuse scheme phase 2		3	3	4	5	5	6
NGEST total	4	8	9	11	14	17	19
Planned central Gaza WWTP (KFW)			7	7	8	11	13
Khanyounis WWTP			2	2	3	5	6
Rafah existing WWTP		1	2	2	2	2	3
Gaza existing WWTP (shikh Ejleen)	5			3	3	3	3
Central desalination plant			35	35	35	55	55
Deiralbalah desalination plant		1	1	1	2	2	2
Gaza desalinization plant		3	3	3	3	3	3
Existing W and WW facilities	25	33	30	30	30	30	30
Total Gaza governorates energy required for water and wastewater facilities	34	46	87	93	99	127	134

Note: WWTP = wastewater treatment plant. NGEST = Northern Gaza Emergency Sewage Treatment. KFW = Kreditanstalt für Wiederaufbau.

APPENDIX C:

Importing Electricity from Israel

TABLE C.1: ELECTRICITY GENERATION IN ISRAEL BY TYPE OF FUEL AND PRODUCER, 2014–15

	COAL		NATURAL GAS		GASOIL		HFO		RENEWABLES		TOTAL	
	GWH	%	GWH	%	GWH	%	GWH	%	GWH	%	GWH	%
2014												
IEC	30	58%	22	42%	0.05	0%	0.01	0%	0	0%	52	84%
IPPs	0	0%	9	91%	0	0%	0.01	0%	0.87	9%	10	16%
Total	30	49	31	49.5	0.05	0.1	0.02	0	0.87	1.4	62	100%
2015												
IEC	29	58%	21	42%	0.37	1%	0.06	0%	0	0%	50	78%
IPPs	0	0%	13	90%	0.12	1%	0.02	0%	1.28	9%	14	22%
Total	29	44.6	34	52.6	0.49	0.7	0.08	0.1	1.28	2	65	100%

Source: Israel's Public Utility Authority (PUA), June 2016.
Note: IEC = Israeli Electric Corporation; IPP = independent power producer.

TABLE C.2: ISRAELI GENERATION CAPACITY, 2007–15

(MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Installed capacity	11,297	11,649	11,664	12,769	12,759	13,248	13,483	13,617	13,617

TABLE C.3: IEC ELECTRICITY SALES BY TYPE OF CONSUMERS, 2014–15

	TOTAL ELECTRICITY CONSUMPTION (%)	2014 (MWH)	TOTAL ELECTRICITY CONSUMPTION (%)	2015 (MWH)
Domestic	34.8	17,604	32.1	15,981
Industrial	18.0	9,108	17.9	8,951
Public and commercial	30.3	15,342	32.0	15,953
Water pumping	4.0	2,018	4.8	2,404
Agriculture	2.6	1,332	3.5	1,769
East Jerusalem electricity company	4.2	2,128	3.9	1,945
Palestinian authority	6.1	3,069	5.8	2,899
Total	100	50,601	100	49,902

Source: IEC Financial Statement of 2015 (published March 31, 2016).

TABLE C.4: ELECTRICITY DEMAND FORECAST FOR ISRAEL, 2016–30

YEAR	GENERATION (GWH)	CONSUMPTION (GWH)	PEAK DEMAND (MW)
2016	67.8	63.4	13,191
2017	70.1	65.5	13,670
2018	72.4	67.7	14,126
2019	74.8	69.9	14,577
2020	76.9	71.9	14,960
2021	79.2	74.0	15,446
2022	81.5	76.2	15,895
2023	83.9	78.4	16,348
2024	86.2	80.6	16,767
2025	88.5	82.7	17,265
2026	91.0	85.0	17,734
2027	93.6	87.5	18,236
2028	96.1	89.8	18,688
2029	98.7	92.2	19,237
2030	101.1	94.5	19,711

Source: Ministry of National Infrastructure, Energy and Water Resources, http://energy.gov.il/Subjects/Electricity/Pages/GxmsMniAboutElectricity.aspx.
Note: The forecast is based on data from IEC and is based on an annual growth of 1.9% in GDP per capita and extreme heat stress conditions.

TABLE C.5: OVERVIEW OF ISRAELI TRANSMISSION AND DISTRIBUTION SERVICE TARIFFS (NIS AGOROT PER KWH, AS OF SEPTEMBER 13, 2015)

SEASON	TOU BLOCK	TRANSMISSION TARIFFS *	TRANSMISSION AND DISTRIBUTION TARIFFS**	DISTRIBUTION TARIFFS***
Winter	Off peak	0.89	3.46	2.55
	Shoulder	1.10	3.89	2.78
	Peak	2.80	7.22	4.38
Transition	Off peak	0.81	3.22	2.41
	Shoulder	1.36	4.17	2.80
	Peak	1.79	4.82	3.01
Summer	Off peak	1.42	4.20	2.77
	Shoulder	2.60	6.32	3.68
	Peak	6.12	12.13	5.90

Source: Israel PUA.
Notes: US$1 = NIS 3.846 (June 30, 2016). Ultra-high voltage = 400 kV and 161 kV; high voltage = 22 kV and 33 kV. TOU = time of use.
* Ultra-high voltage producer selling to ultra-high voltage consumer.
** Ultra-high voltage or high-voltage producer selling to “far away” high-voltage consumer.
*** Ultra-high voltage producer selling to “close by” high-voltage consumer.

TABLE C.6: EFFICIENCY COEFFICIENTS AND RETURN ON EQUITY USED IN ISRAELI TARIFF-SETTING (%)

	SHARE OF ASSETS	EFFICIENCY COEFFICIENT	WEIGHTED EFFICIENCY COEFFICIENT	ANNUAL RETURN ON EQUITY	WEIGHTED RETURN ON EQUITY
Generation	50.1	2.0	1.00	7.62	3.82
Transmission	19.5	1.3	0.25	5.50	1.07
Distribution	30.3	3.7	1.12	6.20	1.88
	100.0		2.38		6.78

Source: Israel PUA and IEC Financial Statements, 2015.

TABLE C.7: PERIOD DEFINITIONS FOR ISRAELI TIME-OF-USE TARIFF RATES

SEASON	TIME OF DAY	TIME-OF-USE PERIOD DEFINITIONS		
		SATURDAYS AND HOLIDAYS	SATURDAYS AND HOLIDAYS	SATURDAYS AND HOLIDAYS
Summer (July – August)	Peak			10→17
	Shoulder			07→10, 17→21
	Off-peak	00→24	00→24	00→07, 21→24
Winter (December–February)	Peak	17→19	16→20	16→22
	Shoulder	19→21		06→08, 08→16, 22→24
	Off-peak	00→17, 21→24	00→16, 20→24	00→06
Transition (remaining months)	Peak			06→ 20
	Shoulder	17→21	06→20	20→22
	Off-peak	00→17, 21→24	00→06, 20→24	00→06, 22→24

Source: Israel PUA. Last updated February 15, 2010.

TABLE C.8: ISRAELI TIME-OF-USE TARIFFS (NIS AGOROT PER KWH)

SEASON	TOU BLOCK	LOW VOLTAGE**	HIGH VOLTAGE**	ULTRA- HIGH VOLTAGE**
Winter	Off-peak	35.60	27.96	25.18
	Shoulder	55.60	46.92	43.62
	Peak	91.29	79.36	73.93
Transition	Off-peak	31.98	24.68	22.10
	Shoulder	39.06	30.99	27.89
	Peak	47.08	38.49	35.06
Summer	Off-peak	33.44	25.62	22.63
	Shoulder	48.01	38.61	34.47
	Peak	105.59	91.49	84.18

Source: Israel PUA as of September 13, 2015.
* US$1 = NIS 3.846 (June 30, 2016).
** Ultra-high voltage = 400 kV and 161 kV; high = 22 kV and 33 kV; low = 400 volt.

TABLE C.9: ISRAELI BULK SUPPLY TARIFFS (NIS AGOROT PER KWH)

LOW VOLTAGE	HIGH VOLTAGE
44.35	35.92

Source: Israel PUA as of September 13, 2015.

TABLE C.10: ISRAELI SYSTEM MANAGEMENT SERVICES TARIFFS (NIS AGOROT PER KWH)

SEASON	TIME-OF-USE	ADMINISTRATIVE COSTS	SYSTEM BALANCE	BACKUP SERVICES	OTHER SYSTEM SERVICES	TOTAL
Winter	Off-peak	0.27	0.58	0.40	4.01	5.26
	Shoulder	0.27	0.58	0.77	4.01	5.63
	On-peak	0.27	0.58	1.35	4.01	6.21
Transition	Off-peak	0.27	0.58	0.34	4.01	5.20
	Shoulder	0.27	0.58	0.43	4.01	5.30
	On-peak	0.27	0.58	0.56	4.01	5.42
Summer	Off-peak	0.27	0.58	0.34	4.01	5.20
	Shoulder	0.27	0.58	0.54	4.01	5.41
	On-peak	0.27	0.58	1.41	4.01	6.27
Average tariff		0.27	0.58	0.54	4.01	5.40

Source: Israel PUA as of September 13, 2015.
Note: US$1 = NIS 3.846 (June 30, 2016).

APPENDIX D:

Importing Natural Gas for Domestic Power Generation

TABLE D.1: PROSPECTIVE INDUSTRIAL CONSUMERS OF NATURAL GAS IN THE WEST BANK

NO.	NAME OF COMPANY	CITY	TYPE OF FACTORY	DIESEL CONSUMPTION (LITER PER YEAR)	LPG CONSUMPTION (KG PER YEAR)	NATURAL GAS DEMAND 1,000 CM PER YEAR
1	BPC Company	Ramallah	Pharmaceutical	134,785	0	126
2	Star Factory	Ramallah	Chemical	59,512	31,055	94
3	Al-Juneidi Factory	Hebron	Food	1,020,000	0	954
4	Aziza Factory	Tulkarem	Food	170,138	0	159
5	NBC Factory	Ramallah	Food	134,611	0	126
6	Siniora Factory	Aziza	Food	202,042	0	189
7	Sinokrot Factory	Ramallah	Food	166,307	116,798	301
8	Al-Jebrini Factory	Hebron	Food	92,028	121,575	238
9	Al-Arz Company	Nablus	Food	0	112,794	141
10	Al-Safa Factory	Nablus	Food	0	116,575	146
11	Al-Betra Company	Hebron	Food	0	67,192	84
12	NAPCO Company	Nablus	Aluminum	0	379,464	474
Total consumption per year				1,979,423	945,453	3,033

Source: Palestinian Federation of Industry, Eco Energy's Calculation of NG Demand.
Notes: LPG = liquid petroleum gas; kg = kilogram; Natural gas conversion factors: 1,000 liters of diesel = 935 cubic meters of (cm) gas; 1 ton LPG = 1,250 cm.

TABLE D.2: FORECAST DEMAND FOR NATURAL GAS BASED ON POWER GENERATION IN THE WEST BANK

	INSTALLED	ELECTRICITY	TOTAL ELECTRICITY	PERCENTAGE OF DOMESTIC	NATURAL GAS
	CAPACITY[a]	GENERATION	DEMAND[b]	PRODUCTION[c]	DEMAND[d]
Year	MW	GWh	GWh	%	bcm
2022	200	1226	6417	19	0.24
2023	200	1226	6802	18	0.24
2024	400	2453	7210	34	0.47
2025	400	2453	7643	32	0.47
2026	400	2453	8101	30	0.47
2027	400	2453	8587	29	0.47
2028	600	3679	9103	40	0.71
2029	600	3679	9649	38	0.71
2030	600	3679	10228	36	0.71

[a] Jenin IPP: 200 MW in 2022, 400 MW by 2024. Tarkumiye IPP: 200 MW by 2028.
[b] Based on 2015 demand in the West Bank of 4,286 GW and assumed growth rate of 6% per annum.
[c] Share of domestic gas-based generation of total electricity demand in the West Bank.
[d] CCGTs have 57% efficiency and operated at 70% capacity.

TABLE D.3: FORECAST DEMAND FOR NATURAL GAS BASED ON POWER GENERATION IN GAZA

	NATURAL GAS–BASED POWER CAPACITY AND GENERATION				TOTAL ELECTRIC	DOMESTIC	NATURAL GAS
	CONVERTED GPP[a]	NEW CCGT[a]	TOTAL CAPACITY	GENERATION	DEMAND[b]	PRODUCTION (%)[c]	DEMAND[d]
Year	MW	MW	MW	GWh	GWh	%	bcm
2022	70		70	429	1462	29	0.11
2023	70		70	429	1550	28	0.11
2024	140		140	858	1643	52	0.21
2025	140		140	858	1741	49	0.21
2026	140	100	240	1472	1846	80	0.33
2027	140	100	240	1472	1956	75	0.33
2028	140	100	240	1472	2074	71	0.33
2029	140	100	240	1472	2198	67	0.33
2030	140	100	240	1472	2330	63	0.33

[a] Gaza Power Plant (GPP): 70 MW conversion from gasoil to gas at 2022, additional 70 MW by 2024; new 100 MW CCGT by 2026
[b] Based on 2015 demand in Gaza of 972 GWh, and assumed average growth rate of 6% per annum.
[c] Share of domestic gas–based generation of total electricity demand in Gaza.
[d] Converted GPP works at 45% efficiency; new CCGT works at 57% efficiency; all plants work at 70% capacity.

FIGURE D.4: NATURAL GAS PRICES IN ISRAEL 2016 (US$ PER MMBTU)

CONSUMER	INITIAL PRICE	INDEXATION
IEC	5.7	U.S. CPI +/- 1% per year *
Major IPPs	4.7-5.0	IEC generation tariff with ceiling
Major industries	4.7-5.5	Basket of fuels with cap
Marketing companies	5.2-5.8	Heavy fuel oil with cap
final price for small industries	6.0-7.0	Heavy fuel oil with cap

Note: MMBTU = million British thermal units.
* IEC's price indexation formula: U.S. CPI+1% per year until 2020 and then U.S. CPI - 1% per year for 7 years.

APPENDIX E:

Importing Electricity from Jordan and Egypt

TABLE E.1: PROJECTED FOSSIL FUEL SUPPLY SITUATION IN THE EGYPTIAN POWER MARKET

AVERAGE CAPACITY UTILIZATION	UNIT	2015	2016	2017	2018	2019	2020	2021
Average (fossil fuel)	%	54%	55%	52%	44%	40%	41%	41%

SPECIFIC GENERATION COST (MARGINAL CASH COST FOR EEHC)	UNIT	2015	2016	2017	2018	2019	2020	2021
Coal	US$ per kWh	0.000	0.000	0.000	0.000	0.000	0.030	0.033
Heavy fuel oil	US$ per kWh	0.042	0.044	0.045	0.047	0.048	0.050	0.052
Light fuel oil	US$ per kWh	0.059	0.059	0.060	0.062	0.064	0.065	0.068
Natural gas	US$ per kWh	0.022	0.024	0.025	0.027	0.029	0.032	0.034
Average (fossil fuel)	US$ per kWh	0.027	0.029	0.030	0.032	0.033	0.035	0.038

SPECIFIC GENERATION COST (MARGINAL ECONOMIC COST)	UNIT	2015	2016	2017	2018	2019	2020	2021
Coal	US$ per kWh	0.000	0.000	0.000	0.000	0.000	0.030	0.033
Heavy fuel oil	US$ per kWh	0.042	0.035	0.045	0.051	0.057	0.063	0.070
Light fuel oil	US$ per kWh	0.096	0.078	0.106	0.119	0.133	0.149	0.167
Natural gas	US$ per kWh	0.039	0.033	0.042	0.046	0.050	0.056	0.063
Average (fossil fuel)	US$ per kWh	0.040	0.034	0.043	0.047	0.052	0.057	0.062

GENERATION	UNIT	2015	2016	2017	2018	2019	2020	2021
Coal	GWh	-	-	-	-	-	5,995	19,376
Heavy fuel oil	GWh	37,489	39,701	39,726	41,118	43,935	45,067	44,987
Light fuel oil	GWh	451	450	427	364	328	336	336
Natural gas	GWh	124,005	131,543	138,433	147,148	154,814	158,803	158,520
Total (fossil fuel)	GWh	161,946	171,694	178,586	188,629	199,076	210,202	223,218

CAPACITY	UNIT	2015	2016	2017	2018	2019	2020	2021
Combined-cycle gas turbine	MW	11,730	12,480	17,230	23,730	29,730	29,730	29,730
Gas turbine	MW	6,794	7,020	5,820	7,030	7,030	7,030	7,030
Steam turbine (oil and gas boiler)	MW	2,800	2,800	2,800	2,832	2,832	2,832	2,832
Steam turbine (coal boiler)	MW	-	-	-	-	-	1,600	5,180
Total (fossil fuel)	MW	21,324	22,300	25,850	33,592	39,592	41,192	44,772

APPENDIX F:

Developing Domestic Renewable Power Generation

TABLE F.1: ESTIMATION OF DISAGGREGATED POTENTIAL FOR RESIDENTIAL ROOFTOP PV

NUMBER OF RESIDENTIAL ROOFTOPS								
GOVERNORATE			POPULATION*	POPULATION (%)	INDIVIDUAL HOUSES (%)*	HOUSEHOLD (HH) SIZE*	NUMBER OF HHS	NO. ROOFTOP FOR PV
West Bank	2,790,331	Region			57.4%	4.9	569,455	326,867
Jenin	303,565	WB-N	*1,094,815*	24.1%			*223,432*	*128,250*
Tubas	62,627	WB-N						
Tulkam	178,774	WB-N						
Nablus	372,621	WB-N						
Qualqilya	108,049	WB-N						
Salfit	69,179	WB-N						
Ramallah	338,383	WB-C	*1,011,269*	22.2%			*206,381*	*118,463*
Jericho	50,762	WB-C						
Jerusalem	411,640	WB-C						
Bethlehem	210,484	WB-C						
Hebron	684,247	WB-S	*684,247*	15.0%			*139,642*	*80,155*
Gaza Strip	1,760,037	Gaza	1,760,037	38.7%	29.3%	5.7	308,778	90,472
North	348,808							
Gaza	606,749							
Dier al Balah	255,705							
Khan Yunis	331,017							
Rafah	217,758							
TOTAL			4,550,368	100.0%			878,234	417,339

Note: WB-N = West Bank north; WB-C = West Bank central.
* Information provided by Palestinian Central Bureau of Statics (PCBS).

TABLE F.2: ESTIMATION OF NUMBER OF ROOFTOPS FOR NONRESIDENTIAL ROOFTOP PV

Public administration	200
Schools	2,200
Commercial	5,000

Source: Information provided by Palestinian Energy and Environmental Research Center (PEC).

TABLE F.3: ASSUMPTIONS REGARDING LAND REQUIREMENTS FOR SOLAR POWER GENERATION IN THE WEST BANK AND GAZA (SQUARE METERS PER KWP)

Rooftop solar	8–12
Utility-scale PV	24–32
CSP	31–40
Wind	210–330

Source: National Renewable Energy Laboratory (NREL). 2013. *Land-Use Requirements for Solar Power Plants in the United States*. Golden, CO: NREL; and NREL. 2009. *Land-Use Requirements of Modern Wind Power Plants in the United States*.

TABLE F.4: ESTIMATION OF OVERALL POTENTIAL FOR ROOFTOP SOLAR PV IN THE WEST BANK AND GAZA

MAXIMUM POTENTIAL CAPACITY – ROOFTOP SOLAR						
West Bank						
	NO. OF ROOFTOPS FOR PV	AREA PER ROOFTOP (M2)	ROOFTOPS AVAILABLE	WELL ORIENTED	AVAILABLE SURFACE (M2)	POTENTIAL CAPACITY (MW)
Residential	326,867	150	30%	30%	4,412,709	490
Public	123	200	40%	100%	9,811	1
Schools	1,349	160	50%	100%	107,925	12
Commercial	3,066	300	30%	100%	275,944	31
Gaza						
	NO. OF ROOFTOPS FOR PV	AREA PER ROOFTOP (M2)	ROOFTOPS AVAILABLE	WELL ORIENTED	AVAILABLE SURFACE (M2)	POTENTIAL CAPACITY (MW)
Residential	90,472	150	30%	30%	1,221,373	136
Public	77	200	40%	100%	6,189	1
Schools	851	160	50%	100%	68,075	8
Commercial	1,934	300	30%	100%	174,056	19
Total West Bank and Gaza						697

TABLE F.5: ESTIMATION OF POTENTIAL FOR UTILITY-SCALE SOLAR POWER GENERATION IN THE WEST BANK AND GAZA

MAXIMUM POTENTIAL CAPACITY – UTILITY SCALE SOLAR					
	TOTAL SURFACE		AVAILABLE ACCORDING TO PETL	AVAILABLE ACCORDING TO PETL	POTENTIAL CAPACITY
	(KM2)	(%)	(%)	(KM2)	(MW PEAK)
Areas A and B	2,488	40%	0.12%	3	103
Area C	3,732	60%	2.64%	98.5	3374
Total	6,220	100%	2.76%	101.5	3476

FIGURE F.6: CURRENTLY INSTALLED AND ONGOING SOLAR PROJECTS AT GAZA HOSPITALS

	MOH FACILITY	UNIT BENEFITING OF THE PROJECT	DONOR	CAPACITY (W)	BUDGET (US$)	STATUS
1	Shifa hospital	Cardiac care	Italian workers syndicate	4,500	50,000	Completed
2	Shifa hospital	ICU	JICA	30,000	150,000	Completed
3	Nassr pediatric hospital	NCU (Nursery)	Sawaed Society	20,000	90,000	Completed
4	Harazen maternity hospital	OT, lab, lighting	UNDP	12,000	60,000	Completed
5	Emirati RC maternity hospital	OT lights	UNDP	8,000	40,000	Completed
6	EGH	ICU	ICRC	30,000	140,000	Completed
7	32 PHC clinics	Refrigerators for vaccines	ICRC	750	190,000	Completed
8	Tahreer maternity hospital	OT, delivery wards, NCU, ED	Human Appeal Int.	50,000	217,180	Ongoing
9	Al-Aqsa hospital	OT, NCU, Cardiac care	UNDP	60,000	225,000	Ongoing
10	Indonesian hospital	OT, ED	UNDP	60,000	225,000	Ongoing
11	Rantissi specialized hospital	NCU, part of Lab	Welfare Association	30,720	150,000	Ongoing
Total				305,970	1,537,180	

Source: Provided to the World Bank by the World Health Organization (WHO) office in Gaza (September 2017).

FIGURE F.7: CRITICAL UNITS IN GAZA MOH HOSPITALS IN NEED OF SOLAR ENERGY

	MOH FACILITY	TARGETED UNIT	HOURS OF POWER SUPPLY	CAPACITY (KWP)	BUDGET (US$)
1	Shifa hospital	Hemodialysis (38 HD unit plus desalinization plant)	12	100	500,000
		NCU for premature babies (35 incubators)	24	30	120,000
		Cardiac care	24	30	120,000
		Laboratory	24	20	80,000
		Sterilization unit—to operate 1 operating theater (OT) sterilizer	12	40	160,000
2	EGH	OT rooms (8 rooms)	6	30	120,000
		NCU (14 beds)	24	30	120,000
		Neurology care (12 beds)	24	30	120,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate 1 OT sterilizer)	12	40	160,000
3	Nasser hospital (Khanyounis)	OT rooms (3 rooms)	6	20	80,000
		ICU (16 beds)	24	30	120,000
		Hemodialysis (18 HD unit plus desalinization plant)	12	50	200,000
		NCU for premature babies (20 incubator)	24	30	120,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate 1 OT sterilizer)	12	40	160,000
4	Rantissi specialized hospital	ICU (4 beds)	24	10	40,000
		Hemodialysis (5 HD units)	12	10	40,000
5	Dorra pediatric hospital	ICU (6 beds)	24	20	80,000
		Laboratory	24	20	80,000
6	Eye hospital	OT rooms (3 rooms)	6	15	60,000
		Sterilization unit (to operate 1 OT sterilizer)	12	40	160,000
7	Beit Hanoun hospital	OT rooms (2 rooms)	6	15	60,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate 1 OT sterilizer)	12	40	160,000
8	Al-Aqsa hospital	Hemodialysis (18 HD units)	12	50	200,000
		Laboratory	24	25	100,000
		Sterilization unit (to operate 1 OT sterilizer)	12	40	160,000
9	Najjar hospital	ICU (6 beds)	24	15	60,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate 1 OT sterilizer)	12	40	160,000
10	Emirati RC maternity hospital	NCU	24	10	40,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate 1 OT sterilizer)	12	40	160,000
Total in US$				1,010	4,140,000

Source: Provided to the World Bank by the World Health Organization (WHO) office in Gaza (September 2017).

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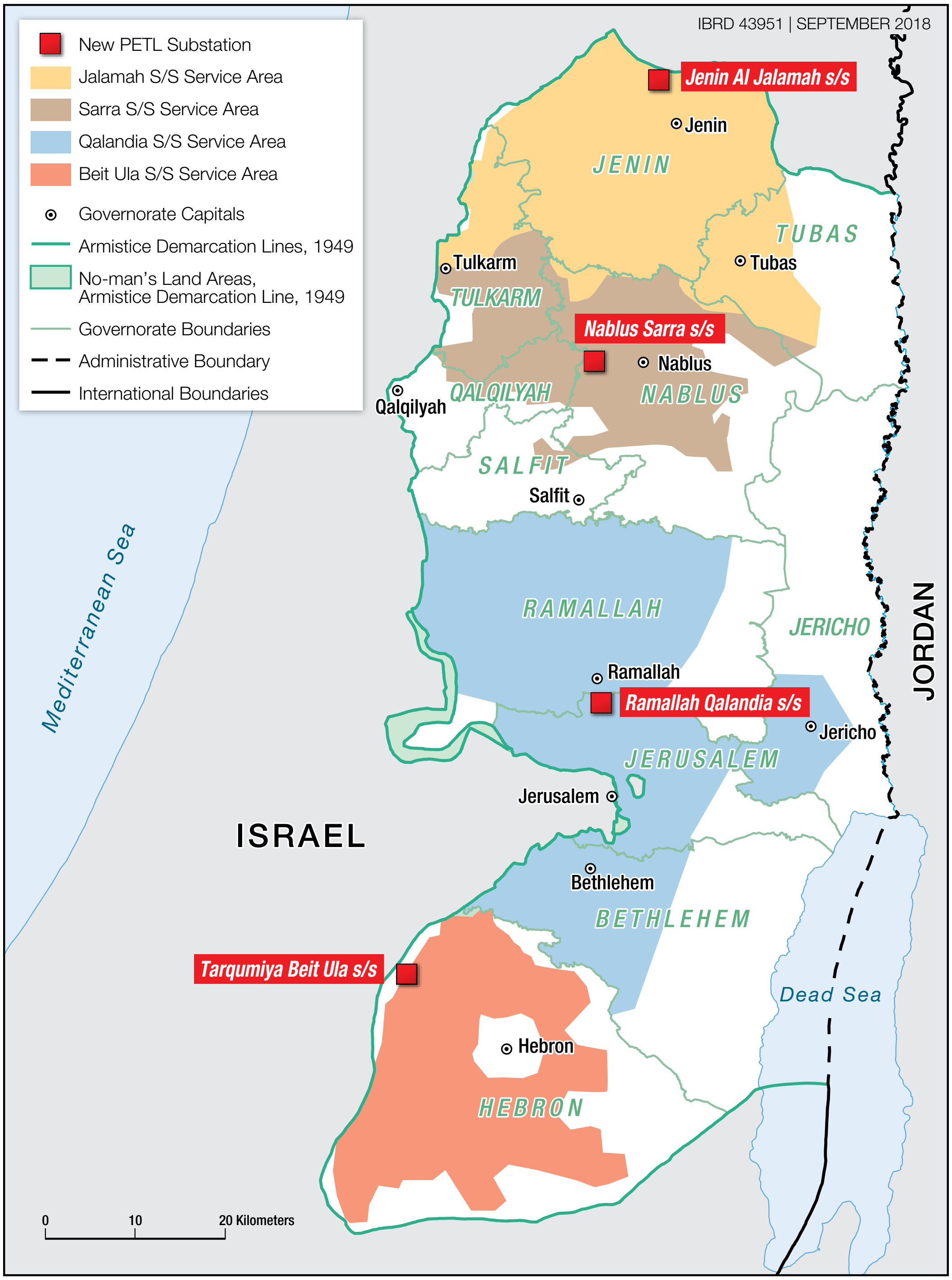
APPENDIX G:

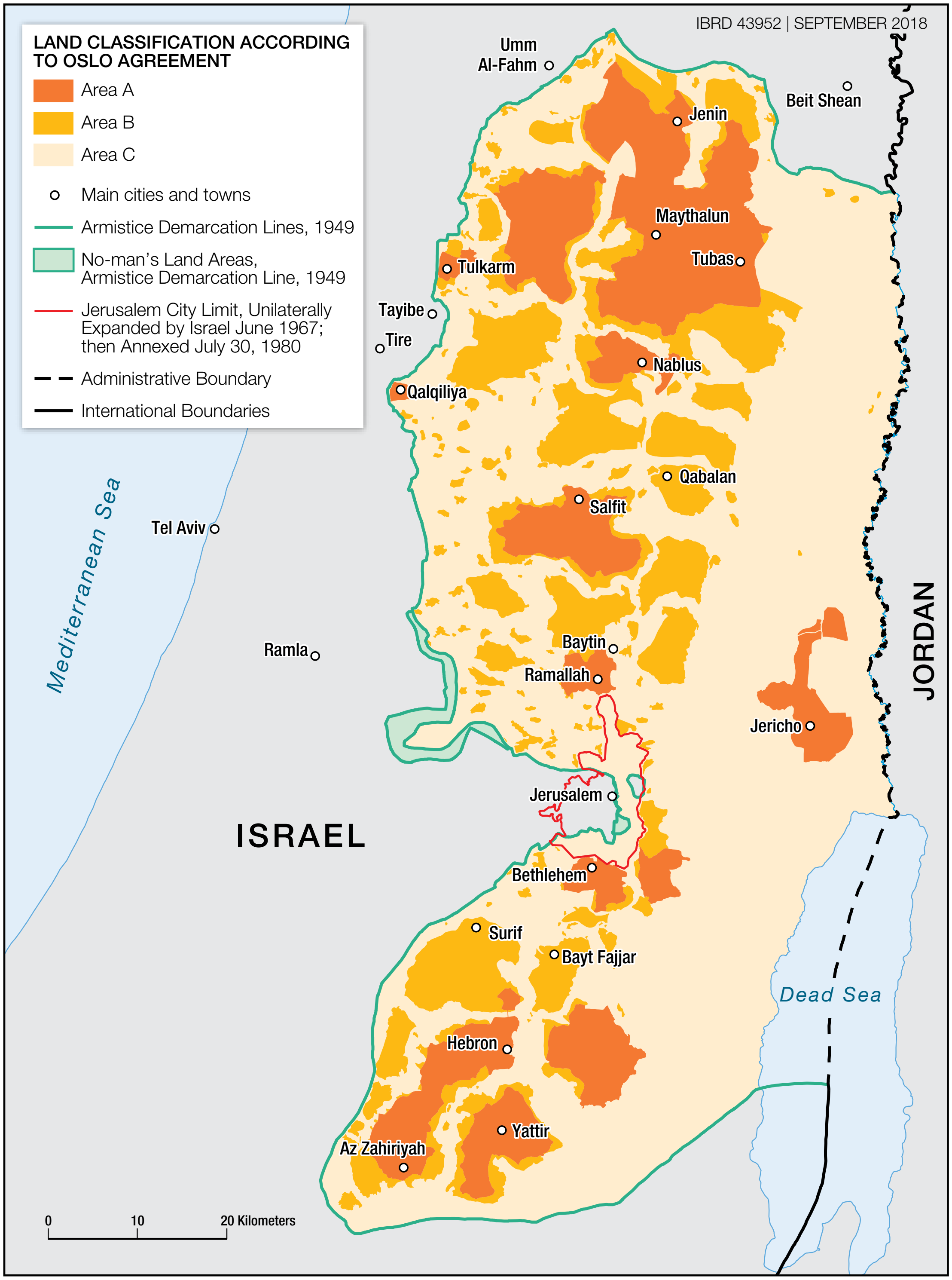
Developing Transmission Infrastructure

Map G.1: Map of Existing Transmission Infrastructure in the West Bank and Gaza

Map G.2: Location and Service Area of New Palestinian Electricity Transmission Company High-Voltage Substations



Map G.3: Land in the West Bank Is Divided into Areas A and B, under Palestinian Civil Administration, and Area C under Israeli Civil Administration



APPENDIX H:

Robust Planning Methodology and Detailed Technical Results

INTRODUCTION

This technical appendix describes the methodological considerations and input assumptions behind the power system expansion model used for the report. The analysis applies concepts from the robust-decision-making framework to develop power-generation capacity expansion plan for both the West Bank and Gaza that takes into consideration endogenous and exogenous uncertainties. It is built around a linear programming (LP) optimization and simulation model that generates scenarios to capture the pervasive uncertainties in a region where geopolitical conditions heavily influence the availability of electricity and fuel supply.

The analysis compares the output of classical methods to power-system expansion planning with the robust-decision-making-related approach to show how uncertainties can affect the choice of technology options. The analysis also presents results that take into account constraints to project-financing access.

The geopolitical conditions, and related uncertainties, call for a significant shift from traditional planning methods. To the extent that political, social, and economic uncertainties can be abstracted for modelling purposes, they have been incorporated in the analysis largely through varying assumptions related to the availability, timing, and cost of infrastructure development.

Objective

Given the uncertainties, the objective of the generation-expansion planning component of the study is to propose a set of generation options that perform well under various conditions. They are designed to be able to satisfy peak load and energy demand up to 2030 reliably, and at the most efficient cost. The analysis thus seeks to answer the following questions:

1. In a deterministic analysis, what does a least-cost capacity expansion plan look like, which ensures the West Bank are Gaza are self-reliant and able to meet demand securely (assuming there are no capital constraints)?
2. What are the features of a capacity plan that ensures the West Bank are Gaza can respond to a wide range of uncertainties including contingencies around electricity imports? What are the cost implications of such a plan? How well does this second plan perform in terms of costs compared with a classic least-cost plan?
3. How does the average cost of production change by sharing reserve margin requirements with neighboring countries?
4. Given capital constraints, what is a balanced mix that combines (ii) and (iii) to keep average costs of production at a specified annual level?
5. How does access to regulated land (known as Area C) affect the generation mix and system costs?
6. If political uncertainties are not resolved over the planning horizon, what is the impact of only implementing projects that are solely within the control of the Palestinian Authority (PA), and what is the impact of delayed action or inaction on unmet demand?

Limitations of the Study

While efforts have been made to include some uncertainties in the expansion plan, it is not comprehensive in this regard. Importantly, climate risks are not included in the analysis. For example, rising air temperatures reduce the efficiency of plants (including most types of solar PV plants) while increasing demand (for cooling) during the summer months, among others.

The location of plants and financial structuring of potential projects are other important issues that can affect which specific projects materialize. These issues are beyond the scope of the study, which does not consider locational issues.

Delays during construction are also not considered in the analysis. Construction delays can impact project costs, and large projects tend to be more exposed to this risk. As an example, doubling the construction time for a gas turbine from 24 to 48 months could increase project costs by close to 10 percent.[1] Delays also expose the project to fluctuations in material prices linked to international commodity prices. Including these issues tends to further strengthen the case for distributed generation options.

METHODOLOGICAL CONSIDERATIONS

Planning for the expansion of power sectors in developing countries is challenging, due in part to the uncertainty associated with demand projections because historical trends are typically different from expected growth patterns. The power sector in the West Bank and Gaza falls in this category. Additionally, the geopolitical situation in the West Bank and Gaza (one of the territories on the World Bank's list of fragile situations) introduces additional layers of significant uncertainty. [2]

Constraints imposed by fragility have been routinely left out of power-sector planning in most conflict-prone countries. It manifests through various impacts on technology choices, timing, cost of and access to financing, and so forth. The lack of financing, delays, and damages are all constraints and risks that need to be considered in planning for these plans to be more effective. Although these issues are well understood in qualitative terms and practiced in the field, it is only recently that consideration is being given to quantitatively formalize this trade-off to produce a power system plan that finds a good balance between cost and risks and characterizes the ever-changing dynamics of fragile states (Bazilian and Chattopadhyay 2016).

For the West Bank and Gaza, uncertainties around demand projections, the level of electricity imports, timing of fuel availability, volumes and costs of fuel, granting of access to expand infrastructure, and the risk of high outage rates mean the classic approach to least-cost expansion planning is not adequate. The classic approach to least-cost planning typically assumes expected outage rates, fuel and plant availability, and a load growth forecast to project a generation mix that satisfies peak load and energy demand under a predefined set of constraints. The robustness of the plan is tested through a carefully selected set of scenarios. Under the current circumstances in the West Bank and Gaza, the sheer number of uncertainties leaves such an approach too vulnerable to failure measured by the inability to meet demand.

An approach to counter this risk could be to plan for the worst or close to worst case scenario, but this comes at cost. While partly justifiable, this cost in the form of capital expenditure is likely to be unwarranted because the system will be overly designed. The approach adopted for this study therefore seeks to balance the goal of meeting demand at all times, with the risk of stranded assets under multiple scenarios.

Bazilian and Chattopadhyay (2016) describe three possible planning techniques for fragile states: (i) least-cost planning tools that include risk premiums as inputs; (ii) extension of least-cost planning models with a simulation component to reflect some of the uncertainties associated with fragile and conflict states; and (iii) stochastic programming and robust decision models that are specifically designed to facilitate decision making under uncertainty.

In a case study for the Republic of South Sudan, Bazilian and Chattopadhyay (2016) employed the first approach (i) to look at the impact of differentiating the cost of capital for risky projects (typically large, scale-efficient infrastructure that are cheaper but highly exposed to the risk of destruction and significant delays) from smaller but less risky options. By using a higher weighted average cost of capital (WACC) for riskier projects as a proxy to capture a wide range of financing risks, the analysis results in a shift away from large, centralized technology options to more decentralized choices. For the case of the West Bank and Gaza, there is no evidence to conclude that financing for scale-efficient projects like thermal power plants will be more expensive than financing for more decentralized options or by how much.

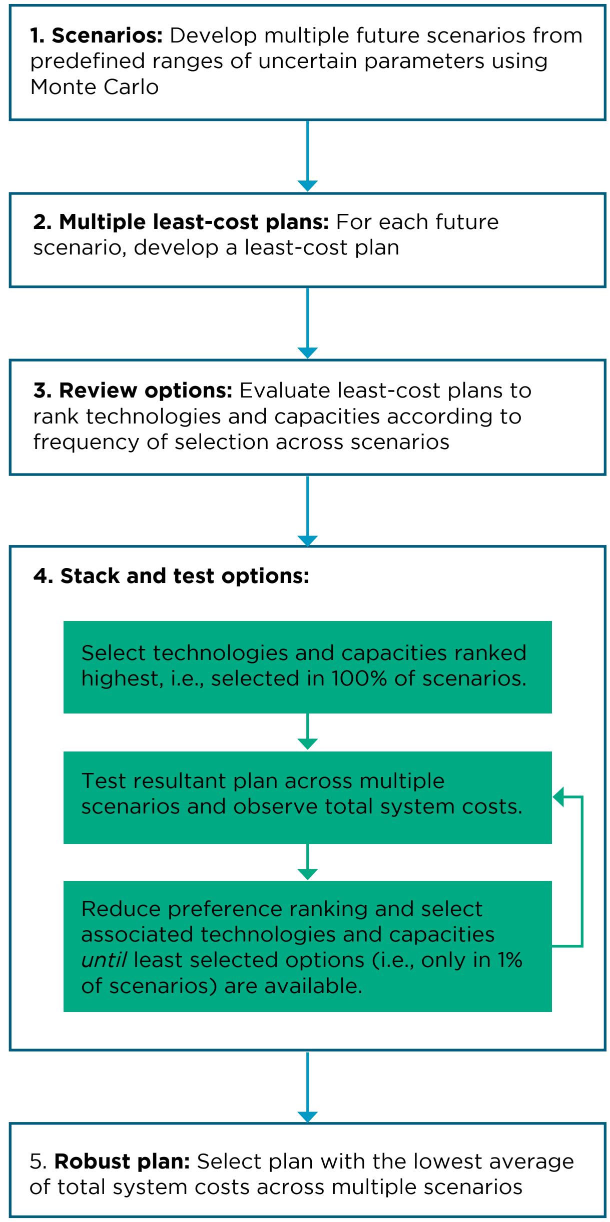
In another case study, Spyrou, and Hobbs (2016) use a two-stage stochastic planning model to analyze the impact of climate risks on the power system expansion plan for Bangladesh—one of the most vulnerable countries to climate change (World Bank 2013). The analysis concludes that modeling the relationship between climate and power system parameters could save up to US$1.6 billion in 2015 dollars. In a two-stage stochastic programming model, an action is taken in the first stage (or the present) knowing that the future could evolve in many different ways, based on a set of random parameters. A set of recourse decisions is then defined to determine a course of action in the second stage that responds to the outcome of the uncertain parameter. The goal is to find a solution that optimizes the expected outcome of a decision. Stochastic programming models are reliant on the fact that probability distributions governing the data are known or can be estimated (Shapiro and Philpott 2007) (Shapiro, Dentcheva, and Ruszczynski 2009).

Establishing such probability distributions for the West Bank and Gaza can be challenging. There is little historical data to inform the design of the distribution parameters. The distribution shapes could be attempted through the use of expert judgement, but the political underpinnings in the West Bank and Gaza increase the subjectivity of such an exercise.

The approach used to deal with uncertainties in this study involves using Monte Carlo simulations to draw scenarios from a range of parametric uncertainties and then running them through a deterministic LP model. The simulations serve to "recognize" the stochastic nature of the parameters, but this process falls short of a full stochastic model because the final selection of the capacity plan is decided by the modeler rather than the model.

The Monte Carlo simulation process considers random variation in uncertain parameters such as demand and generation availability, fuel prices, and so forth, to form a composite sample that represents one realization or "future" of all possible uncertain parameters. The LP dispatch optimization (determination of the optimal output of power generation plants) is solved for the sample to obtain one-point estimate of system costs, prices, and so forth. The process is repeated for a large set of samples (for example, somewhere between 100 and 1,000, depending on the number of parameters and their variance) to form a distribution of the outcomes. The process is fundamentally not very different from running a large number of alternative scenarios with the exception that (i) we directly represent the probability distribution of each uncertainty parameter rather than accepting a predefined scenario with a specific view on the uncertain parameters and (ii) we therefore can evaluate

Figure H.1: Process Flow for Selecting Robust Options



the impact of multiple uncertain parameters on the final output, be it prices or system costs.

The process flow for the analysis is shown in figure H.1. We start by identifying all the input parameters that are uncertain. These include the timing and availability of fuel, energy demand, fuel prices, amount of imports, availability of power plants, and investment costs, among others (see table H.1). The ranges for these uncertain parameters were developed by the project team after consultations in Jordan, Israel, Egypt, and the West Bank and Gaza.

In this type of analysis, it is important to identify the correlations between parameters. Of particular interest was the correlation between fuel and electricity import prices. Since the transition from oil-based generation to gas-based generation, electricity prices in Israel have been decoupled from international oil prices, because most of the production is driven by long-term gas purchase agreements. The growing share of renewable energy will further decouple the two prices.

This is likely to be the case for Egypt as well. We therefore assume no correlation between fuel prices and imports from Israel and Egypt. Electricity prices in Jordan, on the other hand, are correlated with fuel prices, and this assumption has been used in the study. At present, gas generation is based on liquified natural gas, and so prices are linked to the international gas market. However, there are considerations to import gas from Israel or other countries. Jordan is also considering oil shale and nuclear power as generation options, together with a strong renewable energy portfolio. These plans, if implemented, will reduce the link between international oil and electricity prices.

Details of the process flow are as follows:

Step 1: Develop Multiple Scenarios

After identifying the uncertain parameters, multiple scenarios were generated using Monte Carlo sampling techniques. Each scenario contains a random draw from within the distribution of the individual parameters for every year in the planning horizon. For example, it will include a certain demand profile for every year, plant availability for every year, fuel prices for every year, and so on. Since the draws from the various parameters are completely independent, two valid questions arise at this stage: (i) How certain are we that the combination of individual draws adequately cover the worst-case scenarios? (ii) how plausible is the combination of all the individual draws?

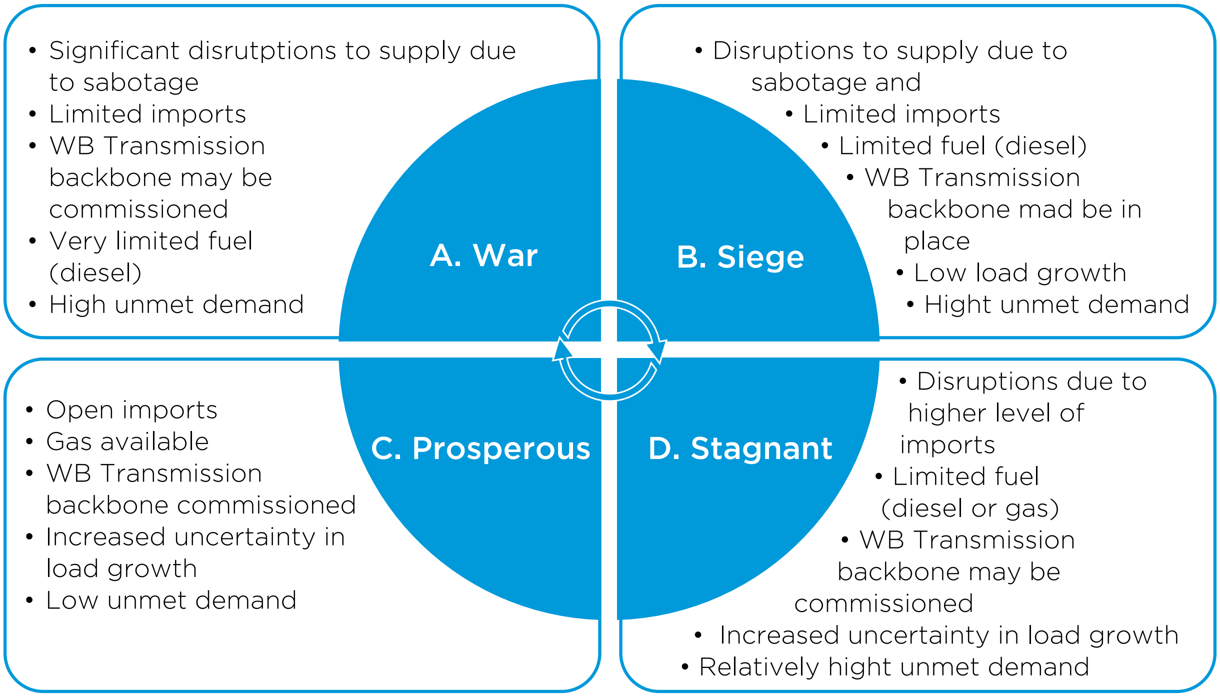
The coverage of scenarios depends on the number of draws for the Monte Carlo analysis. A higher number of draws increases the coverage of scenarios. This needs to be balanced with the computational requirements. The number of scenarios was selected to minimize the variance in total system costs across scenarios, an indication that enough samples across the range of uncertainty have been selected. In this study, 100 draws were used to demonstrate the merits of the study approach.

For question (ii), the primary issue of concern was the link between outages caused by sabotage and demand. As an example, how plausible is a scenario with high outages and high demand growth? Using the study approach, it is also possible to discard combinations of parameters that are unreasonable.

TABLE H.1: INPUT PARAMETERS AND ASSOCIATED UNCERTAINTIES

PARAMETER	UNCERTAINTY
Fuel	Prices, volumes, and availability of diesel (as a result of attacks and politically imposed constraints) Timing, volumes, prices, and availability of gas
CAPEX	Variations in photovoltaic, wind, and concentrated solar power CAPEX
Electricity imports	Prices, volumes, and availability
Demand	High volatility in projected demand
Transmission	Uncertainties around the commissioning of West Bank backbone and West Bank-Gaza connection
Plant availability	Extended outages as a result of damage or difficulty in reaching plant locations; damage due to sabotage incurs a cost to the system

Figure H.2: Characterizing Four Possible Economic Conditions of the West Bank and Gaza



To design the scenarios, the study categorizes four possible states in the West Bank and Gaza: war, siege, economic stagnation, or economic prosperity. These conditions are characterized by different levels of investments in power sector infrastructure and demand characteristics as shown in figure H.2.

For extended periods in the planning horizon, or the entire duration, either territories of the West Bank and Gaza could be in a state of siege (as is the case in Gaza presently), stagnation (as is the case in the West Bank), or prosperity where there are no limits to infrastructure development. A state of war is more transient, marked by particular years with high outages, limited imports, and limited fuel supply. For example, over the entire planning horizon, a territory could be in a state of stagnation with spot disturbances in which supply options are disrupted. History shows destroyed equipment is restored, and this is assumed to continue. It was also decided to establish a minimum availability threshold for imports from Israel, the main source of imports, since it was unrealistic to anticipate this to be completely unavailable.

Step 2: Develop Multiple Least-Cost Plans

For each of the four scenarios we develop an expansion plan using the core LP model. It is important to note that the model considers the entire planning horizon and optimizes capacity and dispatch to minimize system costs for the horizon. It does not optimize the solution on a year-to-year basis. For example, if a scenario draws on natural gas being available but also draws low availability for the gas plants in some years, the model considers this availability and may install more capacity within defined constraints to satisfy the supply-demand balance. It will not only use the higher availability of preceding years to determine optimal capacity and timing. The core LP model is explained in a later section.

Step 3: Review Plans and Rank Options

In this step, we analyze, for every year in every scenario, the frequency with which technology options are picked and, when picked, the capacity that is installed in that year. The aim is to identify those technology-capacity options that are robust across multiple scenarios. These are then ranked by the percentage of times the technology-capacity mix is selected in every scenario and for every year. To determine the capacity that is picked up across multiple scenarios, we approximate the plant capacities to the nearest 10MW. This is similar to creating 10MW “bins.”[3]

Step 4: Stack and Test Options

The most preferred technology-capacity options are those that are selected in most scenarios. Figure H.3 shows variation of the capacity of available generation options across multiple scenarios. Existing capacity is always included. As seen from the figure, 194 MW of the plant PVr-WBC is robust in all scenarios, while the first concentrated solar power (CSP) of 20 MW is only picked up in 11 percent of scenarios. Technology and capacity options that appear in 100 percent of scenarios constitute no-regret options. Moving to the right of the chart, the capacities of technologies increase but are less robust.

While it would be ideal to include only the most robust technology-capacity options, this is unlikely to meet demand, and so it is necessary to add more capacity. We therefore stack less preferred options to increase installed capacity that is, select capacities to right in figure H.3). At this point, we have little idea about the target capacity that will be adequate for the system, because the demand forecast is uncertain. To deal with this problem, we run multiple experiments (multiple scenarios that draw from the uncertain parameters) whenever we include additional options in the stack and observe the performance of the capacity plan. It is important to distinguish this step from step 2, where we develop multiple capacity plans to satisfy multiple future scenarios.

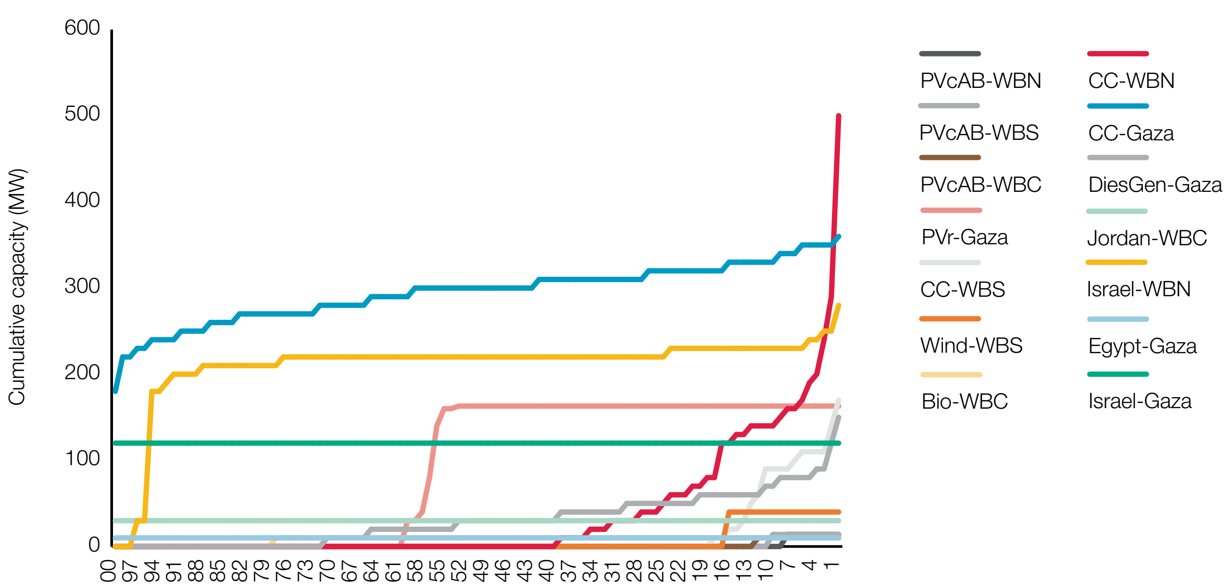
In step 2, the question we answer is this: if the future looked like a particular scenario, what types of plants should be built? When should they be built and how should they be dispatched? In this step, whenever we add onto the stack of technology-capacity options, we take this as our capacity plan and ask the question: If this was my capacity plan, how would it perform in multiple scenarios?

The stack developed in step 4 can also be used to select projects to prioritize. The more robust options at the bottom of the stack should be given a higher priority.

Step 5: Select Robust Plan

The performance of each potential capacity plan is evaluated mainly through the change in total system costs or the objective function (least cost). By observing the total system costs across multiple scenarios, we select the plan with the lowest cost as the “robust” plan.

Figure H.3: Cumulative Capacity by Technology



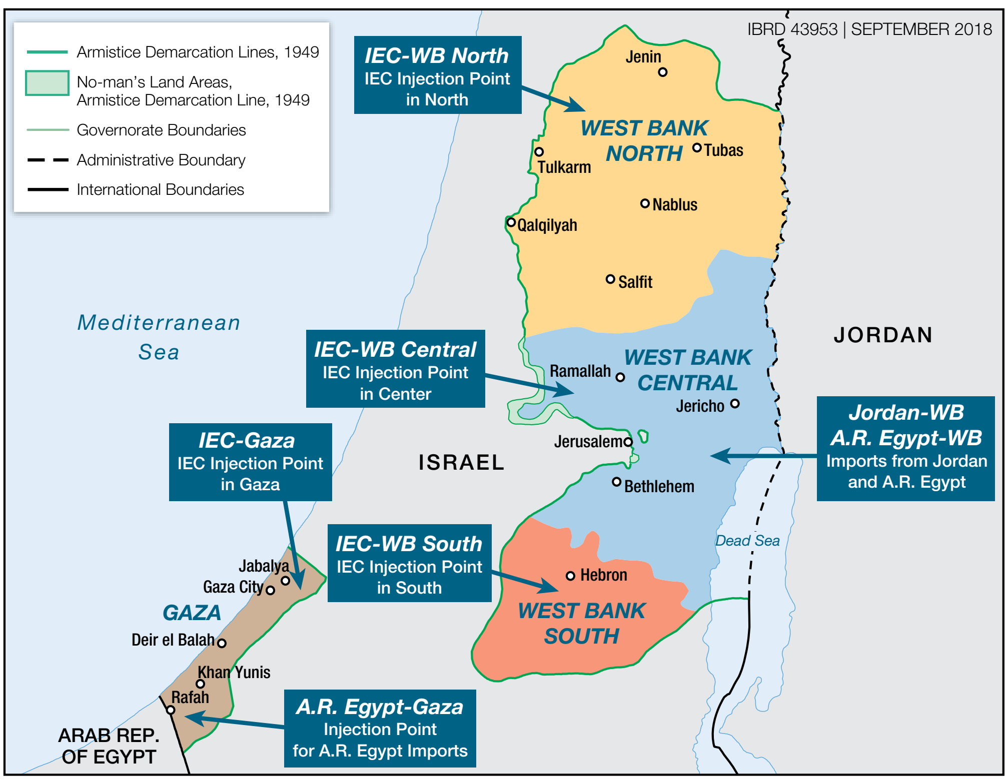
Jiang and Vogt-Schilb (2016) employ a similar approach in a case study for Bangladesh as the quantitative basis for a "robust adaptive strategy that performs acceptably over several dimensions in as many plausible futures as possible." The main differences are (i) Latin hypercube sampling was used to reduce the need for large number of simulations, while we use Monte Carlo sampling for this study, and (ii) after generating multiple expansion plans, the technology-capacity options were placed in large bins to reduce the number of plans, each of which was then tested across multiple scenarios and performance assessed independently. In this study, we develop the capacity plan starting with no-regret options and increasingly adding less preferred options as described in step 4.

STRUCTURE OF THE MODEL

The West Bank is modeled as three separate zones: WB North, WB Central, and WB South (see map H.1). Electricity imports from Israel is injected through three points in the north, central, and south. Demand and solar resource availability is accordingly distributed among the three zones in the West Bank. Gaza is modeled as one separate zone.4

There is currently no transmission network in the West Bank or Gaza, and the two territories are not directly connected either. The analysis of transmission requirements is undertaken separately and not included in the model.

Map H.1: Categorization of Zones and Power Import Connections in West Bank and Gaza



The model used for the West Bank and Gaza is a GAMS-based, least-cost planning tool that is in many ways, simpler to populate (through an Excel front end) and easier to customize than commercial tools, as algorithms and procedures can be built around the basic model to deal with uncertainties.[5] Given the sparse data available and the wide range of uncertainties necessary for the analysis, this flexibility is critical.

Mathematical Description of the LP Model

This section briefly describes the LP least-cost planning model at the core of the analysis. The deterministic least-cost planning model takes into consideration the following as input:

- *Cost:* Investment costs for generation expansion, fuel prices, and fixed and variable operation and maintenance costs
- *Load:* Load forecasts in the form of load duration curves for the planning years
- *Generation:* Operational characteristics of generation plants, such as thermal efficiency, maximum utilization factors, and so on
- *Transmission:* Transfer-capacity limits between zones and associated losses

The main output of the model is a set of generation options and their associated timing, dispatch levels, and residual or unmet demand. From this, the average cost of generation per year (or block of the load duration curve), associated emissions, total system costs, CAPEX requirements, and reserve margins, among others, can be calculated.

The objective function to be minimized is the discounted net cost (at a rate of 10 percent) for the planning period and is calculated as shown in EQ 1.

EQ Set 1: Objective Function

Obj

$$\text{cost} = \sum_y \Big(\frac{1}{(1+\mathrm{r})^{(\mathrm{ord(y)}-1)}} \cdot \Big(\sum_{NR} (\mathrm{CRF}_{NR} \cdot \mathrm{cap}_{NR,y} \cdot \mathrm{GenData}_{NR,\texttt{CAPEXperkW}}) \cdot 1000 +$$

$$\text{what is going on here } \textstyle\sum_{n,RE} \mathrm{VRECapex}_{n,RE,y} + \displaystyle\sum_g (\mathrm{cap}_{g,y} \cdot \mathrm{GenData}_{g,\texttt{FOMperMW}}) + \sum_{IM} (\mathrm{vImportReserves}_{IM,y} \cdot$$

$$\mathrm{ReserveImports}_{IM,y}) + \sum_g (\mathrm{CumRepair}_{g,y} \cdot \mathrm{CRFr}_g \cdot \mathrm{GenData}_{g,\texttt{CostOfRepair}}) \cdot 1000 + \sum_{i,g,f|\mathrm{map}_{g,f}} \Big(\sum_t (\mathrm{Gen}_{i,g,f,y,t} \cdot$$

$$\mathrm{Duration}_t \cdot \mathrm{VC}_{g,y,f})) + \sum_{i,g,f|\mathrm{map}_{g,f}} \Big(\sum_t (\mathrm{Gen}_{i,g,f,y,t} \cdot \mathrm{Duration}_t \cdot \mathrm{GenEmis}_{g,f}))[\mathrm{IncludeCO2Price}] +$$

$$\sum_{i,g,f|\mathrm{map}_{g,f}} \Big(\sum_t (\mathrm{Gen}_{i,g,f,y,t} \cdot \mathrm{Duration}_t \cdot \mathrm{GenData}_{g,\texttt{VOM}})) + \sum_{i,t} (\mathrm{USE1}_{i,y,t} \cdot \mathrm{Duration}_t \cdot \mathrm{VoLL}_y) +$$

Where the sets and decision variables are defined as follows :

Sets:

Name	Domains	Description
i, j	i	nodes
g	g	generators
t	t	time increment of LDC
f	f	fuel type
y	*	years
map	g, f	
s	*	fuel price scenarios
b	b	states
IM	g	imports as generators
EX	f	export fuels
NE	f	nonexport fuels all fuels apart from exports
RE	g	renewables
GE	g	generators
NR	g	nonRE generators
PV	g	PV technologies
te	te	genertor technologies
mapbi	b, i	map nodes to territories
mapij	i, j	map nodes
mapig	i, g	map nodes to generators
AreaC	g	Area C PV and CSP
IEC	g	Israel imports
n	*	

Decision variables:

Name	Domains	Description
Gen	i, g, f, y, t	generation per unit per year per LDC pointin MW
cap	g, y	installed capacity in year y in MW
Build	i, g, y	Build new capacity MW in year y
VRECapex	n, g, y	Annualized RE capex carried from Nth year to last year in USD
Retire	i, g, y	Retire existing capacity
USE	i, y, t	unmet demand in MW
USE1	i, y, t	unserved energy in MW
Unmetreserve	b, y	reserve capacity shortfall
Surplus	i, y, t	surplus power (to get around the min load constraint!)
Fuel	i, f, y	fuel consumption in MMBTU
Tran	i, j, y, t	power transfer from zone i to j in MW
cost		total system cost in billion USD
Repair	g, y	capacity to be repaired by year after year 1
vImportReserves	g, y	imported reserves in MW
CumRepair	*, *	

The sum of *Cap*CAPEXperkW* determines the total annualized investment for all thermal generators in a particular year. The cost recovery factor (CRF) is calculated using a weighted average cost of capital (WACC) of 10 percent.

For renewable energy (RE) plants, a separate term, *BuiltRE,* adds the annualized CAPEX requirements to the objective function. This has been separated as a new variable because the CAPEX for RE plants changes with time. Any new installation therefore applies the CAPEX requirements for the year of installation calculated in a separate equation.

The sum of *Cap*FOMperMW* adds the fixed operating and maintenance costs for all generators per installed kW every year. *VC* + *VOM* together make up the short-run marginal cost for each generator, *VC* being the cost of fuel and *VOM* being variable operating and maintenance costs.

The sum of *CumRepair*CostOfRepair* adds a cost whenever there is damage to a plant. The *CostOfRepair* is assumed to be a third of the CAPEX, and *CumRepair* carries the total annualized repair costs through the planning horizon. Repair costs are assumed to be recovered over 12 years (irrespective of the plant).[6]

Sum of *GenEmis*CO_2Price* adds the cost of CO_2 emissions if required and is set by the flag *IncludeCO2Price*. CO2 prices are not included in the analysis for the West Bank and Gaza.

In addition to regular costs, the objective function includes penalties associated with violation of demand constraint, *VoLL,* which is set at US$750 per megawatt hour (MWh) for this study, and reserve limit, *VoLLReserve,* which is set at US$5,000 per kW in this study. Mathematically, the unserved energy variable relaxes the demand balance constraint to avoid infeasibility in time periods with excess demand. In practice, it is an indirect measure of system reliability. Its valuation is an economic concept that indicates the willingness to pay by electricity consumers to avoid supply interruption (Electricity Commission 2008). The study reports *VoLL* to be as high as US$44,500 per MWh in Australia and US$960 per MWh for Chile. Mathematically, because of the role this plays in balancing demand and supply, the value for lost load needs to be high enough to prevent the model from curtailing load as a means of minimizing system costs. The selected *VoLL* is set at the cost of self-generation through portable household gasoline generators.

The objective function is minimized subject to various constraints described here:

EQ Set 2: Capacity Balance and maximum build capacity

$$\mathbf{CapBal}_{i,g,y}$$

$$\text{cap}_{g,y} = \text{cap}_{g,y-1} + \text{Build}_{i,g,y} - \text{Retire}_{i,g,y} \qquad \forall i,g,y \mid ((\text{ord(y)} > 1) \land \text{mapig}_{i,g})$$

$$\mathbf{CapBal1}_{i,g,y}$$

$$\text{cap}_{g,y} = \text{Build}_{i,g,y} - \text{Retire}_{i,g,y} \qquad \forall i,g,y \mid ((\text{ord(y)} = 1) \land \text{GenData}_{g,\texttt{CAPEXperkW}})$$

$$\mathbf{MaxBuild}_{i,g}$$

$$\sum_y \text{Build}_{i,g,y} \leq \text{GenData}_{g,\texttt{Pderated}} \qquad \forall i,g \mid \text{GenData}_{g,\texttt{CAPEXperkW}}$$

First, the dynamic links across the years is captured in the first equality constraint that defines the variable *Cap*. Capacity may be augmented by building new units (that is, *Build*), or it can be mothballed (*Retire*). Second, the first-year capacity is restricted to the existing capacity, and the total capacity that can be built for a new station over the entire planning horizon is restricted to the planned capacity addition. Additionally, constraints ensure new plants are not mothballed and existing capacity is included. Finally, the capacity addition, annual capacity, and power output are subject to a set of conditions as represented by the last two constraints.

EQ Set 3: Capacity Utilization Limits

$$\mathbf{MaxCFGen}_{i,GE,y}$$

$$\sum_{f|\text{map}_{GE,f}} \left(\sum_t (\text{Gen}_{i,GE,f,y,t} \cdot \text{Duration}_t)\right) \leq \text{cap}_{GE,y} \cdot 8760 \cdot \text{GenData}_{GE,\texttt{MaxCF}} \cdot \text{Availability}_{GE,y}$$
$$\forall i, GE, y$$

$$\mathbf{MaxCFImp}_{i,IM,y}$$

$$\sum_{f|\text{map}_{IM,f}} \left(\sum_t (\text{Gen}_{i,IM,f,y,t} \cdot \text{Duration}_t)\right) \leq \text{cap}_{IM,y} \cdot 8760 \cdot \text{GenData}_{IM,\texttt{MaxCF}} \cdot \text{Availability}_{IM,y} \cdot \sum_{EX|\text{map}_{IM,EX}} \text{ImportVolume}_{EX,y} \qquad \forall i, IM, y$$

$$\mathbf{eTotalIECWB}_y$$

$$\sum_{IEC} (\text{cap}_{IEC,y} + \text{vImportReserves}_{IEC,y}) \leq \text{MaxIECImports}_y \cdot \text{ImportVolume}_{\texttt{IsraelImport},y} \quad \forall y$$

Generation from all units (existing and new) is limited by the maximum capacity factors on the *Cap.* Availability is the maximum capacity factor, and it is one of the random parameters sampled. Imports (which are modelled as generators running on an "import fuel"), are limited to import caps and the availability of the tie line. This is defined by the second equation. The third equation ensures that sum of imports from Israel to the three zones of West Bank do not exceed Israel-West Bank import cap.

EQ Set 4: Destroyed Capacity

$$\mathbf{RepairCap}_{g,y}$$

$$\text{Repair}_{g,y} = \text{cap}_{g,y} \cdot \text{DestroyedCap}_{g,y} \qquad \forall g, y$$

$$\mathbf{TotalRepairs}_{g,y}$$

$$\text{CumRepair}_{g,y} = \text{CumRepair}_{g,y-1} + \text{Repair}_{g,y} \qquad \forall g, y \mid (\text{ord(y)} > 1)$$

$$\mathbf{TotalRepairs1}_{g,y}$$

$$\text{CumRepair}_{g,y} = \text{Repair}_{g,y} \qquad \forall g, y \mid (\text{ord(y)} = 1)$$

Major outages due to damage incur a cost, and the probability of damage is defined as another uncertain parameter. *DestroyedCap* is a fraction that represents the installed capacity destroyed. For distributed generation sources, damage has less of an impact and *DestroydCap* is small. Centralized units are more exposed to the risk of damage that takes the entire plant out of service. These repairs incur a cost to the system that is amortized over 12 years. The first equation calculates the destroyed capacity in a year. The second and third calculated total repairs for all years and the first year respectively. It is this variable that is multiplied by the per kW repair costs in the objective function.

EQ Set 5: Zonal Balance

$$\textbf{DemBalBase}_{i,y,t}$$

$$\sum_{g,f|\text{map}_{g,f}} \text{Gen}_{i,g,f,y,t} + \text{USE}_{i,y,t} + \text{USE1}_{i,y,t} - \text{Surplus}_{i,y,t} + \sum_{j} (\text{Tran}_{j,i,y,t} \cdot 0.97) - \sum_{j} \text{Tran}_{i,j,y,t} = \text{LDCBase}_{i,t,y} \cdot \text{EEScalingFactor}_y \qquad \forall i,y,t \mid \text{IncludeEnergyEfficiency}$$

$$\textbf{DemBal1Base}_{i,y,t}$$

$$\sum_{g,f|(\text{map}_{g,f} \wedge \text{mapig}_{i,g})} \text{Gen}_{i,g,f,y,t} + \text{USE1}_{i,y,t} - \text{Surplus}_{i,y,t} + \sum_{j|\text{mapij}_{i,j}} (\text{Tran}_{j,i,y,t} \cdot \text{lossfactor}) - \sum_{j|\text{mapij}_{i,j}} \text{Tran}_{i,j,y,t} = \text{LDCBase}_{i,t,y} \qquad \forall i,y,t \mid (\text{IncludeEnergyEfficiency} = 0)$$

$$\textbf{eTransferLimit}_{i,j,y,t}$$

$$\text{Tran}_{i,j,y,t} \leq \text{pTransferLimit}_{i,j,y} \qquad \forall i,j,y,t \mid \text{mapij}_{i,j}$$

By Kirchoff's First Law (also known as KCL Kirchoff's current law), the total line flows into and out of a node must equal the difference between the generation flowing into the node and the off-takes. Thus, the nodal balance constraints equate demand, generation, losses, and electricity flows to and from the node. Generation deficit violation variables (*USE1*) are also included to deal with those rare situations in which the system may be unable to meet the load at a node, due to a general shortage of generation or to transmission system failure. Lines have a conventional direction associated with them. A positive *Tran* variable represents power flowing into the node for some lines and power flowing out for others. A fraction of the loss (*LS*) is attributed to the load end of the line.

Demand is one of the key random parameters in the model. Given a distribution of peak and energy, the random sampling process draws a demand profile for each of the load blocks, and the dispatch optimization is repeated for each such demand sample (along with other random parameters). The first equation is used in energy-efficiency scenarios, and the second is used when energy efficiency is not part of the scenario.

The third equation limits transfers to the capacity of the transmission corridor (*pTransferLimit*) which is also randomly sampled.

EQ Set 6: Reserve Requirements

$$\textbf{MinCapReserve}_{b,y}$$

$$\sum_{i|\text{mapbi}_{b,i}} \left(\sum_{g|\text{mapig}_{i,g}} (\text{cap}_{g,y} \cdot \text{ReserveContribution}_{g,y}) \right) + \text{Unmetreserve}_{b,y} \geq (1 + \text{ReserveMargin}) \cdot max\{ \sum_{i|\text{mapbi}_{b,i}} \text{LDCBase}_{i,t,y} | t \} \qquad \forall b, y$$

Reserve is modelled for each territory (*b*). Although provision of regulation is fundamentally different from provision of contingency reserve, and the former is also governed by an additional set of constraints in real-time, the nature of constraints that are relevant in a long-term planning framework is largely similar across regulation and reserve. Contingency reserve response is expected to occur automatically when frequency falls, and generators with spinning reserve respond under 'free governor action." In the longer time frame, generators that are not currently synchronized may synchronize and commence generation. *ReserveContribution* is a factor that determines available capacity that contributes to the reserve requirements.

EQ Set 7: Fuel Consumption and Constraints

$$\textbf{FuelBal}_{i,f,y}$$

$$\text{Fuel}_{i,f,y} = \sum_{g|\text{map}_{g,f}} \left(\sum_{t} \left(\frac{\text{Gen}_{i,g,f,y,t} \cdot \text{Duration}_t}{0.293071 \cdot \text{GenData}_{g,\texttt{Efficiency}}} \right) \right) \qquad \forall i, f, y$$

$$\textbf{FuelLimitCon}_{i,NE,y}$$

$$\text{Fuel}_{i,NE,y} \leq \text{FuelLimit}_{1,NE,y} \cdot \text{FuelLimitFactor}_{NE,y} \qquad \forall i, NE, y$$

$$\textbf{JointFuel}_{i,IM,y,t}$$

$$\sum_{f|\text{map}_{IM,f}} \text{Gen}_{i,IM,f,y,t} \leq \text{cap}_{IM,y} \qquad \forall i, IM, y, t$$

The first equation defines the fuel consumption as a function of the generation from that type of fuel across all generating units over all load duration curve blocks in that year. We have assumed a constant heat rate over the entire generation range of a generator, but this can be changed to represent the detailed heat rate characteristic of the unit using a piecewise linear function. The second constraint is a simple bound on the maximum amount of fuel that is available in a year. It is also possible to represent any take-or-pay fuel contracts for individual generating stations or companies. For this stage of the planning exercise, we do not impose take-or-pay constraints, even though this is likely to be the case for gas supply. Our objective at this stage is to establish what volume of gas for the power sector is least cost. This, together with other domestic uses of gas in the West Bank and Gaza, will inform the structure of any take-or-pay contract, the details of which will need to be thoroughly analyzed. The third constraint ensures that total generation in every load block does not exceed rated capacity.

EQ Set 8: Variable Renewable Energy Profiles

$$\textbf{REProfileConsSolar}_{i,PV,y,t}$$

$$\sum_{f|\text{mapig}_{i,PV}} \text{Gen}_{i,PV,f,y,t} \leq \text{PVProfile}_{t,i} \cdot \text{cap}_{PV,y} \qquad \forall i, PV, y, t$$

$$\textbf{REProfileConsCSP}_{i,g,y,t}$$

$$\sum_{f|\text{mapig}_{i,g}} \text{Gen}_{i,g,f,y,t} \leq \text{CSPProfile}_{t,i} \cdot \text{cap}_{g,y} \qquad \forall i, g, y, t \mid (\text{GenData}_{g,\texttt{Type}} = 7)$$

$$\textbf{REProfileConsWind}_{i,g,y,t}$$

$$\sum_{f|\text{mapig}_{i,g}} \text{Gen}_{i,g,f,y,t} \leq \text{WindProfile}_{t,i} \cdot \text{cap}_{g,y} \qquad \forall i, g, y, t \mid (\text{GenData}_{g,\texttt{Type}} = 8)$$

$$\textbf{RECapAreaC}_{y}$$

$$\sum_{AreaC,te|(\text{GenData}_{AreaC,\texttt{Type}}=\text{TechIndex}_{te})} (\text{cap}_{AreaC,y} \cdot \text{LandUse}_{te}) \leq \text{AvailableLand}_{y} \qquad \forall y$$

EQ Set 9: Combined Solar and PV Capacity Cannot Exceed Total Land Available

$$\textbf{JointFuel}_{i,IM,y,t}$$

$$\sum_{f|\text{map}_{IM,f}} \text{Gen}_{i,IM,f,y,t} \leq \text{cap}_{IM,y} \qquad \forall i, IM, y, t$$

INPUT PARAMETERS

In this section, we describe the main inputs required for the model including the RE profiles, load blocks, and generator data.

Generator Data

Generators are defined by the parameters defined in table H.2. The Gaza Power Plant (GPP) is the only operating power plant. The installation costs for variable VRE technologies are modeled to reduce cover the planning horizon. The rate at which VRE prices reduce is sampled and discussed in a later section.

Renewable energy sources could be a significant part of the energy mix in the West Bank and Gaza, with total potential of between 3,100 and 4,000 MW (depending on the share of CSP and PV. See table H.3). There is considerable technical potential for solar PV and CSP (at least 98 percent of RE potential), but the bulk (at least 76 percent of potential solar generation) is in Area C of the West Bank and can be realized only if Israel grants access to the land. The technical potential for gas- or diesel-fired plants depends on the volume of fuel.

TABLE H.2: GENERATOR PARAMETERS

	FUEL	INSTALLATION COST (2018)	FIXED O&M	VARIABLE O&M	CONTRIBUTION TO RESERVE*	BASE UNIT SIZE	MAX REPAIR COSTS	HEAT RATE
		US$ PER KW	US$ PER KW PER YEAR	US$ PER MWH	%	MW	US$ PER KW	MMBTU PER MWH
Rooftop PV (PVr)[a]	Solar	2,591	15	0.0	0.0	0.0	864	0.0
Utility PV (PVc)[a]	Solar	1,646	13	0.0	0.0	0.5	549	0.0
Concentrated solar power or thermal (CSP)[a]	Solar	5,552	59	10.0	0.8	10.0	1,851	0.0
Wind (Wind)[a]	Wind	1,863	51	0	0.0	1.0	621	0.0
Biogas (Bio)[d]	Landfill/ manure	3,942	107	5.0	1.0	2.0	1,314	14.5[b]
Distributed diesel genset (DiesGen[b]	Diesel	800	15	15.0	1.0	2.0	263	10.0
Combined cycle gas turbine (CC)[b]	Gas/ diesel	1,300	6.2	3.5	1.0	140.0	433	6.7
Simple cycle gas turbine (GT)[b]	Gas/ diesel	1,000	25	7.5	1.0	100.0	333	9.0
Imports from Jordan[c]			5	0.0	Scenario		0.0	0.0
Imports from Israel[c]			5	0.0	Scenario		0.0	0.0
Imports from Egypt[c]			5	0.0	Scenario		0.0	0.0

Sources: [a] team estimates based on NREL Annual Technology Baseline; [b] high end of Lazard's levelized cost of energy analysis (version 9.0); [c] team estimates; [d] International Energy Agency, *World Energy Outlook*.
Note: O&M = operations and maintenance.
* A factor that determines available capacity that contributes to the reserve requirements. PV and wind, for example, are not firm and do not contribute to the reserve margin in the analysis.

TABLE H.3: POTENTIAL GENERATOR CAPACITIES

Gaza	Potential capacity (MW)
Rooftop photovoltaic (PVr)	163
Biogas (Bio)	2
Distributed diesel genset (DiesGen)	Unconstrained
Combined cycle gas turbine (CC)	Unconstrained
Simple cycle gas turbine (GT)	Unconstrained
West Bank North	**Potential capacity (MW)**
Rooftop photovoltaic (PVr)	210
Commercial photovoltaic (PVcAB) - Areas A and B	14
Wind (WindC) - Area C	9
Biogas (Bio)	10
Distributed diesel genset (DiesGen)	Unconstrained
Combined cycle gas turbine (CC)	Unconstrained
Simple cycle gas turbine (GT)	Unconstrained
West Bank Central	**Potential capacity (MW)**
Rooftop photovoltaic (PVr)	194
Commercial photovoltaic (PVcAB) - Areas A and B	7
Commercial photovoltaic (PVcC) - Area C	3,200
Concentrated solar power/thermal (CSP) - Area C	2,424
Biogas (Bio)	8
Distributed diesel genset (Diesel)	Unconstrained
West Bank South	**Potential capacity (MW)**
Rooftop photovoltaic (PVr)	131
Commercial photovoltaic (PVcAB) - Areas A and B	14
Wind (WindC) - Area C	36
Biogas (Bio)	7
Distributed diesel genset (DiesGen)	Unconstrained
Combined cycle gas turbine (CC)	Unconstrained
Simple cycle gas turbine (GT)	Unconstrained

Source: Team estimates.

While there continues to be several discussions with potential investors and the Palestinian Authority around new sources of generation, such as the Jennin power plant, there are no committed generation projects, so we do not include specific candidate projects in the plan. We instead use generic generators to determine the capacities of various technologies that are robust.

Electricity imports are modelled as generators with no CAPEX requirements. The fuel fixed operations and maintenance costs include the cost of providing ancillary services to the West Bank and Gaza, which is priced at US$12 MWh. The capacity is therefore optimized to minimize system costs within export limit constraints and gives the minimum transfer capacity when sizing the connection. Import sources considered are shown in table H.4.

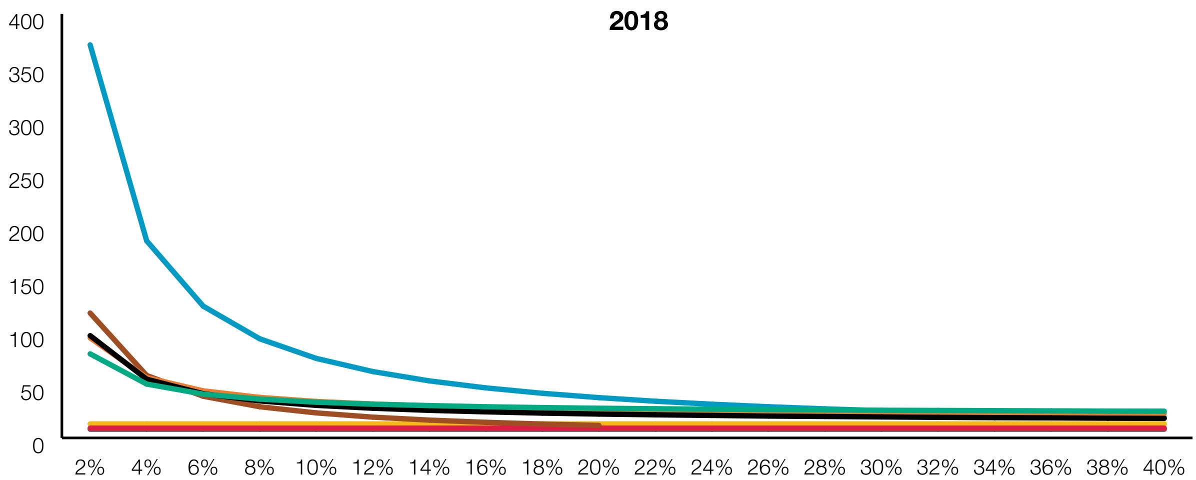
Under 2018 cost conditions, solar PV has the lowest levelized cost of energy (LCOE) of all technologies available, as shown in figure H.4. At low utilization rates, diesel has the lowest, costs making it a good candidate for providing backup services. This also means frequent outages, which affect the availability of plants, increases average system costs.

TABLE H.4: CURRENT CAPACITY AND PRICING OF ELECTRICITY IMPORTS

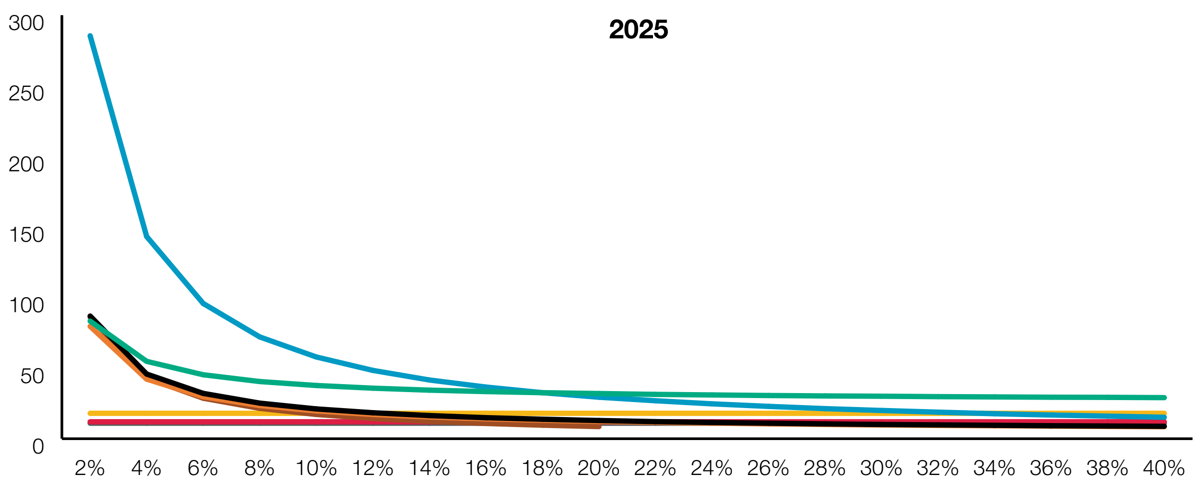
FROM	TO	CURRENT CAPACITY (MW)	2016 PRICE (US$ PER MWH)
Israel	West Bank	800	90.0
Israel	Gaza	120	90.0
Jordan	West Bank	30	95.9
Egypt	Gaza	10	50.0
Egypt	West Bank (through Jordan)	0	N/Aa

Source: Team estimates.
a There is currently no power import from Egypt to the West Bank, but this could include the cost of generation of US$81 per MWh to Egypt and US$6.5 per MWh wheeling charges to Jordan based on current transmission wheeling charges for renewables in Jordan at 4.6 Jordanian fils per kWh.

Figure H.4: Comparison of LCOE in U.S. Cents per kWh for Technology Options

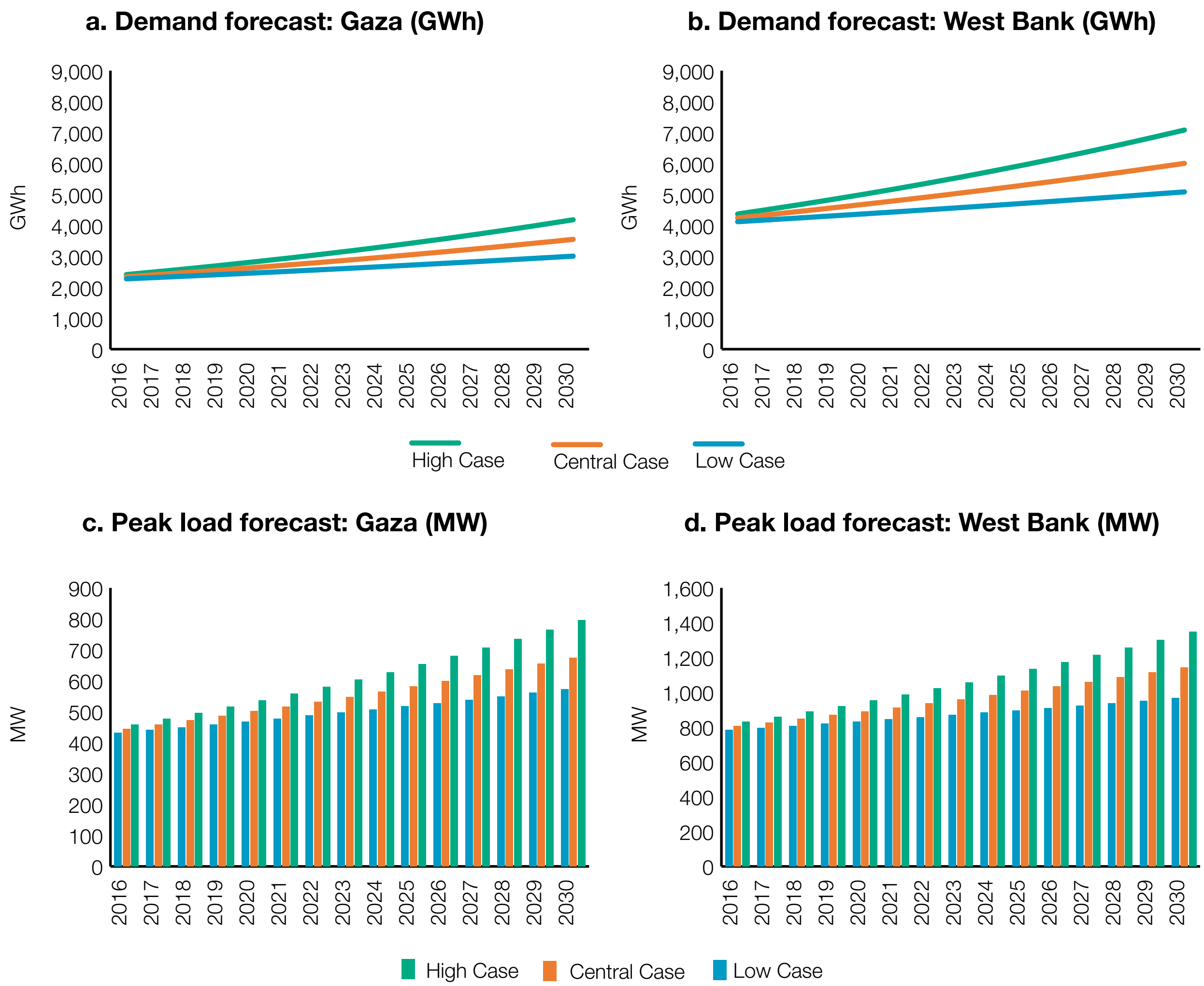


Notes: CAPEX and O&M as shown in table H.3: Diesel = 21 US$ per MMBTU; WACC = 10%; 20-year life for PV and 30 for all others.



Notes: CAPEX and O&M as shown in table H.3: Diesel = 34.2 US$ per MMBTU; Gas = 5.5$ per MMBTU; WACC = 10%; 20-year life for PV and 30 for all others

Figure H.5: Forecast Demand and Peak Load in West Bank and Gaza



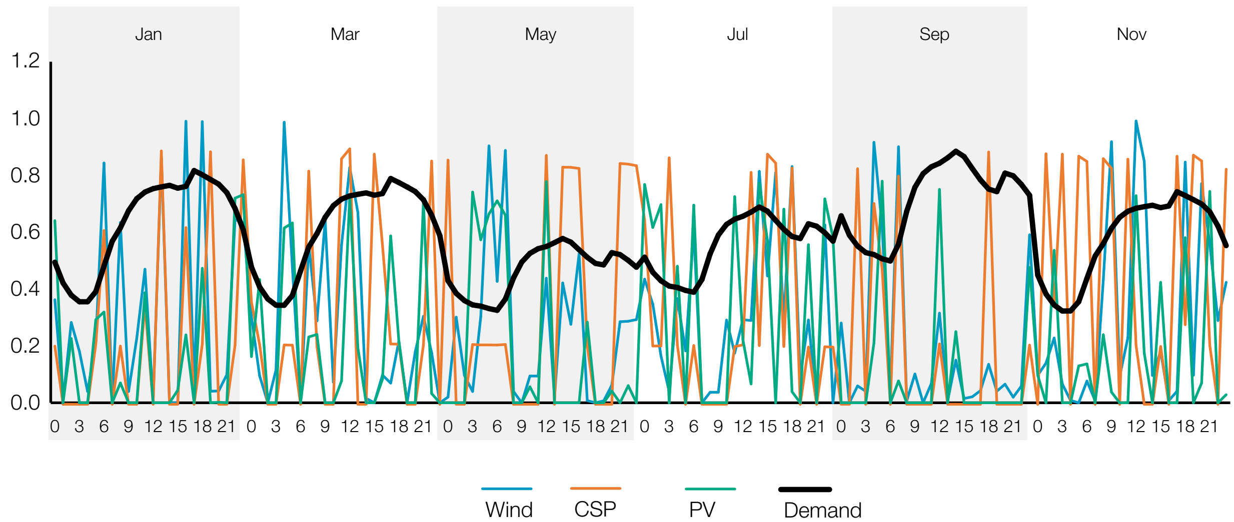
As the utilization rate increases, the high cost of diesel makes these far less attractive. Scale efficient units like CCGTs become more cost effective. We also see CSP outperforming CCGT running on diesel due to the high cost of diesel. These comparisons do not take into account other benefits of the various technologies, such as the provision of ancillary services and system support for thermal units, and avoided generation emissions for renewable energy technologies. A different picture emerges in 2025 when the CAPEX for solar PV in particular is expected to be lower and gas is more likely to be available. In this scenario, the LCOE for CCGT at 70 percent utilization is on par with the LCOE for utility-scale PV at US$0.54 per kWh at a gas price of US$5.5 per MMBTU. CSP costs are also lower, with a high end LCOE close to 15 US cents per kWh.

Demand Data

The demand forecast developed shows a wide range of uncertainty in outer years, rising to nearly 40 percent of the low forecast scenario in 2030. Peak demand forecast was calculated with an assumed load factor of 60 percent based on historical data from Jerusalem District Electricity Company (JDECO). The resultant peak load is between 1,800 MW and 2,500 MW in the West Bank and Gaza, respectively (figure H.5).

The peak and energy forecasts were used to develop load blocks for each year in the horizon. (Load blocks are used to reduce the size of the LP and computing resource requirements.) In the absence of system data, load blocks were developed using simulated

Figure H.6: 24-Hour Profiles from Selected Months for West Bank



hourly load data. Ideally, a year of system hourly load data is the least requirement to first generate the load duration curve and then the load blocks. This becomes even more critical if variable renewable resources are included in the model, because the coincidence between hourly load data and renewable resource availability is important.

For this analysis, we obtained daily load curves for the winter and summer seasons for the Jerusalem area from the distribution company (JDECO). This gives a sense of the daily characteristics of demand. The same daily curve was assumed for the West Bank and Gaza. The same profile was assumed for weekends and weekdays but was shifted downward to simulate lower demand on weekend days. We also obtained monthly energy consumption for the West Bank, which gives a sense of the seasonality and month-to-month variations in demand. Combining this data, we generated a rudimentary load duration curve that characterizes monthly load and seasonal day load variations. The load block definition was maintained for all forecasted years and every demand growth path (low, medium, high, and robust).

The demand for West Bank was distributed across the three zones using historical sales data from the distribution companies. Fifty-four percent of the load was allocated to central West Bank, 26 percent to northern West Bank, and 20 percent to southern West Bank, as shown in table H.5.

TABLE H.5: DISTRIBUTION OF DEMAND IN THE WEST BANK

ZONE	SHARE OF WEST BANK DEMAND
West Bank North	26%
West Bank Central	54%
West Bank South	20%

Renewable Energy Data

Variable renewable energy technologies considered were wind and solar for PV and CSP applications. Unlike a broad resource assessment for a region, hourly energy output data is required to ensure that output is correctly matched to the various load blocks. The system advisor model from the National Renewable Energy Laboratory (NREL) was used to calculate hourly energy output from resource data for all three technologies.[7]

Solar (PV and CSP): To consider year to year variations in solar data, we use typical meteorological year (TMY) data provided by various bodies and entities. TMY data includes monthly data that represent typical conditions and is selected from a multiyear data set.[8] The study utilized TMY data from three locations in Israel that are close to West Bank Tel Aviv for northern West Bank, Atarot for central West Bank, and Bersheva for southern West Bank. TMY data from Al Arish in Egypt was used for Gaza.9

Wind: Hourly wind speed data is not as readily available as irradiation data for most locations. To obtain hourly data for the study, we scaled wind speeds from weather station data (which is typically measured at approximately 10 meters) to 80 m eters. 10

Understanding the complementarity between wind and solar resources will require several years of data, but the daily profiles used show that wind and solar output coincide with each other as shown in figure H.6. CSP could be used to better complement the resources.

Other Input Assumptions

Cost of capital. The weighted average cost of capital is assumed at 10 percent.

Discount rate. The discount rate used to determine the system net present value is assumed at 10 percent.

CHARACTERIZING UNCERTAINTIES

In this section, we discuss the representation of uncertainties in the model. While most of the uncertainties stem from the political conditions, others such as uncertainties around demand forecasts and fuel prices are common to most power systems.

Demand

Demand is sampled between the low forecast and high forecast. The uncertainty is observed in the rate at which demand will grow. We first select a demand point in the first year, and then for each subsequent year we select a demand point between the demand of the preceding year and the high load forecast trajectory. This ensures demand increases steadily (albeit at an unknown rate) as would be expected in the West Bank and Gaza.

Fuel Volumes and Pricing

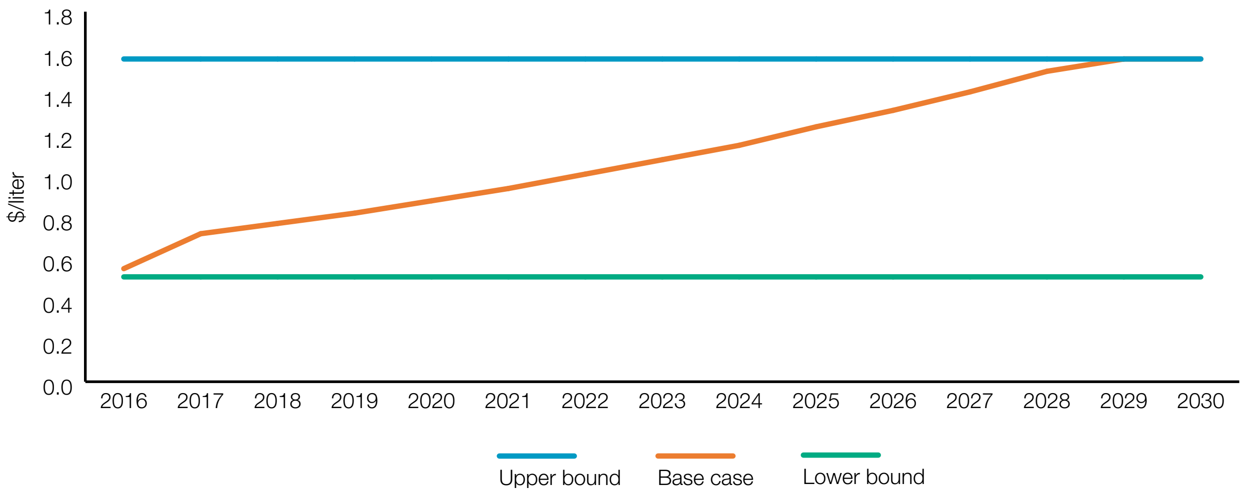
Natural gas. Gas from various fields is considered as potential fuel for both Gaza and the West Bank with variable timing, volumes, and pricing: for example, from different gas fields in Israel available in the north of West Bank, from Gaza or Egypt in the south of West Bank (table H.6). The model is passive to the source of gas and the matrix is simplified, with three sources of gas: one source for Gaza (GazaGas); one for the south of the West Bank (WB_SouthGas, for plants such as Hebron); and a third source for gas in the north (WB_NorthGas, for plants such as the Jenin). Each source of gas has a range of dates gas could be expected, an associated range of possible volumes, and a range of prices. The sampled scenarios draw from these ranges to determine the year gas is available for power production, the volume, and its price.

TABLE H.6: UNCERTAIN PARAMETERS AROUND GAS SUPPLY FOR POWER GENERATION: TIMING, VOLUME, AND PRICING

	AVAILABLE FOR POWER		ANNUAL VOLUME (BCM)		PRICE (US$ PER MMBTU)	
	Earliest	*Latest*	*Min*	*Max*	*Min*	*Max*
Gaza gas	2022	2035	0.2	2.0	4.00	7.50
WB North gas	2021	2035	0.2	2.0	4.00	6.50
WB South gas	2024	2035	0.2	2.0	4.00	7.50

Source: Team estimates.
Note: bcm = billion cubic meters; MMBTU = million British thermal units.

Figure H.7: Diesel Price Range



The sampled volume is the maximum annual volume of gas used for the planning horizon. For example, if the sampled parameters for Gaza gas are 2025 available year, 1.3 billion cubic meters (bcm) volume and price of 5.2 $ per MMBTU, there is no gas available in the model until 2025 and 1.3 bcm available from 2025 at a price of 5.2 $ per MMBTU.

Diesel. The volume of diesel is unconstrained in the model unless an incident reduces supply. Shortages in the past have largely been due to the inability to pay for fuel. Future diesel prices follow the trajectory for international oil price forecasts. Between 2000 and 2015, oil prices in real 2010 U.S. dollars ranged between $32 and $98 per barrel or 66 percent and 200 percent of 2015 prices.11 There is a strong correlation between the price of diesel and crude oil in most markets (EIA 2015), so we assume range of 66–200 percent of the average cost of fuel for GPP in 2015 as an uncertainty range for the price of diesel. Therefore, the price per liter of diesel for every year is sampled between $0.51 and $1.57 for every scenario (see figure H.7).

The volume of diesel is unconstrained. There is a risk to the availability of fuel caused either by damage to pipelines (in the case of gas supply) or restrictions to the movement of fuel tankers (for diesel) this is dealt with in a later section.

Import Volumes and Pricing

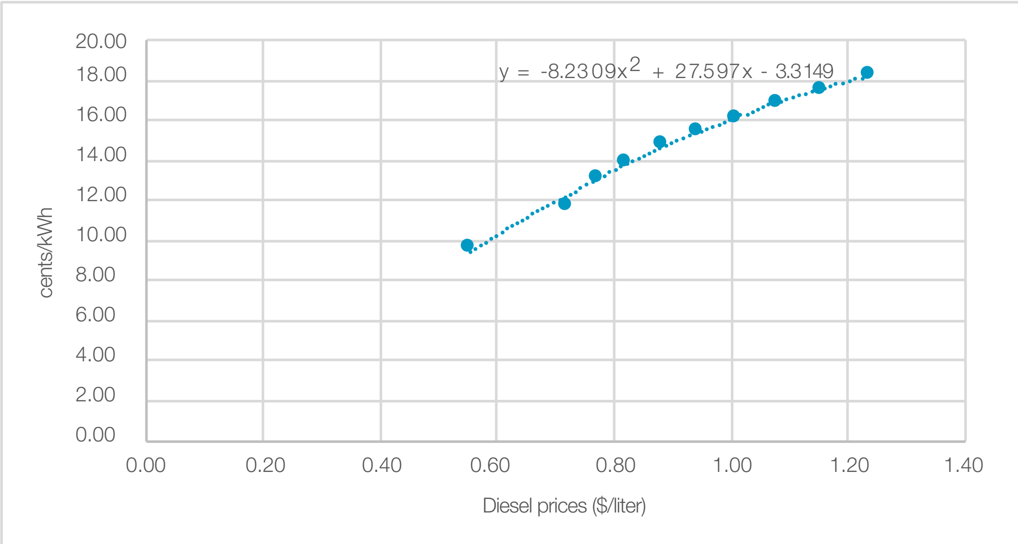
Two forms of uncertainties are simulated for power imports: (i) when import limits could increase due to changes in the West Bank and Gaza's network to accept higher imports or changes in the generation and network capacity of exporting countries to be able to export more power and (ii) import prices following a change in import volumes.

We first sample a year when anticipated changes in the networks allow for increased power imports. Capacity before this year is fixed at current levels and then allowed to increase to an upper limit from the sampled year. For some imports, the upper limit is also a range, because it is unclear. After the capacity change, the price is sampled between the price of a preceding year and an upper limit.

The cost of imports from Jordan is indexed to the cost of fuel, but other import sources are independent of fuel prices because they are largely based on national gas reserves and contracted under long-term purchase agreements.

Imports from Israel. The increase in power imports from Israel to West Bank is contingent on the commissioning of four transmission substations in West Bank. Electricity imports could increase from 850 MW in 2017 to between 1,400 MW and 1,800 MW in 2020.

Figure H 8.9: Relationship between Cost of Imports from Jordan and Diesel Prices



The current import from Israel to Gaza is approximately 120 MW and could be increased to between 220 MW and 270 MW in 2022.

The Israeli Electric Corporation (IEC) sells electricity to JDECO at time-of-use tariffs, but to the rest of the West Bank and Gaza at a bulk tariff rate of approximately US$90 per MWh (close to the weighted average of the time-of-use tariffs). There is the possibility that the rest of the West Bank and Gaza will be transitioned to time-of-use tariffs. There is also the likelihood that the price of electricity sold to the West Bank and Gaza will increase with the change in import volumes. The team estimates this to be up to US$110 per MWh.

Pricing before the change in import limit is increased by 1 percent per annum. The 1 percent annual increase then continues from the new price. Consider an example in which 2020 is the year sampled for an increase in Israeli imports into West Bank. By 2020, the cost of imports would be approximately US$92.7 per MWh due to the 1 percent change in prices. The price beyond 2020 is sampled between US$92.7 per MWh and a defined upper limit. If the new price is sampled as US$95 per MWh, for example, it is applied from 2021 and increased at 1 percent per annum from 2022.

Imports from Jordan. An increase in power imports from Jordan to the West Bank is contingent on upgrading the current connection and the availability of excess capacity and energy in Jordan. Both parameters are uncertain, as is the price at which power will be sold eventually. It is estimated that the earliest the connection could be upgraded is 2022, increasing import capacity up to 1,000 MW. The cost of imports from Jordan is indexed to fuel prices. The relationship is simplified using the polynomial function that best approximates the correlation between forecast fuel prices and forecast tariffs from 2016 to 2025 as shown in figure H.8.

Imports from Egypt. An increase in power imports from Egypt to Gaza is contingent on upgrading the current distribution link through the Sinai region, increasing the capacity of the grid in Gaza, the availability of excess generation in Egypt, and power transfer capability of the Egyptian network to wheel power to the point of the connection line. The earliest this could be expected is estimated to be in 2021 at a capacity of 70–150 MW (see table H.7).12 Because this is uncertain, the volume of imports is also sampled within this range.

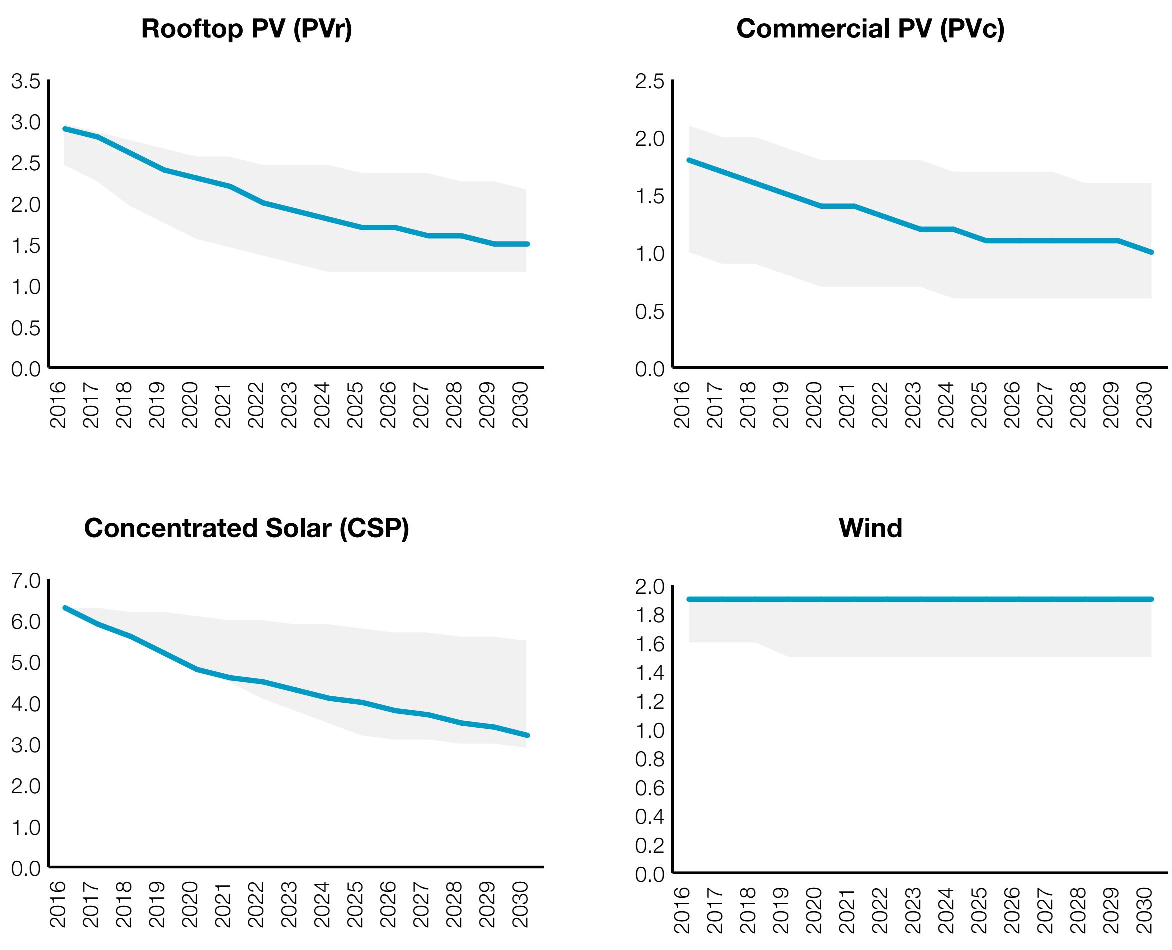
Jordan is connected with the Egyptian network at 500 kV, and it is possible for Jordan to wheel power from Egypt through to the West Bank. This is contingent on the completion of the Green Corridor project by 2018–19 and the availability of excess capacity and energy in Egypt.[13] If this is incremental to current exports from Jordan, the Jordan-West Bank connection needs to have been commissioned as well. An additional 50–200 MW could be wheeled to Egypt through Jordan.

TABLE H.7: CHANGES IN ELECTRICITY IMPORT SOURCES AND CAPACITIES

FROM	TO	CHANGE IN CAPACITY		CAPACITY (MW)		PRICE AFTER CHANGE ($ PER MWH)	
		Earliest	*Latest*	*Before*	*Max After*	*Min*	*Max*
Israel	West Bank	2020	2030	850	1400-1800	Preceding year	110
Israel	Gaza	2022	2035	120	270	Preceding year	110
Jordan	West Bank	2022	2035	30	100-200		Based on oil price
Egypt	Gaza	2021	2035	10	70-150	81	100
Egypt	West Bank	Same as Jordan-West Bank		0	50-200	87.5a	106.5a

Source: Team estimates.
a Same rate sold to Gaza plus US$6.5 per MWh wheeling charge to Jordan.

Figure H.9: CAPEX Range for VRE Technologies (US$ per Watt)



Notes: Base case scenario CAPEX estimates based on NREL's 2016 Annual Technology Baseline. Lower bounds and upper bound for wind are estimated by NREL in the 2016 Annual Technology Baseline. For wind, CAPEX is expected to increase due to the need for higher masts and bigger turbines to maximize low wind speeds. Upper bound for PV is from the International Energy Agency (IEA) *World Energy Outlook*. Upper bound for CSP is calculated by team using IEA trajectory for CSP without storage.

Cost and Land Access for VRE technologies

Installation costs for VRE technologies are expected to decline, but the speed of decline is unclear (see a comparison of costs by NREL for example.)14 Investment cost estimates for the region produced by the International Energy Agency for the *World Energy Outlook* are considered to be on the high side, especially when compared with the results of tenders from various countries.[15] (For example, a recent bid in Zambia yielded US$0.06 per kWh.) While this is unlikely to be the case in the West Bank and Gaza, there is uncertainty around what could be expected in the future. We therefore include a range of installation costs for VRE technologies. The team's CAPEX estimates are based on NREL's 2016 Annual Technology Baseline and the range of CAPEX variation is shown in figure H.9. We ensure that CAPEX for rooftop and utility-scale PV are increased or reduced in tandem, but assume that the CAPEX for wind and CSP are independent from other technologies.

CSP and PV have different land requirements, capital costs and generation profiles. CSP requires 30 percent more land per MW installed, and is more than three times more expensive than PV but is dispatchable, while PV is not. The share of CSP and PV is optimized by the model subject to land constraints. The land constraint is defined by EQ Set 9, which ensures that the total installed capacity of CSP and PV does not exceed available land. As noted, at least 76 percent of the solar potential is in Area C, and therefore projects are subject to Israel granting access to the site. We assume the earliest the West Bank and Gaza could access Area C is 2018 and the latest date of 2035. Allowing for a two-year construction period, the earliest solar projects are allowed from 2020.

The study demonstrates the benefit of utilizing the solar resource in Area C, so the model is set up such that from the year access is granted, all potential land is available for use. We do not take the fact that access is granted on a project-by-project basis into consideration.

Fuel Interruptions and Plant Outages

There are several risks that could ultimately affect the volume of fuel available for power generation including the risk of vandalism to gas pipelines, reduced fuel volumes due to lack of payment and restrictions to the transportation of diesel. We define a probability of outage on the sources of fuel supply and a range of availability for each year as shown in table H.8.

The annual probability of interruption and availability of fuel are selected to show the relative risks associated with different sources following discussions with various stakeholders. The probability of outage on imported electricity together with the availability also captures possible challenges in exporting countries.

A similar set of risks apply to power plants and the connection lines. Centralized plants are more vulnerable to destruction than decentralized options. In the model, we specify a share of installed capacity that is taken out of service when there are damages. This percentage is assumed to be 50 percent, 75 percent, or 100 percent of capacity for centralized units and less than 5 percent for decentralized units. In effect, this penalizes larger units because the availability can be significantly reduced due to damages that affect the cost per unit of production.

TABLE H.8: ANNUAL PROBABILITY OF OUTAGE AND MINIMUM AVAILABILITY FOR FUEL SOURCES

	PROBABILITY OF INTERRUPTION	MINIMUM AVAILABILITY
Gaza Gas	0.12	0.3
West Bank North gas	0.05	0.6
West Bank South gas	0.10	0.6
Gaza diesel	0.40	0.3
West Bank diesel	0.30	0.4
Israel imports	0.02	0.8
Jordan imports	0.05	0.7
Egypt imports	0.20	0.6

Source: Team assumptions.

Damages incur costs to the system determined by *RepairCosts*. Without knowing a priori the extent of damage, it is difficult to assess the costs or length of outage. For example,, replacing the step-up transformers or fuel tanks to a gas plant both result in a complete shutdown of the plant, but the cost implications and duration of outages are completely different. In the model, we assume the cost of repairs to be a third of the cost of installation and randomly select a duration of outage between a full year to as little as one month.16 The availability of plants is calculated as follows:

(1-Share of Damaged Capacity) × *(1–Duration of Outage)* × *Max Availability of Plant*

Plants in Gaza are at a higher risk than those in the West Bank, as shown in table H.9.

TABLE H.9: ANNUAL RISKS ASSOCIATED WITH GENERATORS

GAZA	PROBABILITY OF DAMAGE	PERCENT OF CAPACITY SUBJECT TO DAMAGE	MINIMUM DURATION OF OUTAGE (% OF YEAR)	MAXIMUM DURATION OF OUTAGE (% OF YEAR)
Rooftop PV (PVr)	0.05	1	8	50
Biogas (Bio)	0.05	100	10	80
Distributed diesel genset (Diesel)	0.10	1	10	80
Combined cycle gas turbine (CC)	0.15	50-100	10	100
Simple cycle gas turbine (GT)	0.15	50–100	10	100
Israel – Gaza	0.02	100	5	25
Egypt – Gaza	0.20	100	8	50
WEST BANK	**PROBABILITY OF DAMAGE**	**% OF CAPACITY SUBJECT TO DAMAGE**	**MINIMUM DURATION OF OUTAGE (% OF YEAR)**	**MAXIMUM DURATION OF OUTAGE (% OF YEAR)**
Rooftop PV (PVr)	0.05	1	8	50
Commercial PV (PVcAB)	0.05	1	10	70
Concentrated solar power/thermal (CSP)	0.10	50-100	10	100
Wind (WindC) - Area C	0.05	5	10	80
Biogas (Bio)	0.05	100	10	80
Distributed diesel genset (Diesel)	0.10	1	10	80
Combined cycle gas turbine (CC)	0.10	50–100	10	100
Simple cycle gas turbine (GT)	0.10	50–100	10	100
Israel – West Bank	0.02	100	5	25
Jordan – West Bank	0.10	100	5	70
Egypt – West Bank	0.15	100	5	70

source: Elaboration based on team assumptions.

Distribution of Uncertain Parameters
Multiple experiments were performed to develop the capacity plan and, before discussing the results of the analysis, it is worth examining the uncertain parameters to understand their distribution. The energy demand for 2030 sampled across multiple scenarios is negatively skewed with a mean of 4,032 GWh and 6,856 GWh in Gaza and the West Bank, respectively, as seen in figure H.10. This is higher than the 2030 median forecast of3,548 GWh and 6,004 GWh. We can also see that 30 percent of scenarios sample 2030 PV prices at or below US$1 per W, and the cost of CSP is relatively high in comparison. The price range for gas between US$4 per MMBTU and US$7.5 MMBTU (which translates to US$0.027–0.05 per kWh for the fuel cost assuming a CCGT) makes it a competitive option, so the critical parameter related to gas is the timing or availability. Eighty-three percent of the experiments included the availability of gas in the West Bank by 2030 compared with 66 percent of samples in Gaza. This is because there are two likely sources of gas in the West Bank (either north or south) and gas in the north has an earlier likelihood of materializing. Finally, access to Area C in the West Bank is critical for large-scale deployment of solar technologies and construction of the transmission backbone; 68 percent of the samples allowed access to Area C by 2030, with 30 percent allowing access by 2022.

Figure H.10: Distribution of Uncertain Parameters from the Experiments

a) Distribution of energy demand in 2030 in Gaza and West Bank (GWh)

b) Distribution of CAPEX for CSP and Utility-scale PV in 2030 (US$ per kW)

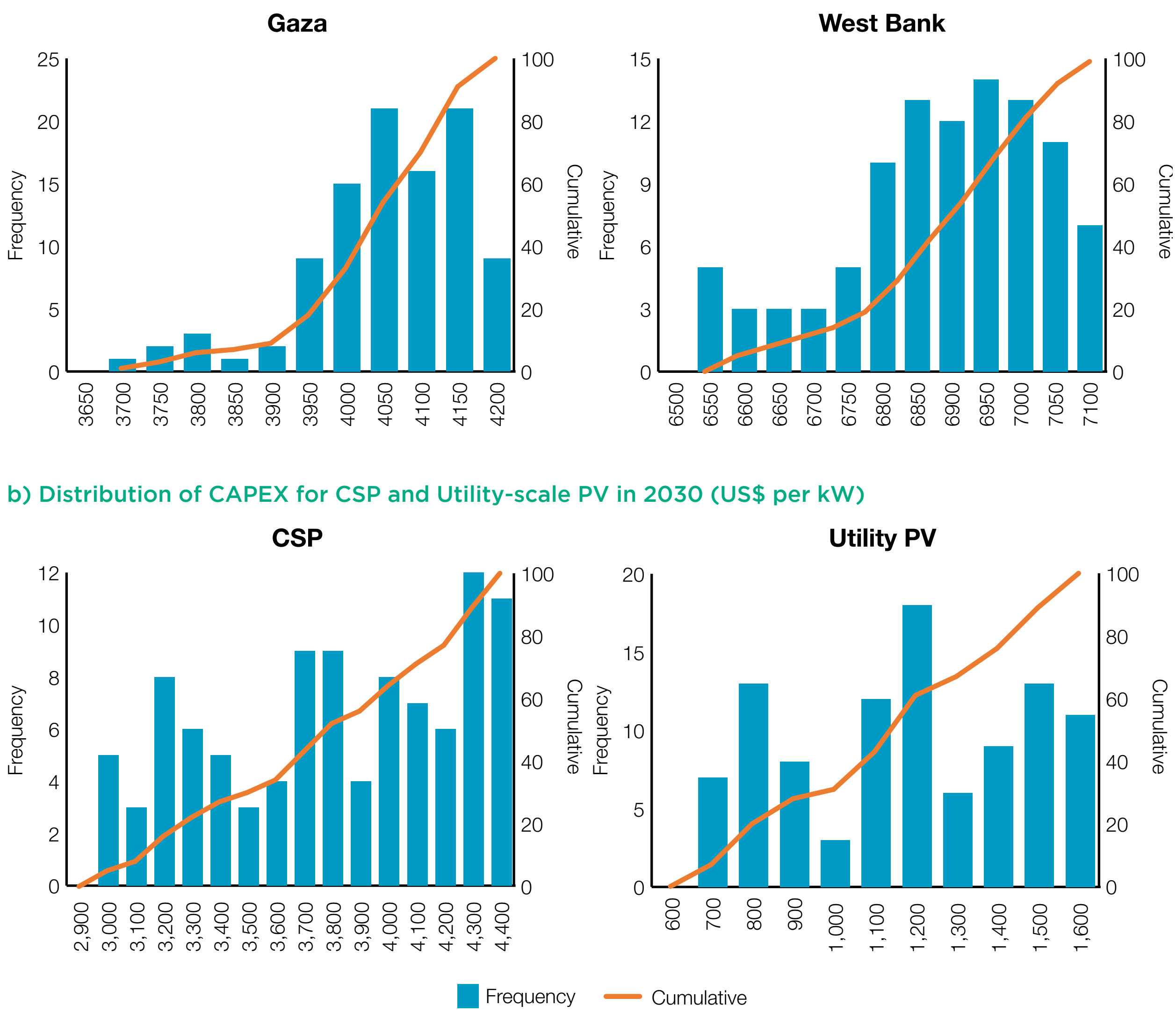
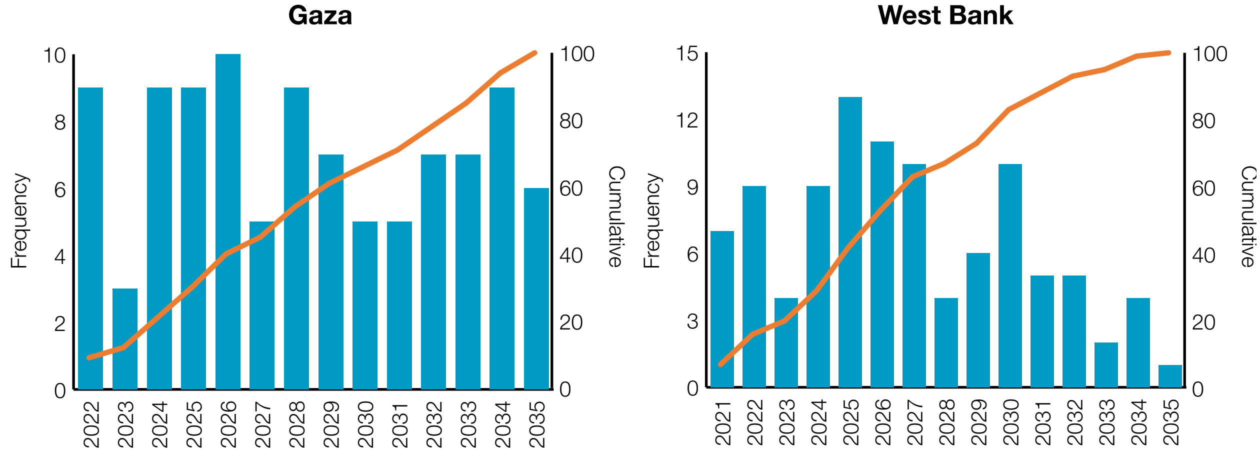
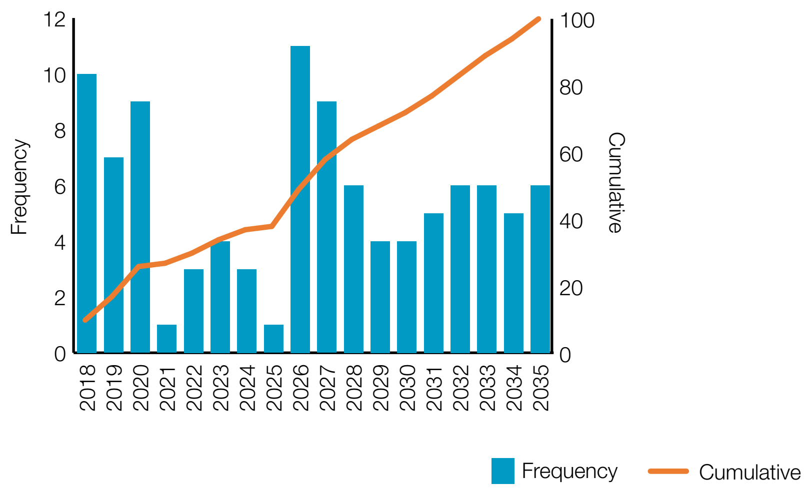


Figure H.10: Distribution of Uncertain Parameters from the Experiments (continued)

c) Distribution of the timing of gas for power production in Gaza and West Bank (year)



d) Distribution of access to Area C in West Bank



Source: Team elaboration.
NOTES: The charts show the underlying frequency distribution of the labeled parameters. The bar charts show the number of times a value on the x-axis is sampled. For example, in panel a for Gaza, 21 samples had projected demand at 4000 GWh in 2020. The curves show the cumulative frequency of the labeled parameters. The unit of the x-axis is indicated in parenthesis in the title of each panel.

Combining these randomly generated parameters yields a vast array of possible future scenarios, each with a different set of implications. For example, a scenario with access to Area C by 2020 may have a relatively higher PV CAPEX trajectory resulting in little installed PV or vice versa. To keep track of the multiple future scenarios, we adopted a scoring system from which we can assess the underlying conditions for each scenario.

DETAILED RESULTS

This section describes the scenarios analyzed, highlighting the differences in results with the aim of providing insights to these differences. A discussion of the policy implications and relevance of the scenarios to the West Bank and Gaza is found in the main report.

Nine expansion scenarios were developed for the West Bank and six for Gaza to answer the questions raised by the study. The scenarios are not necessarily incremental, and some are used to illustrate the impact of modelling and policy choices, as described in table H.10.

Additionally, existing capacity options are tested and a situation where no action taken is also simulated to show the impact of inaction.

TABLE H.10: EXPANSION PLANS DEVELOPED TO ANSWER STUDY QUESTIONS

SCENARIOS	DESCRIPTION
	West Bank
WS1: Classic least cost	Least-cost plan based on a best estimate of the future in the West Bank and Gaza with reserve requirements satisfied domestically (high security)
WS2: Domestic reserves	Robust expansion plan that considers uncertainties with reserve requirements satisfied domestically (high security)
WS3: Shared reserves	Robust expansion plan that considers uncertainties with reserve requirements shared with imports (partial reliance on electricity imports for security)
WS4: Area C access	WS3 with full access to Area C from 2018
WS5: Cost cap	WS3 with system average cost capped at IE import tariffs
WS6: PENRA Vision	Palestinian Energy And Natural Resources Authority (PENRA) Vision to limit generation from any source to under 50%, with IEC providing reserves
WS7: Planned Future	Scenario with current generation options under consideration by PENRA
WS8: High IEC	Scenario with full supply from IEC and minimal investments in near-committed RE projects
WS9: Do Nothing	Continuation of the status quo with limited increase in IEC imports
	Gaza
GS1: Planned Future	Scenario with current generation options under consideration by PENRA
GS2: PENRA Vision	PENRA Vision to limit generation from any source to under 50%, with IEC providing reserves
GS3: Full supply with GPP	Full supply to Gaza with the Gaza Power Plant (GPP)
GS4: High IEC	Full supply to Gaza with IEC and GPP shut down and minimal investments in RE
GS5: Meet demand with gas	Full supply with gas from Gaza marine gas fields
GS6: Do Nothing	Continuation of the status quo with limited increase in IEC imports

A deterministic least-cost plan could be costly because it is tailored for a particular scenario, and there is a high chance of regret or failure or underutilized assets when underlying assumptions change. To improve the resilience of the capacity plan to uncertainties, we employ the methodology described to develop subsequent capacity plans. A plan that performs well under uncertainty may not necessarily be optimal for any one particular future scenario—even the most likely future scenario—but will reduce the risk of over- or underinvestment. We first look at a robust plan that ensures the West Bank is able to cover all contingencies internally.

Given that there is currently very little installed capacity, such a plan will require significant investments over short periods. We therefore look at a scenario where reserve requirements are shared with interconnected systems to benefit from one of the main benefits of such connections—that is, the distribution of reserve capacity requirements among them. Given the high potential of solar in Area C, the impact of access to Area C on generation options is evaluated in WS4. In WS5, we examine the impact imposing cost constraints on the model based on the policy of the PA to cap the cost of energy to the costs of imports from IEC. These scenarios are only relevant for the West Bank, because supply options to Gaza are much more limited and most constraints result in unmet demand.

Scenarios WS6 and GS2 evaluate PENRAs long-term vision to limit electricity generation from any source to under 50 percent, which diversifies the energy mix.

Apart from S1, in which parameters were fixed, most other cases considered uncertainties around demand, fuel pricing, and availability as described in previous sections. Features of the scenarios are described in Table H.10.

The presentation of results follows the sequence of questions raised. Results for the West Bank are first presented, followed by results for Gaza.

West Bank

A Classic Least-Cost Plan

In a deterministic analysis, what does a least-cost capacity expansion plan look like, which ensures the West Bank and Gaza are self-reliant and able to meet demand securely (assuming there no capital constraints)?

A classic least-cost plan based on the planners' best estimate of the future performs extremely well if that future materializes. Under the static conditions described in Table H.11 , power generation switches from IEC imports to gas and meets entire demand (Figure H.11 – panel a). At approximately 6 US cents per kWh, CCGT is the least-cost option when gas is available followed by utility-scale PV at approximately US$1,041 per kW and US$0.07 per kWh. Also, 410 MW of distributed diesel capacity is installed from 2018 largely to satisfy reserve margin requirements and this is maintained through to 2030 (Figure H.11 – panel b).

TABLE H.11: UNDERLYING ASSUMPTIONS FOR THE DETERMINISTIC PLAN

PARAMETER	ASSUMPTION
Demand	Central case
Diesel prices	Base case
Gas prices	US$5.75 per MMBTU
Increase in Israel–West Bank	2021
Increase in Jordan–West Bank	2024
Egypt–West Bank	2024
Increase in Israel-Gaza	2024
Increase in Egypt-Gaza	2023
Israel import price	US$90 per MWh + 1% p.a.
Jordan import price	Based on diesel price
Egypt import price	US$81 per MWh + 1% p.a.
Timing of gas (West Bank)	2022
Timing of gas (Gaza)	2023
Volume of gas (West Bank)	1.1 bcm
Volume of gas (Gaza)	1.1bcm
Reserve margin requirements	15%
Access to Area C	2020
Financial constraints	No
Unplanned outages	No
RE CAPEX	Base case

Figure H.11: Energy and Mix and 2030 Capacity Share in a Deterministic Scenario

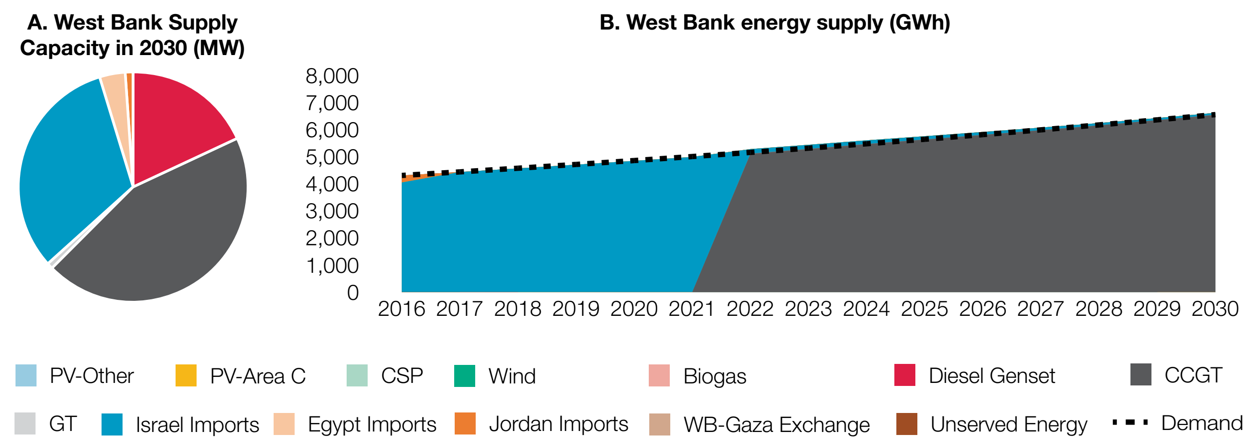
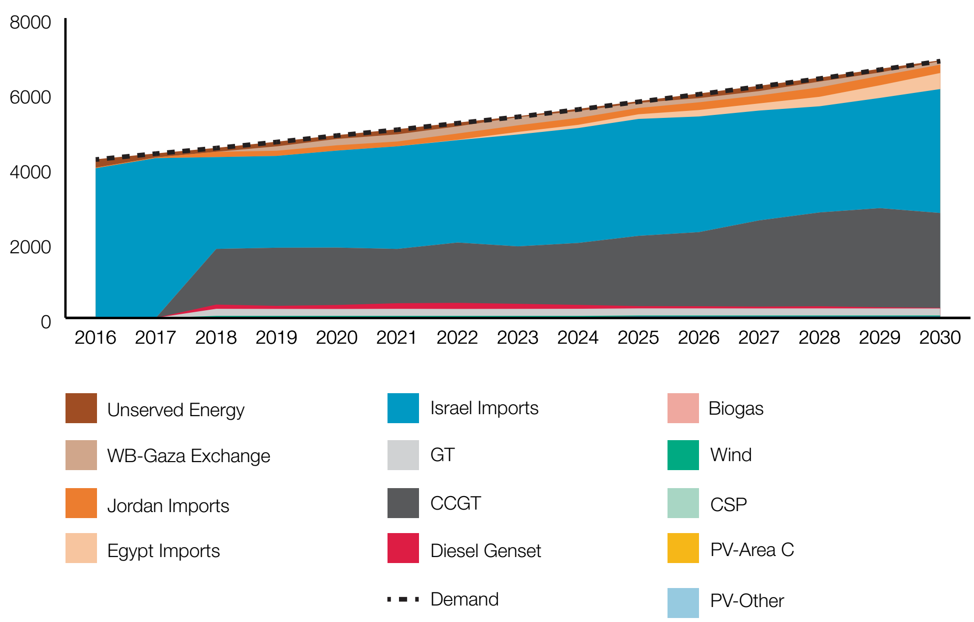


Figure H.12: Energy and Mix for the Deterministic Plan under Test Conditions



How well does the least-cost plan perform under uncertainty?

To test the performance of the classic least-cost plan, it is subjected to 100 simulations in which various parameters such as demand, fuel availability and pricing, disruptions, and import volumes are varied. On average (across the 100 samples), the share of gas in the energy mix drops to 45 percent, largely substituted by imports from Israel (figure H.12).

In terms of reliability measured by the level of unmet demand, there is little impact, as unserved energy is just 334 GWh over the planning horizon. Outages are covered by a combination of diesel generators and imports from Egypt, Jordan, and Israel. However, a comparison of costs shows that undiscounted system costs nearly double, from US$8.7 billion to US$16.5 billion (figure H.13).

Figure H.13: Comparison of System Costs for the Deterministic Scenario (US$ billions)

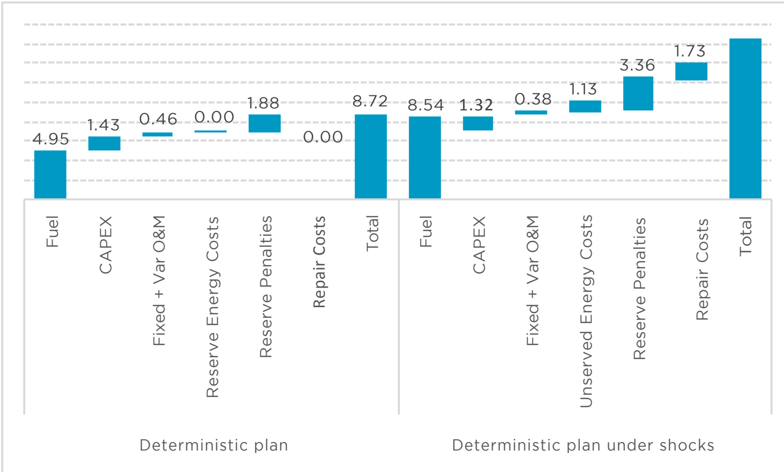
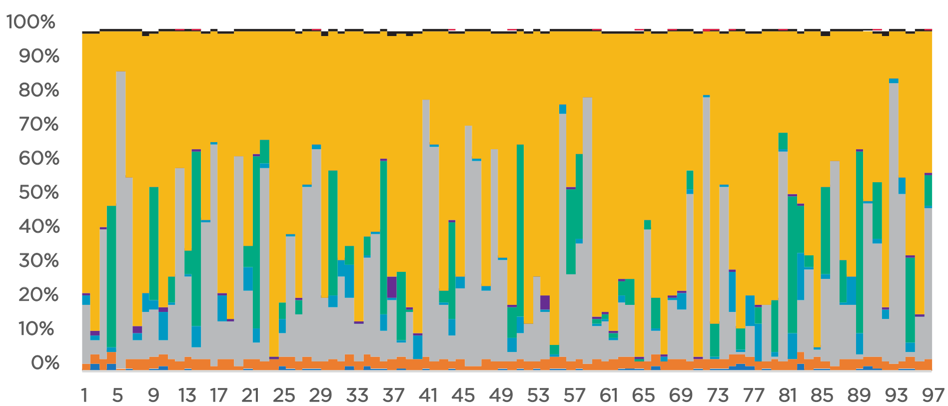


Figure H.14: Total Energy Mix for 100 Possible Future Scenarios (2020–2030)



In some scenarios, gas materializes earlier than 2023, so on average there is some gas in 2022. This helps reduce system costs, but the gains are offset by the other scenarios when gas is available beyond 2023. Absent gas is replaced by imports to the extent permitted. Destructions also add to the cost, but the highest change in costs is due to higher fuel costs (US$3.6 billion higher) as gas is substituted with more expensive options when delayed or unavailable.

Incorporating Uncertainties

What are the features of a capacity plan that ensures that the West Bank can respond to a wide range of uncertainties including contingencies around electricity imports? What are the cost implications of such a plan?

An optimal capacity plan was generated for multiple sampled scenarios. Each plan is perfectly suited for the particular scenario, but the plans will perform differently across multiple scenarios. One hundred future scenarios were developed and for each of these, a capacity plan was generated using the core LP model.

As seen from figure H.14, IEC imports continue to be a steady source of imports for West Bank across multiple scenarios. Generation from gas (CCGT) is also prominent as well as PV which was not picked up in the deterministic scenario.

In terms of capacity, the standard deviations in figure H.15 show Israel imports provide a steady source of capacity. Technologies like CSP are also picked up in later years, when access to Area C is granted. There is wide range around the solar PV capacity in Area C due to the combination of CAPEX and access to land. Diesel generators appear to be a robust option across multiple scenarios, but, as seen from figure H.14, the utilization of these units is low because of the high cost of fuel. However, they are best suited for providing system reserve because of the low CAPEX requirements.

From the capacity plans, the most robust was developed. Capacities of a particular technology with high frequency of selection across scenarios are more robust. A plan comprising solely of no-regret options is unlikely to satisfy demand and will result in high system costs. Therefore, capacity and technology options that are less preferred across the scenarios need to be included in the expansion plan. Whenever additional capacity is added, the capacity plan is tested across multiple scenarios. As more capacity is added, CAPEX requirements increase but unmet demand reduces and total system costs reduce accordingly. Beyond a certain point, unmet demand is minimized and additional investments increase system costs. The lowest point is selected as the optimum capacity plan. (See figure H.16)

Figure H.15: Mean Capacity by Fuel for Specific Years, Showing Range as Error Bars and Standard Deviation as Dots

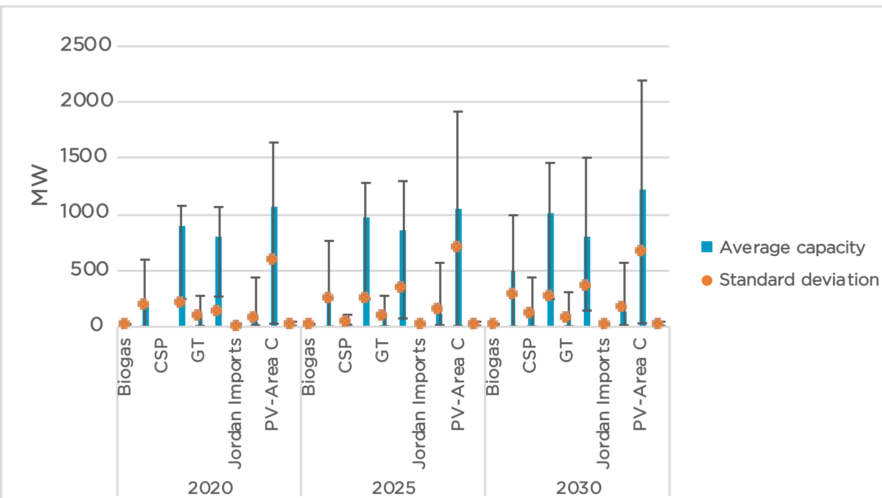
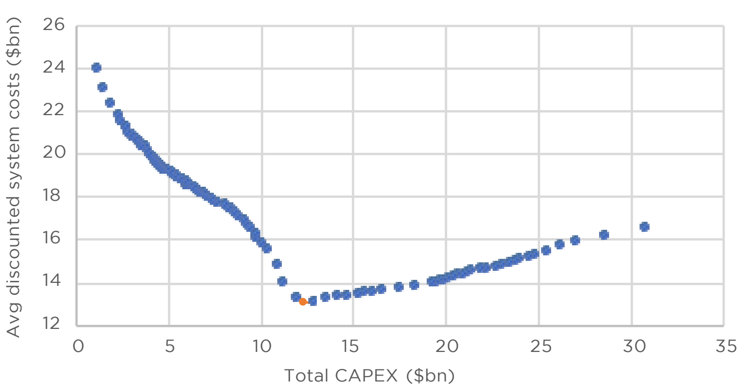
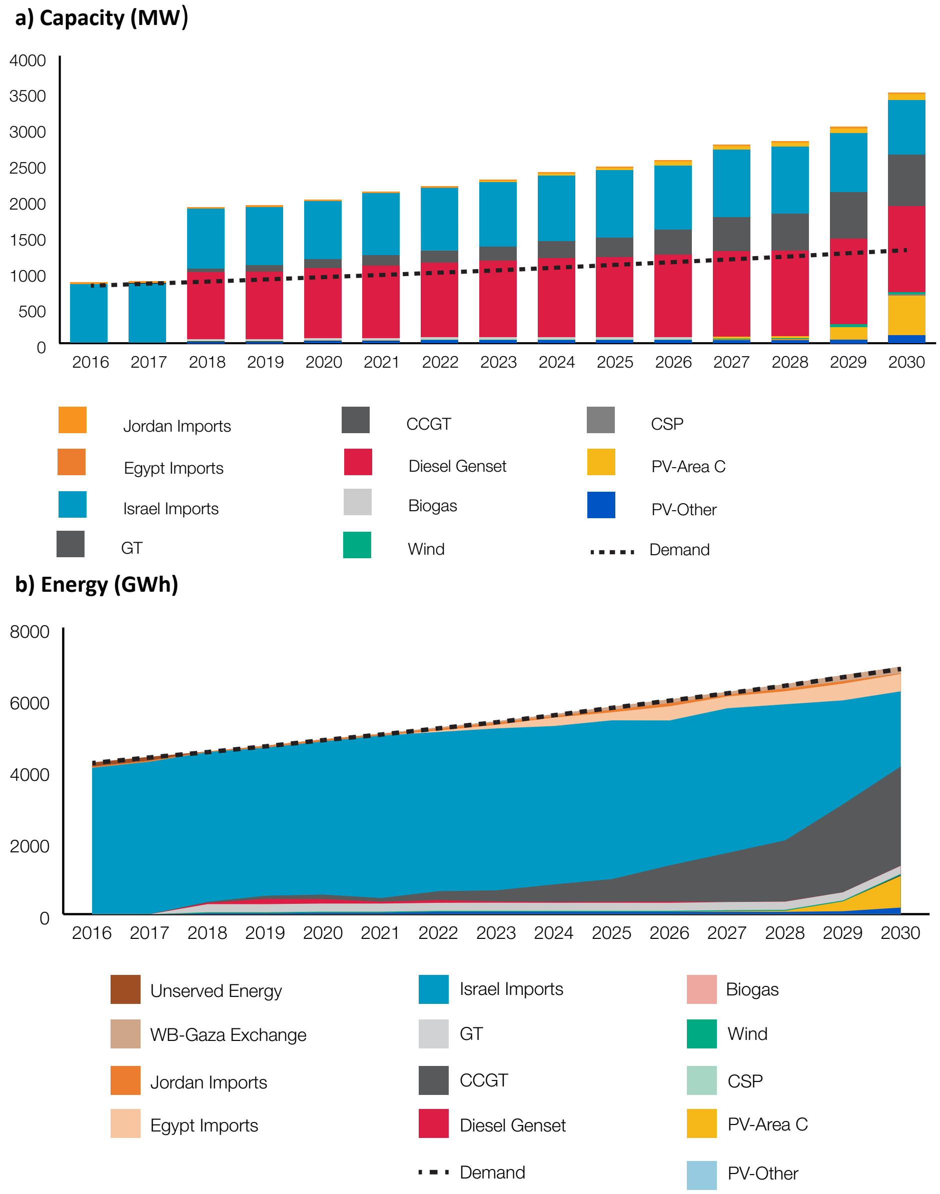


Figure H.16 : Total CAPEX and System Costs for 100 Capacity Plans Tested across Multiple Scenarios



Note: Installed capacity is increased with increasingly less preferred technology capacities across the 100 capacity plans.

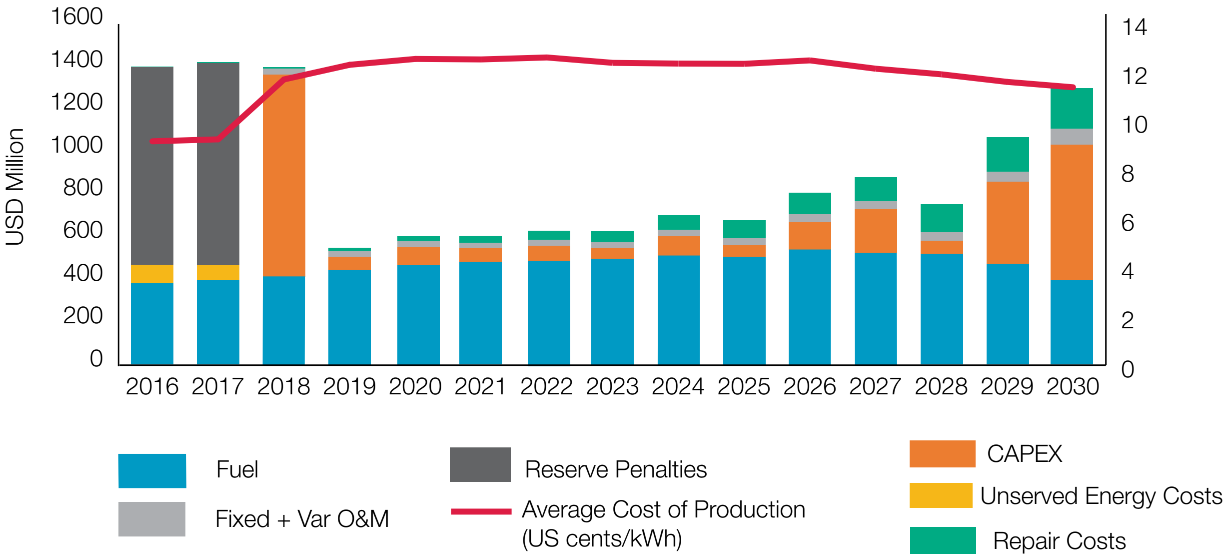
Figure H.17: Robust Capacity Plan and Energy Mix



The resultant capacity plan performs better than the deterministic plan by saving nearly US$1.2 billion over the planning horizon. The net present value of the robust plan is US$7.1 billion compared with the deterministic plan at US$8.6 billion. CAPEX requirements in the robust capacity plan are US$1.3 billion higher than the classic case, but unserved energy costs are 47 percent lower and repair costs are less than half the results from the deterministic scenario.

Total capacity is 3,484 MW for average expected peak capacity of 1,300 MW (figure H.17). The total capacity is high but needed to meet the planning requirements. System reserve requirements is set at 15 percent above peak demand and must be satisfied internally. Import capacity therefore does not contribute to reserve requirements. Additionally, PV does not provide firm capacity and so does not contribute to the reserve margin limits. While the low CAPEX requirements for distributed diesel plants make them an attractive option to meet reserve margins, energy output shows they are low on the merit order of dispatch because of the relatively higher cost of fuel and utilization is approximately 1 percent. PV capacity helps reduce fuel and repair costs.

Figure H.18: Associated Costs for the Self-Reliant Robust Capacity Plan



Transforming a system with no installed capacity to one that is self-reliant in a short period of time, as illustrated in this scenario, is extreme and impractical but illustrates the merits of considering uncertainties in the planning process. US$945 million is required in 2018 alone to avoid the reserve requirement penalty.

CAPEX requirements are annualized, and its impact on the average cost of generation is distributed across several years. For a self-reliant system, the average cost of generation increases from US$0.092 per kWh to US$0.124 kWh in 2019 and drops in later years to US$0.114 per kWh (figure H.18). While the impact on the average cost is reasonable, raising the required capital, associated infrastructure, and human capital needs will be more challenging. To reduce the financial burden on consumers, a longer time frame will be required to develop a capacity mix that is self-reliant. During this period, imports will continue to play a significant role in the energy mix.

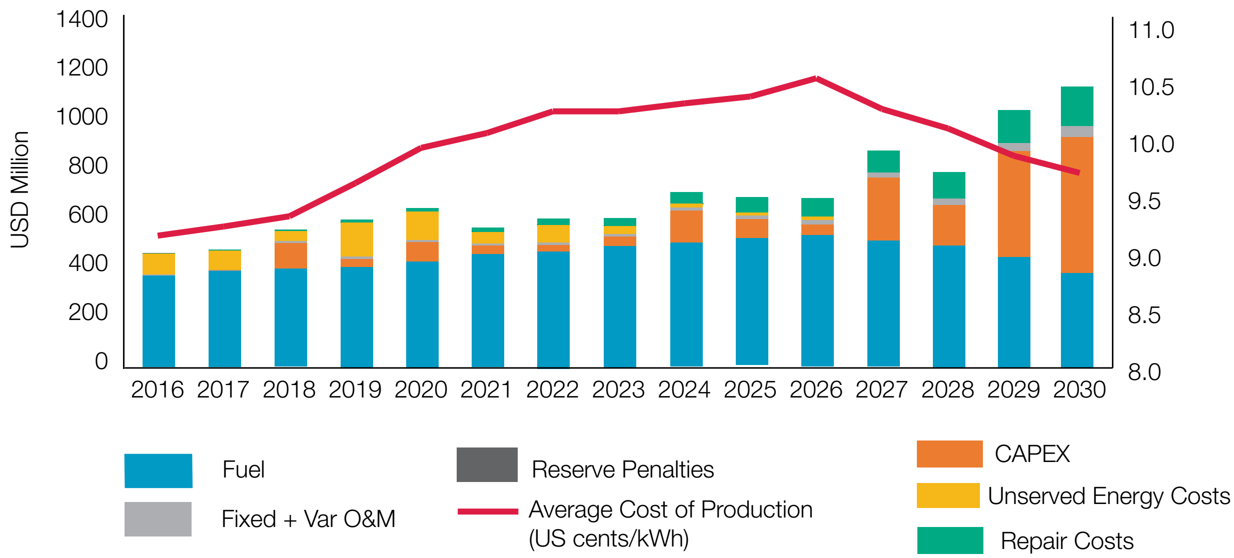
How does the average cost of production change by sharing reserve margin requirements with neighboring countries?

A power system designed to be operated independently misses the benefits of large connected systems. A major benefit of connecting power systems is the ability to distribute reserve margin requirements, thereby reducing total system costs. While this is technically optimal, other nontechnical considerations may constrain the benefits associated with operating in connected systems.

To evaluate the cost of a completely self-reliant system for the West Bank and Gaza, the robust plan is compared with a plan that is not constrained to satisfy reserve margin requirements internally. The same steps outlined in the flowchart (Figure H.1) are followed to develop the alternative plan with the main difference being that the need to meet reserve margin requirements internally is removed.

Partially relying on imports reduces CAPEX requirements from US$2.2 billion to US$1.4 billion (figure H.19). There is some loss of reliability as unserved energy increases from 0.3 percent to 1.1 percent. However, the average cost is more stable and does not exceed 10.6 US cents per kWh with nearly US$ 200 million in fuel savings.

Figure H.19: Associated Costs for the Robust Capacity Plan with Shared Reserves



Comparison of Least-Cost and Policy-Based Scenarios

Table H.12 summarizes the results for the West Bank. Supply from Israel to the West Bank has been stable in the past, and if this continues, the cost of inaction on system reliability (WS9) is modest with 4 percent unmet demand over the planning horizon as demand outgrows the pace of system expansion. By 2030, unmet demand is estimated at 9 percent of unmet demand.

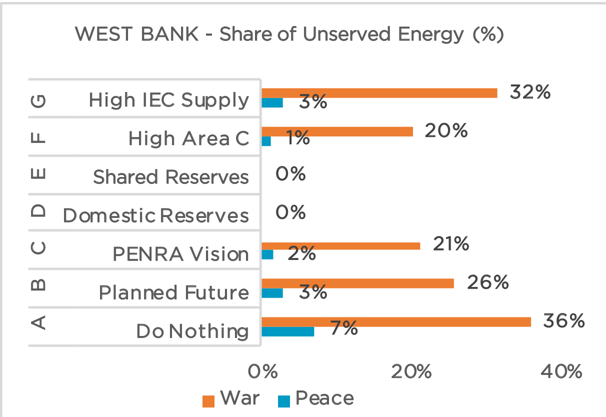
If supply from IEC grows with demand (WS8), unmet demand estimated at 1.3 percent and the average cost of electricity is approximately US$0.098 per kWh.

PENRA's current expansion plan is also robust with unmet demand under 1 percent, but with US$927 million in CAPEX requirements is more expensive than reliance on IEC. On the other hand, PENRA's policy to cap projects below the costs of IEC imports delays investment and results in 4.2 percent of unmet demand.

Across the scenarios, WS7 (the Planned Future) has the lowest combination of CAPEX requirements and unmet demand. In general, the scenarios with higher local generation have lower unmet demand.

Additional tests were run to assess the performance of the plans under stability (labelled *peace*) and extreme shocks (labelled *war*). The tests were carried out over the period 2025–30 for a select number of scenarios. The more diversified scenarios performed better under severe shocks than the less diversified scenarios. For example, WS4 has a low combination of fuel costs and unmet demand under shocks figure H.20. Domestic reserves are more expensive both under stability and during shocks but provides the highest security of supply (least unmet demand).

Figure H.20: Performance of Scenarios under Stability and Extreme Shocks in West Bank



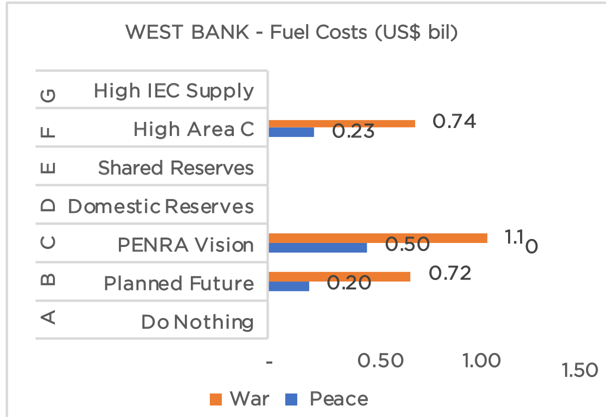


TABLE H.12: SUMMARY OF RESULTS FOR THE WEST BANK

			CLASSIC LCP	DOMESTIC RESERVE	SHARED RESERVE	HIGH AREA C	PRICE CAP	PENRA VISION	PLANNED FUTURE	HIGH IEC	DO NOTHING
			WS1	WS2	WS3	WS4	WS5	WS6	WS7	WS8	WS9
1.	2030 total available capacity	MW	2,066	3,485	2,440	2,792	2,052	2,641	2,127	1,607	987
	PV other	MW	22	109	159	39	39	574	147	147	15
	PV Area C	MW	0	554	554	1,094	0	0	0	0	0
	CSP	MW	0	7	0	0	0	0	0	0	0
	Wind	MW	9	10	10	10	10	50	0	0	0
	Biogas	MW	25	30	30	30	20	30	0	0	0
	Diesel genset	MW	597	1,190	50	30	0	30	0	0	0
	CCGT	MW	572	720	720	590	780	730	520	0	0
	GT	MW	0	0	0	0	0	0	0	0	0
	Israel imports	MW	699	761	806	887	1,111	1,119	1,430	1,430	942
	Egypt imports	MW	93	82	82	82	78	77	0	0	0
	Jordan imports	MW	49	21	29	30	14	31	30	30	30
2.	Peak demand	MW	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304
3.	Domestic capacity: 2030	MW	1,226	2,621	1,523	1,793	849	1,414	667	147	15
4.	Domestic cap. as share of peak: 2030	%	94%	201%	117%	137%	65%	108%	51%	11%	1%
5.	Average cost of energy	U.S. cents/kWh	13.57	11.77	9.94	9.88	9.49	10.16	10.06	9.78	9.79
6.	Total CAPEX	US$ mill	1,323	2,833	1,982	2,284	1,139	2,133	850	174	0
7.	Total OPEX	US$ mill	378	464	241	347	100	280	174	102	71
8.	Total fuel	US$ mill	3,606	869	673	482	374	748	566	0	0
9.	Unserved energy costs	US$ mill	1,135	169	658	782	2,553	547	222	811	2,645
10.	Total penalties (other)	US$ mill	5,093	2,908	794	657	363	2,697	1,183	391	482
11.	Total system costs	U$D mill	11,535	7,243	4,348	4,551	4,530	6,406	2,995	1,478	3,197
12.	Total unmet demand	GWh	1,513	225	878	1,043	3,404	730	296	1,081	3,527
13.	Total energy demand	GWh	81,669	81,669	81,669	81,669	81,669	81,669	81,669	81,669	81,669

			CLASSIC LCP	DOMESTIC RESERVE	SHARED RESERVE	HIGH AREA C	PRICE CAP	PENRA VISION	PLANNED FUTURE	HIGH IEC	DO NOTHING
			WS1	WS2	WS3	WS4	WS5	WS6	WS7	WS8	WS9
14.	Share of total unmet demand (total)	%	1.9%	0.3%	1.1%	1.3%	4.2%	0.9%	0.4%	1.3%	4.3%
15.	Share of energy imports: 2030	%	58%	38%	37%	33%	52%	44%	62%	96%	90%
16.	Diversity factor: 2030	%	0.37	0.28	0.27	0.25	0.39	0.26	0.49	0.91	0.79
17.	2030 share of energy mix		6,873	6,904	6,906	6,894	6,900	6,892	6,883	6,860	6,869
	PV other	%	1%	3%	4%	1%	1%	14%	3%	3%	0%
	PV Area C	%	0%	13%	13%	25%	0%	0%	0%	0%	0%
	CSP	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Wind	%	0%	0%	0%	0%	0%	2%	0%	0%	0%
	Biogas	%	3%	3%	3%	3%	2%	3%	0%	0%	0%
	Diesel genset	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CCGT	%	37%	40%	40%	34%	43%	37%	32%	0%	0%
	GT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Israel imports	%	48%	30%	30%	26%	44%	32%	62%	95%	88%
	Egypt imports	%	6%	7%	7%	7%	8%	9%	0%	0%	0%
	Jordan imports	%	3%	0%	0%	0%	1%	3%	0%	1%	2%
	Unserved energy	%	0.3%	0.0%	0.0%	0.1%	1.1%	0.0%	0.0%	0.6%	8.6%

Gaza

Given the limited supply options, the scenarios in Gaza focus on various policy options. With the exception of GS2, all the scenarios are tests of various supply options under uncertainty.

Comparison of Least-Cost and Policy-Based Scenarios

Table H.13 summarizes the results for Gaza. Unlike in the West Bank, the cost of inaction on system reliability (GS6) is severe, with 52 percent unmet demand over the planning horizon.

Scenario GS4, which allows increased imports from IEC, offers the best combination of costs and unmet demand.

Additional tests were run to assess the performance of the plans under stability (labelled *peace*) and extreme shocks (labelled *war*). The tests were carried out over the period 2025–30 for a select number of scenarios. As seen for the West Bank, the more diversified scenarios performed better under sever shocks than the less diversified scenarios. GS2 (PENRA Vision) has a low combination of fuel costs and unmet demand under shocks (figure H.21).

Figure H.21: Performance of Scenarios under Stability and Extreme Shocks in Gaza

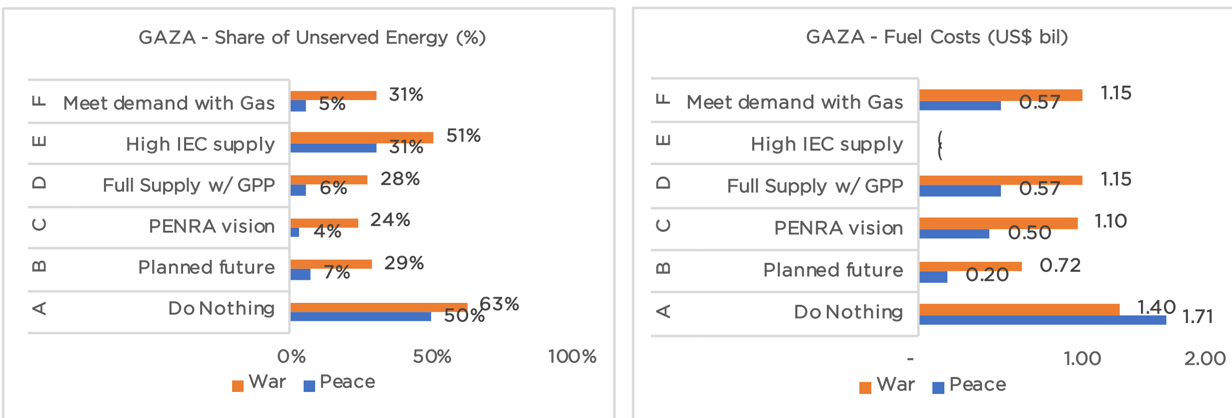


TABLE H.13: SUMMARY OF RESULTS FOR GAZA

			PLANNED FUTURE	PENRA VISION	FULL SUPPLY W/GPP	HIGH IEC	GAZA SUPPLY WITH GAS	DO NOTHING
			GS1	GS2	GS3	GS4	GS5	GS6
1.	2030 total available capacity	MW	975	1,077	1,395	971	970	190
	PV other	MW	163	163	163	163	163	0
	PV Area C	MW	0	0	0	0	0	0
	CSP	MW	0	0	0	0	0	0
	Wind	MW	0	0	0	0	0	0
	Biogas	MW	2	2	2	2	0	0
	Diesel genset	MW	0	120	0	0	0	0
	CCGT	MW	560	460	560	0	677	60
	GT	MW	0	60	0	0	0	0
	Israel imports	MW	240	199	660	796	120	120
	Egypt imports	MW	10	73	10	10	10	10
	Jordan imports	MW	0	0	0	0	0	0
2.	Peak demand	MW	767	767	767	767	767	767
3.	Domestic capacity: 2030	MW	725	805	725	165	840	840
4.	Domestic capacity as share of peak: 2030	%	95%	105%	95%	22%	110%	110%
5.	Average cost of energy	U.S. cents per kWh	13.39	15.44	11.41	10.37	15.15	14.68
6.	Total CAPEX	US$ mill	1,035	1,066	1,035	385	1,185	0
7.	Total OPEX	US$ mill	236	280	205	76	246	173
8.	Total fuel	US$ mill	2,264	3,471	718	4	3,987	1,588
9.	Unserved energy costs	US$ mill	2,834	1,630	1,333	2,167	2,390	18,108
10.	Total penalties (other)	US$ mill	1,644	8,473	1,637	220	1,962	763
11.	Total System costs	US$ mill	8,013	14,920	4,928	2,851	9,769	20,632

			PLANNED FUTURE	PENRA VISION	FULL SUPPLY W/GPP	HIGH IEC	GAZA SUPPLY WITH GAS	DO NOTHING
			GS1	GS2	GS3	GS4	GS5	GS6
12.	Total Unmet demand	GWh	3,779	2,173	1,778	2,889	3,186	24,144
13.	Total Energy demand	GWh	46,538	46,538	46,538	46,538	46,538	46,538
14.	Share of total unmet demand	%	8%	5%	4%	6%	7%	52%
15.	Share of energy imports: 2030	%	29%	45%	46%	93%	16%	26%
16.	Diversity factor: 2030	%	0.54	0.36	0.46	0.84	0.72	0.47
17.	2030 share of energy mix		4,032	4,032	4,032	4,032	4,032	4,032
	PV other	%	6%	6%	6%	6%	6%	0%
	PV Area C	%	0%	0%	0%	0%	0%	0%
	CSP	%	0%	0%	0%	0%	0%	0%
	Wind	%	0%	0%	0%	0%	0%	0%
	Biogas	%	0%	0%	0%	0%	0%	0%
	Diesel genset	%	0%	0%	0%	0%	0%	0%
	CCGT	%	68%	47%	51%	0%	83%	11%
	GT	%	0%	1%	0%	0%	0%	0%
	Israel imports	%	28%	33%	45%	92%	14%	24%
	Egypt imports	%	2%	12%	1%	2%	1%	2%
	Jordan imports	%	0%	0%	0%	0%	0%	0%
	Unserved energy	%	0%	1%	0%	0%	2%	63%

SEQUENCING INVESTMENTS

The analysis identifies options that are robust in multiple possible future scenarios, but it also clearly shows reliance on external decisions, least of which is technical. Without a change, the underlying geopolitical conditions, options for power supply that are directly within the control of the PA are limited. However, we see that these options, while not the cheapest, are indeed least cost. For example, based on the assumed likelihood of gas availability, CCGT is a robust option across all applicable scenarios. However, the construction of thermal plants is only least cost when gas is available. Translating any plan into reality will require a different approach, where decisions are taken as uncertainties resolve over time.

There are, however, options that are optimal with either high or limited imports, and these are obvious targets for immediate action. The approach used for the study shows how technology and capacity that are robust across multiples scenarios can be determined. For example, the analysis shows that solar (both rooftop PV and centralized) are optimal investments in both the West Bank and Gaza because they are less dependent on external factors. In the interim, strengthening imports from Israel also helps keep down average system costs. Imports from Egypt will also help diversify supply and increase reliability of supply.

The West Bank and Gaza stand to benefit from evolutions in power systems because there are no locked-in technologies. The cost of PV has dropped by over 60 percent since 2010 and costs of storage technologies such as utility-scale batteries or fuel cells are on a downward trajectory. As the unit costs of storage reach parity with cheapest source of imports, it will be beneficial to consider battery storage as a means of improving the security of supply (see box H.1). A list of generation technologies and triggers for action is presented in table A8.14.

The possibility for off-shore wind in Gaza helps diversify the sources of generation and the average cost of generation is therefore relatively lower as shown in Fig B1-b where change in price ranges are much higher.

TABLE H.14: TRIGGERS FOR DECIDING ON VARIOUS TECHNOLOGY OPTIONS

Technology	Decision trigger
Solar PV and other small RE (Area A and Gaza)	Immediate
Solar PV (Areas B and C)	When access is granted
Increased imports from Jordan	When Jordan is able to export power
Increased imports from Egypt	When Egypt is able to export power
Increased imports from IEC	Immediate
Storage	When unit cost of storage is close to cost of reserves from imports
Additional thermal plant in Gaza	When there is clarity around gas availability
Additional thermal plant in the West Bank	When there is clarity around gas availability
West Bank backbone	When access is granted and there is clarity around availability of gas for centralized self- generation or higher imports from Jordan especially.
West Bank-Gaza connection	When access is granted or Israel is willing to construct and operate the line and there is clarity around availability of centralized self- generation or higher imports from Jordan. especially.

Box H.1: Improving the Security of Supply with Renewable Energy Technologies

The West Bank and Gaza's ability to generate their own electricity offers relatively higher security than importing electricity, because, unlike electricity, fuel can be purchased from several markets, which reduces dependence on a single source. The most secure system will be one unconstrained by fuel requirements. Renewable energy technologies (RETs), namely solar, wind and battery, offer this potential for the West Bank and Gaza.

As the costs of RETs fall, certain CAPEX combinations for solar technologies, wind, and batteries yield overall unit costs that are low enough to merit closer examinations. A simplified exercise was undertaken to illustrate the concept. The analysis takes 2030 hourly load conditions and meets this demand with RETs through several combinations of investment costs. Figure H.B1.1 shows combinations of costs that yield average system costs of US$0.12, 0.13, 0.14, and 0.15 per kWh.

For example, if the cost of storage drops to $263 per kWh, it could be combined with low cost offshore wind between $2,402 and $3,753 per kW and/or PV between $299 and $790 per kW. These ranges can be combined to yield US$0.15 per kWh. In other words, if the cost of PV drops by 60 percent, reaching $790 per kW, and storage, for example, falls to $263 per kWh, it is a combination that could be attractive for large-scale deployment of RE.

Figure H.B1.1 : Percentage change in capex from 2016 costs that can result in average costs of generation under 16 UScents per kWh in West Bank

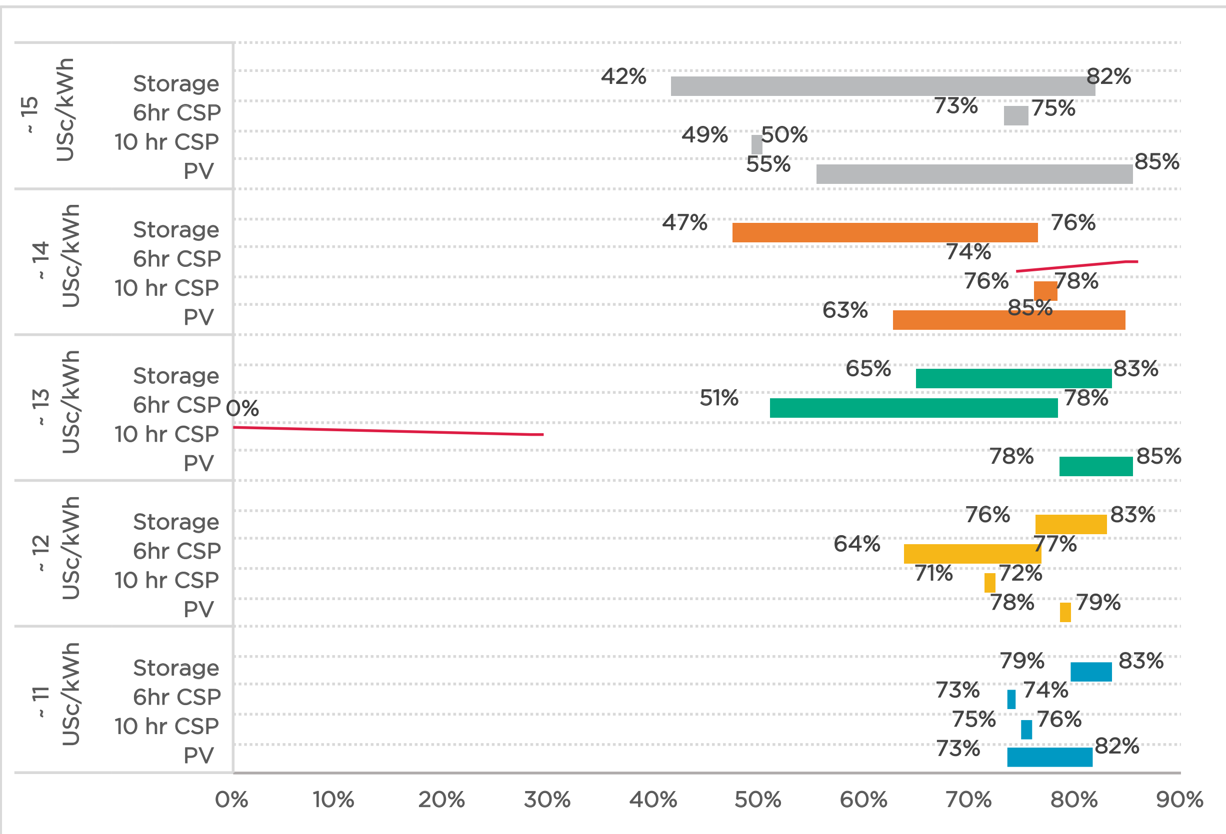
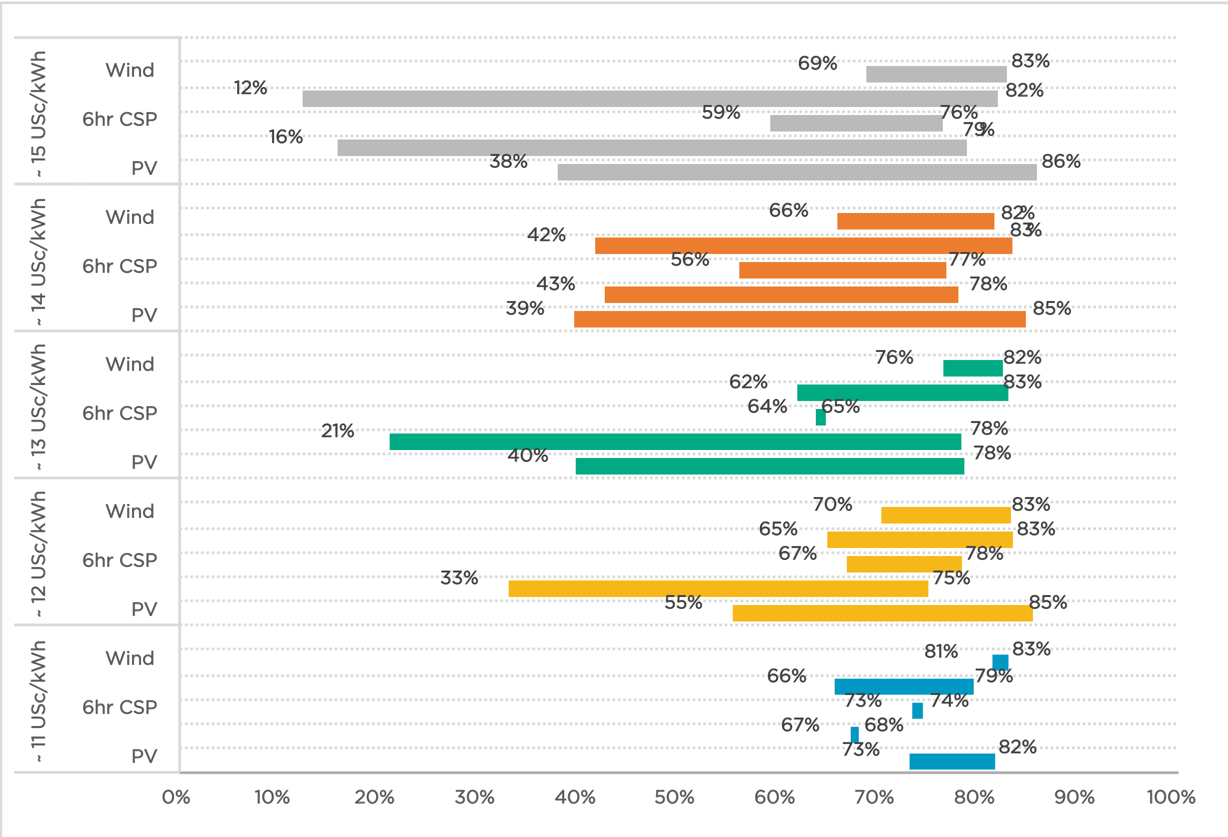


Fig B1-b: Percentage change in capex from 2016 costs that can result in average costs of generation under 16 UScents per kWh in Gaza



Reference costs (2017)

PV	10 hr CSP	6hr CSP	Wind	Storage
$/kW	$/kW	$/kW	$/kW	$/kWh
1567	6650	5552	5141	375

NOTES

1 Based on the following: overnight CAPEX, $750 per kW; weighted average cost of capital, 10 percent; plant life, 40 years; half of CAPEX needed from start of construction.
2 Find the list at http://siteresources.worldbank.org/EXTLICUS/Resources/511777-1269623894864/FY15FragileSituationList.pdf.
3 Plant capacities are modelled as continuous variables to reduce computational time, so the capacity plans likely contain different plant capacities for each of the scenarios (even if by a small number). In reality, plant capacities are discrete variables rather than continuous. For example, generation plants are typically commissioned in blocks equal to the size of the units (for example, 48 MW could be configured as 12 MW x 4 units). In the model, we assume this to be continuous, allowing capacity increases that do not necessarily match unit sizes. CCGT capacity of 1.1 MW could be added, for example, which is not realistic. However, the objective of this exercise is to develop a sense of the generation mix going forward. The error introduced by this approximation is therefore not important.
4 Within the scope of the project, all imports are modeled as generators connected to the relevant zones. This mathematically yields similar results as the primary focus is on the impact of energy imports into the West Bank and Gaza and not necessarily energy exchange between.
5 General Algebraic Modeling System (GAMS) is a fully documented model and has been used for other World Bank assignments in Ukraine, Bangladesh, Bulgaria, and South Africa.
6 The cost per kW to repair a plant depends on the extent of damage. To simplify the problem, we assume a single cost amortized over 12 years. This has been estimated from past World Bank projects that refurbished or rehabilitated thermal plants, mostly to improve efficiency.
7 The system advisor model (SAM) is a performance and financial model for RE planning from the U.S. *National Renewable Energy Laboratory* (NREL), https://sam.nrel.gov/.
8 Weather data overview are available at https://www.nrel.gov/analysis/sam/help/html- php/index.html?weather_format.htm.
9 Solar resource data obtained from EnergyPlus, https://energyplus.net/weather. EnergyPlus is a tool funded by the U.S. Department of Energy's Building Technologies Office, and managed by NREL.
10 Wind speed data from weather stations was obtained from the Iowa Environmental Mesonet program of the Iowa State University of Science and Technology. It collects environmental data from cooperating members with observing networks, http://mesonet.agron.iastate.edu/ASOS/.
11 World Bank Global Economic Monitor Commodities (http://databank.worldbank.org/data/reports.aspx?source=Global-Economic-Monitor-(GEM)-Commodities).
12 Capacity range is based on National Electric Power Company (NEPCo) annual reports.
13 The Green Corridor Project is a major grid upgrade to the north-south transmission corridor in Jordan.
14 See annual technology costs from NREL at http://www.nrel.gov/docs/fy16osti/66944.pdf.
15 See the International Energy Agency's World Energy Outlook model, http://www.worldenergyoutlook.org/weomodel/.
16 The cost of repairs is based on the rehabilitation of thermal plants carried out by the World Bank.

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APPENDIX I:

Financial Sector Model Methodology

OVERALL APPROACH

The financial model of the Palestinian Authority (PA) power sector will be built on three levels:

1. Level 1: Simple cash flow models of the six Palestinian power distribution utilities DISCOs: Gaza Electricity Distribution Company (GEDCO), Hebron Electricity Distribution Company (HEPCO), Jerusalem District Electricity Company (JDECO), Northern Electricity Distribution Company (NEDCO), Southern Electricity Distribution Company (SELCO), and Tubas Electricity Distribution Company (TEDCO)
2. Level 2: A simple cash flow model of the new Palestinian transmission utility Palestinian Electricity Transmission Company (PETL)
3. Level 3: A simple characterization of the net impact of the power sector on the budget of the Palestinian Authority in the form of subsidies

The financial model uses as its historical reference period the years 2011–15. The financial model projects forward for the period 2016–30.

The objective of the financial modeling is to evaluate the tariffs setting and the creditworthiness of the distribution companies (DISCOs) and especially of PETL as an off-taker for a series of major new commercial term commitments for the bulk purchase of power into the Palestinian territories and to identify a series of measures that could be taken to improve this creditworthiness. In particular, these measures could include the following:

- Improvements in the commercial and operational performance of the DISCOs
- Increases in the retail tariff to the end consumer
- Injection of additional public subsidy to the sector

The financial model uses PA electricity physical demand projections from the robust planning model and transmission and distribution costs forecast based on the various planning scenarios.

The financial model was used to explore the financial impacts on the sector based on three scenarios from the robust planning model that covered the entire range of power production costs from lowest to highest. For the West Bank, these included Planned Future, Maximum Cooperation, and PENRA Vision scenarios, and for Gaza, these included Planned Future, Maximum Independence, and Maximum Cooperation. The detailed description of the scenarios is provided in the planning model section of the main report under Part II.

The financial model assumes the following:

- PETL will act as a single buyer. PETL will import *all* the electricity that is available from Israeli Electric Corporation (IEC), Jordan, and Egypt and will buy *all* the electricity produced in the PA (combined cycle gas turbine, solar, wind, biomass, and so forth).
- PETL will act also as a single supplier to the DISCOs using the IEC transmission infrastructure or its own transmission infrastructure. (Transmission costs are included in PETL tariffs shown in the financial model.)
- The DISCOs invest in their own distribution infrastructure (distribution costs are included in DISCOs tariffs shown in the financial model).

Level 1: Distribution Utilities

Output Variable: Electricity Average Equilibrium Cost and Retail Tariff in Each Distribution Utility as Well as Aggregate

Based on data projections and the chosen levels for input parameters, the model solves for the retail electricity price level that ensures the financial equilibrium of each utility. This should initially be done at the utility level. However, Palestinian Electricity Regulatory Council (PERC) currently has a policy of charging a single uniform tariff throughout the West Bank and Gaza, so the model will also calculate the average cost recovery tariff across the five distribution utilities, as well as computing the transfers that would be needed across utilities to ensure their individual financial sustainability should the uniform tariff be applied. Those whose financial equilibrium tariff is above the sector average would need to receive a net compensatory transfer, and vice versa.

Input Variables: Distribution Losses and Revenue Collection Ratio

The financial model will be set up to allow the user to choose target values for distribution losses and revenue collection ratios for the year 2030. These two parameters reflect the overall operational and financial performance of the utility and can be improved over time through management effort. Given that there are measures under way to improve the poor current performance in these areas, the model assumes that the full benefit of these measures will be achieved by 2030. The user should be able to input more or less ambitious targets for both of these variables to see what impact this has on the equilibrium tariff.

Data Projections: Characterizing the Revenues and Expenditures

Basic data on the revenues and expenditures of the utilities is collected by PERC for the purposes of determining the revenue requirement for the cost-plus-tariff-setting process.

On the revenue side, the model takes historical data on billings and collections in both physical and financial terms. The difference between power purchased and power billed will give *distribution losses*. The difference between power billed and power collected will give the *collection losses*. The projection of the revenue side will be based on *physical demand projections* provided by the robust planning model and on *return on equity* set by the regulator (PERC). The tariff to be applied to the demand projections will be based on the solution of the model as noted above.

On the expenditure side, the model uses data from the DISCOs financial annual reports on operations and maintenance (O&M), taxes, debt service, planned investments, and power purchase costs. O&M are projected based on *demand projections* and on *efficiency factor* to be set by the regulator. Debt service and planned investments are projected based on information about the *repayment profile* of currently held debts, *interest rate on debt,* and *investment plans* for the period. The distribution utilities' most significant expenditure is power purchase.

The projection of the wholesale power price over time will be an output of the Level 2 model covering PETL.

Affordability Check: How Power Bills Weigh on Household Budgets

As an add-on to the financial analysis of the DISCOs, the model includes a module that will allow checking for affordability and computing the potential value of consumer subsidies. The affordability check is based on data for the average household income across 10 deciles of the Palestinian income distribution that is derived from the PCBS Labor Force Survey for 2013. These will need to be rolled forward to reflect anticipated real income growth through 2030.

Subsistence electricity consumption can be estimated as the amount of electricity needed to provide a basic package of energy services in the household. Such information was derived from the PCBS Household Energy Surveys. Based on an estimate of subsistence electricity consumption the weight of the power bill associated with the equilibrium retail tariff can be calculated as a share of household income. When this share exceeds 5 percent, an affordability issue is presumed to arise. On this basis, it is possible to calculate the total amount of government demand-side subsidy that would be needed to keep the cost of subsistence consumption below the 5 percent threshold.

The model calculates and displays two distinct subsidies. The first is the subsidy requirement to maintain financial equilibrium if retail tariffs are not adjusted as additional power-supply options come online. The second is the subsidy requirement to provide targeted subsidies to the poorest, who cannot afford increases in tariffs. The subsidies are then compared in scenarios where DISCO efficiencies are, and are not, improved to provide a sense of the impact of DISCO inefficiencies on the PA budget.

Level 2: PETL

Output Variable: Average Wholesale Price of Electricity to Be Charged by PETL to Discos

Based on data projections and the chosen levels for input parameters, the model solves for the average wholesale power price level that ensures the financial equilibrium of the PA power sector, and for Gaza and for the West Bank separately.

Input Variable: Average Unit Subsidy to the Wholesale Price of Electricity to Be Applied by PA
The financial model allows the user to choose the percentage of the wholesale electricity price that would be subsidized by the PA. The value of this supply-side subsidy is initially set to zero to understand the full tariff implications of the proposed investment plan. If the resulting retail tariff proves to be unaffordable (based on the affordability check), then the problem can be addressed either through incorporating a supply-side subsidy at the level of PETL or a demand-side subsidy directly to consumers of the distribution utilities, or a combination of the two. Although in practice, supply-side subsidies are more commonplace, demand-side subsidies are far preferable from an economic standpoint.

Data Projections: Characterizing Revenues and Expenditures
On the expenditure side, PETL's expenditures can be divided between those associated with wholesale power purchase and those associated with operating the transmission system.

In terms of wholesale power purchase, in the future PETL will be the holder of various power purchase agreements (PPAs) signed with different suppliers that may include IEC, Israeli Independent Power Producers (IPPs), gas-fired IPPs in the West Bank and Gaza, solar IPPs in the West Bank and Gaza, and power import contracts with Jordan and Egypt. The output of the planning model will give the total amount of power from each source that PETL will need to purchase in any given year. The planning model will also have unit cost information for each of these projects. On the basis of this information, a financial PPA price will need to be estimated bearing in mind the potential financing conditions for power-generation infrastructure in the West Bank and Gaza, particular for domestic IPPs. Multiplying each power-purchase price by the corresponding volume of power will give the total wholesale power purchase bill in any given year. The overall volume of supply should be compatible with the demand projections used in the planning model and also feed into the Level 1 DISCOs model.

PETL also faces other costs associated with operating and developing the transmission system. These include *transmission losses*, *O&M expenditures*, *taxes*, debt service, and any investments needed to upgrade the transmission network. These data is obtainable from the PETL Price Waterhouse Coopers (PWC) Business Plan or from PETL itself.

On the revenue side, PETL's future revenue will be the wholesale power tariff multiplied by the total amount of energy demanded by the DISCOs.

Level 3: Palestinian Authority

Data Projections: Characterizing Fiscal Flows to the Power Sector
The model will take stock of all the ways in which the energy sector results in revenues or expenditures to the public budget.

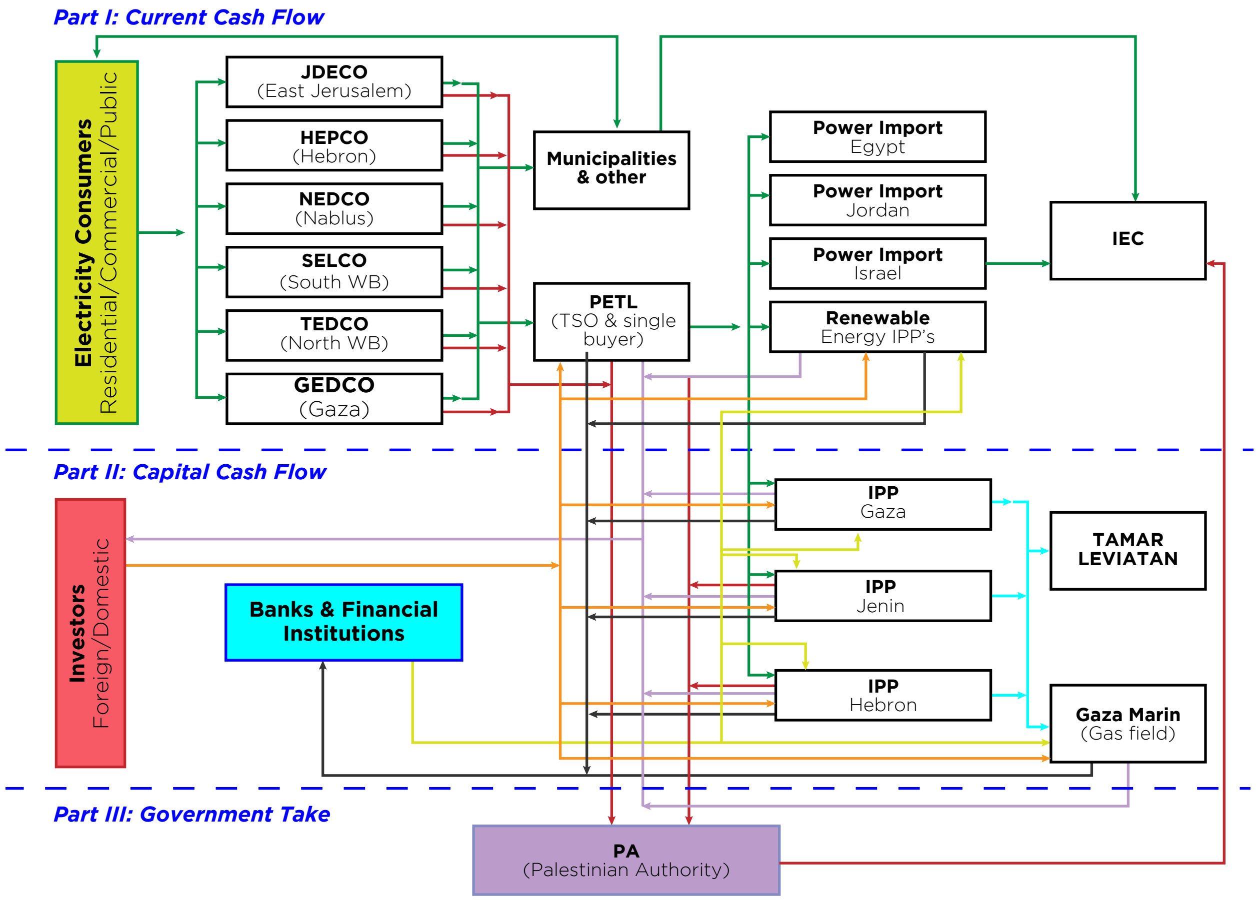
On the revenue side, the power sector contributes tax revenues through the application of value-added tax (VAT) and corporation taxes (VAT is not calculated in the model at this stage). It is not clear whether there are any other positive fiscal contributions at present, but the future development of Gaza Marine would potentially provide an important revenue source, although certainly not earmarked to the power sector.

On the expenditure side, the power sector draws several implicit and explicit subsidies from the public budget, for which we do not yet have a comprehensive inventory. The ones that we do know about include net lending, subsidy to DISCOs to compensate for higher IEC prices, and potentially a pass-through of capital grants and concessional finance from donors.

Furthermore, the demand and supply-side subsidies calculated in Levels 1 and 2, respectively, enter the Level 3 model as a projected subsidy expenditure for the sector. The impact of this subsidy on the overall fiscal balance of the PA would need to be gauged to identify a level of public subsidy that is affordable in fiscal terms. Since power is only one of the sectors handled through the budget, it would be important to know the overall revenue and expenditure balance of the PA and how this is projected to evolve over time.

In summary, the schematic chart of figure I.1 illustrates the flows into and between the different entities of the PA power sector presented in the financial model. Tables I.1 to I.6 provide the input and output variables used in the financial model for each distribution company.

Figure I.1: Flow of Activities among the West Bank and Gaza Power-Generation Entities



Legend

- Power cash flow[1] (Kwh x predicted electricity tariff)
- Taxes, net lending[2], capital subsidies or guarantees and royalties
- Net capital investments[3]
- O&M and financial expenses
- Loans
- Principal payments
- Gas purchase

1. Power cash flow includes repayments of debts to ICE.
2. DISCOs (and some municipalities) are currently paying directly to IEC for the purchased power distributed to Palestinian customers. Since DISCOs do not pay 100% their electricity supplies, namely IEC, the PA is indirectly subsidizing the DISCOs due to the monthly sums taken by the Israeli Ministry of Finance from Palestinian taxes collected on their behalf ("clearance revenues") to compensate from the Palestinian DISCO's non-payment for purchased electricity from IEC ("Net lending")
3. Capital investments minus return on capital

TABLE I.1: FINANCIAL MODEL INPUTS AND OUTPUTS—GEDCO

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GEDCO purchases and sales																					
Purchase of electricity from IEC and Jordan/ PETL	GWh	1,763	1,642	1,730	1,385	1,432	1,486	1,504	1,724	2,036	2,328	2,612	2,996	3,149	3,297	3,471	3,649	3,749	3,900	4,035	4,170
Total losses	%	30.0%	30.0%	30.0%	26.5%	26.2%	26.0%	25.8%	25.6%	25.4%	25.2%	24.9%	24.7%	24.5%	24.3%	24.1%	23.9%	23.6%	23.4%	23.2%	23.0%
Total power sales	GWh	1,234	1,149	1,211	1,018	1,056	1,099	1,116	1,283	1,519	1,742	1,960	2,255	2,377	2,496	2,635	2,778	2,862	2,986	3,099	3,211
Collection rate	%	65.0%	68.0%	71.0%	64.0%	65.0%	66.7%	68.5%	70.2%	71.9%	73.7%	75.4%	77.1%	78.9%	80.6%	82.3%	84.1%	85.8%	87.5%	89.3%	91.0%
Total power paid by consumers	GWh	802	781	860	652	686	734	764	900	1,093	1,283	1,478	1,739	1,874	2,012	2,170	2,336	2,456	2,614	2,766	2,922
Operating income (power sales)	NIS mill	615	599	632	509	518	592	575	717	832	942	1,039	869	1,391	1,494	1,587	1,618	1,723	1,680	1,788	1,832
Other income	NIS mill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total income	NIS mill	615	599	632	509	518	592	575	717	832	942	1,039	869	1,391	1,494	1,587	1,618	1,723	1,680	1,788	1,832
GEDCO operating costs																					
Electricity purchase from IEC and Jordan/ PETL	NIS mill	701	817	911	916	795	808	760	932	1,054	1,133	1,219	951	1,581	1,665	1,731	1,720	1,799	1,704	1,781	1,786
O&M expenses	NIS mill	53	56	54	58	63	66	66	76	90	103	115	132	139	146	153	161	166	172	178	184
Depreciation expenses	NIS mill	NA	NA	NA	13	13	13	13	13	13	22	22	22	22	22	22	22	22	22	22	22
Running cost	NIS mill	NA	NA	NA	NA	NA	0	0	0	0	16	16	16	16	16	16	16	16	16	16	16
Financial cost	NIS mill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Return on equity	NIS mill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total electricity costs	NIS mill	755	873	965	986	872	887	840	1,021	1,157	1,273	1,372	1,121	1,758	1,848	1,921	1,919	2,002	1,914	1,997	2,008
GEDCO income																					
Annual income/loss before income tax	NIS mill	-139	-274	-334	-477	-354	-295	-265	-304	-325	-331	-333	-252	-367	-354	-335	-301	-280	-234	-210	-176
Income tax - 15%	NIS mill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Annual income	NIS mill	-139	-274	-334	-477	-354	-295	-265	-304	-325	-331	-333	-252	-367	-354	-335	-301	-280	-234	-210	-176
GEDCO purchase, sale, and equilibrium tariff																					
Average purchase cost / PETL tariff	NIS/kWh	0.398	0.497	0.527	0.661	0.555	0.544	0.505	0.541	0.518	0.487	0.467	0.318	0.502	0.505	0.499	0.471	0.480	0.437	0.441	0.428
Average retail tariff	NIS/kWh	0.498	0.521	0.522	0.500	0.490	0.807	0.753	0.796	0.761	0.734	0.703	0.500	0.742	0.743	0.731	0.693	0.701	0.643	0.646	0.627
Electricity average equilibrium cost	NIS/kWh	0.941	1.117	1.123	1.513	1.270	1.209	1.099	1.134	1.058	0.992	0.928	0.645	0.938	0.919	0.886	0.822	0.815	0.732	0.722	0.687

*Assuming Planned Future planning scenario from 2016 to 2030.

TABLE I.2: FINANCIAL MODEL INPUTS AND OUTPUTS—JDECO

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
JDECO Purchases and Sales																					
Purchase of electricity from IEC and Jordan/ PETL	GWh	1,797	1,943	1,902	1,935	2,114	2,084	2,142	2,199	2,186	2,391	2,511	2,446	2,548	2,509	2,563	2,677	2,796	2,918	2,913	3,012
Total losses	%	27.7%	26.4%	26.2%	24.9%	23.9%	23.8%	23.8%	23.7%	23.6%	23.6%	23.5%	23.5%	23.4%	23.3%	23.3%	23.2%	23.2%	23.1%	23.1%	23.0%
Total power sales	GWh	1,299	1,431	1,403	1,454	1,609	1,588	1,633	1,678	1,670	1,827	1,920	1,872	1,952	1,923	1,966	2,055	2,148	2,244	2,241	2,320
Collection rate	%	95.9%	96.6%	83.4%	95.0%	90.5%	90.5%	90.6%	90.6%	90.6%	90.7%	90.7%	90.7%	90.8%	90.8%	90.8%	90.9%	90.9%	90.9%	91.0%	91.0%
Total power paid by consumers	GWh	1,245	1,381	1,171	1,381	1,444	1,437	1,479	1,520	1,513	1,656	1,742	1,698	1,772	1,746	1,786	1,867	1,952	2,040	2,039	2,111
Operating income (Power sales)	NIS mill	695	875	889	951	949	946	943	970	975	1,129	1,184	1,223	1,246	1,205	1,214	1,248	1,278	1,065	1,285	1,309
Other income	NIS mill	54	57	83	72	68	67	68	70	70	76	80	78	81	80	82	85	89	93	93	96
Total income	NIS mill	749	932	971	1,022	1,017	1,012	1,012	1,041	1,045	1,206	1,265	1,301	1,328	1,285	1,296	1,334	1,368	1,158	1,378	1,405
JDECO operating costs																					
Electricity purchase from IEC and Jordan/ PETL	NIS mill	563	800	832	886	871	741	731	756	762	909	960	1,011	1,030	991	999	1,030	1,056	814	1,058	1,079
O&M expenses	NIS mill	146	148	163	172	188	185	190	195	194	212	223	217	226	223	228	238	248	259	259	267
Depreciation expenses	NIS mill	24	21	20	30	37	36	36	36	35	37	36	36	36	35	35	35	34	34	34	33
Interest rate on debt	%	2.75%	3.52%	2.10%	-1.04%	-0.64%	3.50%	3.75%	4.00%	4.25%	4.50%	4.75%	5.00%	5.25%	5.50%	5.75%	6.00%	6.25%	6.50%	6.75%	7.00%
Financing expenses	NIS mill	22	34	28	-15	-11	59	62	63	64	64	64	63	63	62	61	60	59	58	57	56
Running cost	NIS mill	NA	NA	NA	NA	NA	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Other expenses	NIS mill	NA	NA	4	4	6	4	5	5	5	5	5	5	5	5	5	6	6	6	6	6
Return on equity	NIS mill	NA	NA	NA	NA	NA	23	22	21	20	19	17	15	13	11	9	6	4	1	0	-2
Total electricity costs	NIS mill	754	1,004	1,046	1,076	1,091	1,045	1,041	1,071	1,076	1,242	1,302	1,344	1,369	1,323	1,332	1,370	1,402	1,167	1,408	1,434
JDECO income																					
Annual income/loss before income tax	NIS mill	-5	-71	-75	-54	-74	-14	-13	-14	-16	-22	-25	-32	-33	-32	-33	-35	-37	-14	-36	-38
Income tax - 15%	NIS mill	3	0	0	3	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net annual income	NIS mill	-8	-71	-75	-56	-82	-14	-13	-14	-16	-22	-25	-32	-33	-32	-33	-35	-37	-14	-36	-38
JDECO purchase, sale, and equilibrium tariff																					
Average purchase cost / PETL tariff	NIS/kWh	0.313	0.412	0.437	0.458	0.412	0.356	0.341	0.344	0.349	0.380	0.382	0.413	0.404	0.395	0.390	0.385	0.378	0.279	0.363	0.358
Average retail tariff	NIS/kWh	0.535	0.612	0.633	0.654	0.590	0.658	0.638	0.638	0.644	0.682	0.680	0.720	0.703	0.690	0.680	0.669	0.655	0.522	0.630	0.620
Electricity average equilibrium cost	NIS/kWh	0.606	0.727	0.894	0.779	0.755	0.727	0.704	0.705	0.711	0.750	0.747	0.791	0.773	0.758	0.746	0.734	0.718	0.572	0.691	0.680

*Assuming Planned Future planning scenario from 2016 to 2030.

TABLE I.3: FINANCIAL MODEL INPUTS AND OUTPUTS—NEDCO

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NEDCO purchases and sales																					
Purchase of electricity from IEC and Jordan/ PETL	GWh	414	474	480	502	549	576	1,125	1,193	1,232	1,274	1,289	1,470	1,498	1,668	1,763	1,799	1,842	1,882	2,051	2,122
Total losses	%	19%	17%	12%	14%	17%	17%	17%	18%	18%	19%	19%	20%	20%	20%	21%	21%	22%	22%	23%	23%
Total power sales	GWh	337	392	420	435	458	478	928	979	1,007	1,035	1,042	1,182	1,198	1,327	1,395	1,416	1,442	1,465	1,588	1,634
Collection rate	%	79%	70%	87%	86%	98%	99%	99%	100%	100%	101%	101%	102%	102%	103%	103%	104%	104%	105%	105%	106%
Total power paid by consumers	GWh	266	274	365	376	450	472	922	978	1,010	1,044	1,056	1,204	1,226	1,364	1,441	1,470	1,504	1,535	1,672	1,728
Operating income (power sales)	NIS mill	189	223	232	245	242	252	452	493	521	589	606	734	744	811	852	867	878	706	939	976
Other income	NIS mill	2	6	24	40	NA	46	48	51	53	55	55	63	64	72	76	77	79	81	88	91
Total income	NIS mill	191	230	256	285	NA	298	501	544	574	643	661	797	808	883	928	944	957	787	1,027	1,067
NEDCO operating costs																					
Electricity purchase from IEC and Jordan/ PETL	NIS mill	179	200	230	250	247	205	384	410	430	484	493	608	606	659	687	692	696	525	745	760
O&M expenses	NIS mill	10	17	12	13	NA	15	29	30	31	32	33	37	38	42	45	46	47	48	52	54
Depreciation expenses	NIS mill	1	2	2	2	NA	1	2	3	4	6	6	6	6	6	6	6	6	6	6	6
Interest rate on debt	%	NA	NA	NA	NA	NA	4%	4%	4%	4%	5%	5%	5%	5%	6%	6%	6%	6%	7%	7%	7%
Financing expenses	NIS mill	NA	NA	NA	NA	NA	10	11	17	19	21	22	22	26	25	26	25	22	19	5	13
Running cost	NIS mill	NA	NA	NA	NA	NA	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Other expenses	NIS mill	1	NA	1	5	NA	6	12	13	13	14	14	16	16	18	19	19	20	20	22	23
Return on equity	NIS mill	NA	NA	NA	NA	NA	17	18	20	22	25	27	30	33	36	40	45	49	54	59	65
Total electricity costs	NIS mill	191	219	245	269	NA	254	455	493	519	583	596	720	726	788	824	834	841	673	890	922
NEDCO Income																					
Annual income/loss before income tax	NIS mill	0.5	11	12	15	NA	60	63	70	77	85	92	107	115	131	144	155	166	168	195	210
Income tax - 15%	NIS mill	0.4	2	5	7	NA	9	9	11	12	13	14	16	17	20	22	23	25	25	29	32
Net annual income	NIS mill	0.1	9	7	9	NA	51	54	60	65	73	78	91	98	112	123	132	141	143	166	179
NEDCO purchase, sale, and equilibrium tariff																					
Average purchase cost / PETL tariff	NIS/kWh	0.348	0.410	0.444	0.487	0.450	0.356	0.341	0.344	0.349	0.380	0.382	0.413	0.404	0.395	0.390	0.385	0.378	0.279	0.363	0.358
Average retail tariff	NIS/kWh	0.561	0.569	0.551	0.563	0.528	0.533	0.490	0.504	0.516	0.564	0.573	0.610	0.607	0.594	0.591	0.590	0.584	0.460	0.561	0.565
Electricity average equilibrium cost	NIS/kWh	0.716	0.797	0.671	0.717	NA	0.539	0.493	0.504	0.514	0.558	0.565	0.598	0.592	0.577	0.572	0.568	0.559	0.438	0.533	0.533

*Assuming Planned Future planning scenario from 2016 to 2030.

TABLE I.4: FINANCIAL MODEL INPUTS AND OUTPUTS—TEDCO

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
TEDCO purchases and sales																					
Purchase of electricity from IEC and Jordan/ PETL	GWh	71	81	85	96	104	118	213	226	234	242	245	279	284	317	334	341	350	357	389	403
Total losses	%	3%	16%	14%	15%	16%	17%	17%	17%	18%	18%	19%	19%	20%	20%	21%	21%	22%	22%	23%	23%
Total power sales	GWh	69	68	73	81	87	99	177	187	192	197	198	225	228	252	265	269	274	278	301	310
Collection rate	%	97%	105%	97%	85%	76%	77%	78%	79%	80%	81%	82%	83%	84%	85%	86%	87%	88%	89%	90%	91%
Total power paid by consumers	GWh	67	72	71	68	67	76	139	148	154	160	163	187	192	215	228	234	241	248	271	282
Operating income (power sales)	NIS mill	30	35	39	46	46	42	73	80	84	96	99	121	123	136	144	148	151	125	165	173
Other income	NIS mill	0	3	5	6	8	9	16	17	17	18	18	20	21	23	25	25	26	26	29	30
Total income	NIS mill	30	38	44	52	54	51	89	96	102	113	117	141	144	159	168	173	176	151	194	202
TEDCO operating costs																					
Electricity purchase from IEC and Jordan/ PETL	NIS mill	27	33	38	45	42	42	73	78	82	92	94	115	115	125	130	131	132	100	141	144
O&M expenses	NIS mill	3.7	4.9	5.1	6.3	7.4	8.4	15.1	16.0	16.5	17.1	17.3	19.7	20.1	22.4	23.6	24.1	24.7	25.2	27.5	28.5
Depreciation expenses	NIS mill	NA	NA	NA	NA	NA	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Interest rate on debt	%	NA	NA	NA	NA	NA	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Financing expenses	NIS mill	NA	NA	NA	NA	NA	2.0	2.2	3.7	4.4	5.1	5.9	6.5	7.9	8.5	9.5	10.2	10.5	10.8	9.2	11.0
Running cost	NIS mill	NA	NA	NA	NA	NA	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other expenses	NIS mill	0.6	0.6	0.8	0.7	0.7	0.8	1.5	1.6	1.6	1.7	1.7	2.0	2.0	2.2	2.3	2.4	2.5	2.5	2.7	2.8
Return on equity	NIS mill	NA	NA	NA	NA	NA	1.6	1.5	1.3	1.1	1.0	0.8	0.6	0.4	0.3	0.3	0.4	0.7	1.0	1.8	2.5
Total electricity costs	NIS mill	31.1	38.7	44.1	51.8	50.4	55.0	93.1	100.4	105.3	117.5	120.0	144.7	146.0	159.1	166.8	169.2	171.0	139.8	183.2	189.7
TEDCO income																					
Annual income/loss before income tax	NIS mill	-1.0	-1.1	0.1	0.2	3.4	-2.2	-3.1	-2.9	-2.5	-3.2	-2.5	-3.1	-1.7	0.0	1.8	3.8	6.1	12.1	12.2	15.1
Income tax - 15%	NIS mill	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.8	1.8	2.3
Net annual income	NIS mill	-1.0	-1.1	0.1	0.1	2.9	-2.2	-3.1	-2.9	-2.5	-3.2	-2.5	-3.1	-1.7	0.0	1.8	3.8	5.2	10.3	10.4	12.9
TEDCO purchase, sale, and equilibrium tariff																					
Average purchase cost / PETL tariff	NIS/kWh	0.378	0.407	0.447	0.468	0.407	0.356	0.341	0.344	0.349	0.380	0.382	0.413	0.404	0.395	0.390	0.385	0.378	0.279	0.363	0.358
Average retail tariff	NIS/kWh	0.432	0.506	0.527	0.563	0.529	0.556	0.526	0.538	0.549	0.597	0.606	0.644	0.641	0.631	0.630	0.629	0.625	0.503	0.608	0.612
Electricity average equilibrium cost	NIS/kWh	0.465	0.539	0.619	0.756	0.757	0.720	0.672	0.678	0.684	0.733	0.736	0.773	0.761	0.740	0.730	0.722	0.709	0.564	0.675	0.672

*Assuming Planned Future planning scenario from 2016 to 2030.

TABLE I.5: FINANCIAL MODEL INPUTS AND OUTPUTS—HEDCO

		2011	2012	2013	2014	2015	2016	2017	2018
HEPCO purchases and sales									
Purchase of electricity from IEC and Jordan/ PETL	GWh	362	369	373	379	411	419	650	673
Total losses	%	22%	19%	20%	19%	20%	21%	21%	21%
Total power sales	GWh	282	300	299	306	328	333	516	532
Collection rate	%	74%	74%	70%	82%	81%	82%	83%	83%
Total power paid by consumers	GWh	209	222	209	251	267	273	427	443
Operating income (power sales)	NIS mill	154	181	181	193	193	175	246	260
Other income	NIS mill	14	13	16	15	16	16	25	26
Total income	NIS mill	167	194	197	208	209	191	270	285
HEPCO operating costs									
Electricity purchase from IEC and Jordan/ PETL	NIS mill	136	160	170	176	164	149	222	231
O&M expenses	NIS mill	13	17	19	15	16	17	26	27
Depreciation expenses	NIS mill	9	9	9	10	10	10	10	9
Interest rate on debt	%	NA	NA	NA	NA	NA	4%	4%	4%
Financing expenses	NIS mill	2	12	1	3	7	25	26	31
Running cost	NIS mill	NA	NA	NA	NA	NA	0	0	0
Other expenses	NIS mill	NA	0	0	1	1	1	1	1
Return on equity	NIS mill	NA	NA	NA	NA	NA	12	12	12
Total electricity costs	NIS mill	160	197	199	206	198	214	297	311
HEPCO income									
Annual income/loss before income tax	NIS mill	7	-3	-2	2	11	-10	-15	-15
Income tax - 15%	NIS mill	1	0	0	0	2	0	0	0
Net annual income	NIS mill	6	-3	-2	2	9	-10	-15	-15
HEPCO purchase, sale, and equilibrium tariff									
Average purchase cost / PETL tariff	NIS/kWh	0.377	0.433	0.456	0.464	0.398	0.356	0.341	0.344
Average retail tariff	NIS/kWh	0.545	0.604	0.605	0.630	0.590	0.641	0.576	0.585
Electricity average equilibrium cost	NIS/kWh	0.766	0.889	0.952	0.821	0.743	0.782	0.696	0.702

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HEPCO purchases and sales													
Purchase of electricity from IEC and Jordan/ PETL	GWh	695	720	744	729	719	738	733	732	792	810	850	901
Total losses	%	21%	21%	21%	22%	22%	22%	22%	22%	22%	23%	23%	23%
Total power sales	GWh	549	567	585	571	563	576	571	569	614	627	656	694
Collection rate	%	84%	85%	85%	86%	87%	87%	88%	88%	89%	90%	90%	91%
Total power paid by consumers	GWh	461	480	499	491	487	502	501	503	547	562	593	632
Operating income (power sales)	NIS mill	274	307	322	339	334	339	338	338	359	300	376	399
Other income	NIS mill	26	27	28	28	27	28	28	28	30	31	32	34
Total income	NIS mill	300	335	350	367	362	367	365	366	389	330	408	434
HEPCO operating costs													
Electricity purchase from IEC and Jordan/ PETL	NIS mill	242	274	285	301	291	292	286	282	299	226	309	323
O&M expenses	NIS mill	28	29	30	29	29	29	29	29	32	32	34	36
Depreciation expenses	NIS mill	9	11	11	11	10	10	10	10	10	10	10	10
Interest rate on debt	%	4%	5%	5%	5%	5%	6%	6%	6%	6%	7%	7%	7%
Financing expenses	NIS mill	34	37	41	44	47	50	53	55	57	61	59	66
Running cost	NIS mill	0	1	1	1	1	1	1	1	1	1	1	1
Other expenses	NIS mill	1	1	2	2	1	2	2	2	2	2	2	2
Return on equity	NIS mill	11	11	10	8	7	6	5	4	3	2	2	1
Total electricity costs	NIS mill	326	362	377	394	386	388	384	381	403	333	415	438
HEPCO income													
Annual income/loss before income tax	NIS mill	-15	-18	-18	-20	-18	-16	-14	-13	-11	-2	-6	-4
Income tax - 15%	NIS mill	0	0	0	0	0	0	0	0	0	0	0	0
Net annual income	NIS mill	-15	-18	-18	-20	-18	-16	-14	-13	-11	-2	-6	-4
HEPCO purchase, sale, and equilibrium tariff													
Average purchase cost / PETL tariff	NIS/kWh	0.349	0.380	0.382	0.413	0.404	0.395	0.390	0.385	0.378	0.279	0.363	0.358
Average retail tariff	NIS/kWh	0.594	0.640	0.645	0.692	0.687	0.675	0.674	0.671	0.657	0.533	0.634	0.632
Electricity average equilibrium cost	NIS/kWh	0.707	0.755	0.756	0.804	0.792	0.773	0.766	0.758	0.736	0.592	0.701	0.694

*Assuming Planned Future planning scenario from 2016 to 2030.

TABLE I.6: FINANCIAL MODEL INPUTS AND OUTPUTS—SELCO

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SELCO purchases and sales																					
Purchase of electricity from IEC and Jordan/ PETL	GWh	121	125	124	124	131	178	207	214	221	229	237	232	229	235	233	233	252	258	271	287
Total losses	%	37%	30%	29%	28%	27%	27%	26%	26%	26%	26%	25%	25%	25%	25%	24%	24%	24%	24%	23%	23%
Total power sales	GWh	76	88	88	89	96	131	152	158	164	171	177	174	172	177	177	177	192	197	208	221
Collection rate	%	54%	59%	58%	71%	79%	80%	81%	82%	82%	83%	84%	85%	85%	86%	87%	88%	89%	89%	90%	91%
Total power paid by consumers	GWh	41	52	51	63	76	104	123	129	135	142	148	147	147	153	154	156	170	176	187	201
Operating income (Power sales)	NIS mill	48	56	54	76	67	73	93	98	102	112	116	120	118	119	118	117	124	104	130	136
Other income	NIS mill	2	5	6	4	9	9	11	11	11	12	12	12	12	12	12	12	13	13	14	15
Total income	NIS mill	50	61	60	80	77	82	103	108	113	123	128	132	129	131	129	129	137	117	143	151
SELCO operating costs																					
Electricity purchase from IEC and Jordan/ PETL	NIS mill	43	54	53	71	49	63	71	74	77	87	91	96	93	93	91	90	95	72	98	103
O&M expenses	NIS mill	8	9	18	15	19	20	23	24	25	25	26	26	25	26	26	26	28	29	30	32
Depreciation expenses	NIS mill	5	5	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Interest rate on debt	%	NA	NA	NA	NA	NA	4%	4%	4%	4%	5%	5%	5%	5%	6%	6%	6%	6%	7%	7%	7%
Financing expenses	NIS mill	2	2	2	2	3	15	14	15	15	14	14	13	12	11	11	10	9	9	8	8
Running cost	NIS mill	NA	NA	NA	NA	NA	0	0	0	0	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Other expenses	NIS mill	-2	0	-2	0	-7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on equity	NIS mill	NA	NA	NA	NA	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total electricity costs	NIS mill	56	71	78	95	71	105	115	120	123	134	138	142	137	138	135	133	140	116	144	149
SELCO income																					
Annual income/loss before income tax	NIS mill	-6	-10	-18	-15	5	-22	-12	-11	-10	-11	-10	-10	-8	-7	-5	-4	-3	1	0	1
Income tax - 15%	NIS mill	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net annual income	NIS mill	-6	-10	-18	-15	5	-22	-12	-11	-10	-11	-10	-10	-8	-7	-5	-4	-3	1	0	1
SELCO purchase, sale, and equilibrium tariff																					
Average purchase cost / PETL Tariff	NIS/kWh	0.356	0.433	0.426	0.570	0.373	0.356	0.341	0.344	0.349	0.380	0.382	0.413	0.404	0.395	0.390	0.385	0.378	0.279	0.363	0.358
Average retail tariff	NIS/kWh	0.639	0.636	0.610	0.851	0.703	0.804	0.754	0.756	0.752	0.789	0.781	0.818	0.800	0.778	0.764	0.751	0.728	0.591	0.692	0.676
Electricity average equilibrium cost	NIS/kWh	1.375	1.368	1.544	1.495	0.940	1.005	0.934	0.927	0.913	0.947	0.929	0.964	0.934	0.900	0.876	0.854	0.820	0.660	0.766	0.742

*Assuming Planned Future planning scenario from 2016 to 2030.

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