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Securing Energy for Development in West Bank and Gaza

Annexes

June 30, 2017







Annex 1: The Palestinian Electricity Sector

Figure A1.1 - Electricity supply system in West Bank and Gaza

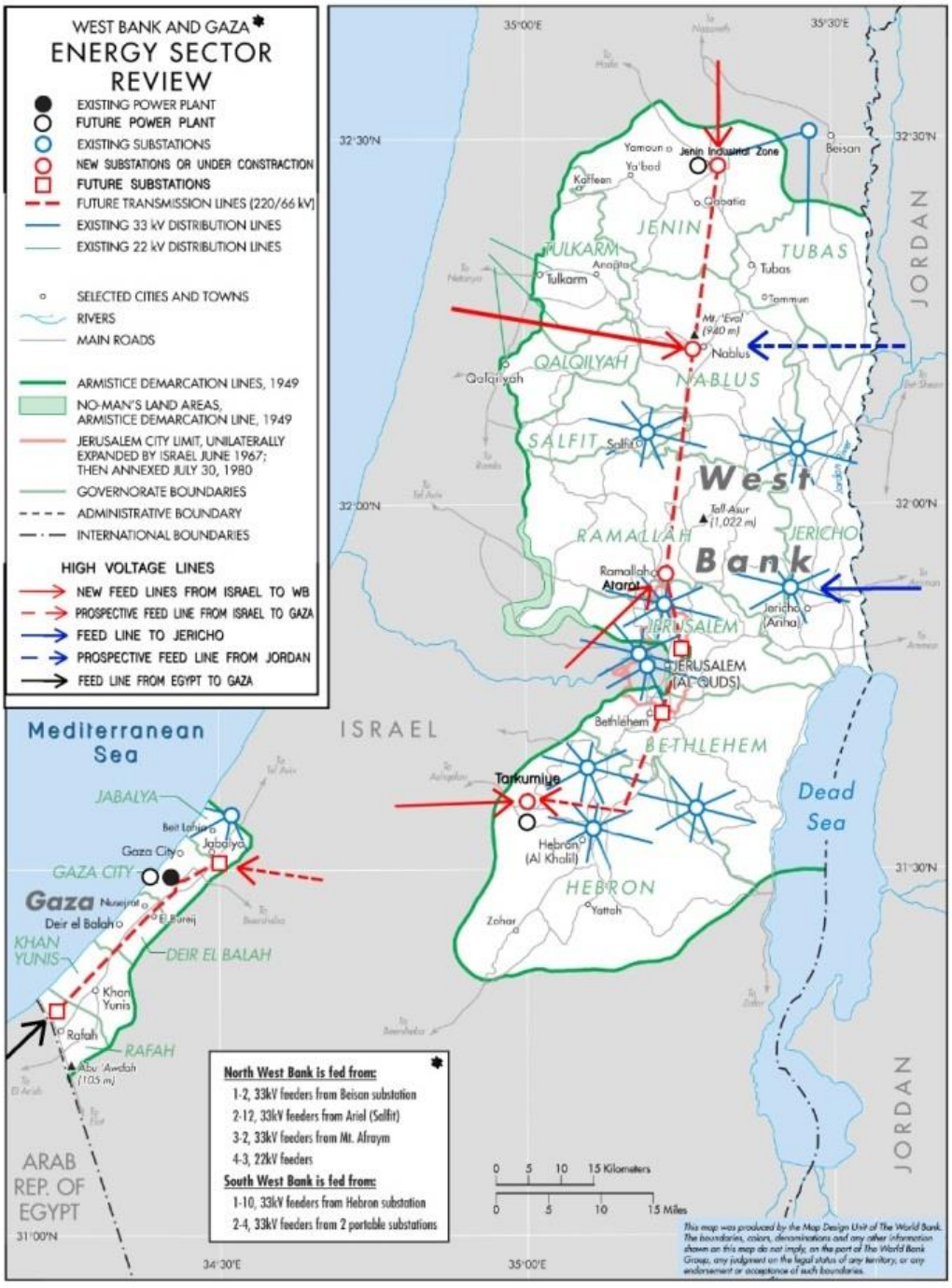
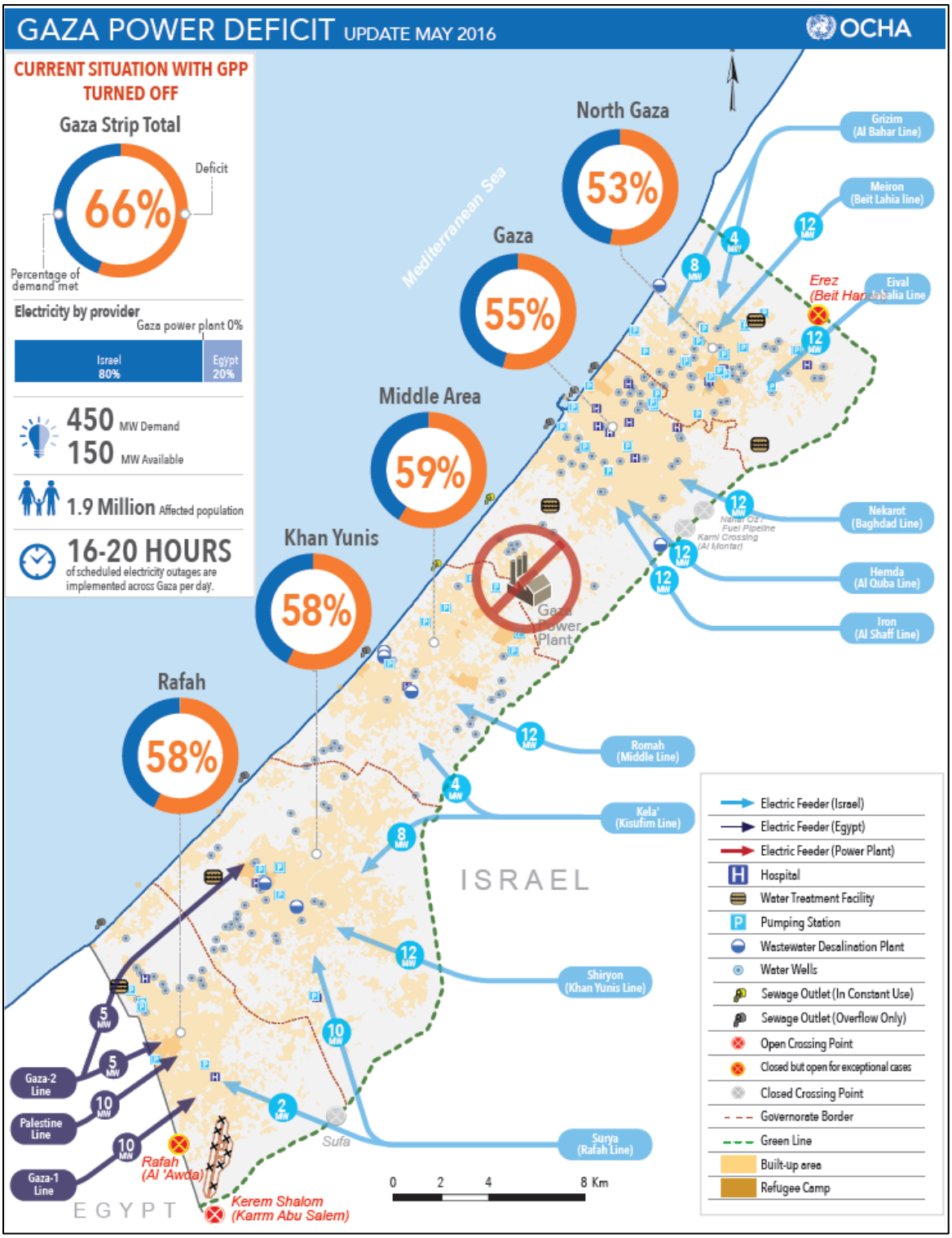


Figure A1.2 – Power supply to Gaza



Source: OCHA, 2016

Figure A1.3 – PERC Flat Tariff Structure

Flat Tariff

Applied to residential, commercial and industrial customers consuming < 60MWh/mnth

SEGMENTS	2011	2012	2014	Feb-15	Sep-15
Residential (post-paid) - All West bank Except Jericho & Jordan Valley [NIS/kWh]					
1- 160 kWh/month	1 - 100kWh/mnth: 0.4085	0.465	0.490	0.441	0.437
161- 250 kWh/month	101 - 200kWh/mnth: 0.4546	0.510	0.528	0.475	0.471
251-400 kWh/month	Abov 200kWh/mnth: 0.4795	0.590	0.635	0.572	0.543
401- 600 KWh/month		0.620	0.665	0.600	0.581
Above 600 KWh		0.690	0.735	0.662	0.642
Fixed fees/day	0.333	0.333	0.333	0.333	0.333
Residential (pre-paid) - All West bank except Jericho & Jordan Valley [NIS/kWh]					
Flat Rate (no segments)	0.467	0.520	0.565	0.500	0.475
Fixed fees/day	0	0	0	0	0
Residential (post-paid) - Only Jericho & Jordan Valley [NIS/kWh]					
1- 500 kWh/month	NA	0.480	NA	0.450	0.428
Above 500 kWh/month	NA	0.520	NA	0.490	0.466
Residential (pre-paid) -Only Jericho & Jordan Valley [NIS/kWh]					
Flat Rate (no segments)	NA	0.520	NA	0.475	0.451
Commercial (post-paid) - Single & 3-phase [NIS/kWh]					
Flat Rate (no segments)	0.518	0.630	0.667	0.614	0.596
Fixed fees/day	0.667	0.667	0.667	0.667	0.667
Commercial (pre-paid) - Single & 3-phase [NIS/kWh]					
Flat Rate (no segments)	0.508	0.600	0.637	0.586	0.568
Fixed fees/day	0.34	0	0	0	0
Industrial (Low Voltage) - less than 60MWh consumption / month [NIS/kWh]					
Flat Rate (no segments)	0.428	0.500	0.537	0.500	0.485
Fixed fees/day	1	1	1	1	1
Industrial (Med Voltage - 6.6, 11, 33kV) [NIS/kWh]					
Flat Rate (no segments)	0.399	0.450	0.487	0.440	0.414
Fixed fees/day	4	4	4	4	4
Industrial 2 (Marble and Stone) [NIS/kWh]					
Flat Rate (no segments)	NA	NA	NA	0.54	0.5238
Water pump [NIS/kWh]					
Flat Rate (no segments)	0.467	0.500	0.537	0.485	0.460
Fixed fees/day	1	1	1	1	1
Agriculture [NIS/kWh]					
Flat Rate (no segments)	0.409	0.460	0.497	0.448	0.440
Fixed fees/day	0.333	0.333	0.333	0.333	0.333
Street Lights [NIS/kWh]					
Flat Rate	0.407	0.466	0.503	0.453	0.450
Fixed fees/day	0.333	0.333	0.333	0.333	0.333
Temporary Service (post-paid) [NIS/kWh]					
Flat Rate	0.683	0.800	0.837	0.754	0.754
Fixed fees/day	0.667	0.667	0.667	0.667	0.667
Temporary Service (pre-paid) [NIS/kWh]					
Flat Rate	0.683	0.800	0.837	0.754	0.754
Fixed fees/day	0.34	0.34	0.34	0	0

Figure A1.4 – PERC Time of Use (TOU) Tariff Structure

TOU tariff

Applied to Industrial customers consuming > 60MWh/mnth

Low Voltage [NIS/kWh]

Season	TOU tariff Category	2015 Israel Tariff	2011 PA Tariff	2012 PA Tariff	Feb 2015 PA Tariff	Sep 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 & 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/kWh]

Season	TOU tariff Category	Tariff ISL 2015 [6]	2011 PA Tariff [4]	2012 PA Tariff [3]	Feb 2015 PA Tariff [2]	Sep 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 & 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

Figure A1.5 - JDECO BALANCE SHEETS

(figures 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 & 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
Non-Current Assets					
Property Plant & 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 non-current assets	7,130,789	22,717,324	32,248,657	43,470,784	46,554,248
Total non-current 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
Non-current 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 non-current 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 & equity	1,113,684,434	1,332,524,798	1,612,802,780	1,835,240,965	2,016,654,251

*Source: 2011-2015 Annual Reports (all years audited by PWC)

Figure A1.6 - JDECO INCOME STATEMENTS

(figures 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 & Admin 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 & 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/Losses before other income & 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/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/Loss	-7,742,387	-71,405,267	-74,970,659	-56,445,855	-81,878,644

*Source: 2011-2015 Annual Reports (all years audited by PWC)

Figure A1.7 - SELCO BALANCE SHEETS

(figures 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
Non-Current 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 non-current 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: Financial statements (2011-2013 audited by Talal Abu Gazaleh but 2014-2015 draft/unaudited form)

Figure A1.8 - SELCO INCOME STATEMENTS

(Figures in NIS excluding VAT)

	2011	2012	2013	2014	2015
Revenues					
Electricity Sales + 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/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: Financial statements (2011-2013 audited by Talal Abu Gazaleh but 2014-2015 draft/unaudited form)

Figure A1.9 - HEPCO BALANCE SHEETS

(figures in NIS excluding VAT)

	2011	2,012	2013	2014	2015
Current Assets					
Cash & 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 & 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 + 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 – Provision	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 & in-kind donations	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	-23,062,166	-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 & Owner's Equity	636,633,067	721,845,520	821,008,517	850,433,946	890,938,053

*Source: Annual Reports (NOTE: above financial statements are not audited)

Figure A1.10 - HEPCO INCOME STATEMENTS

(figures in NIS excluding VAT)

	2011	2,012	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 & Admin 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 / 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: Annual Reports (NOTE: above financial statements are not audited)

Figure A1.11 - GEDCO BALANCE SHEET

(figures 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
Non-Current 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 Non-Current 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
Non-Current 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 Non-Current 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 Prof- 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)

Figure A1.12 - GEDCO INCOME STATEMENT

(figures 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 Prof -Exhibit (A)	708,759,437	-74,335,858

Source: GEDCO financial statements (unaudited)

Figure A1.13 - NEDCO BALANCE SHEETS

(figures 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 & 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
Non-current assets				
Property & Equipment	230,296,617	253,445,831	258,628,054	261,864,378
Projects uner construction	NA	1,037,694	691,256	3,331,636
Stock items	NA	22,683,775	28,566,280	25,916,981
Total Non-current 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
Non-curent 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 non-current liabilities	300,700	NA	NA	NA
Total non-current 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 & Equity	342,435,094	477,826,398	571,076,646	533,330,768

Source: Financial Statements audited by Ernst and Young (2015 financial statements not available)

Figure A1.14 - NEDCO INCOME STATEMENTS

(figures in NIS excluding VAT)

	2011	2012	2013	2014
Operating Income				
Electricity Sales (billed) + subscriptions + services etc	188,881,771	225,555,641	254,389,364	260,922,894
Electricity purchases + salaries & wages + depreciation	-178,567,444	-199,879,476	-229,675,461	-249,814,659
Gross profit / Operating Income	10,314,327	25,676,165	24,713,903	11,108,235
Operating Expenses				
General & Admin 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/Losses before other income & 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: Financial Statements audited by Ernst and Young (2015 financial statements not available)

Figure A1.15 - TEDCO BALANCE SHEETS

(figures 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 & 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/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 & Equity	42,601,466	52,749,958	65,859,471	116,322,231	80,994,086

Source: Financial statements audited by Jamal Abu Farha

Figure A1.16 - TEDCO INCOME STATEMENTS

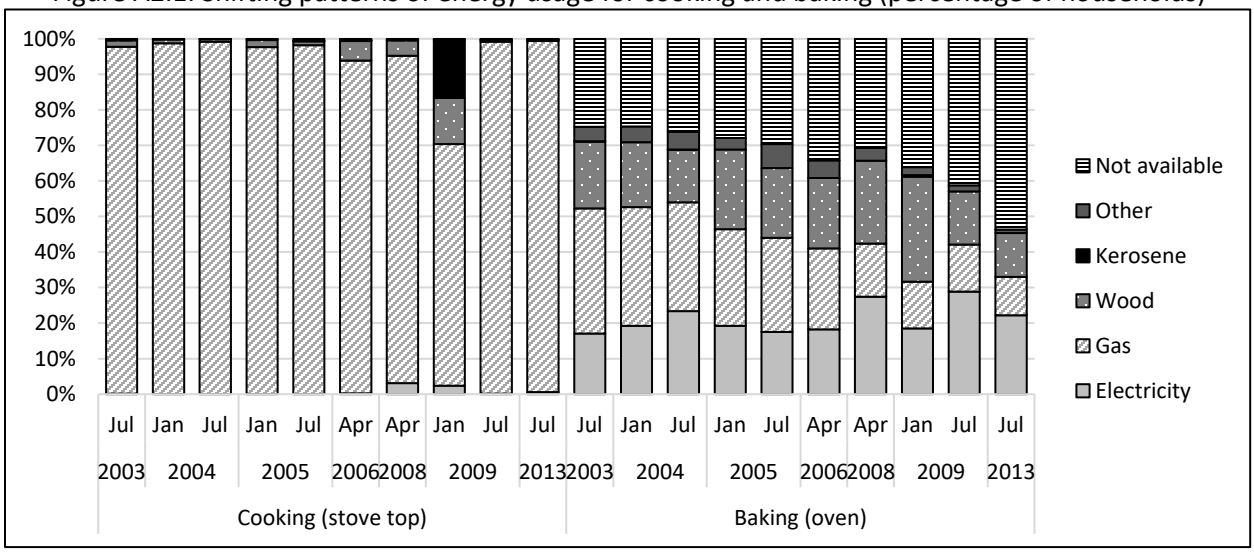
(figures in NIS excluding VAT)

	2011	2012	2013	2014	2015
Revenues					
Electricity Sales - Pre paid			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 misc services	0	2,163,512	1,696,691	3,118,616	3,610,845
Government Support for Elec Production (Subsidy)	0	0	2,976,902	2,472,444	2,821,416
Income from transformer maint 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 & admin 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 maint center	-294,189	215,432	43,924	50,693	475,533
Total Profit from elec sales (not including transf maint center)	-689,589	-1,302,811	65,042	129,307	2,949,525
Total Net Profit (including tranf maint 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 & Reserves	0	0	81,724	124,000	2,567,155

Source: Financial statements audited by Jamal Abu Farha

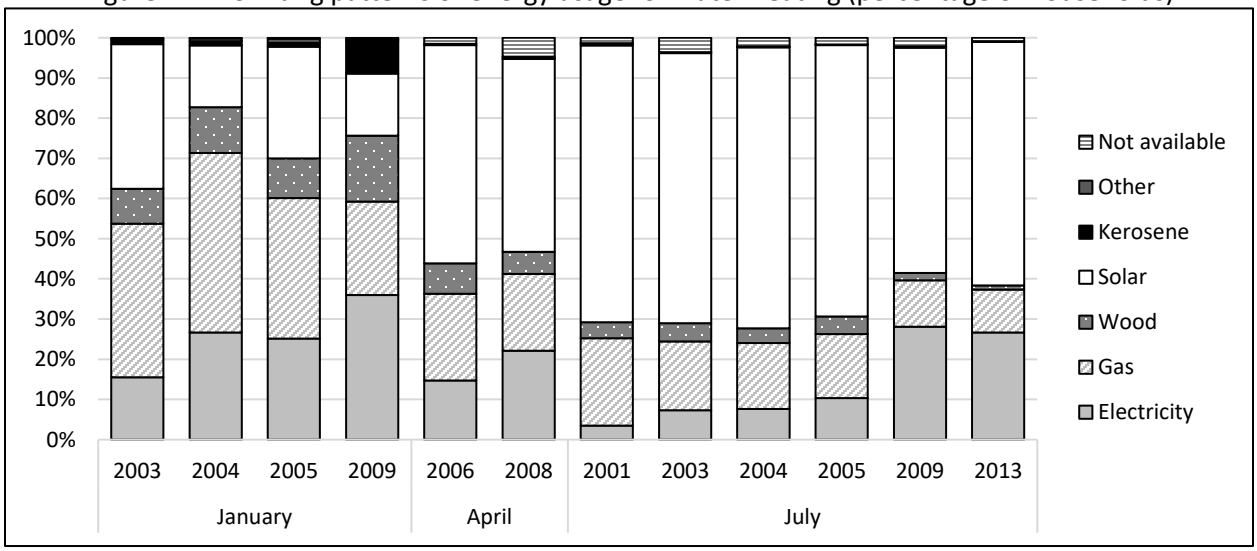
Annex 2: Electricity Demand

Figure A2.1: Shifting patterns of energy usage for cooking and baking (percentage of households)



Source: PCBS Household Energy Surveys, 2003-2013

Figure A2.2: Shifting patterns of energy usage for water heating (percentage of households)



Source: PCBS Household Energy Surveys, 2001-2013

Figure A2.1: 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

Source: Own elaboration

Figure A2.4: Electricity consumption regression model results for the winter season

Independent variable	Observations	R-square	
Household grid electricity consumption, Jan.	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

Source: Own elaboration

Figure A2.5: Existing and forecasted 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 TPS	2	1	1	2	2	3	3
Waste Water Treatment Plant WWTP	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 Deslination Plant		3	3	3	3	3	3
Existing W and WW Facilties	25	33	30	30	30	30	30
Total Gaza Governorates Energy Required for W & WW Facilties	**34**	**46**	**87**	**93**	**99**	**127**	**134**

Annex 3: Importing Electricity from Israel

Figure A3.1: Electricity Generation in Israel by Type of Fuel and Producer, 2014-2015

	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: PUA, June 2016

Figure A3.2: Israeli Generation Capacity, 2007-2015

(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

Figure A3.3: IEC electricity sales by type of consumers, 2014–2015

	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)

Figure A3.4: Electricity demand forecast for Israel, 2016-2030

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

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.

Source**:** Ministry of National Infrastructure, Energy and Water resources, http://energy.gov.il/Subjects/Electricity/Pages/GxmsMniAboutElectricity.aspx

Figure A3.5: Overview of Israeli transmission and distribution service tariffs (NIS Agorot per KWh, as of 13.09.2015)

Season	ToU block	Transmission tariffs *	Transmission & 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

* 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

Exchange rate: US$ 1 = NIS 3.846 (June 30, 2016)

Ultra high voltage = 400 Kilo Volt & 161 KV, high voltage = 22 KV & 33 KV

Source: Israel PUA

Figure A3.6: 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.

Figure A3.7: Period Definitions for Israeli Time-of-Use Tariff Rates

Season	Time of day	Time of Use period definitions		
		Saturdays and holidays	Fridays and days before holidays	Weekdays
Summer (July – August)	Peak Shoulder Off-peak	 00→24	 00→24	10→17 07→10 , 17→21 00→07 , 21→24
Winter (December – February)	Peak Shoulder Off-peak	17→19 19→21 00→17 , 21→24	16→20 00→16 , 20→24	16→22 06→08 ,08→16, 22→24 00→06
Transition (Remaining months)	Peak Shoulder Off-peak	 17→21 00→17 , 21→24	 06→20 00→06 , 20→24	06→20 20→22 00→06 , 22→24

Source: Israel PUA. Last update 15.02.2010.

Figure A3.8: 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 13.09.2015.

* Exchange rate: US$ 1 = NIS 3.846 (June 30, 2016)

** Ultra-high voltage = 400 KV & 161 KV, high = 22 KV & 33 KV, low = 400 Volt

Figure *A3.9: Israeli Bulk Supply Tariffs (NIS Agorot per KWh)*

Low voltage	High Voltage
44.35	35.92

Source: Israel PUA as of 13.09.2015

Figure A3.10: Israeli System Management Services Tariffs (NIS Agorot/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 13.09.2015

Exchange rate: US$ 1 = NIS 3.846 (June 30, 2016)

Annex 4: Importing Natural Gas for Domestic Power Generation

Figure A4.1: Prospective industrial consumers of natural gas in the West Bank

No.	Name of Company	City	Type of Factory	Diesel Consumption (L/year)	LPG Consumption (kg/year)	Natural Gas Demand 1000 CM/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	Aluminium	0	379,464	474
Total Consumption/year				**1,979,423**	**945,453**	**3,033**

Source: Palestinian Federation of Industry - Eco Energy's Calculation of NG Demand

* Natural gas conversion factors: 1000 liters of Diesel = 935 cubic meters of gas 1 ton LPG=1250 cubic meters

Figure A4.2: Forecast demand for natural gas based on power generation in the West Bank

	Installed Capacity [1]	Electricity Generation	Total electricity Demand [2]	% of domestic Production [3]	Natural gas demand[4]
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

[1] Jenin IPP: 200 MW at 2022, 400 MW at 2024; Tarkumiye IPP: 200 MW at 2028

[2] Based on 2015 demand in the WB of 4286 GW and assumed growth rate of 6% per annum

[3] Share of domestic gas based generation of total electricity demand in the West Bank

[4] CCGTs have 57% efficiency and operated at 70% capacity

Figure A4.3: Forecast demand for natural gas based on power generation in Gaza

	Natural Gas based power Capacity & Generation				Total electric	% domestic	Natural gas
	Converted GPP[1]	New CCGT[1]	Total capacity	Generation	Demand [2]	production [3]	demand [4]
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

[1] GPP: 70 MW conversion from gasoil to gas at 2022, additional 70 MW at 2024; New 100 MW CCGT at 2026

[2] Based on 2015 demand in Gaza of 972 GWh, and assumed average growth rate of 6% per annum

[3] Share of domestic gas based generation of total electricity demand in Gaza

[4] Converted GPP works at 45% efficiency; new CCGT works at 57% efficiency, all plants work at 70% capacity

Figure A4.4: Natural Gas Prices in Israel 2016 ($/mmbtu)

consumer	Initial price	Indexation
IEC	5.7	U.S. CPI +- 1%/yr *
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

* IEC's price indexation formula: U.S. CPI+1% /year until 2020 and then U.S. CPI - 1%/year for 7 years

Annex 5: Importing Electricity from Jordan & Egypt

Figure A5.1: 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	USD/kWh	0.000	0.000	0.000	0.000	0.000	0.030	0.033
Heavy Fuel Oil	USD/kWh	0.042	0.044	0.045	0.047	0.048	0.050	0.052
Light Fuel Oil	USD/kWh	0.059	0.059	0.060	0.062	0.064	0.065	0.068
Natural Gas	USD/kWh	0.022	0.024	0.025	0.027	0.029	0.032	0.034
Average (fossil fuel)	USD/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	USD/kWh	0.000	0.000	0.000	0.000	0.000	0.030	0.033
Heavy Fuel Oil	USD/kWh	0.042	0.035	0.045	0.051	0.057	0.063	0.070
Light Fuel Oil	USD/kWh	0.096	0.078	0.106	0.119	0.133	0.149	0.167
Natural Gas	USD/kWh	0.039	0.033	0.042	0.046	0.050	0.056	0.063
Average (fossil fuel)	USD/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 & 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**

Annex 6: Developing Domestic Renewable Power Generation

Table A6.1: Estimation of disaggregated potential for residential rooftop PV

Number of Residential Rooftops								
Governorate	**Population***			**% population**	**% individual houses***	**Household (HH) size***	**Number of HHs**	**# 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

*Source: PCBS

Table A6.2: Estimation of number of rooftops for non-residential rooftop PV

Public Administration	200
Schools	2200
Commercial	5000

Source: PEC

Table A6.3: Assumptions regarding land requirements for solar power generation in Palestine (m^2/KWp)

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

Source: NREL – Land-use requirements for solar power plants in the US (2013), Land-Use Requirements of Modern Wind Power Plants in the US (2009)

Table A6.4: Estimation of overall potential for rooftop solar PV in Palestine

Maximum Potential Capacity – Rooftop Solar						
West Bank						
	# rooftop for PV	Area per rooftop (m2)	% rooftop 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						
	# rooftop for PV	Area per rooftop (m2)	% rooftop 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 & Gaza						697

Table A6.5: Estimation of potential for utility scale solar power generation in Palestine

Maximum Potential Capacity – Utility Scale Solar					
	total surface		Available according to PETL	Available according to PETL	Potential Capacity
	(km2)	(%)	(%)	(km2)	(MWp)
Area A&B	2488	40%	0.12%	3	103
Area C	3732	60%	2.64%	98.5	3374
TOTAL	6220	100%	2.76%	101.5	3476

Figure A6.6: Currently installed and on-going solar projects at Gaza hospitals

	MOH facility	Unit benefiting of the project	Donor	Capacity (W)	Budget (USD)	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	On-going
9	Al-Aqsa hospital	OT, NCU, Cardiac care	UNDP	60,000	225,000	On-going
10	Indonesian hospital	OT, ED	UNDP	60,000	225,000	On-going
11	Rantissi Specialized hospital	NCU, part of Lab	Welfare Association	30,720	150,000	On-going
TOTAL				**305,970**	**1,537,180**	

Source: World Health Organization (WHO)

Figure A6.7: Critical units in Gaza MOH hospitals in need of solar energy

	MOH facility	Targeted Unit	Hours of power supply	Capacity (KWp)	Budget USD
1	Shifa hospital	Hemodialysis (38 HD unit + desalination plant)	12	100	500,000
		NCU for premature babies (35 incubator)	24	30	120,000
		Cardiac Care	24	30	120,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate one OT sterilizer)	12	40	160,000
2	EGH	OT rooms (eight 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 one OT sterilizer)	12	40	160,000
3	Nasser hospital (Khanyounis)	OT rooms (three rooms)	6	20	80,000
		ICU (16 beds)	24	30	120,000
		Hemodialysis (18 HD unit + desalination plant)	12	50	200,000
		NCU for premature babies (20 incubator)	24	30	120,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate one 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 (three rooms)	6	15	60,000
		Sterilization unit (to operate one OT sterilizer)	12	40	160,000
7	Beit Hanoun hospital	OT rooms (two rooms)	6	15	60,000
		Laboratory	24	20	80,000
		Sterilization unit (to operate one 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 one 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 one 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 one OT sterilizer)	12	40	160,000
Grand Total in USD				**1,010**	**4,140,000**

Source: World Health Organization (WHO)

Annex 7: Developing Transmission Infrastructure

Figure A7.1: Map of existing transmission infrastructure in Palestine

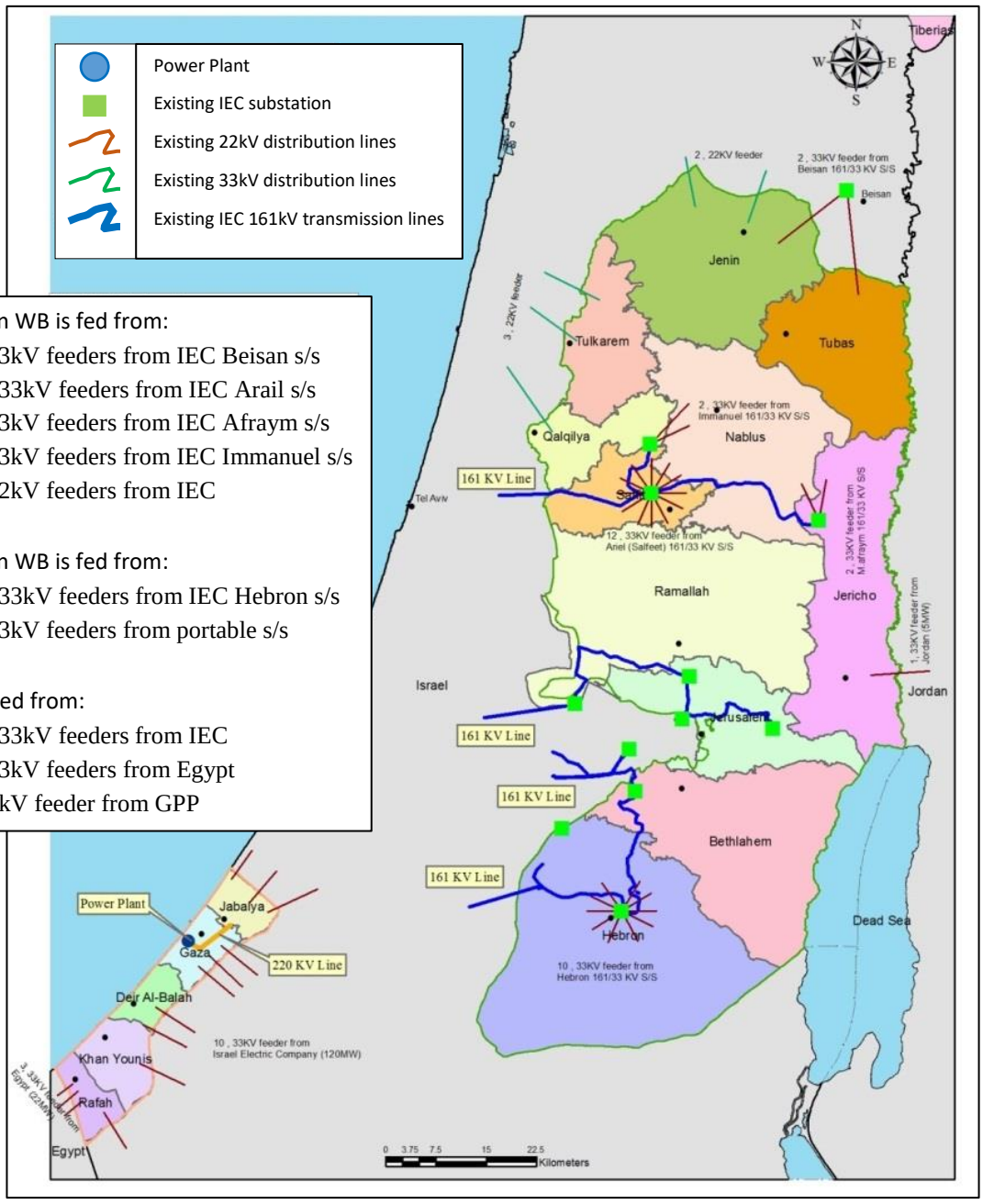


Figure A7.2: Location and service area of new PETL high voltage substations

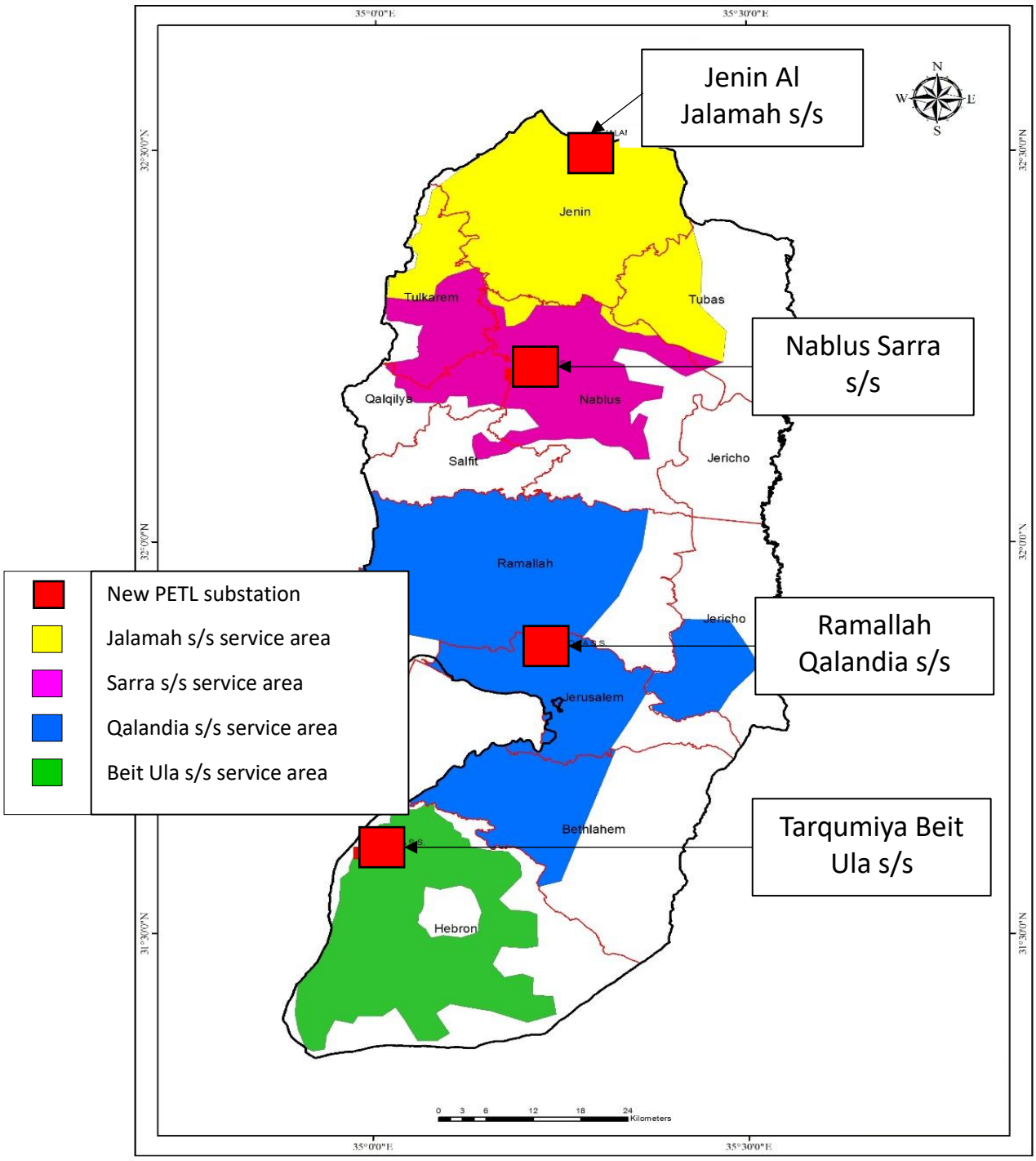
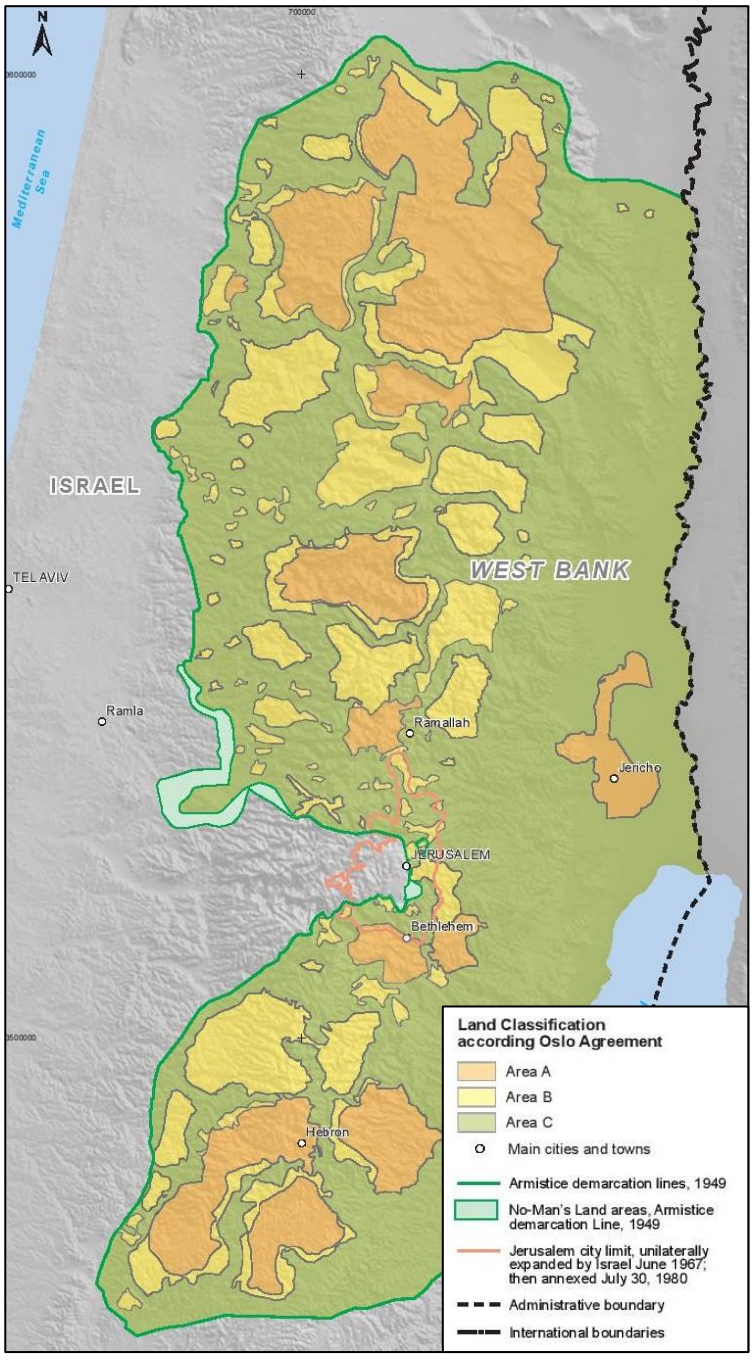


Figure A7.3: Land in the West Bank is divided into Areas A and B, under Palestinian civil administration, and Area C under Israeli civil administration



Annex 8: Robust Planning Methodology and Detailed Technical Results

Introduction

This Technical Annex describes the methodological considerations, input assumptions and additional results to support messages in the section on power system expansion planning included in the main report of the *Securing Energy for Development* study. The analysis applies concepts from the Robust Decision Making (RDM) framework to develop a 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 RDM-related approach to show how uncertainties can affect the choice of technology options. The analysis also presents results that take into account constraints with access to project financing.

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 described, 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:

i) In a deterministic analysis, what does a least cost capacity expansion plan look like, which ensures Palestine is self-reliant and able to meet demand securely (assuming there are no capital constraints)?
ii) What are the features of a capacity plan that ensures Palestine 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?
iii) How does the average cost of production change by sharing reserve margin requirements with neighboring countries?
iv) Given capital constraints, what is a balanced mix that combines (ii) and (iii) to keep average costs of production at a specified annual level?

v) How does access to regulated land (known as Area C) affect the generation mix and system costs?

vi) 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, amongst 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%[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 in part due to the uncertainty associated with demand projections because historical trends are typically different from expected growth patterns. The power sector in Palestine falls in this category. Additionally, the geopolitical situation in Palestine (one of the Territories listed on the bank's list of fragile situations)[2] introduces additional layers of significant uncertainty.

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, etc. The lack of financing, delays and damages are all constraints and risks that need to be considered in planning for these 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

[1] Based on the following: overnight capex - $750/kW; weighted average cost of capital – 10%; plant life – 40 years; half of capex needed from start of construction.

[2] http://siteresources.worldbank.org/EXTLICUS/Resources/511777-1269623894864/FY15FragileSituationList.pdf

plan that finds a good balance between cost and risks and characterizes the ever changing dynamics of fragile states. (Bazilian & Chattopadhyay, 2016).

For Palestine in particular, 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 Palestine, 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, namely: a) Least-cost planning tools that include risk premiums as inputs; b) Extension of least-cost planning models with a simulation component reflect some of the uncertainties associated with fragile and conflict states; and c) 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 employed the first approach (a) above to look at the impact of differentiating the cost of capital for risky projects (typically large, scale-efficient infrastructure which 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 Palestine, 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 1.6 billion 2015 US$. 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 & Philpott, 2007) (Shapiro, Dentcheva, & Ruszczynski, 2009)

Establishing such probability distributions for Palestine 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 Palestine 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 linear programming (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 modeller rather than the model.

The Monte Carlo simulation process considers random variation in uncertain parameters such as demand and generation availability, fuel prices, etc to form a composite sample that represents one realization or "future" of all possible uncertain parameters. The LP dispatch optimization is solved for the sample to obtain one point estimate of system costs, prices, etc. The process is repeated for a large set of samples (e.g., somewhere between 100 and 1000 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: a) we directly represent the probability distribution of each uncertainty parameter rather than accepting a pre-defined scenario with a specific view on the uncertain parameters; and b) we therefore can evaluate 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 A - 1. We start by identifying all the input parameters which are uncertain. These include: the timing and availability of fuel, energy demand, fuel prices, amount of imports, availability of power plants, investment costs, amongst others (see Table A - 1). The ranges for these uncertain parameters were developed by the project team after consultations in Jordan, Israel, Egypt, and Palestine.

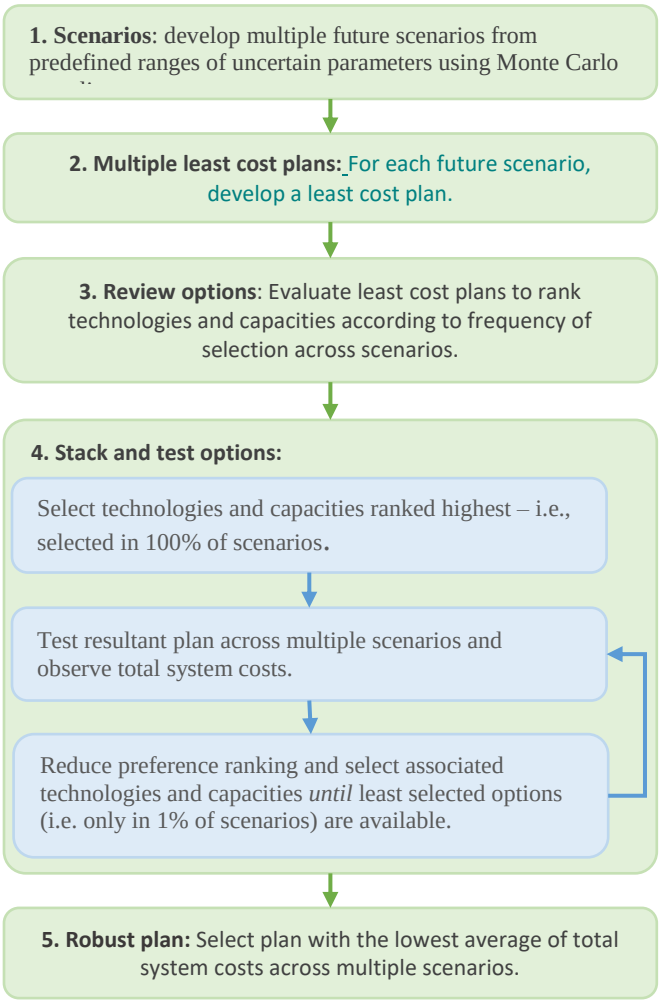


Figure A - 1: Process flow for selecting robust options

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 LNG 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 linkage between international oil and electricity prices.

Table A - 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 PV, wind and CSP 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 interconnection
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.

Details of the process flow are:

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, etc. Since the draws from the various parameters are completely independent, two valid questions arise at this stage: a) how certain are we that the combination of individual draws adequately cover the worst case scenarios?; and b) 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 was used to demonstrate the merits of the study approach.

For question (b), 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.

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 A-4.

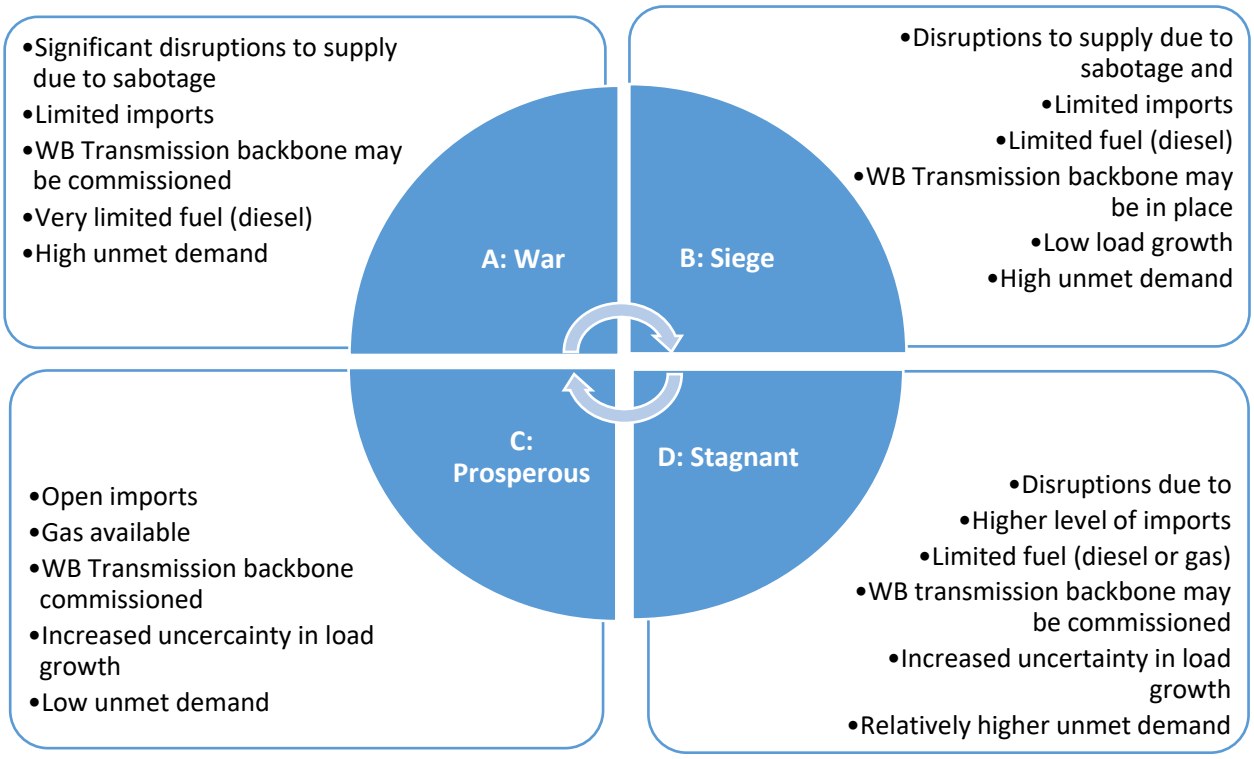


Figure A - 2: Characterizing four possible economic conditions of Palestine

For extended periods in the planning horizon, or the entire duration, either territories of Palestine 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 are 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 scenarios above, 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 consider 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 A - 3 shows variation of the capacity of available generation options across multiple scenarios. Existing capacity is always included. As seen from the figure, 194MW of the plant PVr-WBC is robust in all scenarios, while the first concentrated solar power (CSP) of 20MW is only picked up in 11% of scenarios. Technology and capacity options that appear in 100% of scenarios constitute no-regret options. Moving to the right of the chart, the capacities of technologies increase but are less robust.

[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 (eg, 48MW could be configured as 12MW 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 1.1MW 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.

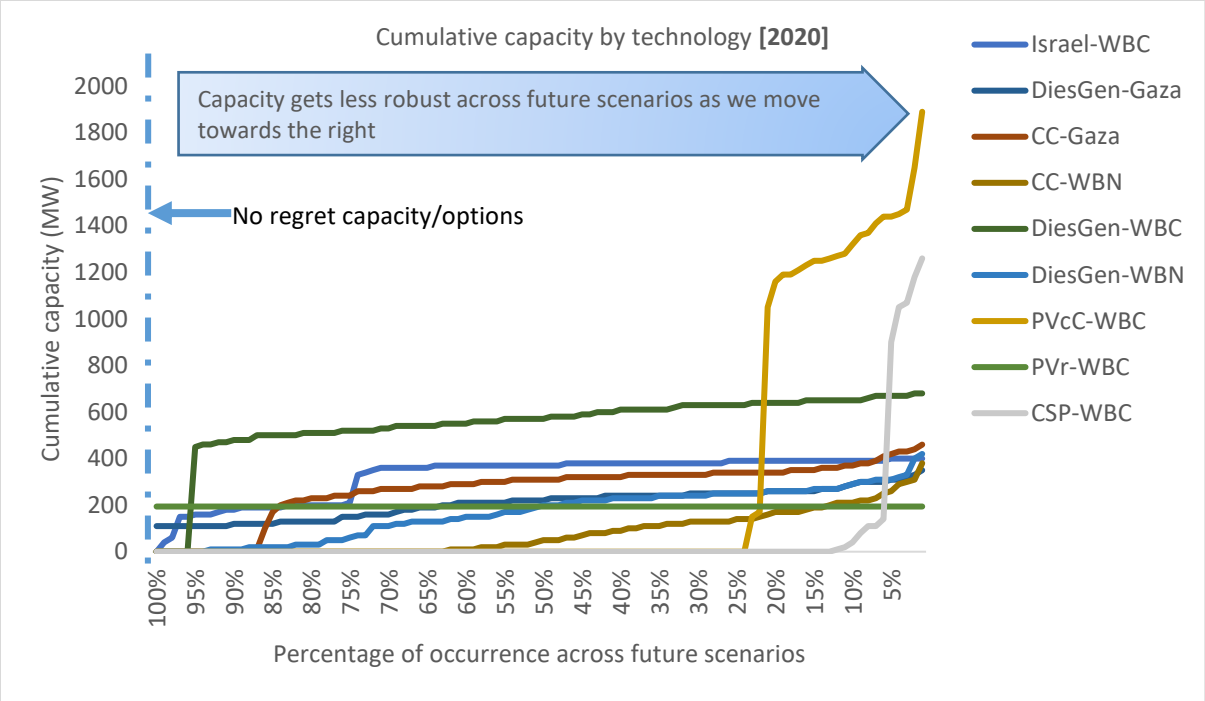


Figure A - 3: Cumulative capacity by technology

While it would be ideal to only include 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 (ie, select capacities to right in Figure A - 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.

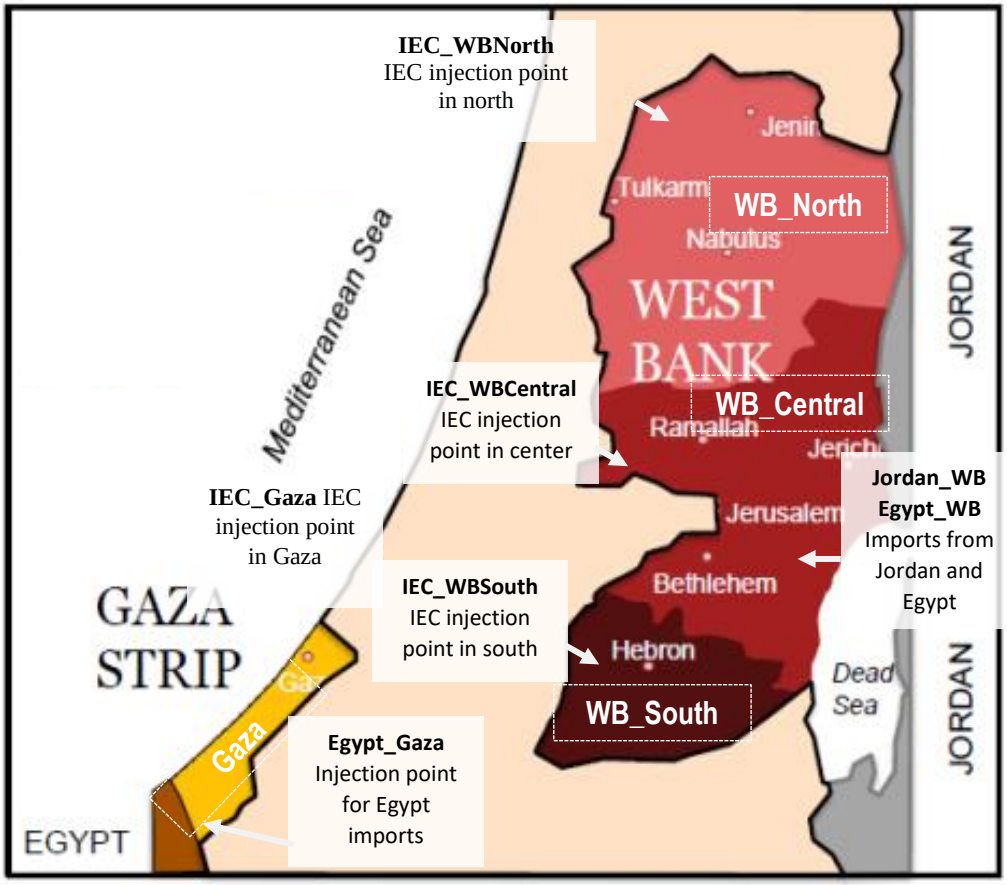
Step 5: Select robust plan

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.

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: a) Latin hypercube sampling was used to reduce the need for large number of simulations, while we use Monte Carlo sampling for this study; and b) 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 above.

Structure of the model

West Bank is modeled as three separate zones – WB_North, WB_Central and WB_South (see Figure A - 4). Electricity imports from Israel is injected through three points in the North, Central and South. Demand and solar resource availability is accordingly distributed amongst the three zones in West Bank. Gaza is modeled as one separate zone.[4]



[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 Palestine and not necessarily energy exchange between.

Figure A - 4: Categorization of zones and power import connections in West Bank and Gaza

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

The model used for for Palestine is a GAMS[5]-based least-cost planning tool that is in many ways, simpler to populate (through an Excel front end) and easier to customize or build algorithms/procedures around the basic model to deal with uncertainties. 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, fixed and variable operation and maintenance (O&M) costs;
- *Load:* Load forecasts in the form of load duration curves (LDC) for the planning years;
- *Generation:* Operational characteristics of generation plants such as thermal efficiency, maximum utlization factors, amongst others;
- *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, reserve margins amongst others can be calculated.

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

EQ Set 1: Objective function

[5] General Algebraic Modeling System (GAMS) is a fully documented model and has been used for other Bank assignments in Ukraine, Bangladesh, Bulgaria, and South Africa.

$$\text{cost} = \frac{1}{1000000} \cdot \sum_{y} \left(\frac{1}{(1+\text{r})^{(\text{ord(y)}-1)}} \cdot \left(\sum_{NG} (\text{CRF}_{NG} \cdot \text{cap}_{NG,y} \cdot \text{GenData}_{NG,\texttt{CAPEXperkW}}) \cdot 1000 + \right. \right.$$
$$\sum_{g} (\text{cap}_{g,y} \cdot \text{GenData}_{g,\texttt{FOMperMW}}) + \sum_{g} (\text{CumRepair}_{g,y} \cdot \text{CRFr}_{g} \cdot \text{GenData}_{g,\texttt{CostOfRepair}}) \cdot 1000 +$$
$$\sum_{i,g,f|\text{map}_{g,f}} \left(\sum_{t} (\text{Gen}_{i,g,f,y,t} \cdot \text{Duration}_{t} \cdot \text{VC}_{g,y,f}) \right) + \sum_{i,g,f|\text{map}_{g,f}} \left(\sum_{t} (\text{Gen}_{i,g,f,y,t} \cdot \text{Duration}_{t} \cdot \text{GenEmis}_{g,f} \cdot \right.$$
$$\text{CO2Price}_{y,\texttt{CO2Price}})) [\text{IncludeCO2Price}] + \sum_{i,g,f|\text{map}_{g,f}} \left(\sum_{t} (\text{Gen}_{i,g,f,y,t} \cdot \text{Duration}_{t} \cdot \text{GenData}_{g,\texttt{VOM}}) \right) +$$
$$\sum_{i,t} (\text{USE1}_{i,y,t} \cdot \text{Duration}_{t} \cdot \text{VoLL}) + \sum_{i,t} (\text{Surplus}_{i,y,t} \cdot \text{Duration}_{t} \cdot \text{DumpPrice}) + \sum_{b} (\text{Unmetreserve}_{b,y}) \cdot$$
$$\left. \left. \text{VoLLReserve}) \right) \right)$$

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, y1	*	years
map	g, f	
l	*	use fuel limit 1 for yes 0 for no
b	b	states
NG	g	new generators
EX	f	export fuels
NE	f	nonexport fuels all fuels apart from exports
GE	g	generators
te	te	genertor technologies
mapbi	b, i	map nodes to territories
mapij	i, j	map nodes
mapig	i, g	map nodes to generators

Decision Variables

Name	Domains	Description
Gen	i, g, f, y, t	generation per unit per year per LDC point in MW
cap	g, y	installed capacity in year y in MW
Build	i, g, y	Build new capacity MW in year y
Retire	i, g, y	Retire existing capacity
USE	i, y, t	Import
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	
cost		total system cost in USD
Repair	g, y	capacity to be in a year re-paired
CumRepair	g, y	cumulative capacity to be repaired

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%.

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.

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.

Sum of *CumRepair*CostOfRepair* add 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*CO2Price* adds the cost of CO_2 emissions if required and is set by the flag *IncludeCO2Price*. CO_2 prices are not included in the analysis for Palestine.

[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 Bank projects that refurbished/rehabilitated thermal plants mostly to improve efficiency.

In addition to regular costs, the objective function includes penalties associated with violation of demand constraint, *VoLL* - which is set at USD 750 per MWh for this study, and reserve limit, *VoLLReserve* which is set at USD 5,000 per KW in this study. Mathematically, the unserved energy variable is 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 of electricity consumers to avoid supply interruption (Electricity Commission, 2008). The study reports VoLL to be as high as USD 44,500 per MWh in Australia and USD 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

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

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

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

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

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

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

Firstly, the dynamic linkages across the years is captured in the first equality constraint that defines the variable *Cap*. Capacity may be augmented by building new units (i.e., *Build*), or it can be mothballed (i.e., *Retire*). Secondly, 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

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

$$\sum_{f|\text{map}_{GE,f}} (\sum_{t}(\text{Gen}_{i,GE,f,y,t} \cdot \text{Duration}_t)) \leq \text{cap}_{GE,y} \cdot 8760 \cdot \text{Availability}_{GE,y} \qquad \forall i, GE, y$$

$$\mathbf{eTotalImports}_{i,EX,y,t}$$

$$\sum_{g|(\mathrm{mapig}_{i,g} \wedge \mathrm{map}_{g,EX})} (\mathrm{Gen}_{i,g,EX,y,t}) \leq \mathrm{MaxImports}_{EX,y} \cdot \mathrm{FuelLimitFactor}_{EX,y} \qquad \forall i, EX, y, t$$

Generation from all units (i.e., 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

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

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

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

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

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

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

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 which takes the entire plant out of service. These repairs incur a cost to the system which 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

DemBalBase$_{i,y,t}$

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

DemBal1Base$_{i,y,t}$

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

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 know 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, electricity flows to/from the node. Generation deficit violation variables (*USE1*) are also included in order 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 block 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

MinCapReserve$_{b,y}$

$$\sum_{i|\text{mapbi}_{b,i}} \Big(\sum_{g|\text{mapig}_{i,g}} (\text{cap}_{g,y} \cdot \text{GenData}_{g,\texttt{ReserveContribution}}) \Big) + \text{Unmetreserve}_{b,y} \geq 1.15 \cdot max\{ \sum_{i|\text{mapbi}_{b,i}} (\text{LDCBase}_{i,t,y}) \big| t \} \qquad \forall b, y$$

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 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 timeframe, generators that are not currently synchronised may synchronise and commence generation. *ReserveContribution* is a factor that determines available capacity that contributes to the reserve requirements.

EQ. Set 7: Fuel consumption and constraints

$\mathbf{FuelBal}_{i,NE,y}$

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

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

$$\mathrm{Fuel}_{i,NE,y} \leq \mathrm{FuelLimit}_{1,NE,y} \cdot \mathrm{FuelLimitFactor}_{NE,y} \qquad \forall i, NE, y \mid \sum_{y1} (\mathrm{FuelLimit}_{1,NE,y1})$$

$\mathbf{JointFuel}_{i,g,y,t}$

$$\sum_{f|\mathrm{map}_{g,f}} (\mathrm{Gen}_{i,g,f,y,t}) \leq \mathrm{cap}_{g,y} \qquad \forall i, g, y, t$$

The first equation defines the fuel consumption as a function of the generation from that type of fuel across all generating units over all LDC 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/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 Palestine 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

$$\mathbf{REProfileConsSolar}_{i,g,y,t}$$

$$\sum_{f|((\neg(\text{GenData}_{g,\texttt{Type}}=8))\wedge\text{mapig}_{i,g})} (\text{Gen}_{i,g,f,y,t}) \leq \text{REProfile}_{t,i}\cdot\text{cap}_{g,y}\ \forall i,g,y,t \mid (\text{GenData}_{g,\texttt{Fuel}}=8)$$

$$\mathbf{REProfileConsCSP}_{i,g,y,t}$$

$$\sum_{f|\text{mapig}_{i,g}} (\text{Gen}_{i,g,f,y,t}) \leq \text{CSPProfile}_{t,i}\cdot\text{cap}_{g,y} \qquad \forall i,g,y,t \mid (\text{GenData}_{g,\texttt{Type}}=8)$$

$$\mathbf{ControlRECap}_{i,te}$$

$$\sum_{g,y|((\text{GenData}_{g,\texttt{Fuel}}=8)\wedge(\text{GenData}_{g,\texttt{Type}}=\text{TechIndex}_{te}))} (\text{Build}_{i,g,y}) \leq \text{TechnologyCaps}_{i,te,\texttt{MaxCap}} \qquad \forall i,te$$

These equations define the limits of generation from variable RE sources. *REProfile* is the maximum utilization of the RE plant in every time block. All three types of VRE (PV, CSP and wind) have unique profiles.

EQ. Set 9: Combined solar and PV capacity cannot exceed total land available

$$\mathbf{JointFuel}_{i,g,y,t}$$

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

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 A - 2. The Gaza Power Plant (GPP) is the only operating power plant. The installation costs for variable RE (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.

Table A - 2: Generator parameters

	Fuel	Installation cost (2018)	Fixed O&M	Variable O&M	Contribution to reserve*	Base unit size	Max repair costs	Heat rate
		$/kW	$/kW-yr	$/MWh	%	MW	$/kW	MMBTU/MWh
[1]Rooftop PV (PVr)	Solar	2,591	15	0	0	0	864	0
[1]Utility PV (PVc)	Solar	1,646	13	0	0	0.5	549	0

[1]Concentrated Solar Power/Thermal (CSP)	Solar	5,552	59	10	0.75	10	1,851	0
[1]Wind (Wind)	Wind	1,863	51	0	0	1	621	0
[4]Biogas (Bio)	Landfill/ Manure	3,942	107	5	1	2	1,314	[2]14.5
[2]Distributed Diesel Genset (DiesGen)	Diesel	800	15	15	1	2	263	10
[2]Combined Cycle Gas Turbine (CC)	Gas/ Diesel	1,300	6.2	3.5	1	140	433	6.7
[2]Simple Cycle Gas Turbine (GT)	Gas/ Diesel	1,000	25	7.5	1	100	333	9
[3]Imports from Jordan			5	0	Scenario		0	0
[3]Imports from Israel			5	0	Scenario		0	0
[3]Imports from Egypt			5	0	Scenario		0	0

* 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.

SOURCES: 1 – Team estimates based on NREL Annual Technology Baseline; 2 – High end of Lazard's levelized cost of energy analysis (Version 9.0). 3 – Team estimates. 4 - IEA World Energy Outlook

Renewable energy sources could be a significant part of the energy mix in Palestine with total potential of approximately between 3,100 and 4,000 MW (depending on the share of CSP and PV. See Table A - 3). There is considerable technical potential for solar PV and CSP (at least 98% of RE potential), but the bulk (at least 76% of potential solar generation) is in Area C of the West Bank and can only be realized if Israel grants access to the land. The technical potential for gas/diesel fired plants depends on the volume of fuel.

Table A - 3: Potential generator capacities

Gaza	Potential Capacity (MW)
Rooftop PV (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 PV (PVr)	210
Commercial PV (PVcAB) - Area A, 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 PV (PVr)	194
Commercial PV (PVcAB) - Area A, B	7
Commercial PV (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 PV (PVr)	131
Commercial PV (PVcAB) - Area A, 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 PA 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 O&M costs include the cost of providing ancillary services to Palestine which is priced at 12 $/MW-h. The capacity is therefore optimized to minimize system costs within export limit constraints and gives the minimum transfer capacity when sizing the interconnection. Import sources considered are shown in Table A - 4.

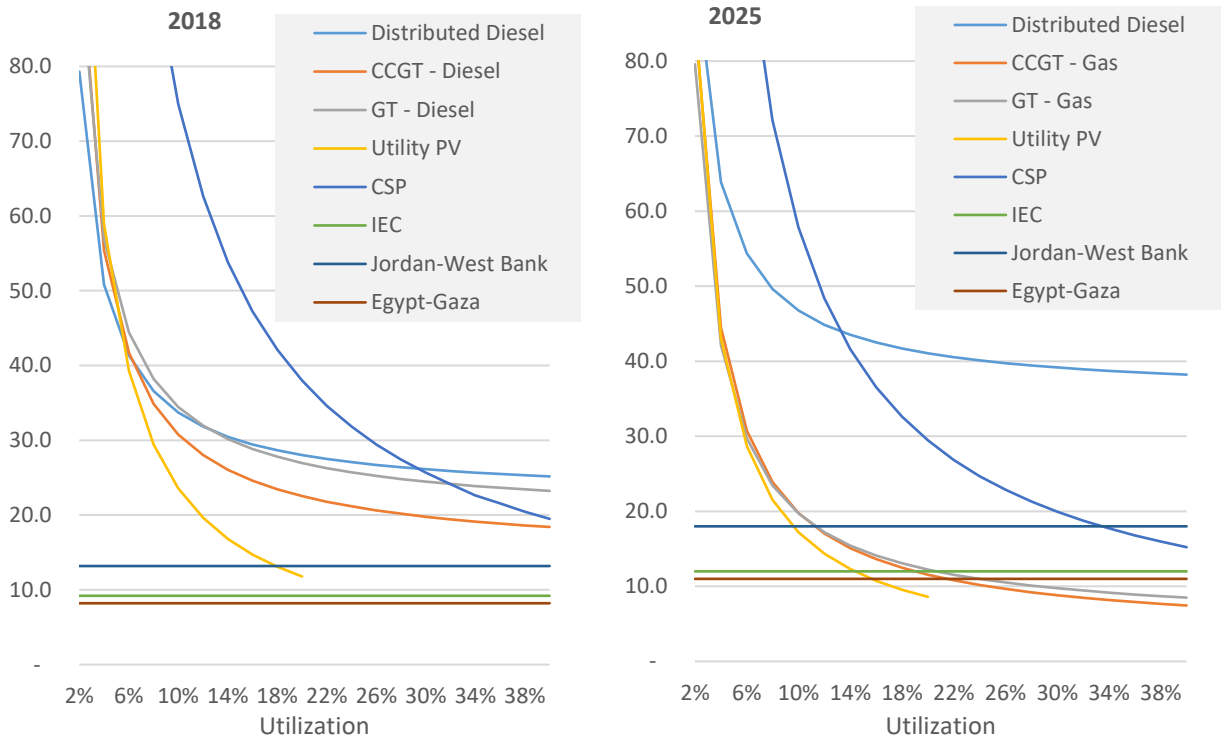
Table A - 4: Current capacity and pricing of electricity imports

From	To	Current capacity (MW)	2016 price ($/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/A[1]

[1] There is currently no power import from Egypt to the West Bank but this could include the cost of generation of 81 $/MWh to Egypt and 6.5 $/MWh wheeling charges to Jordan based on current transmission wheeling charges for renewables in Jordan at 4.5 fils/kWh

SOURCE: Team estimates

Under 2018 cost conditions, solar PV has the lowest levelized cost of energy (LCOE) of all technologies available as shown in Figure A - 5. At low utilization rates, diesel has the lowest costs making them good candidates for providing back-up services. This also means frequent outages which affect the availability of plants increases average system costs.



NOTES: Capex and O&M as shown in Table A - 3; Diesel= 21 $/MMBTU; WACC=10% ; 20 year life for PV and 30 for all others

NOTES: Capex and O&M as shown in Table A - 3; Diesel= 34.2 $/MMBTU; Gas=5.5$/MMBTU; WACC=10% ; 20 year life for PV and 30 for all others

Figure A - 5: Comparison of LCOE in US cents/kWh for technology options

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% utilization is on par with the LCOE for utility scale PV at 5.4 US cents/kWh at a gas price of 5.5 US$/MMBTU. CSP costs are also lower with a high end LCOE close to 15 US cents/kWh.

Demand Data

The demand forecast developed shows a wide range of uncertainty in outer years rising to nearly 40% of the low forecast scenario in 2030. Peak demand forecasts was calculated with an assumed load factor of 60% based on historical data from JDECO. The resultant peak load is between 1,800MW and 2,500MW in Palestine (Figure A - 6).

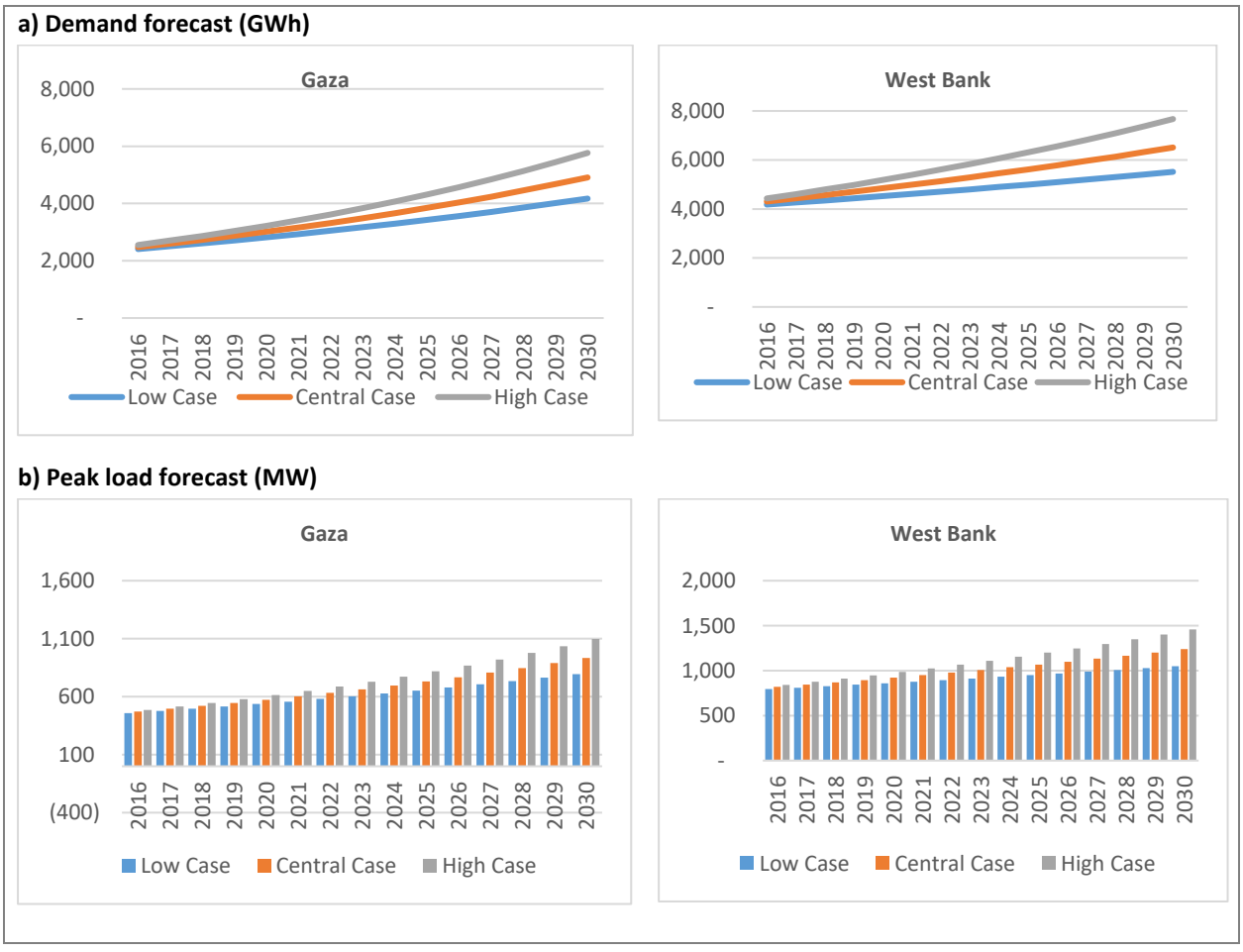


Figure A - 6: Forecast demand and peak load in West Bank and Gaza

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 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 West Bank and Gaza. The same profile was assumed for weekends and weekdays but was shifted downwards to simulate lower demand on weekend days. We also obtained monthly energy consumption for 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 which 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. 54% of the load was allocated to central West Bank, 26% to northern West Bank and 20% to southern West Bank as shown in Table A - 5.

Table A - 5: Distribution of demand in 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 (SAM) 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 multi-year data set[8]. The

[7] The System Advisor Model (SAM) is a performance and financial model for RE planning from NREL (https://sam.nrel.gov/)

[8] Weather Data Overview available here (https://www.nrel.gov/analysis/sam/help/html-php/index.html?weather_format.htm)

study utilized TMY data from three locations in Israel which are close to West Bank namely: 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 10m) to 80m. [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 A - 7. CSP could be used to better complement the resources.

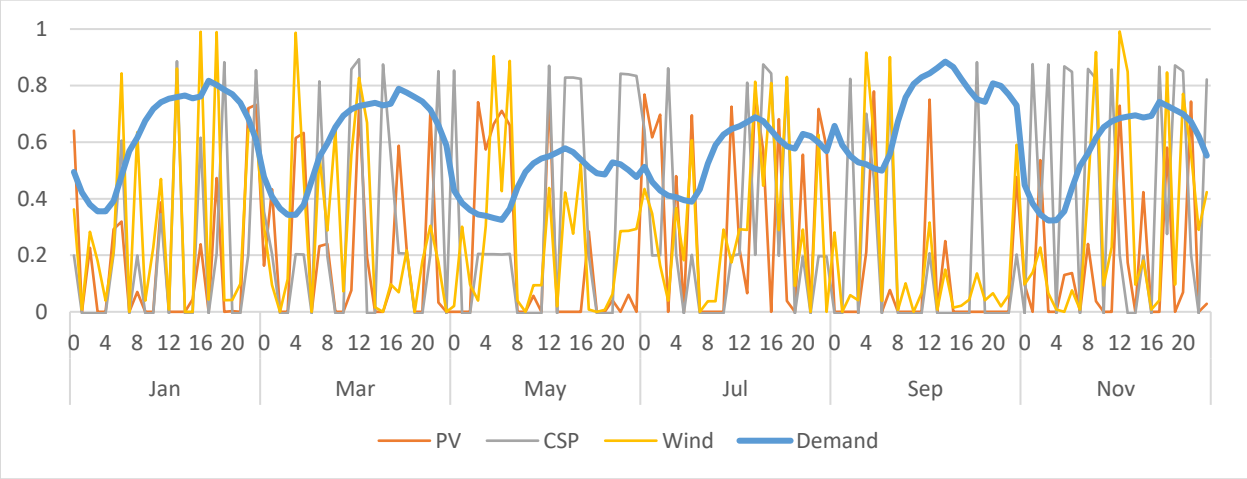


Figure A - 7: 24 hour profiles from selected months for West Bank

Other input assumptions

Cost of capital: The weighted average cost of capital (WACC) is assumed at 10%.
Discount rate: The discount rate used to determine the system net present value is assumed at 10%.

[9] Solar resource data obtained from EnergyPlus (https://energyplus.net/weather). EnergyPlus is a tool funded by the U.S. Department of Energy's (DOE) Building Technologies Office (BTO), 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/)

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 Palestine.

Fuel Volumes and Pricing

Natural Gas: Gas from various fields is considered as potential fuel for both Gaza and 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, etc). The model is passive to the source of gas and the matrix is simplified as three sources of gas – one source for Gaza (GazaGas), one for south of West Bank (WB_SouthGas - for plants in the south such as Hebron) and a third source for gas in the north (WB_NorthGas - for plants such as the Jenin power plant). Each source of gas has a range of dates gas could be expected, an associated range of possible volumes and also 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 A - 6: Uncertain parameters around gas supply for power generation: timing, volume and pricing

	Available for power		**Annual Vol BCM**		**Price ($/MMBTU)**	
	Earliest	*Latest*	*Min*	*Max*	*Min*	*Max*
GazaGas	2022	2035	0.2	2.0	4.00	7.50
WB_NorthGas	2021	2035	0.2	2.0	4.00	6.50
WB_SouthGas	2024	2035	0.2	2.0	4.00	7.50

SOURCE: Team estimates

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 BCM volume and price of 5.2 $/MMBTU, there is no gas available in the model until 2025 and 1.3 BCM available from 2025 at a price of 5.2 $/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 US dollars ranged between $32 and $98 per barrel or 66% and 200% 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% of the average cost of fuel for the GPP in 2015 as an uncertainty range for the price of diesel. Therefore price per liter of diesel for every year is sampled between $0.51 and $1.57 for every scenario (see Figure A - 8).

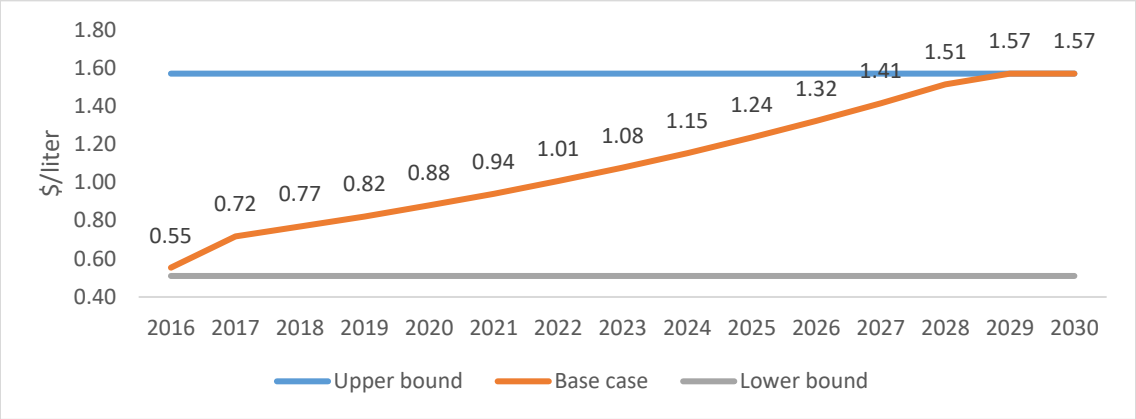


Figure A - 8: Diesel price range

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 namely: a) when import limits could increase due to changes in Palestine'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 b) 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.

[11] World Bank Global Economic Monitor Commodities (http://databank.worldbank.org/data/reports.aspx?source=Global-Economic-Monitor-(GEM)-Commodities)

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 from 2020.

The current import from Israel to Gaza is approximately 120 MW and could be increased to between 220 MW and 270 MW from 2022.

The IEC sells electricity to JDECO at time-of-use tariffs, but to the rest of Palestine 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 Palestine will be transitioned to time-of-use tariffs. There is also the likelihood that the price of electricity sold to Palestine will increase with the change in import volumes. The team estimates this to be up to 110 $/MWh.

Pricing before the change in import limit is increased by 1% per annum. The 1% 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 92.7 $/MWh due to the 1% change in prices. The price beyond 2020 is sampled between 92.7 $/MWh and a defined upper limit. If the new price is sampled as 95 $/MWh for example, it is applied from 2021 and increased at 1% per annum from 2022.

Imports from Jordan: Increase in power imports from Jordan to the West Bank is contingent on upgrading the current interconnection and the availability of excess capacity/energy in Jordan. Both parameters are uncertain together with the price at which power will be sold eventually. It is estimated that the earliest the interconnection 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 2016-2025 as shown in Figure A - 9 ..

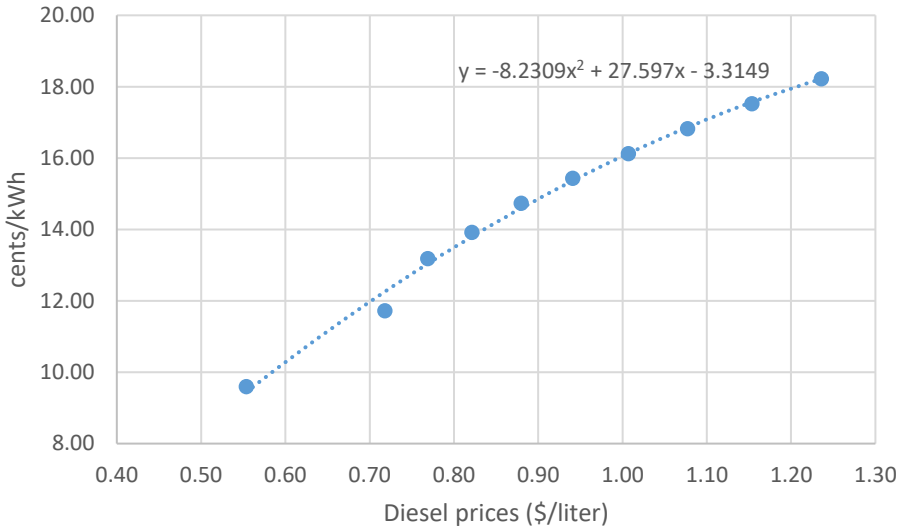


Figure A - 9: Relationship between cost of imports from Jordan and diesel prices

Imports from Egypt: 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 interconnection line. The earliest this could be expected is estimated to be in 2021 at a capacity between 70-150 MW[12]. Because this is uncertain, the volume of imports is also sampled within this range.

Jordan is interconnected 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[13] by 2018/2019, and the availability of excess capacity/energy in Egypt. If this is incremental to current exports from Jordan, the Jordan-West Bank interconnection needs to have been commissioned as well. An additional 50-200 MW could be wheeled to Egypt through Jordan.

Table A - 7: Changes in electricity import sources and capacities

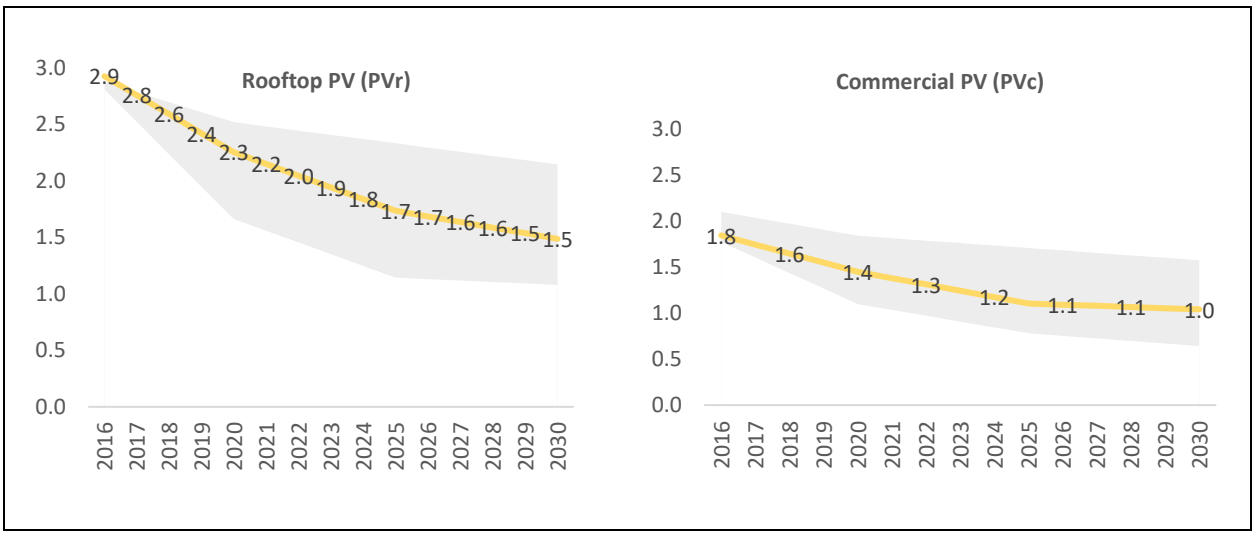
From	**To**	**Change in capacity**		**Capacity (MW)**		**Price After Change ($/MWh)**	
		Earliest	*Latest*	*Before*	*Max After*	*Min*	*Max*
Israel	West Bank	2020	2030	850	1400-1800	Preceding year	110
Israel	Gaza	2022	2035	120	270	Preceding year	110
Jordan	West Bank	2022	2035	30	100-200	Based on oil price	
Egypt	Gaza	2021	2035	10	70-150	81	100
Egypt	West Bank	Same as Jordan-West Bank		0	50-200	87.5[1]	106.5[1]

[1] Same rate sold to Gaza plus 6.5 $/MWh wheeling charge to Jordan
SOURCE: Team estimates

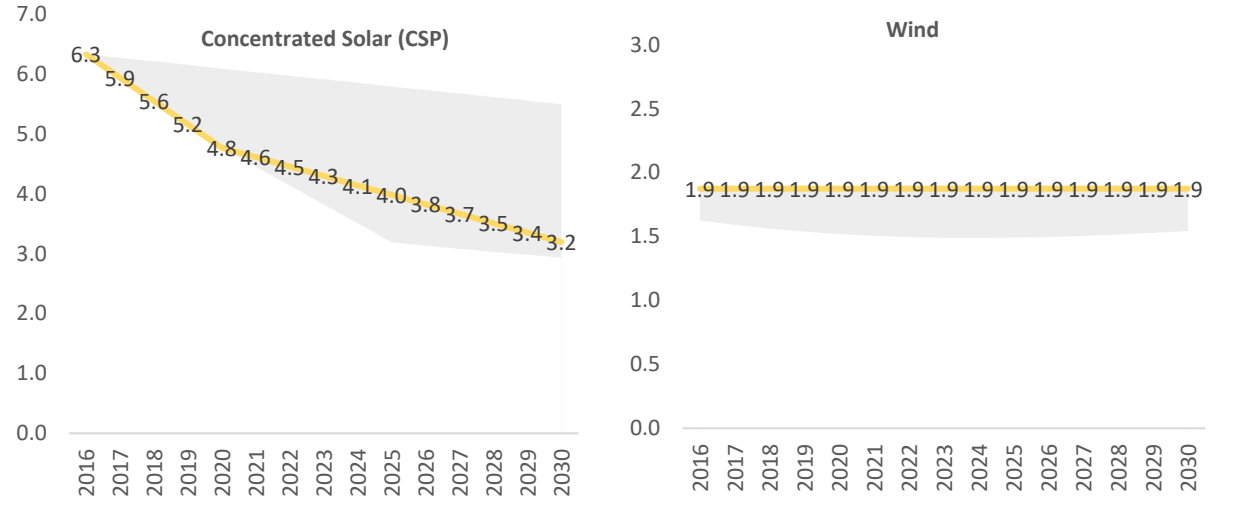
[12] Capacity range is based on NEPCo Annual Reports
[13] The Greed Corridor Project is a major grid upgrade to the North-South transmission corridor in Jordan.

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 (IEA) for the World Energy Outlook[15] are considered to be on the high side, especially when compared with the results of tenders from various countries (for example, a recent bid in Zambia yielded 6 cents/kWh). While this is unlikely to be the case in Palestine, 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 A - 10. 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.



[14] Annual technology costs (http://www.nrel.gov/docs/fy16osti/66944.pdf)
[15] IEA's World Energy Outlook Model (http://www.worldenergyoutlook.org/weomodel/)



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 IEA World Energy Outlook. Upper bound for CSP is calculated by team using IEA trajectory for CSP without storage.

Figure A - 10: Capex ($/W) range for VRE technologies

CSP and PV have different land requirements, capital costs and generation profiles. CSP requires 30% more land per MW installed, and is more than 3 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% of the solar potential is in Area C, and therefore projects are subject to Israel granting access to the site. We assume the earliest Palestine 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 will demonstrate 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 A - 8Table A - 1 The minimum availability defines the longest period of outage.

Table A - 8: Annual probability of outage and minimum availability for fuel sources.

	Probability of Interruption	Minimum Availability
Gaza Gas	0.12	0.3
WB_NorthGas	0.05	0.6
WB_SouthGas	0.10	0.6
GazaDiesel	0.40	0.3
WestBank 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

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. Details of the risks associated with the various fuel sources are included in a separate section of the main report. 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 interconnection 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%, 75% or 100% of capacity for centralized units and less than 5% for decentralized units. In effect, this penalizes larger units because the availability can be significantly reduced due to damages which affect the cost of per unit of production.

Damages incur costs to the system determined by *RepairCosts*. Without knowing apriori the extent of damage, it is difficult to assess the costs or length of outage. For examply, replacing the step-up transformers or fuel tanks to a gas plant both result in a complete shut-down 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:

$$(1 - Share\ of\ Damaged\ Capacity) \times (1 - Duration\ of\ Outage)) \times Max\ Availability\ of\ Plant$$

Plants in Gaza are at a higher risk than those in the West Bank as shown in Table A - 9.

[16] The cost of repairs is based on the rehabilitation of thermal plants carried out by the World Bank.

Table A - 9: Annual risks associated with generators

Gaza	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
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-WB	0.02	100	5	25
Jordan-WB	0.10	100	5	70
Egypt-WB	0.15	100	5	70

SOURCE: Own elaboration based on team assumptions

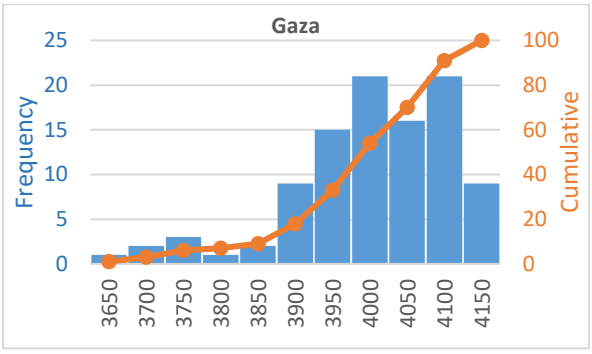
Distribution of uncertain parameters

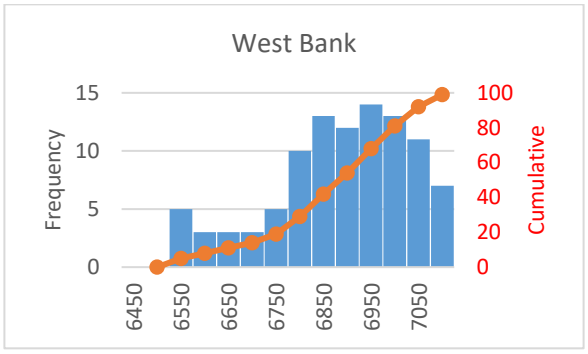
Multiple experiments were performed to develop the capacity plan and, before discussing the results of the analysis, it is worth examining the uncertain parameters to understand their distribution. The energy demand for 2030 sampled across multiple scenarios is negatively skewed with a mean of 4,032 GWh and 6,856 GWh in Gaza and West Bank respectively, as seen in

Figure A - 11. This is higher than the 2030 median forecast of3,548 GWh and 6,004 GWh. We can also see that 30% of scenarios sample 2030 PV prices at or below $1/w, and the cost of CSP is relatively high in comparison. The price range for gas between $4/MMBTU and $7.5/MMBTU (which translates to $2.7-5 cents/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. 83% of the experiments included the availability of gas in West Bank by 2030 compared with 66% of samples in Gaza. This is because there are two likely sources of gas in 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% of the samples allowed access to Area C by 2030 with 30% allowing access by 2022.

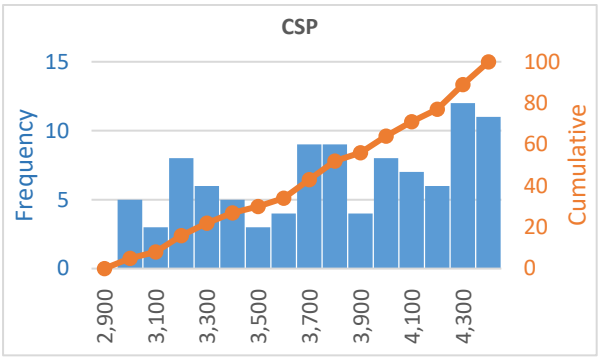
Figure A - 11: Distribution of uncertain parameters from the experiments

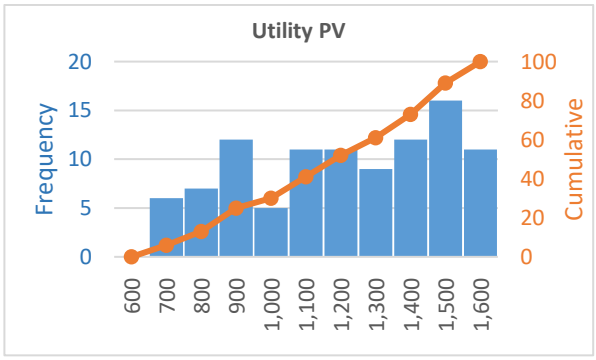
a) Distribution of energy demand in 2030 in Gaza and West Bank (GWh)



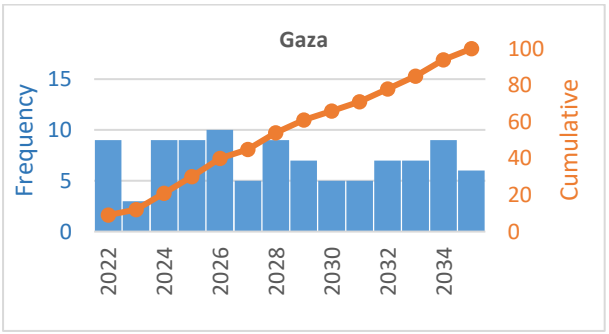


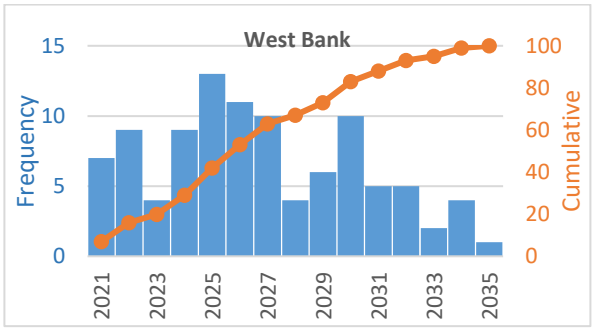
b) Distribution of capex for CSP and Utility-scale PV in 2030 ($/kW)



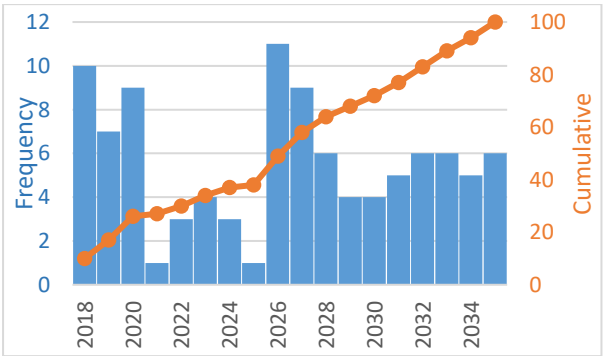


c) Distribution of the timing of gas for power production in Gaza and West Bank (year)





e) Distribution of access to Area C in West Bank



SOURCE: Own elaboration

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 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 context of Palestine is included in the main report.

Nine expansion scenarios were developed for 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 A - 10.

Additionally, existing capacity options are tested and a situation where no action taken is also simulated to show the impact of inaction.

Table A - 10: Expansion plans developed to answer study questions

Case	Description
WEST BANK	
WC1: Classic least cost	Least cost plan based on a best estimate of the future in Palestine with reserve requirements satisfied domestically (high security)
WC2: Domestic reserves	Robust expansion plan that considers uncertainties with reserve requirements satisfied domestically (high security)
WC3: Shared reserves	Robust expansion plan that considers uncertainties with reserve requirements shared with imports (partial reliance on electricity imports for security)
WC4: Area C access	WC3 with full access to Area C from 2018
WC5: Cost cap	WC3 with system average cost capped at IEC import tariffs.
WC6: PENRA vision	Palestinian Energy And Natural Resources Authority (PENRA) vision to limit generation from any source to under 50% with IEC providing reserves
WC7: Planned future	Scenario with current generation options under consideration by PENRA
WC8: High IEC	Scenario with full supply from IEC and minimal investments in near-committed RE projects

WC9: Do nothing	Continuation of the status quo with limited increase in IEC imports.
GAZA	
GC1: Planned future	Scenario with current generation options under consideration by PENRA
GC2: PENRA vision	PENRA vision to limit generation from any source to under 50% with IEC providing reserves
GC3: Full Supply w/ GPP	Full supply to Gaza with the Gaza Power Plant (GPP)
GC4: High IEC	Full supply to Gaza with IEC and GPP shut down and minimal investments in RE
GC5: Meet demand with Gas	Full supply with gas from Gaza marine gas fields
GC6: 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 under-utilized 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 under-investment. 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 interconnections – that is, the distribution of reserve capacity requirements amongst. Given the high potential of solar in Area C, the impact of access to Area C on generation options is evaluated in WC4. In WC5, 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 West Bank because supply options to Gaza are much more limited and most constraints result in unmet demand.

Scenarios WC6 and GC2 evaluate PENRAs long term vision to limit electricity generation from any source to under 50% which diversifies the energy mix.

Apart from C1 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 **Error! Reference source not found.**.

The presentation of results follows the sequence of questions raised. Results for 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 Palestine is 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 **Error! Reference source not found.**, power generation switches from IEC imports to gas and meets entire demand. 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 7 US cents per kWh.

Table A - 11: Underlying assumptions for the deterministic plan

Parameter	Assumption
Demand	Central case
Diesel prices	Base case
Gas prices	5.75 $/MMBTU
Increase in Israel-WB	2021
Increase in Jordan-WB	2024
Egypt-WB	2024
Increase in Israel-Gaza	2024
Increase in Egypt-Gaza	2023
Israel Import price	90 $/MWh + 1% p.a.
Jordan Import price	Based on diesel price
Egypt Import price	81 $/MWh + 1% p.a.
Timing of gas (WB)	2022
Timing of gas (Gaza)	2023
Volume of gas (WB)	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

428MW of distributed diesel capacity is installed from 2018 largely to satisfy reserve margin requirements and this is maintained through to 2030.

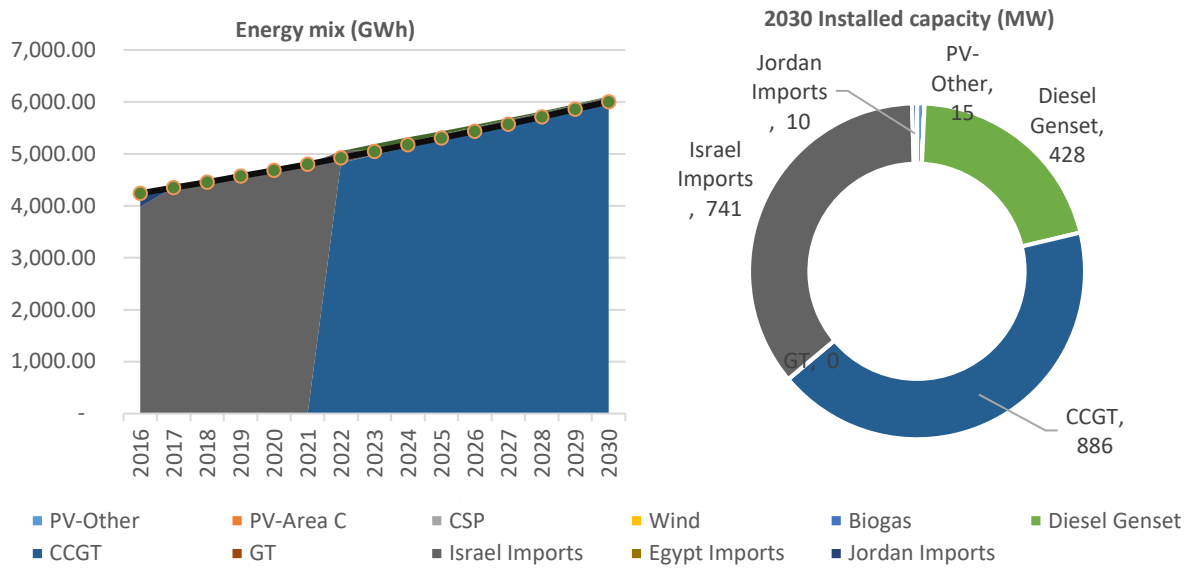


Figure A - 12: Energy and mix and 2030 capacity share in a deterministic scenario

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%, largely substituted by imports from Israel (Figure A - 13).

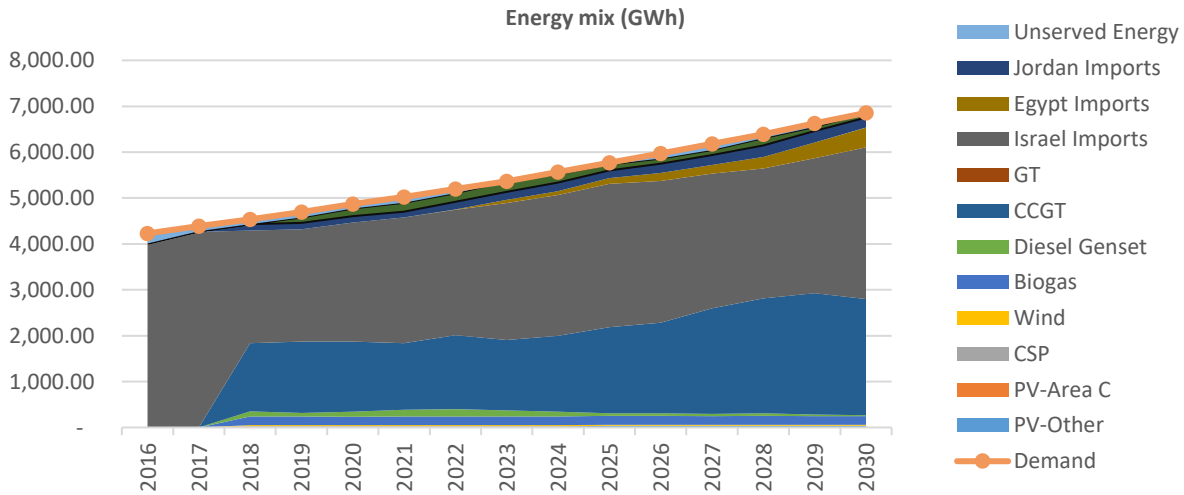


Figure A - 13: Energy and mix for the deterministic plan under test conditions

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 bn to US$ 16.5 bn (Figure A - 14).

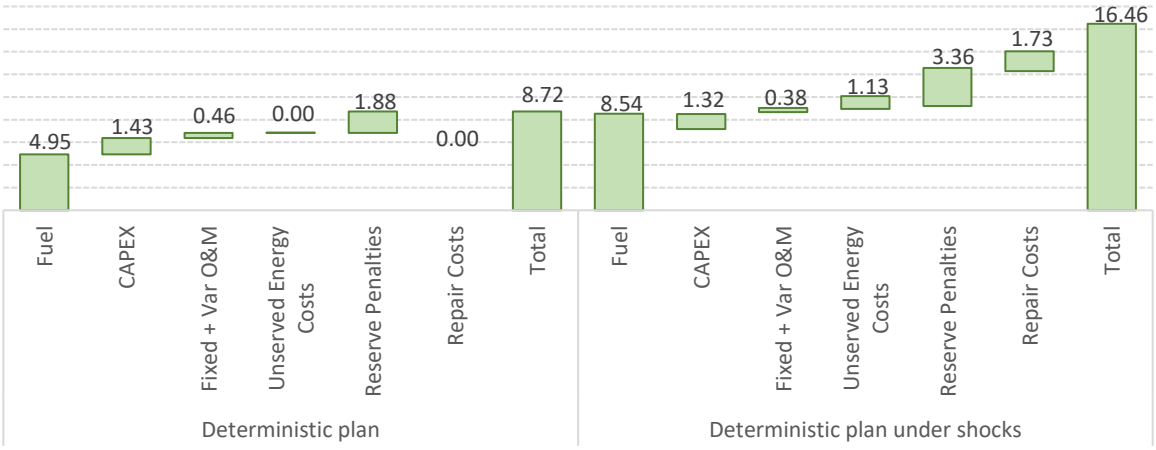


Figure A - 14: Comparison of system costs in US$ billion for the deterministic scenario

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. The absence of gas is substituted 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 bn 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 scenario. Each plan is perfectly suited for the particular scenario but the plans will perform differently across multiple scenarios. 100 future scenarios were developed and for each of these, a capacity plan was generated using the core LP model.

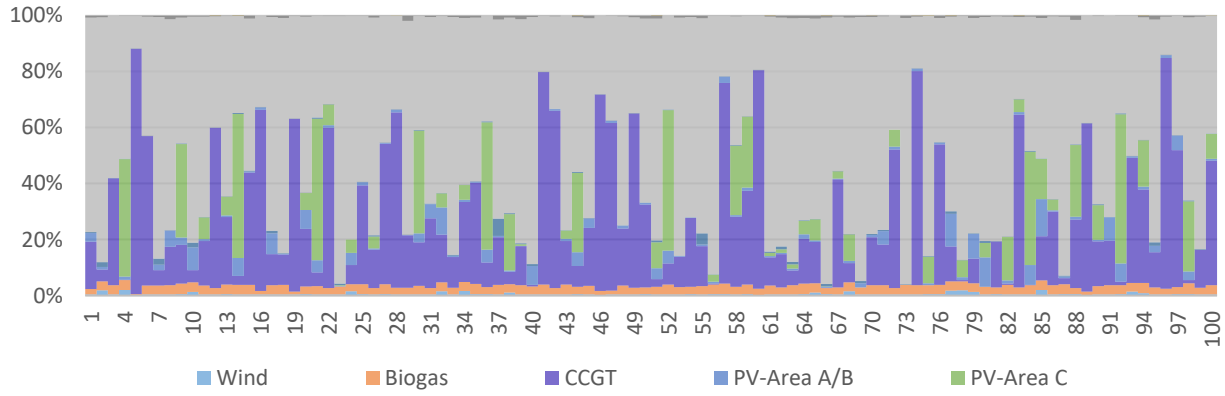


Figure A - 15: Total energy mix (2020-2030) for 100 possible future scenarios

As seen from Figure A - 15, 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 A - 16 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 A - 15, 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.

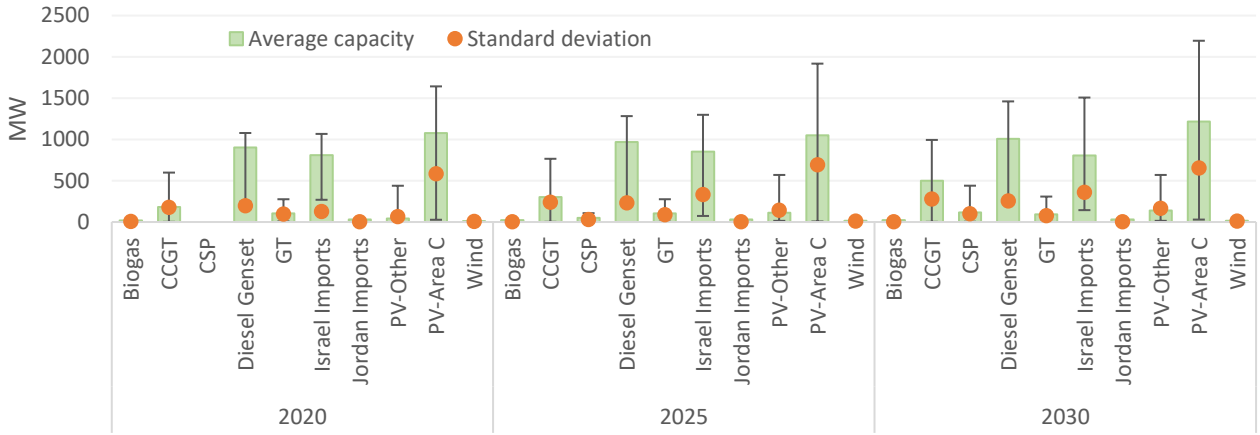


Figure A - 16: Mean capacity by fuel for specific years showing range as error bars and standard deviation as dots

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.

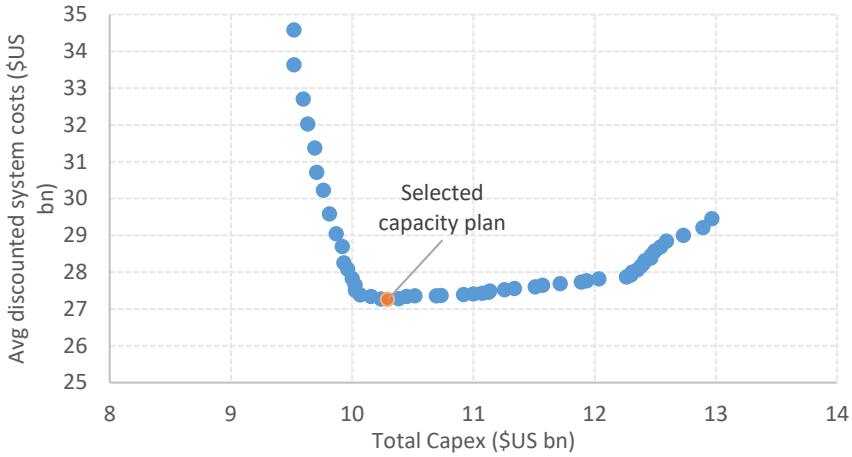
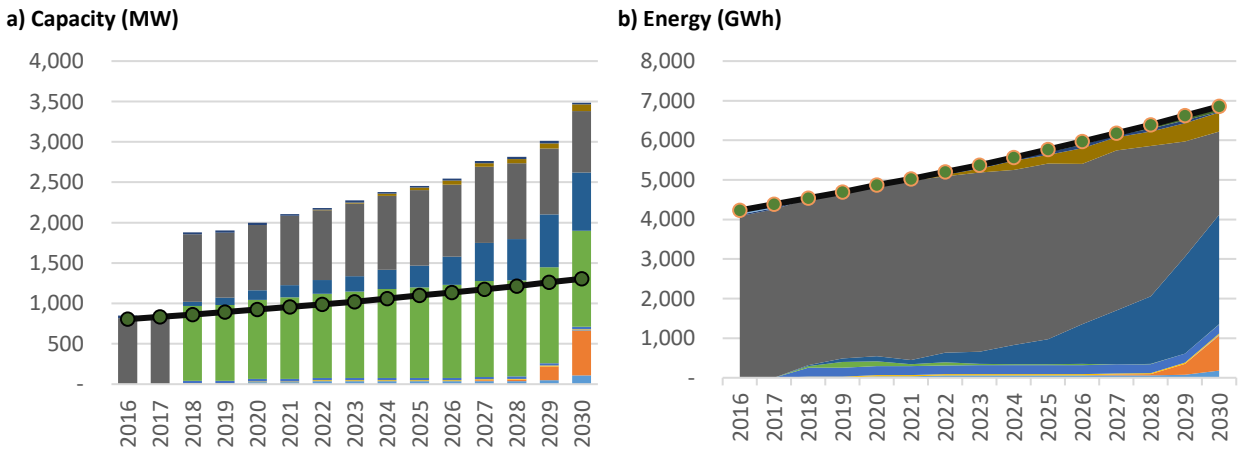


Figure A - 17: Total capex and system costs for 100 capacity plans tested across multiple scenarios. NOTE: Installed capacity is increased with increasingly less preferred technology capacities across the 100 capacity plans.

The resultant capacity plan performs better than the deterministic plan by saving nearly US$ 1.2 billion over the planning horizon. The NPV 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 is US$ 1.3 billion higher than the classic case but unserved energy costs are 47% 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 A - 18). The total capacity is high but required to meet the planning requirements. System reserve requirements is set at 15% 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%. PV capacity helps reduce fuel and repair costs.



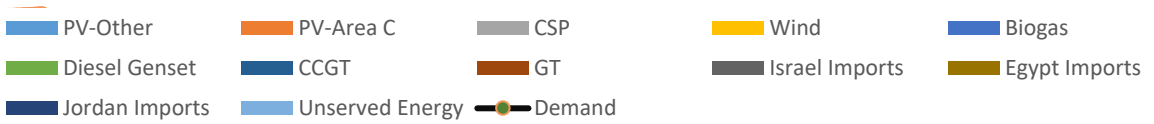


Figure A - 18: Robust capacity plan and energy mix

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 9.2 US cents per kWh to 12.4 US cents per kWh in 2019 and drops in later years to 11.4 US cents per kWh (Figure A - 19). 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 timeframe 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.

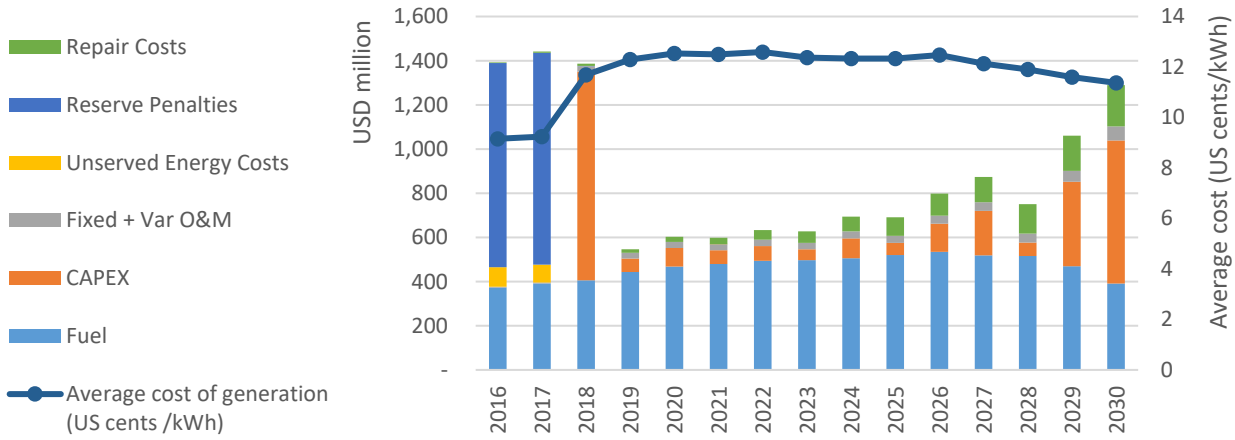


Figure A - 19: Associated costs for the self-reliant robust capacity plan

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 interconnected systems. A major benefit of interconnecting power systems is the ability to distribute reserve margin requirements thereby reducing total system costs. While this is technically optimal, other non-technical considerations may constrain the benefits associated with operating an interconnected system.

To evaluate the cost of a completely self-reliant system for Palestine, 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 A - 1**Error! Reference source not found.**) 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 bn to US$ 1.4 bn (Figure A - 20). There is some loss of reliability as unserved energy increases from 0.3% to 1.1%. 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.

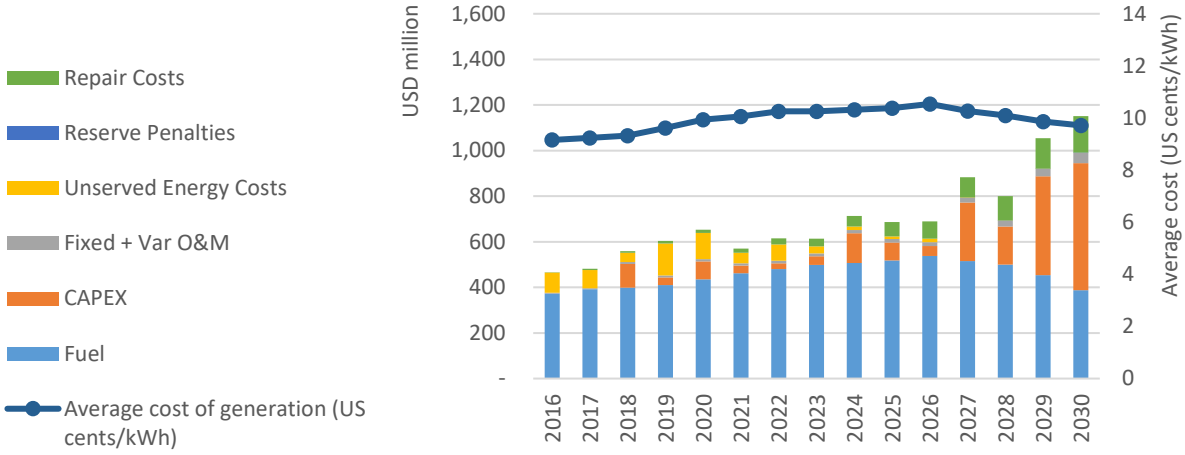


Figure A - 20: Associated costs for the robust capacity plan with shared reserves

Comparison of least cost and policy-based scenarios

Table A - 12 summarizes the results for West Bank. Supply from Israel to West Bank has been stable in the past and if this continues, the cost of inaction on system reliability (WC9) is modest with 4% unmet demand over the planning horizon as demand outgrows the pace of system expansion. By 2030, unmet demand is estimated at 9% of unmet demand.

If supply from IEC grows with demand (WC8), unmet demand estimated at 1.3% and the average cost of electricity is approximately 9.8 US cents per kWh.

PENRA's current expansion plan is also robust with unmet demand under 1% 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% of unmet demand.

Across the scenarios, WC7 (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 from 2025-2030 for a select number of scenarios. The more diversified scenarios performed better under sever shocks than the less diversified scenarios. For example, WC4 has a low combination of fuel costs

and unmet demand under shocks Figure A - 21. Domestic reserves is more expensive both under stability and during shocks but provides the highest security of supply (least unmet demand).

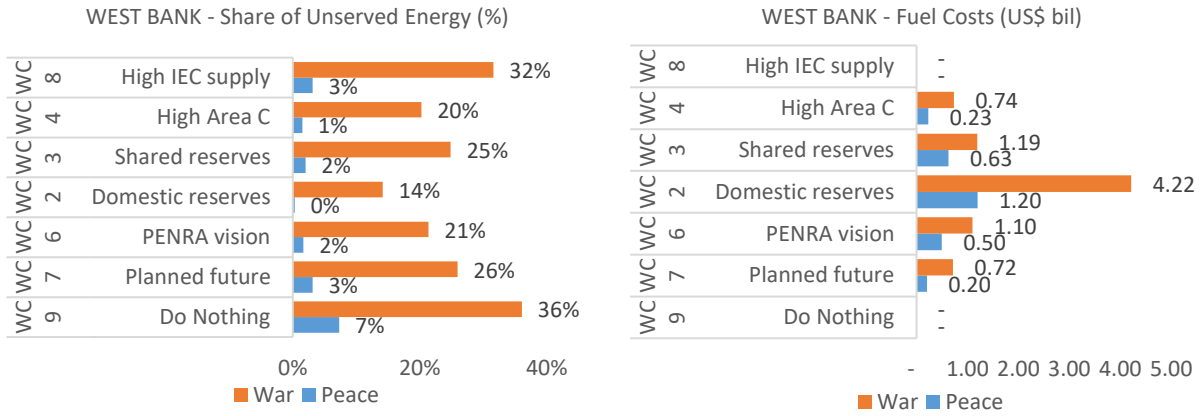


Figure A - 21: Performance of scenarios under stability and extreme shocks in West Bank

Table A - 12: Summary of results for West Bank

			Classic LCP WC1	Domestic reserve WC2	Shared Reserve WC3	High Area C WC4	Price cap WC5	PENRA Vision WC6	Planned future WC7	High IEC WC8	Do nothing WC9
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	*US cents/kWh*	13.57	11.77	9.94	9.88	9.49	10.16	10.06	9.78	9.79
6.	Total Capex	*USD mill*	1,323	2,833	1,982	2,284	1,139	2,133	850	174	0
7.	Total Opex	*USD mill*	378	464	241	347	100	280	174	102	71
8.	Total Fuel	*USD mill*	3,606	869	673	482	374	748	566	0	0
9.	Unserved Energy Costs	*USD mill*	1,135	169	658	782	2,553	547	222	811	2,645
10.	Total Penalties (other)	*USD mill*	5,093	2,908	794	657	363	2,697	1,183	391	482
11.	Total System Costs	*USD 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
14.	Share of Total Unment 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 GC2, all the other scenarios are tests of various supply options under uncertainty.

Comparison of least cost and policy-based scenarios

Table A - 13 summarizes the results for Gaza. Unlike the West Bank, the cost of inaction on system reliability (GC6) is severe with 52% unmet demand over the planning horizon.
Scenario GC4 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 from 2025-2030 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. GC2 (PENRA vision) has a low combination of fuel costs and unmet demand under shocks Figure A - 22.

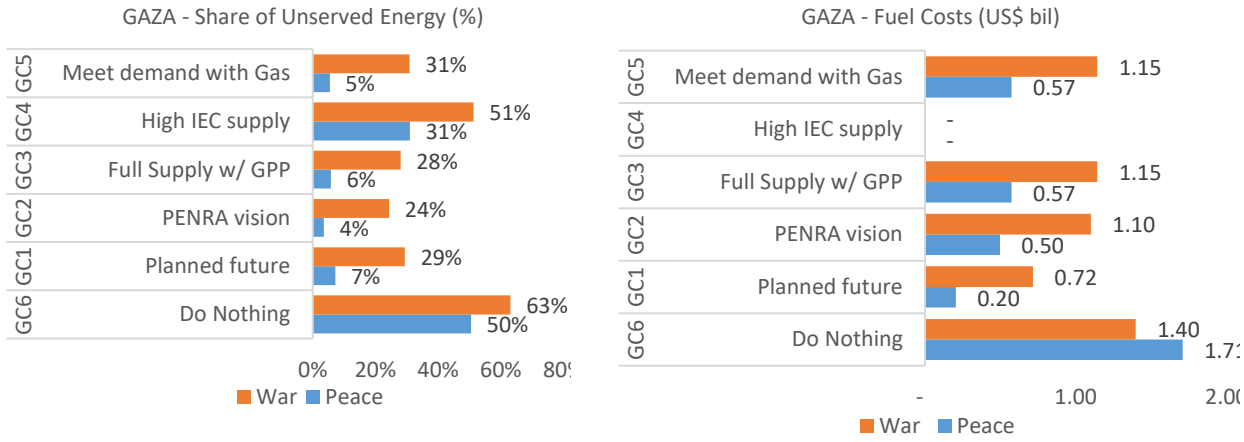


Figure A - 22: Performance of scenarios under stability and extreme shocks in Gaza

Table A - 13: Summary of results for Gaza

			Planned future	PENRA Vision	Full supply w/GPP	High IEC	Gaza supply with gas	Do nothing
			GC1	GC2	GC3	GC4	GC5	GC6
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	US cents/kWh	13.39	15.44	11.41	10.37	15.15	14.68
6.	Total Capex	USD mill	1,035	1,066	1,035	385	1,185	0
7.	Total Opex	USD mill	236	280	205	76	246	173
8.	Total Fuel	USD mill	2,264	3,471	718	4	3,987	1,588
9.	Unserved Energy Costs	USD mill	2,834	1,630	1,333	2,167	2,390	18,108
10.	Total Penalties (other)	USD mill	1,644	8,473	1,637	220	1,962	763
11.	Total System Costs	USD mill	8,013	14,920	4,928	2,851	9,769	20,632
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 Unment 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 geo-political 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 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.

Palestine stands at an advantage to benefit from evolutions in power systems because there are no locked-in technologies. The cost of PV has dropped by over 60% 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 A-1). A list of generation technologies and triggers for taking action are summarized in Table A - 14..

Table A - 14: Triggers for deciding on various technology options

Technology	**Decision trigger**
Solar pv and other small RE (Area A and Gaza)	Immediate
Solar pv (Area 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 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.

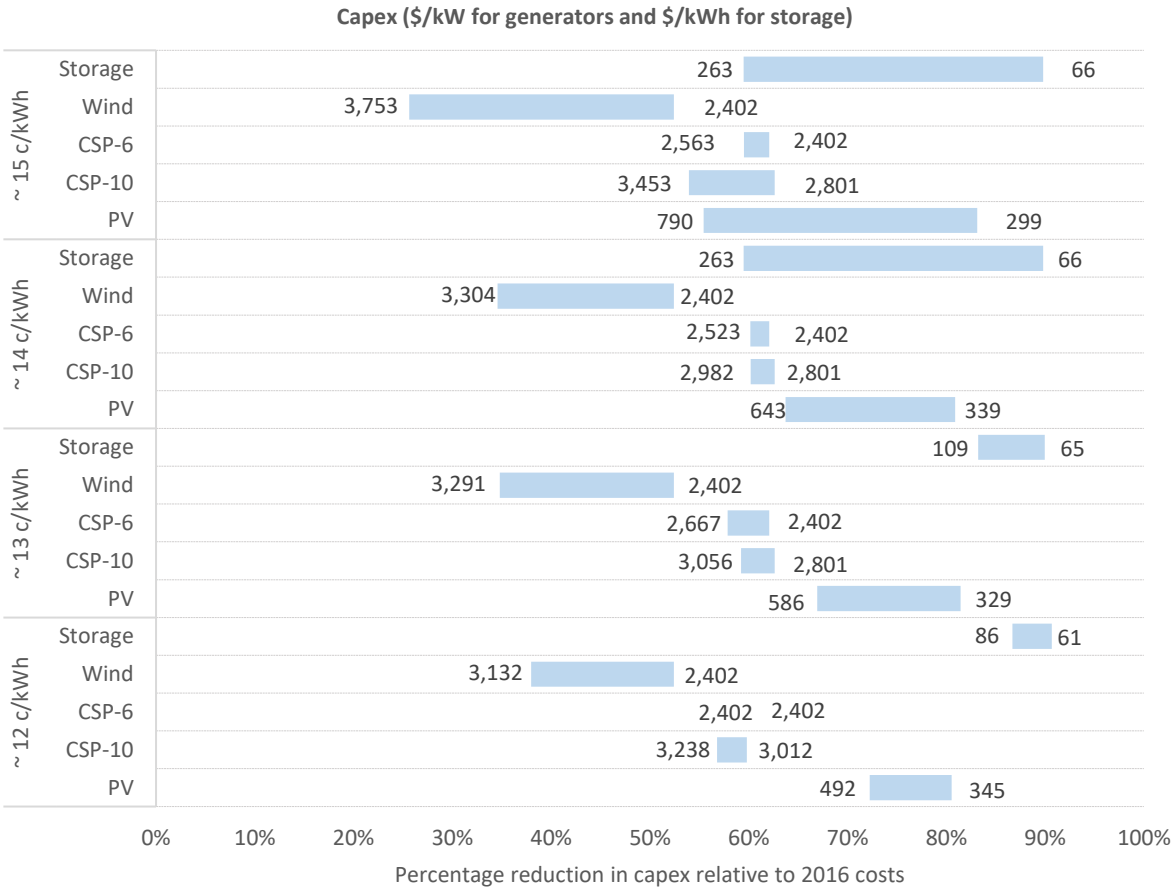
West Bank-Gaza interconnection	When access is granted or Israel is willing to construct and operate the line and there is clarity around availability of centralized self-generation or higher imports from Jordan especially.

Box A-1: Improving the security of supply with renewable energy technologies

Palestine's ability to generate its 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 Palestine.

As the costs of RETs fall, certain capex combinations for solar technologies, wind and batteries yield over all unit costs that are reasonably low 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. The chart below shows combinations of costs that yield average system costs of 12, 13, 14 and 15 US cents 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 15 UScents per kWh. In other words, if the cost of PV drops by 60% 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.



Annex 9: Financial Sector Model Methodology

Overall Approach

The financial model of the Palestinian Authority (PA) power sector will be built on three levels.

- Level 1: simple cash flow models of the six Palestinian power distribution utilities DISCOs (JDECO, GEDCO, HEPCO, NEDCO, SELCO & TEDCO).
- Level 2: a simple cash flow model of the new Palestinian transmission utility PETL.
- 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 use as its historic reference period, the years 2011-2015. The financial model will project forwards for the period 2016-2030.

The objective of the financial modeling is to evaluate the tariffs setting and the creditworthiness of the 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 T&D costs forecast based on the various planning scenarios.

The Financial Model was used to explore the financial impacts on the sector based on 3 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 that:

- PETL will act as a single buyer. PETL will import all the electricity that is available from IEC, Jordan and Egypt and will buy all the electricity produced in the PA (CCGT, Solar, wind, biomass etc.).
- 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 assures the financial equilibrium of each utility. This should initially be done at the utility level. However, PERC currently has a policy of charging a single uniform tariff throughout Palestine, 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 in such a way as 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 underway to improve the poor current performance in these areas, the model assume 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 historic 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 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 (see below).

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 to check for affordability and compute the potential value of consumer subsidies. The affordability check is based on data for the average household income across ten 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%, 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% 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 assures 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 allow 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 so as 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 PPAs signed with different suppliers that may include IEC, Israeli IPPs, gas-fired IPPs in Palestine, solar IPPs in Palestine, 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 Palestine, 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 feeding 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 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

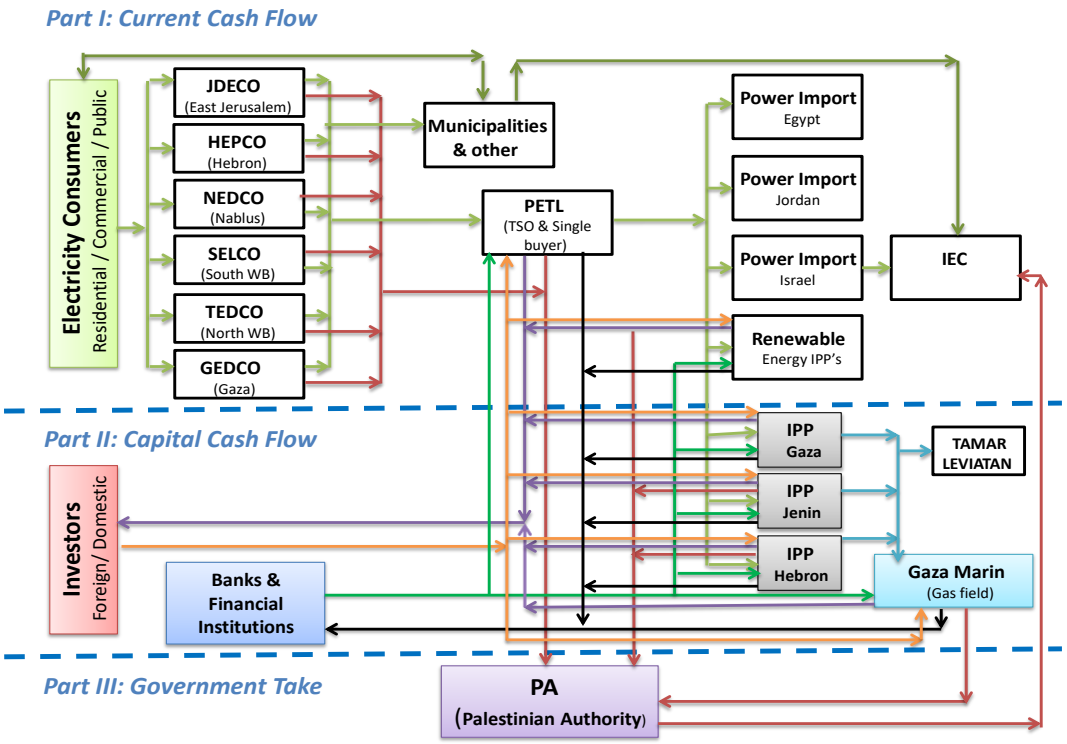
The model will take stock of all the ways in which the energy sector results in revenues or expenditures to the public budget.

On the revenue side, the power sector contributes tax revenues through the application of 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 a number of 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 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 in order 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.

By way of summary, the schematic chart below illustrates the flows into and between the different entities of the PA power sector presented in the financial model.



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 IEC.
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 suppliers, 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

Figure A9.1 - 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 & 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)	mil NIS	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	mil NIS	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Income	mil NIS	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 & Jordan/ PETL	mil NIS	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	mil NIS	53	56	54	58	63	66	66	76	90	103	115	132	139	146	153	161	166	172	178	184
Depreciation Expenses	mil NIS	NA	NA	NA	13	13	13	13	13	13	22	22	22	22	22	22	22	22	22	22	22
Running cost	mil NIS	NA	NA	NA	NA	NA	0	0	0	0	16	16	16	16	16	16	16	16	16	16	16
Financial cost	mil NIS	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Return On Equity	mil NIS	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Electricity Costs	mil NIS	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	mil NIS	-139	-274	-334	-477	-354	-295	-265	-304	-325	-331	-333	-252	-367	-354	-335	-301	-280	-234	-210	-176
Income Tax - 15%	mil NIS	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Net Annual income	mil NIS	-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 2016-2030

Figure A9.2 - 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 & 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)	mil NIS	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	mil NIS	54	57	83	72	68	67	68	70	70	76	80	78	81	80	82	85	89	93	93	96
Total Income	mil NIS	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 & Jordan/ PETL	mil NIS	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	mil NIS	146	148	163	172	188	185	190	195	194	212	223	217	226	223	228	238	248	259	259	267
Depreciation Expenses	mil NIS	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	mil NIS	22	34	28	-15	-11	59	62	63	64	64	64	63	63	62	61	60	59	58	57	56
Running cost	mil NIS	NA	NA	NA	NA	NA	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Other Expenses	mil NIS	NA	NA	4	4	6	4	5	5	5	5	5	5	5	5	5	6	6	6	6	6
Return On Equity	mil NIS	NA	NA	NA	NA	NA	23	22	21	20	19	17	15	13	11	9	6	4	1	0	-2
Total Electricity Costs	mil NIS	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	mil NIS	-5	-71	-75	-54	-74	-14	-13	-14	-16	-22	-25	-32	-33	-32	-33	-35	-37	-14	-36	-38
Income Tax - 15%	mil NIS	3	0	0	3	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Annual income	mil NIS	-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 2016-2030

Figure A9.3 - 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 & 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)	mil NIS	189	223	232	245	242	252	452	493	521	589	606	734	744	811	852	867	878	706	939	976
Other Income	mil NIS	2	6	24	40	NA	46	48	51	53	55	55	63	64	72	76	77	79	81	88	91
Total Income	mil NIS	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 & Jordan/ PETL	mil NIS	179	200	230	250	247	205	384	410	430	484	493	608	606	659	687	692	696	525	745	760
O & M Expenses	mil NIS	10	17	12	13	NA	15	29	30	31	32	33	37	38	42	45	46	47	48	52	54
Depreciation Expenses	mil NIS	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	mil NIS	NA	NA	NA	NA	NA	10	11	17	19	21	22	22	26	25	26	25	22	19	5	13
Running cost	mil NIS	NA	NA	NA	NA	NA	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Other Expenses	mil NIS	1	NA	1	5	NA	6	12	13	13	14	14	16	16	18	19	19	20	20	22	23
Return On Equity	mil NIS	NA	NA	NA	NA	NA	17	18	20	22	25	27	30	33	36	40	45	49	54	59	65
Total Electricity Costs	mil NIS	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	mil NIS	0.5	11	12	15	NA	60	63	70	77	85	92	107	115	131	144	155	166	168	195	210
Income Tax - 15%	mil NIS	0.4	2	5	7	NA	9	9	11	12	13	14	16	17	20	22	23	25	25	29	32
Net Annual income	mil NIS	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 2016-2030

Figure A9.4 - 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 & 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)	mil NIS	30	35	39	46	46	42	73	80	84	96	99	121	123	136	144	148	151	125	165	173
Other Income	mil NIS	0	3	5	6	8	9	16	17	17	18	18	20	21	23	25	25	26	26	29	30
Total Income	mil NIS	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 & Jordan/ PETL	mil NIS	27	33	38	45	42	42	73	78	82	92	94	115	115	125	130	131	132	100	141	144
O & M Expenses	mil NIS	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	mil NIS	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	mil NIS	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	mil NIS	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	mil NIS	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	mil NIS	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	mil NIS	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	mil NIS	-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%	mil NIS	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	mil NIS	-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 2016-2030

Figure A9.5 - Financial Model inputs and outputs – HEDCO

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
HEPCO Purchases and Sales																					
Purchase of electricity from IEC & Jordan/ PETL	GWh	362	369	373	379	411	419	650	673	695	720	744	729	719	738	733	732	792	810	850	901
Total Losses	%	22%	19%	20%	19%	20%	21%	21%	21%	21%	21%	21%	22%	22%	22%	22%	22%	22%	23%	23%	23%
Total Power Sales	GWh	282	300	299	306	328	333	516	532	549	567	585	571	563	576	571	569	614	627	656	694
Collection rate	%	74%	74%	70%	82%	81%	82%	83%	83%	84%	85%	85%	86%	87%	87%	88%	88%	89%	90%	90%	91%
Total Power Paid by consumers	GWh	209	222	209	251	267	273	427	443	461	480	499	491	487	502	501	503	547	562	593	632
Operating Income (Power sales)	mil NIS	154	181	181	193	193	175	246	260	274	307	322	339	334	339	338	338	359	300	376	399
Other Income	mil NIS	14	13	16	15	16	16	25	26	26	27	28	28	27	28	28	28	30	31	32	34
Total Income	mil NIS	167	194	197	208	209	191	270	285	300	335	350	367	362	367	365	366	389	330	408	434
HEPCO Operating Costs																					
Electricity Purchase from IEC & Jordan/ PETL	mil NIS	136	160	170	176	164	149	222	231	242	274	285	301	291	292	286	282	299	226	309	323
O & M Expenses	mil NIS	13	17	19	15	16	17	26	27	28	29	30	29	29	29	29	29	32	32	34	36
Depreciation Expenses	mil NIS	9	9	9	10	10	10	10	9	9	11	11	11	10	10	10	10	10	10	10	10
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	mil NIS	2	12	1	3	7	25	26	31	34	37	41	44	47	50	53	55	57	61	59	66
Running cost	mil NIS	NA	NA	NA	NA	NA	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Other Expenses	mil NIS	NA	0	0	1	1	1	1	1	1	1	2	2	1	2	2	2	2	2	2	2
Return On Equity	mil NIS	NA	NA	NA	NA	NA	12	12	12	11	11	10	8	7	6	5	4	3	2	2	1
Total Electricity Costs	mil NIS	160	197	199	206	198	214	297	311	326	362	377	394	386	388	384	381	403	333	415	438
HEPCO Income																					
Annual income/loss before income tax	mil NIS	7	-3	-2	2	11	-10	-15	-15	-15	-18	-18	-20	-18	-16	-14	-13	-11	-2	-6	-4
Income Tax - 15%	mil NIS	1	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Annual income	mil NIS	6	-3	-2	2	9	-10	-15	-15	-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	0.377	0.433	0.456	0.464	0.398	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	0.545	0.604	0.605	0.630	0.590	0.641	0.576	0.585	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	0.766	0.889	0.952	0.821	0.743	0.782	0.696	0.702	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 2016-2030

Figure A9.6 - 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 & 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)	mil NIS	48	56	54	76	67	73	93	98	102	112	116	120	118	119	118	117	124	104	130	136
Other Income	mil NIS	2	5	6	4	9	9	11	11	11	12	12	12	12	12	12	12	13	13	14	15
Total Income	mil NIS	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 & Jordan/ PETL	mil NIS	43	54	53	71	49	63	71	74	77	87	91	96	93	93	91	90	95	72	98	103
O & M Expenses	mil NIS	8	9	18	15	19	20	23	24	25	25	26	26	25	26	26	26	28	29	30	32
Depreciation Expenses	mil NIS	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	mil NIS	2	2	2	2	3	15	14	15	15	14	14	13	12	11	11	10	9	9	8	8
Running cost	mil NIS	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	mil NIS	-2	0	-2	0	-7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return On Equity	mil NIS	NA	NA	NA	NA	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Costs	mil NIS	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	mil NIS	-6	-10	-18	-15	5	-22	-12	-11	-10	-11	-10	-10	-8	-7	-5	-4	-3	1	0	1
Income Tax - 15%	mil NIS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Annual income	mil NIS	-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 2016-2030