LEBANON COST-OF-SERVICE AND TARIFF DESIGN STUDY

Final report

MAY 2020

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ESMAP
Energy Sector Management Assistance Program

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Submitted to the World Bank by:
Economic Consulting Associates

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CONTENTS

ABBREVIATIONS AND ACRONYMS

A	Ampere
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CMO	Commodity Markets Outlook
COSS	Cost of Service Study
DSP	Distribution System Provider
ECA	Economic Consulting Associates
EDF	Electricité de France
EDL	Electricité Du Liban
ECW	Energy Conversion Works
FSRU	Floating Storage Regasification Unit
GDP	Gross Domestic Product
GoL	Government of Lebanon
GW	Gigawatt
GWh	Gigawatt hour
HV	High Voltage
IMF	International Monetary Fund
IPP	Independent Power Producer
KPS	Karpowership
kVA	Kilovolt ampere
kVARH	Kilovolt ampere reactive hours
kW	Kilowatt
kWh	Kilowatt hour
LNG	Liquefied natural gas
LRAIC	Long Run Average Incremental Cost
MEW	Ministry of Energy and Water
MMBTU	Million British Thermal Units
MOF	Ministry of Finance
MV	Medium voltage
MW	Megawatt
MWh	Megawatt-hour
NPTP	National Poverty Targeting Program
OCGT	Open Cycle Gas Turbine
O&M	Operation and maintenance
TOU	Time of Use
UNHCR	Office of the United Nations High Commissioner for Refugees
WB	World Bank

ENERGY UNITS

To > To Convert:	Cubic meter of LNG	Metric Ton of LNG	Cubic Meter of gas	Cubic Foot of Gas	Million Btu of Gas	Therm	Gigajoule	Kilowatt Hour	Barrel Crude
From					**Multiply by**				
1 Cubic Meter of LNG	1	.405	584	20,631	21.04	210.4	22.19	6,173	3.83
1 Metric Ton of LNG	2.47	1	1,379	48,690	52	520	54.8	15,222	9.43
1 Cubic Meter of gas	.00171	.000725	1	35.3	.036	.36	.038	10.54	.0065
1 Cubic Foot of Gas	.00005	.00002	.0283	1	.00102	.0102	.00108	.299	.00019
1 Million Btu of Gas	.048	.0192	27.8	981	1	10	1.054	292.7	.182
1 Therm	.0048	.00192	2.78	98.1	0.1	1	.1054	29.27	.0182
1 Gigajoule	.045	0.18	26.3	930	0.95	9.5	1	277.5	.173
1 Kilowatt Hour	.000162	.000065	.0949	3.3	.00341	.03418	.0036	1	.00062
1 Barrel Crude	.261	.106	153	5.390	5.5	55.0	5.79	1.610	1

ACKNOWLEDGEMENTS

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PREFACE

This report aims to provide background of the electricity sector in Lebanon and to estimate the current and future costs of the sector in order to inform reform plans that are needed to recover the sector financial viability.

Data and assumptions in the report are based on the Ministry of Energy and Water's 2019 updated Electricity Sector Policy Paper and its investment plan as of end July 2019. When this report was prepared, not all data for 2018 and 2019 were available, hence it relies primarily on data from 2017. Since then, certain sector conditions and plans have evolved. Market conditions have also changed, including, but not limited to, fuel prices used in the cost estimation. Certain numbers in this report will need to be updated accordingly.

The report objective is not to provide precise numbers but rather to offer insights into the cost structure of the sector to determine areas of cost savings. It projects how the future sector costs and subsidy requirements will be impacted by ongoing and planned investments and reforms, such as adding efficient generation capacity, switching to natural gas, reducing system losses, and recovering collection. The projections are based on two scenarios. The base case scenario is aligned with the 2019 updated Policy Paper, which includes adding fast track generation and new power plants, switching from liquid fuels to gas, and aggressive loss reduction; the alternative scenario tests certain sensitivity related to the timeline of new generation investments and the trajectory of loss reductions. Given the recent political, economic, and health developments – particularly the nation-wide protests since October 2019, the establishment of new government in February 2020, the default of the Euro bonds in March 2020, and the ongoing Covid-19 pandemic – the timeline laid out in the scenarios may no longer be appropriate. Certain investment plans and reform actions may also need to be adjusted. Nevertheless, the report provides a sound trajectory for reforming the Lebanon power sector with key actions to reduce the sector costs. The years referred to in each scenario, therefore, should not be considered absolute in terms of 2020 or 2021, but rather as year 1 or year 2 starting from the launch of the sector reforms.

Based on these projections, the report gives an indication of the tariff level needed to recover sector costs. Since sector costs will likely change with the recent developments outlined above, an updated estimate and tariff scenario will be needed. It is important to note that tariff increases are advisable only once supply has improved so that the total costs paid by consumers for both public and private electricity do not increase. This is the assumption underlying the two scenarios considered by this report. Since sector costs are highly dependent on oil prices, an automatic tariff indexation mechanism to pass through the fluctuations of oil prices should be considered. The report also provides suggestions on designing efficient tariff structures, based on international practices, which can reflect costs while encouraging energy conservation and ensuring affordability for poor and vulnerable groups. The decision on tariff adjustments ultimately lies with the Government as they have different implications for subsidy requirements and need to be integrated in the broader socioeconomic agenda.

EXECUTIVE SUMMARY

Introduction

This study determines EDL's cost of service, to facilitate reduction of sector subsidies

The objective of this study is to conduct a cost-of-service study and tariff analysis for the electricity industry in Lebanon that will facilitate the reform of electricity tariffs, reduce costly financial transfers, and better address affordability for disadvantaged households. A key output of the study is to estimate the Government subsidy required to cover the difference between Electricite Du Liban's (EDL's) forecast revenues and costs.

The scope of this study includes forecasting demand, supply and costs of service, and advising on tariff design

This study is comprised of the following parts:

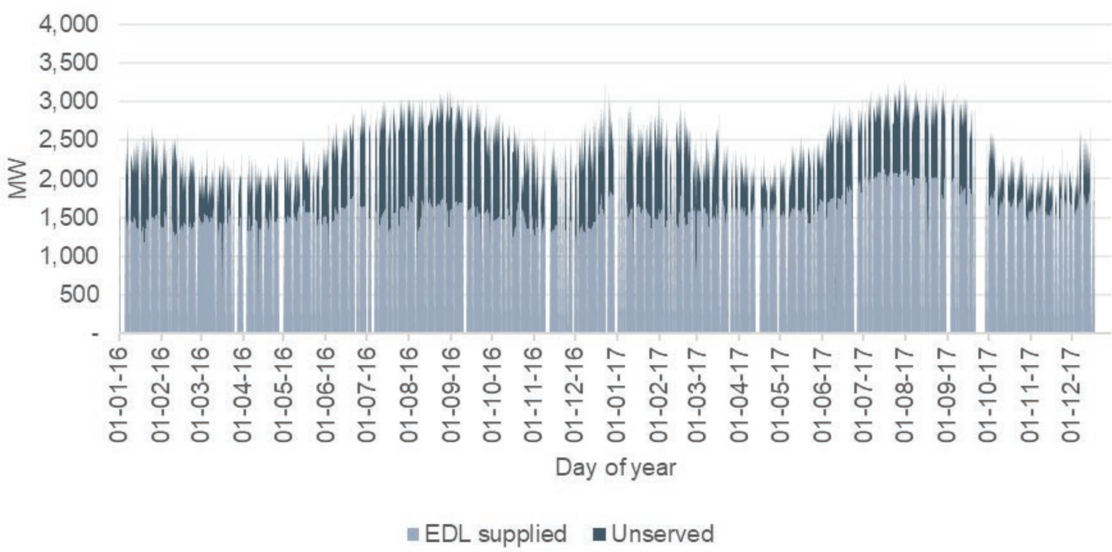
- Describes the challenges facing the Lebanon power sector.
- Estimates demand for electricity in Lebanon and provides an overview of the Ministry of Energy and Water (MEW) plans to meet that demand.
- Estimates EDL's future costs and the revenue that it needs to earn to cover those costs, given various assumptions about the future; and estimates the likely impacts on required Government subsidies, given assumptions about future tariff increases.
- Provides recommendations for revising the structure of EDL's tariffs, to increase revenue in the short term and improve the efficiency of price signals in the medium to long term.

The current situation

EDL is supplying around two thirds of electricity demand, although demand is uncertain

The electricity sector in Lebanon suffers from a shortage of supply. EDL estimated that it supplied only 59% of demand in 2016 and 67% of demand in 2017, as illustrated in the figure below, with most of the remainder supplied by private generators at higher tariffs.

EDL estimated demand and supply, 2016-2017



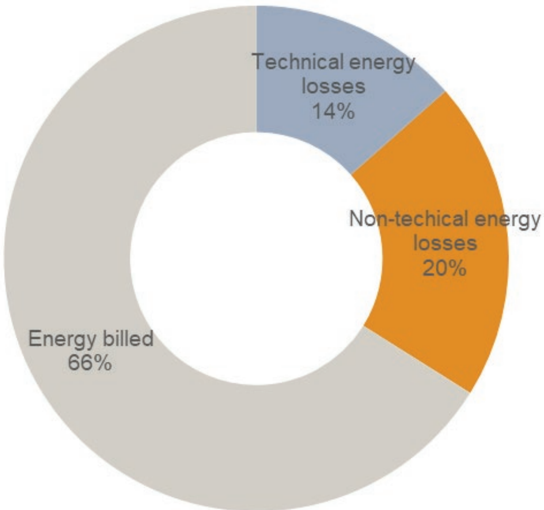
EDL estimates its peak demand to be around 3,511 MW in 2017. This estimation is only approximate and likely to be affected by customers shifting some consumption to private generators (many of which were not metered until recently). Using a higher load factor, for example 67% as per neighbouring Jordan, increases estimated peak demand to over 4,000 MW. Any demand forecast for Lebanon will be inherently uncertain, given the current situation.

The supply shortfall is mostly due to the shortage of generating capacity. In total, EDL has approximately 2,200 MW of generating capacity. EDL's generation is predominantly from expensive fuel oils (both Heavy Fuel Oil and Light Fuel Oil), with many of its plants now old. EDL's mix of reasonably efficient plants and very old inefficient plants (all running on fuels that are significantly more expensive than gas would be) results in high fuel costs, which averaged $0.11 per kWh in 2017.

Around a third of EDL's energy produced/purchased is lost. Theft and billing errors are the primary cause for concern

- EDL's network losses were 34% of total energy sent out (i.e., produced or purchased) in 2017, as illustrated in the figure below. Non-technical losses – comprising of theft and billing errors – are estimated to be 20% of energy sent out, which is exceptionally high. As a comparison, nearby Jordan has distribution losses (both non-technical and technical) of 12.9% and transmission losses of 1.7%.

EDL cost of supply in 2017

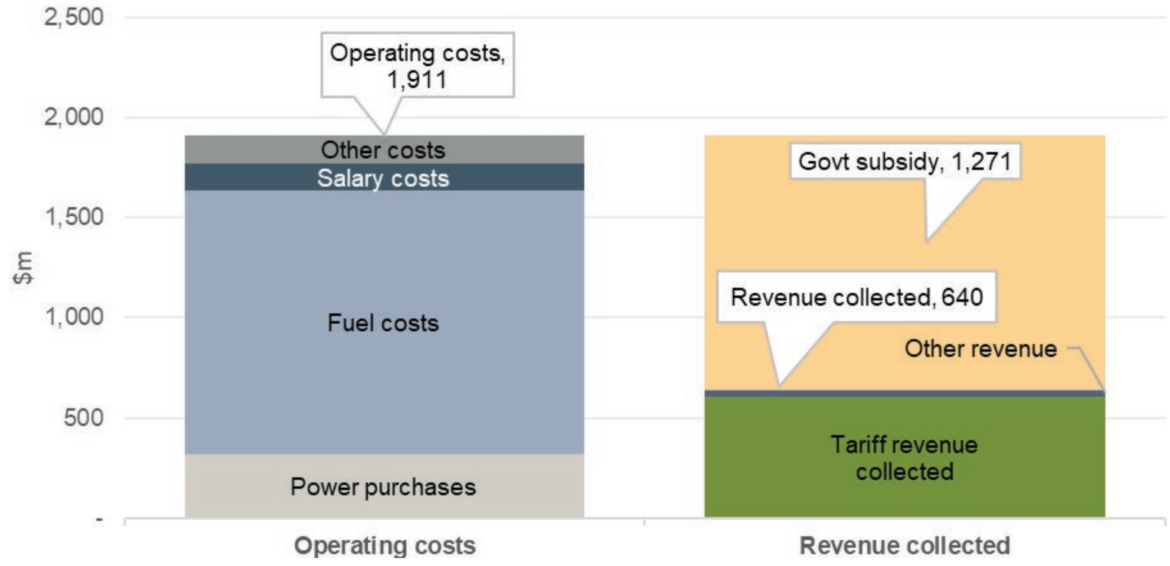


- The figure below shows the key components of EDL's cost of supply in 2017. Fuel costs plus payments to independent power producers (IPP) sum to $0.11 per kWh sent out. Once 34% losses are added, the cost goes up to $0.16 per kWh sold (billed). After accounting for EDL's other operating costs (including generation operations and maintenance - O&M, staffing costs, network repairs and maintenance) and financing costs (relating to past investments), the cost further increases to $0.24 per kWh sold, which is lower than the price of private generation estimated at $0.30 per kwh.
- Poor collection rates in 2016 and 2017 further increased the cost of supply (not shown in the figure above), but EDL expects to resolve collection issues in the future. Given the COVID-19 pandemic, collection activities of EDL bills have been slowed down or stopped in some areas. Therefore, the resolution of collection issues and increase of collection rates forecasted for the short-term timeline may no longer be appropriate.

Reliance on fuel oils, high losses, and low tariffs results in high Government subsidies

The Lebanon power sector has relied on Government subsidies for decades. In 2017, EDL's total cash costs for 2017 were approximately $1.9bn[1], while revenue collected was only $0.6bn. EDL therefore had to rely on the government subsidy of around $1.3bn to cover the difference, as illustrated in the figure below.

EDL cash costs, revenues, and subsidies in 2017



Forecast demand and supply

In the base case, we assume 3% demand growth and aggressive loss reductions, which when combined lead to relatively little growth in the generation required

We forecast demand and supply under two cases – a base case as provided by MEW and an alternative case that is more conservative.

In the base case, we accept EDL's estimated peak demand of 3,511 MW in 2017. We assume 3% growth in electricity demand, plus a one-off reduction in demand of 8% in 2021 following an assumed tariff increase of 74%, all based on MEW assumptions. This 74% increase in tariff is under the assumption that 'fast track' generation will be added, hence improving supply to consumers and replacing private generators. The new tariff would still be below the weighted average cost of electricity to consumers (i.e., the combined cost of EDL and private generator supplied electricity to the average consumer). Although we have not assessed the MEW's assumption of the one-off reduction in demand of 8% in detail, this estimate appears within the plausible range of demand price elasticities, bearing in mind they will always be inherently uncertain given the unique situation in Lebanon (uncertain demand, poor quality of grid supply, historically low tariff - EDL's retail tariffs, which currently stand at an average of $0.09 per kWh, have not changed since 1994).

We also adopt MEW's aggressive loss reduction forecasts, from 34% in 2018 to 10.6% in 2022 (as a percentage of energy sent out), with most of these reductions happening from 2019 to 2021.

The result is that forecast demand growth is largely offset by reduced losses, such that the resulting forecast of energy that needs to be generated ('sent out') in 2023 is similar to 2017, as illustrated in the figure below. Only after 2023 does the required energy sent out start to grow significantly.

Our alternative demand forecast uses more conservative assumptions, which leads to similar required generation growth but lower energy sales

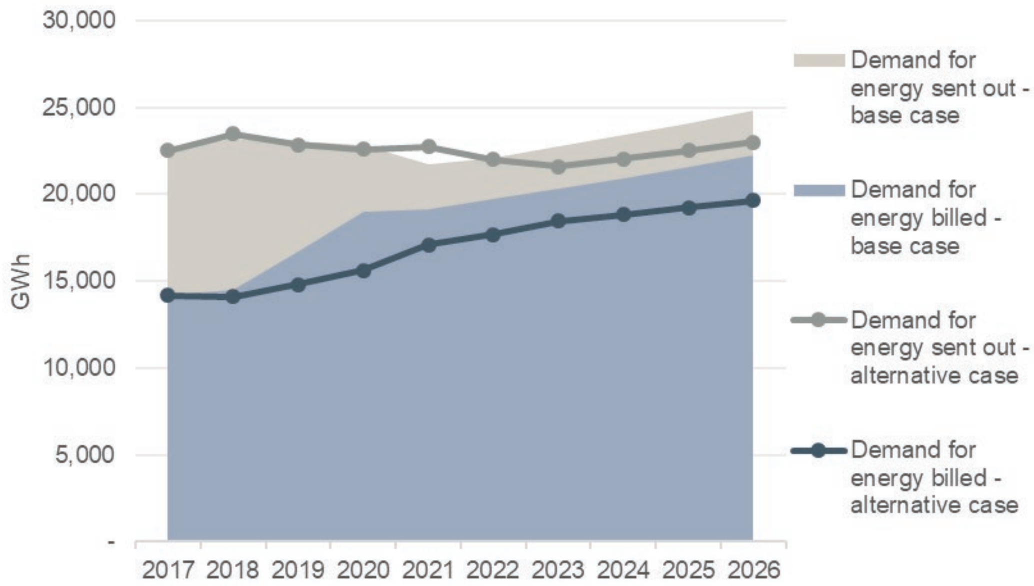
In the alternative case, we make more conservative assumptions about future demand and loss reductions:

- Peak demand is slightly over 4,000MW in 2017, estimated based on EDL data but assuming a load factor equal to that in Jordan (after adjusting for displaced persons). EDL's estimated load factor in the base case is probably being exaggerated by load shifting to unmetered private generation.
- Growth in energy demand is lower than MEW forecasts, based on IMF GDP forecasts as of October 2018 and an econometric analysis of historical growth rates. The forecast is approximately 1% growth per year for the next few years, before increasing to 2.3% per year for 2023 onwards.

- System loss reductions are slower (less aggressive) than MEW forecasts. We assume losses are reduced from 34% in 2017 to 14.6% in 2023, compared to losses of 10.6% in 2022/2023 in the base case.

The net result is that forecast required energy sent out (i.e. generated) is quite similar in the alternative case and base case, at least until 2023. But the energy billed is around 10% lower in the alternative case from 2018 onwards, primarily due to smaller loss reductions.

Total Energy demand (base case vs alternative case)



MEW expects LNG to be available from 2022 and plans to add significant new gas-fired generating capacity

In the base case, we adopt MEW's generation expansion plan, which involves adding:

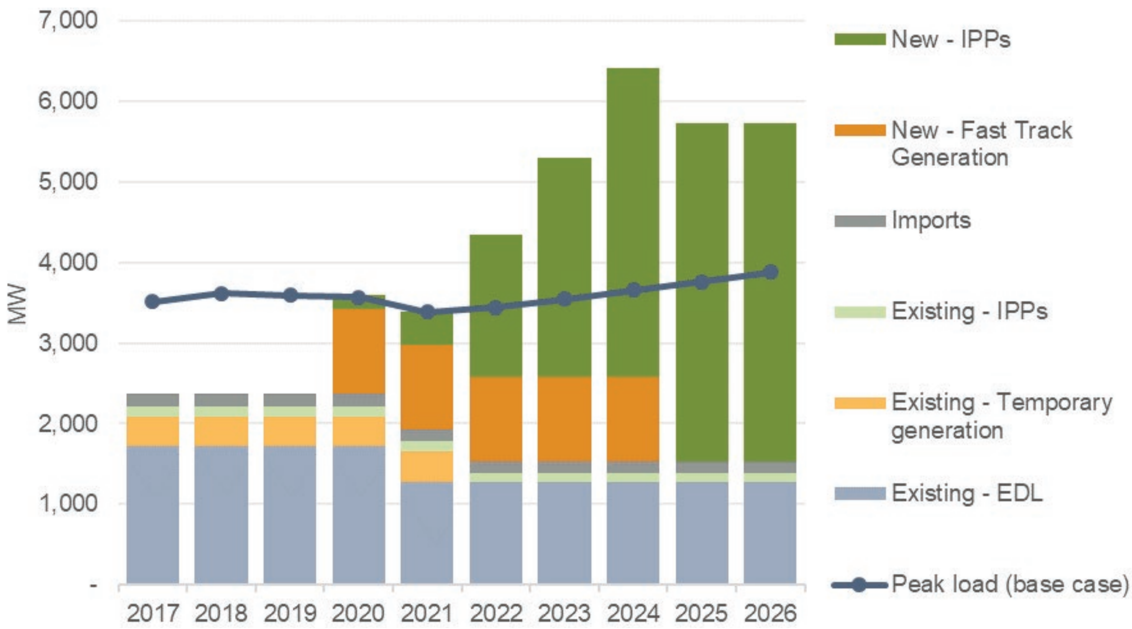
- Approximately 2,600 MW of new LNG-fired CCGT plants over the next 10 years, starting in 2022 when new LNG is expected to first become available in some regions
- 1,050 MW of 'fast-track' generation, such as LNG-fired containerised reciprocating engines. This fast-track generation can theoretically be commissioned in 2020 (initially running on fuel oil until LNG becomes available) and be in place till around 2024, once most of the CCGT is commissioned.
- Approximately 1,500 MW of new renewable capacity, added gradually and comprising mostly solar PV and wind, but also a small amount of new hydro.

The resulting installed capacity is summarised in the figure below. The generation expansion plan is based on the MEW 2019 updated Electricity Sector Policy Paper and its investment plan as of end July 2019. The planned capacity and timing for some thermal and RE permanent and 'fast-track' generation, given in this report, have evolved with changing sector conditions; MEW expects to refine this plan over time, as demand and realistic timeframes for LNG and plant commissioning are better understood.

MEW's planned capacity additions will probably still not be enough to meet all future demand

The figure below shows planned available capacity against forecast peak load. MEW's planned expansions appear to have been calibrated to meet peak demand in 2020 and 2021, although it is likely that there will still be some unserved demand in these years, because (a) MEW's plan does not include sufficient reserve margin to ensure there is enough spare capacity during plant outages, (b) the renewable capacity cannot be fully relied on during peak hours, and (c) demand is uncertain and could be higher than EDL's base case estimate.

Available capacity vs peak load (base case)

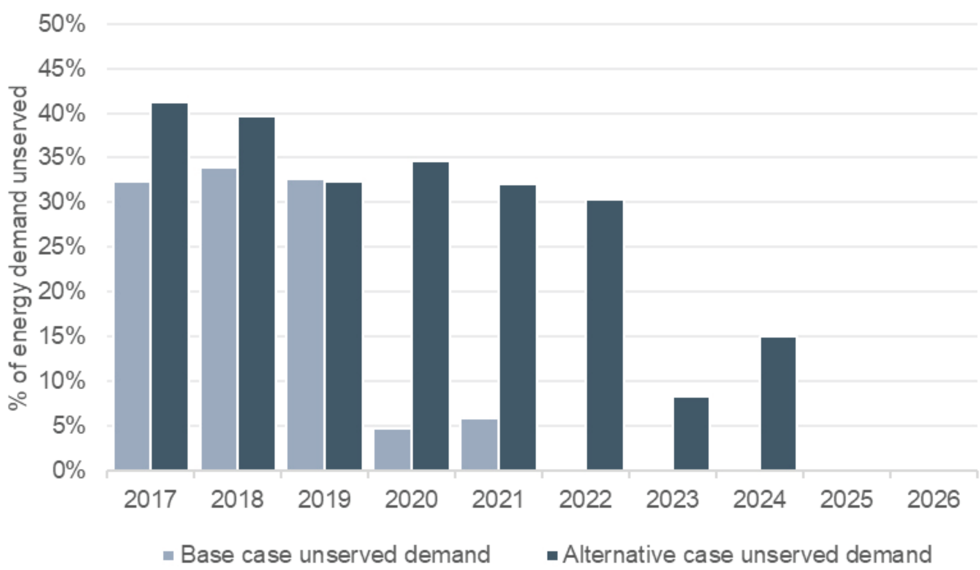


In the alternative case, most capacity additions are delayed by one year, which leads to significantly higher unserved demand

In the alternative case we are more conservative in our assumptions regarding the timing of new capacity. Most significantly, we assume fast-track generation is delayed by one year, as are the new Deir Ammar, Zahrani, and Selaata CCGT plants. The effect of this, alongside higher generation requirements in the alternative case due to more conservative loss reduction assumptions, is significantly higher unserved demand (between 8% and 35%) from 2020 through to 2024, as illustrated in the figure below.

Another reason for the high unserved demand in the alternative case is the assumption that Zouk and Jieh plants are decommissioned as per MEW assumptions in 2021; if decommissioning of these plants is delayed by two years then unserved demand will be much lower in 2021 and 2022.

Unserved demand (base case vs alternative case)

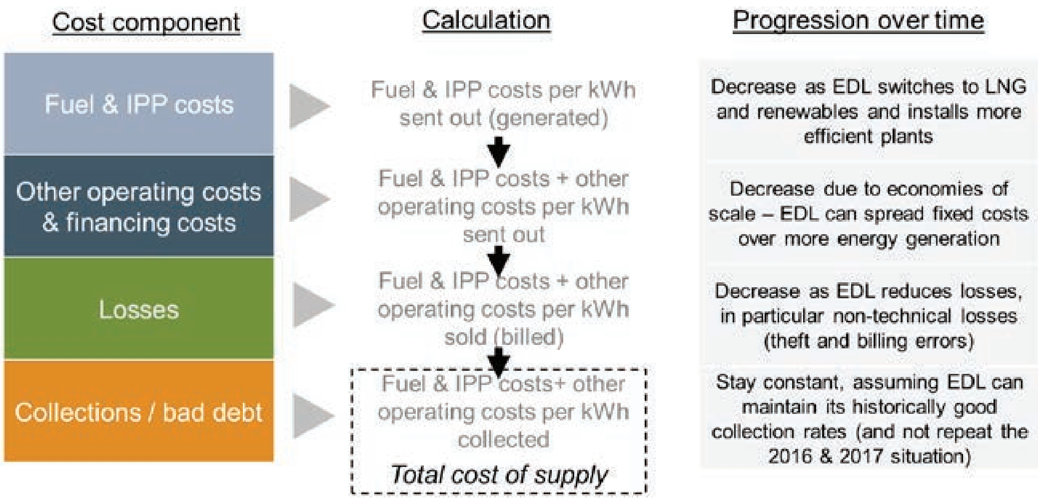


Forecast revenue requirement / cost of service

The revenue requirement is the amount of revenue that EDL needs to collect to cover its costs and eliminate Government subsidies

EDL's revenue requirement is the amount that EDL needs to collect to cover its overall costs and to eliminate Government subsidies. Our approach to calculating the revenue requirement is summarised in the figure below.

Overview of approach to calculating EDL's revenue requirement

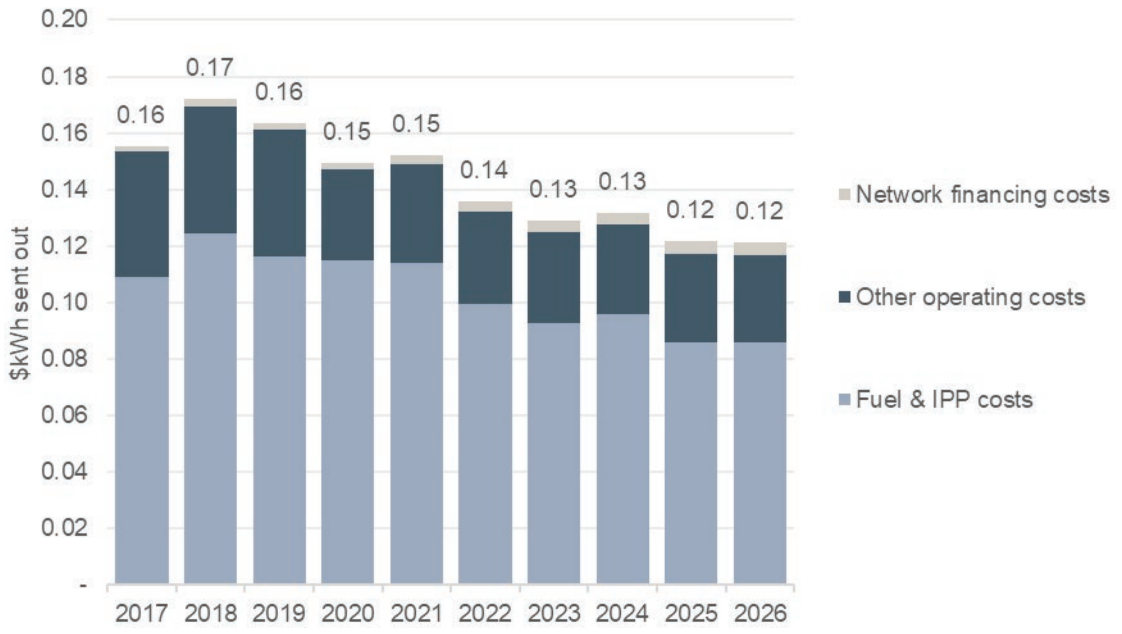


The introduction of LNG and new CCGTs should reduce costs by around 3c per kWh generated

The figure below summarises EDL's forecast cost of supply per kWh sent out. It includes fuel & IPP costs, other operating costs, and network financing costs, but excludes the cost of losses and collections/bad debt.

In 2017, the cost of supply is equal $0.16 per kWh sent out, with fuel and IPP costs accounting for approximately 70% of this. From 2022 onwards, when LNG is expected to arrive and new CCGTs begin being commissioned, total costs are forecast to drop to around $0.13 per kWh sent out. In other words, the fuel cost savings from using LNG in new efficient plants are expected to outweigh the cost of new IPP payments – to the extent that total costs are expected to reduce by around $0.03 per kWh. All forecasts exclude inflation and assume that the oil price is constant at $66/barrel (bbl) from 2018 onwards.[2] Given the recent drop in oil prices, the forecasted fuel and total costs may no longer be appropriate for the short-term (year 2020) and need adjustment. Nevertheless, the reduction of costs when switching from liquid fuels to LNG is still valid and underlines this action as a key reform to reduce sector costs.

Forecast cost of supply per kWh sent out, excluding losses and collections (base case)



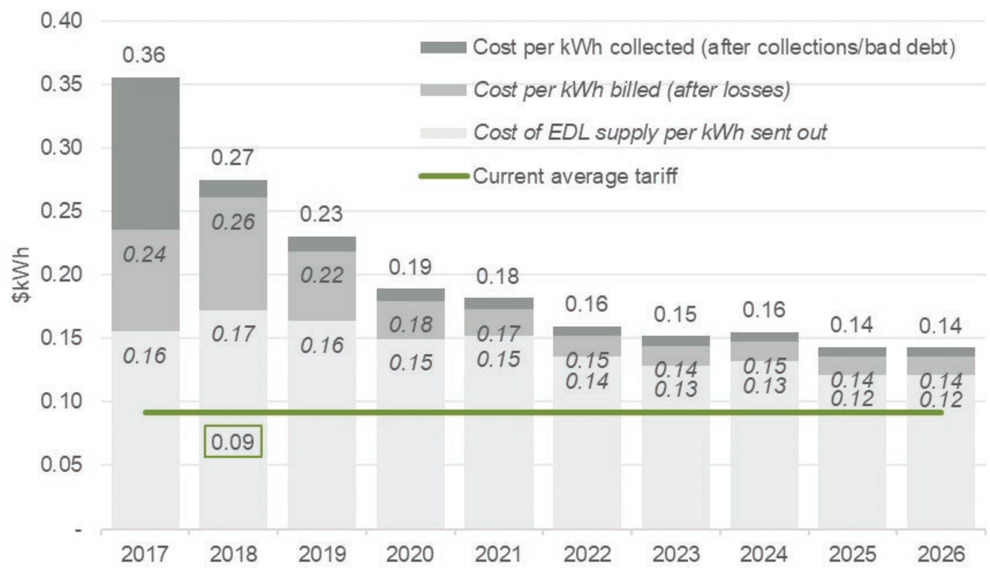
Large loss reductions will bring about cost savings of around 6c per kWh

EDL's 34% losses means that its 2017 cost of supply of $0.16 per kWh sent out becomes $0.24 per kWh sold, as shown in the figure below. In the base case, we assume aggressive loss reductions in line with MEW assumptions. The result is a reduction in the cost of supply per kWh sold of around $0.06 per kWh (in 2017 losses cost $0.08 per kWh and by 2021 losses cost $0.02 per kWh).

The total cost reflective tariff is around $0.16 per kWh from 2022 onwards

As above, collection rates were poor in 2016 and 2017, but are expected to be high from 2018 onwards[3], and therefore only have a small effect on the total revenue requirement, as shown in the figure below. The final cost of supply per kWh collected reduces from around $0.27per kWh in 2018 down to $0.16 per kWh in 2022 as losses are reduced, new generating capacity is added, and LNG is used to fuel generator.

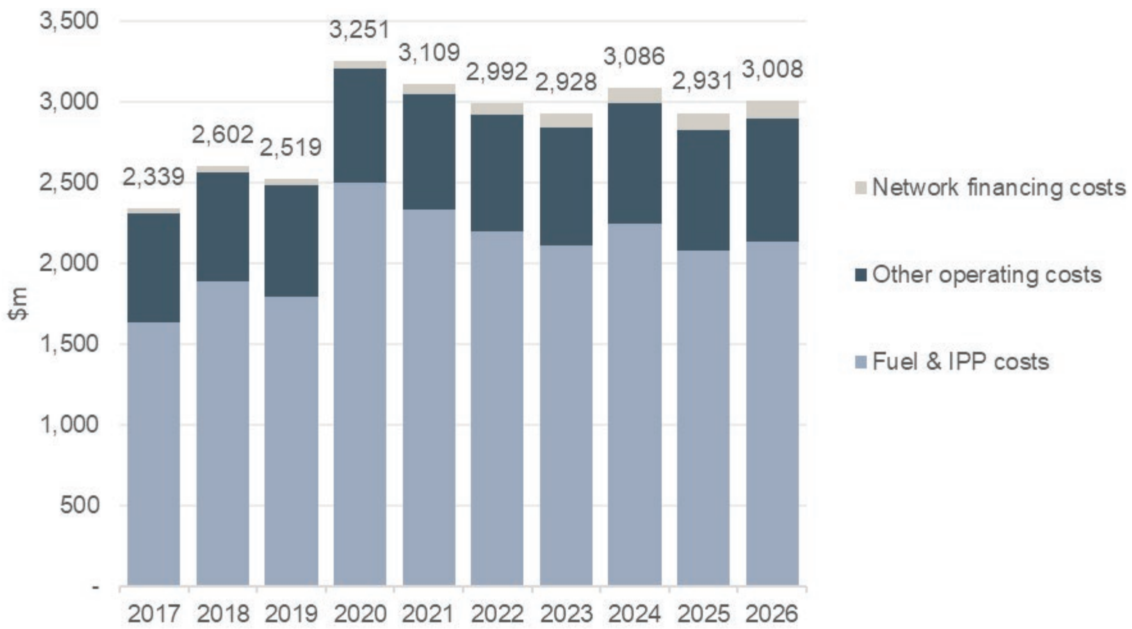
Forecast cost of supply per kWh collected (base case)



The total cost of supply increases by up to $1bn due to increased volumes generated

Although the per unit cost decreases significantly over time, as illustrated above, the total cost of supply increases significantly over the same period due to EDL generating more power. In the base case scenario, the forecast cost of supply peaks at about $3.25bn in 2020 and levels out at around $3bn from 2022 onwards. As discussed previously, this assumes the oil price stays constant at $66/bbl.

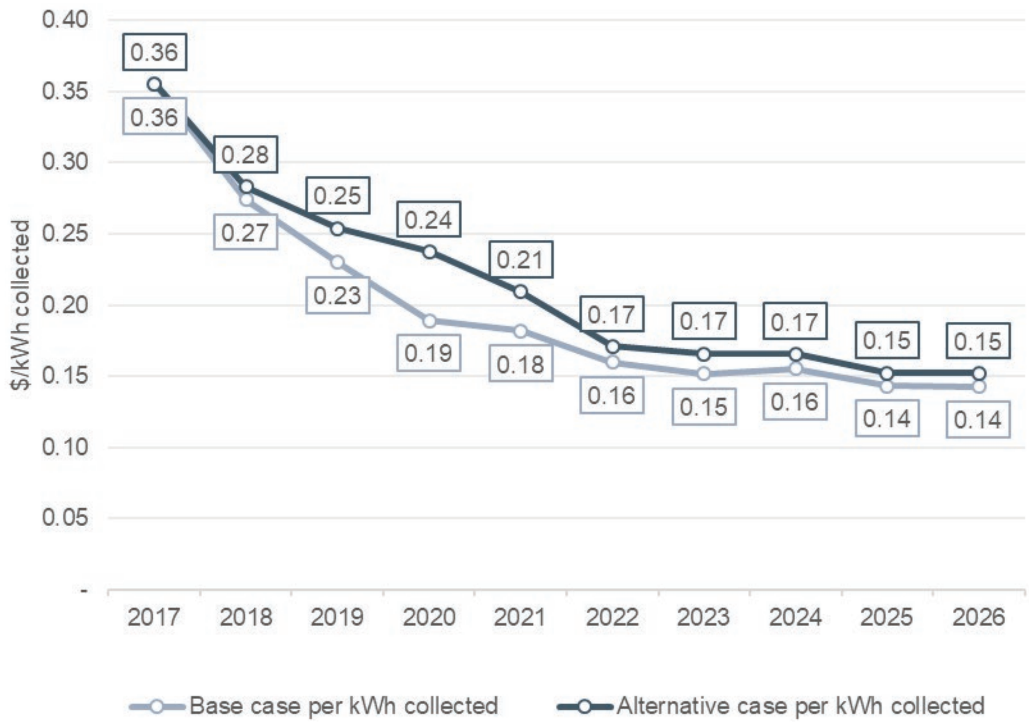
Forecast cost of supply (base case)



In the alternative case, per kWh costs are higher – the 2022 cost-reflective tariff is around 17c per kWh

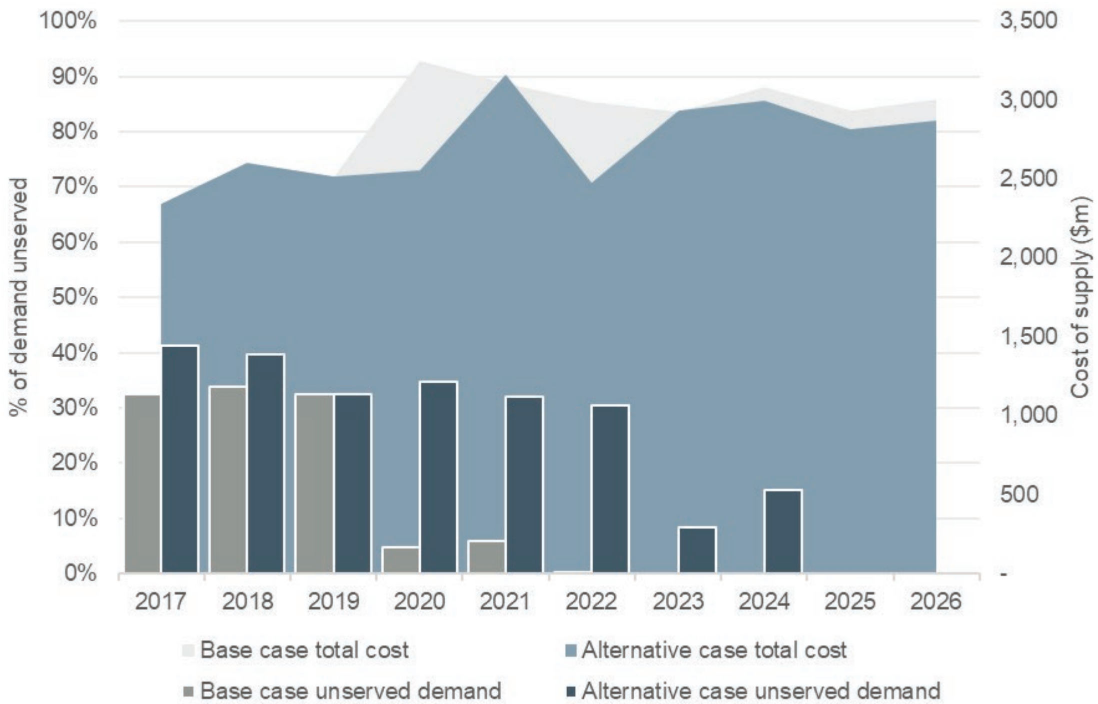
In the alternative case, the per unit costs of supply remain higher for longer, as illustrated in the figure below. Before 2022 the cost-reflective tariff is significantly higher in the alternative case – e.g., in 2021 it is $0.21 per kWh versus $0.18 per kWh in the base case. From 2022 the cost of supply in the alternative case levels out at around $0.17 per kWh (rather than $0.16 per kWh in the base case). This difference is caused primarily by smaller loss reductions.

Forecast cost of supply per kWh collected (base case vs alternative case)



Despite the higher unit costs, the total costs of supply in the alternative case are lower than in the base case because less energy is generated, due to delays in commissioning new IPPs. This however comes at an obvious economic cost, due to higher unserved demand in the alternative case, as illustrated in the figure below.

Forecast cost of supply and unserved demand (base case vs alternative case)



A fuel-cost pass-through mechanism should be introduced

Our forecasts all assume that the oil price stays constant at $66/bbl, yet we know that oil prices are volatile and have a heavy impact on Lebanon's power sector. The increase in the oil price was largely responsible for the cost per kWh in 2018 being approximately 27% higher than 2017 levels. To reduce EDL and the Government's exposure to costs outside of its control, the Government should introduce a fuel price indexation to pass through the fluctuations of oil price to consumers (with consideration for smoothing mechanisms to avoid abrupt tariff changes to consumers).

Without such a pass-through, Government could increase tariffs to cost-recovery tariffs (i.e., as calculated in this report), yet a few days or weeks later the oil price could change, and the sector may be again be running a large deficit (or surplus). Such mechanisms are widespread internationally for power sectors that have significant exposure to international oil prices.

Forecast required subsidy

In the base case, we assume that historical sector arrears are recovered and that tariffs will be increased to cost recovery levels of 16c per kWh in 2020

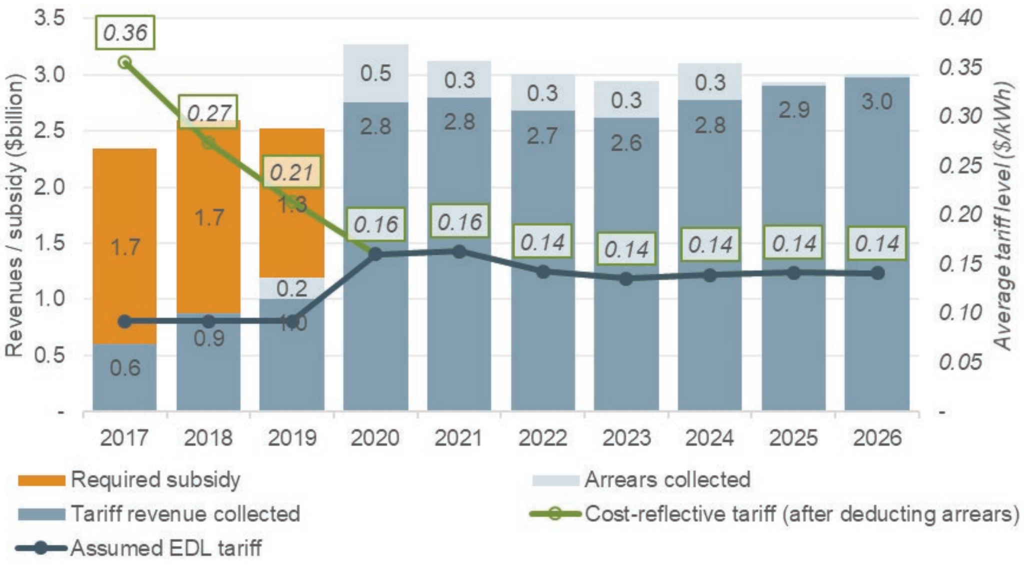
We calculate the required sector subsidy as the difference between EDL's total cost of supply and EDL's total revenues collected. In the base case, we adopt MEW's assumptions that:

- Sector arrears, totalling ~$2bn, are collected between 2019 and 2024, which translates to average arrear recovery of $340m per year.
- From 2020 onwards, tariffs will be set at a level that will eliminate the subsidy (16c per kWh in 2020, a 74% tariff increase), which coincides with the commissioning of fast-track generation and therefore most demand being met by EDL supply.

The forecast subsidy is $1.7bn in 2018 and $1.3bn in 2019

- The resulting sector subsidies that are required to cover EDL's costs of supply – until tariffs are increased – are $1.7bn in 2018 and $1.3bn in 2019, as shown in the figure below. As noted elsewhere, this assumes that oil prices remain fixed at $66/bbl (in real terms – all our forecasts exclude inflation). Without a fuel cost pass-through mechanism, subsidies will be very sensitive to oil price changes.

Forecast sector subsidy and assumed average tariff (base case)

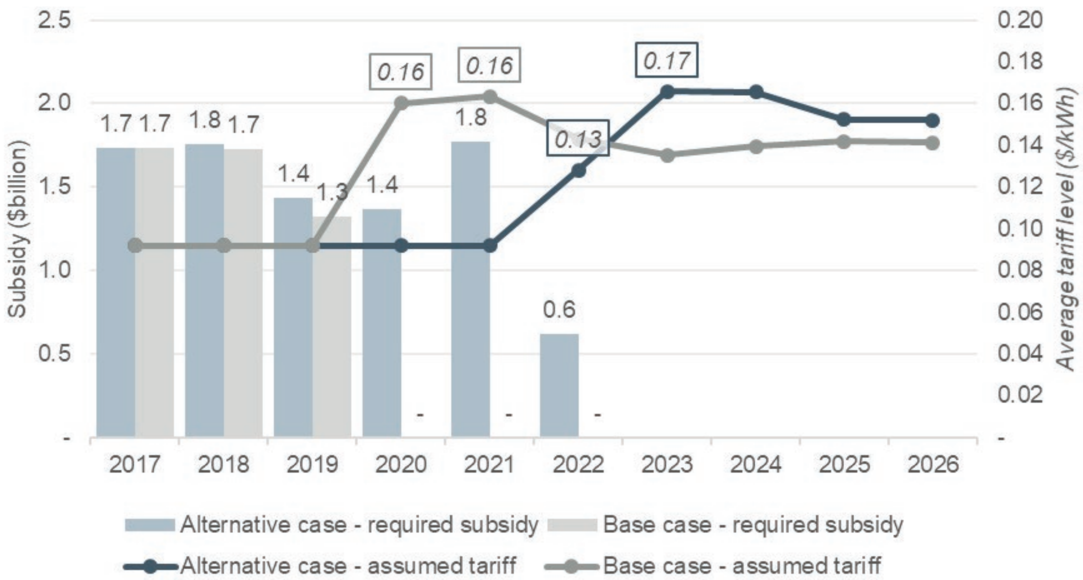


In the alternative case, we assume most arrears are not recovered and tariff increases are phased. The resulting subsidy is higher

In the alternative case we assume that (a) Only $200m per year in arrears, related to DSP payment enhancement, is recovered in 2019 and 2020 respectively, and (b) tariffs are increased more gradually – by 40% in 2022 (to $0.13 per kWh) and 30% in 2023 (to $0.17 per kWh), such that 75% of costs are met in 2022 and 100% in 2023.

- The resulting sector subsidies that are required to cover EDL's costs of supply are $1.8bn in 2018, $1.4bn in 2019 and 2020, and $1.8bn in 2021, as illustrated in the figure below. In 2022 LNG arrives and the first tariff increase kicks in, which reduces the subsidy to $0.6bn. In 2023 the second tariff increase eliminates the subsidy altogether.

Forecast sector subsidy and assumed average tariff (base case vs alternative case)



Tariff design recommendations

First cost-recovery, then more efficient price signals

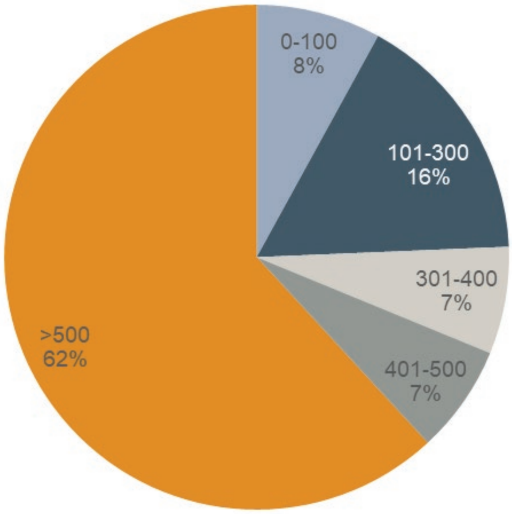
EDL's tariffs are currently far below cost recovery levels. This means that consumers currently face prices that do not reflect either average or marginal costs of supply. To encourage efficient consumption, EDL's first order of priority should be to increase tariffs to something approaching average cost-recovery levels. Once cost-recovery is achieved, EDL can turn its attention to the detail of the tariff structure and how it can be tweaked to better reflect marginal costs.

To improve cost-recovery in the short-term, EDL could target high consumption consumers

Lebanon's Government appears committed to tariff increases accompanied by supply improvements, but there are numerous options for applying tariff increases, i.e., will they be applied uniformly (all charges increase by the same amount) or targeted to particular customer types? Targeted increases may help minimise the political ramifications of increases.

One option is to target the high consumption block, where EDL earns most of its revenues. Customers in the last tariff block (>500 MWh) consume 32% of residential and energy in the residential and commercial category, yet account for 62% of revenue in that category, as summarised in the figure below.

Share of EDL's residential and commercial energy charge revenue by tariff block in 2016



The table below shows the approximate impacts of different tariff increase scenarios. It shows that there is no avoiding widespread tariff increases if Government wants to eliminate sector subsidies, but that targeting high consumption customers could help ease the burden. For example, the last scenario shows that if EDL leaves the first two consumption blocks untouched, it would need to increase all other tariffs by 94% (scenario 6 in the table below) to achieve a 74% increase in average tariffs and eliminate the subsidy altogether if assumptions in the base case hold true – including LNG arrival, new CCGT generation, loss reductions, and a $66/bbl oil price).

Example tariff increase scenarios

	Tariff adjustment scenario	% increase in total EDL revenues billed	Increase in 2020 revenue ($bn)	Average tariff level ($/kWh)
1	First four residential & commercial consumption blocks combined into a single block and the energy charge for that combined block set to $0.08 per kWh	17.5%	0.29	0.11
2	Residential & commercial energy charge increased by 50%, except the first two blocks	15.8%	0.26	0.11
3	Energy charge increased by 50% for all customers that are not LV residential & commercial	17.9%	0.30	0.11
4	All customers' energy charges increased by 50%, except the first two blocks	33.7%	0.55	0.12
5	All customers' tariffs (both energy and fixed) increased by 50%, except the first two blocks*	39.3%	0.64	0.13
6	All customers' tariffs (both per energy and fixed) increased by 95%, except the first two blocks*	74.0%	1.19	0.16

*EDL was unable to provide a breakdown of connection numbers by customer type. For the purposes of calculating expected impacts on per connection revenues (related to fixed charges), we assume that 50% of connections fall within the first two block: Residential and Commercial: 1-100, Residential and Commercial: 101-300 categories.

Source: ECA analysis based on EDL and MEW data

Another possible strategy might be to target commercial customers

Currently residential and commercial customers pay the same tariff under a rising block tariff structure. This means that commercial customers pay low tariffs for the first increments of monthly consumption, which is rare by international standards. There are no strong reasons for commercial businesses to receive heavily subsidised power as is currently the practice in Lebanon.

Ideally EDL would reclassify existing customers. There is currently no reliable record of residential vs commercial customers in EDL's billing database. But this will take significant time. A quicker approach to differentiating commercial customers (and wealthier residential households) would be to set charges based on the capacity (rating of the circuit breaker) of a customer's connection. This approach might allow EDL to do away with the rising block tariff structure altogether. Unfortunately, in the absence of billing data on residential and commercial customers, we are unable to reliably estimate the effects of separating out residential and commercial customers.

Overhauling the overall tariff structure in this way might help reduce the political and social reactions to tariff increases. The practical implications of implementing such a mechanism should be discussed with EDL.

A third possible strategy for improving cost-recovery would be to improve the targeting of social benefits

Currently all low-voltage residential and commercial customers pay low tariffs for the first increments of monthly consumption, as a way of protecting vulnerable households. The downside to this approach is that all customers receive subsidised power for the first few tariff blocks, not just low-income households. Using a direct social assistance mechanism, such as the National Poverty Targeting Program (NPTP), would allow EDL to do away with rising block tariffs, thereby improving cost-recovery.

In the medium to long term, once cost-recovery is achieved, EDL should adjust its tariff design to improve economic price signals

In the medium to long term, once EDL achieves cost-recovery, its focus should turn to designing tariff structures that encourage the economically efficient use of electricity. Key recommendations to improve the cost-reflectivity of EDL's tariff structure, and incentivise shifting consumption away from peak periods, include:

- All MV and HV customers should pay demand charges, to better signal marginal capacity costs.
- There should be seasonal demand charges to reflect that peak load in summer is significantly higher than other months.
- Time-of-day tariffs should be implemented for larger customers to encourage them to shift demand to off-peak hours.
- EDL should distinguish between commercial and residential customers at different voltage levels, given their costs of supply at different voltage levels will vary significantly.

1. INTRODUCTION

In this section we summarise the objective of this study and outline the structure of the report.

1.1 Objective of this study

This study's objective is to undertake a cost of service study to facilitate sector reform

The objective of this study is to conduct a cost-of-service study and tariff analysis for the electricity industry in Lebanon, which will facilitate the reform of electricity tariffs, reduce costly financial transfers, and better address affordability for disadvantaged households. A key output of the study is to estimate the Government subsidy required to cover the difference between Electricite Du Liban's (EDL's) forecast revenues and costs.

1.2 Timing, data sources and key assumptions

This report was first prepared in late 2018 and relies primarily on 2017 data

Although this final report is dated early 2020, a first draft was issued to the World Bank and Ministry of Energy and Water (MEW) in late 2018. This report therefore relies primarily on data made available by EDL and MEW for the calendar year 2017, along with a few data points from 2018 that were provided during the review process.

The analysis is heavily reliant on inputs and assumptions prepared by the Ministry

As noted throughout the report, we define our 'base case' scenario based on inputs and assumptions provided by MEW advisors, who were in close consultation with EDL staff. Most of these inputs and assumptions were settled on after significant discussion with us (the consultant) and on review of our draft report. In a few cases we (the consultant) formed significantly different views on the appropriate assumptions. We therefore also present an 'alternative case' scenario to test the impact of different inputs and assumptions.

Issues arose during data collection, but they do not affect the overall conclusions of this report

There were often issues with the data provided by EDL – not due to a lack of effort or cooperation on EDL's part, but rather due to inadequate reporting frameworks at EDL. While we (the consultant), World Bank staff, and advisors to MEW went to considerable effort to reconcile data issues, not all were resolved.

Data issues, alongside the inherent challenge of modelling a power sector facing such challenges (high unserved energy, reliance on Government subsidies, underperformance by the utility, etc.), mean that most numbers detailed in this report should be treated with caution. While we do not have confidence that the numbers presented in this report are precise, we do have confidence in the key conclusions and recommendations made.

1.3 Structure of this report

The remainder of this report comprises of four main sections, as illustrated in the figure below.

Figure 1 Structure of this report

2. Current situation

Sets the scene by describing the challenges facing the Lebanon power sector.

3. Demand and supply of electricity

Describes estimated demand for electricity in Lebanon and provides an overview of MEW plans to meet that demand.

4. Cost of service / revenue requirement

Describes EDL's future costs and the revenue that it needs to cover those costs, given various assumptions about the future. It also sets out the likely impacts on required Government subsidies, given assumptions about future tariff increases.

5. Tariff design and revision

Sets out recommendations for revising the structure of EDL's tariffs, to increase revenue in the short term and improve the efficiency of price signals in the medium to long term.

Source: ECA

2. ASSESSMENT OF THE CURRENT SITUATION

In this section we set the scene by describing the challenges that the Lebanon power sector is currently facing. These challenges help explain why current demand for power is uncertain (Section 3), they impact heavily EDL's cost of supply and revenue requirement (Section 4), and they influence our recommendations on tariff design (Section 5).

2.1 Shortage of generating capacity

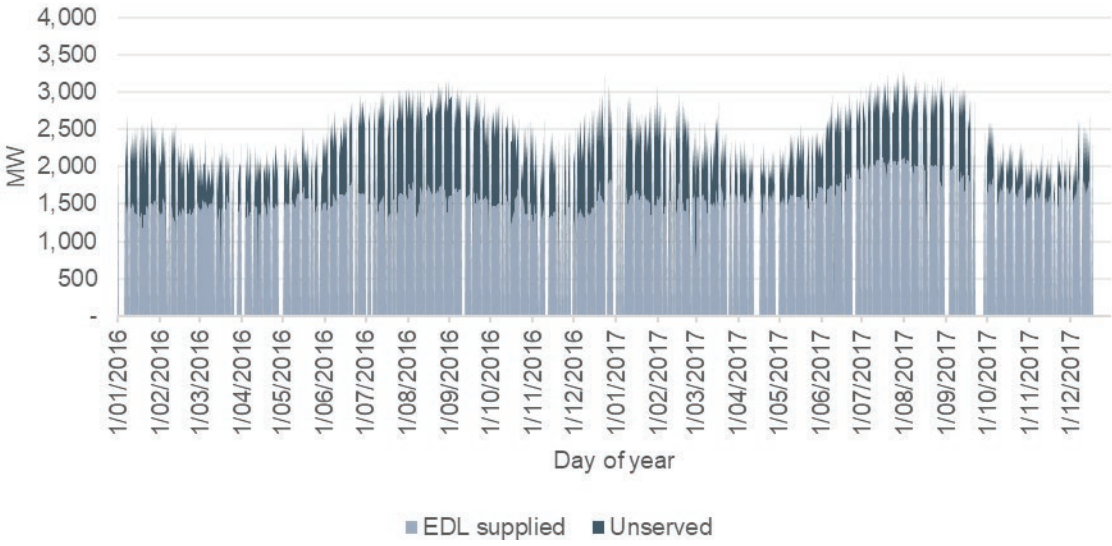
EDL is supplying around two thirds of electricity demand, although demand is uncertain

The electricity sector in Lebanon is served primarily by EDL, a vertically integrated utility that relies mostly on its own generating plants, supplemented by a few small IPPs (mostly hydro) and some temporary generation (in the form of privately-owned floating power barges).

The electricity sector has suffered from a shortage of supply for many years, dating back to the civil unrest of the 1970s, 1980s, and early 1990s. In the past, Lebanon relied heavily on imports from Egypt and Syria, but in recent years imports have been minimal, due in part to escalation of the war in Syria.

EDL estimated that it supplied only 59% of demand in 2016 and 67% of demand in 2017, with most of the remainder supplied by private generators at higher tariffs, as illustrated in Figure 2 below.

Figure 2 EDL estimate of electricity demand and supply, 2016 & 2017



Source: ECA analysis based on EDL and MEW data

In 2017, average EDL supply was 1,717 MW[4], which is 218 MW more than in 2016 and was higher in the second half of the year. Average demand in 2017 was estimated at 2,609 MW and had two peaks: the main one in summer months where the average demand was 2,846 MW (measured between the 1st of June and the 30th of September) and a smaller one in January and February. The unserved demand was on average 891 MW over the course of 2017.

4 1,692 MW as measured at the exit of the high-voltage system, grossed up for EDL's estimated losses on the high-voltage system (1.5%)

It is likely that EDL's estimate of peak demand, 3,511 MW in 2017, is an underestimate. But ultimately demand is uncertain.

EDL estimates demand by substituting load-shed feeder data with supply data in the same hour on previous days. In other words, the missing values were populated with feeder data recorded in the same hour on the previous day.

EDL estimated its 2017 peak demand to be equal to 3,511 MW[5] (on the 1st of August). We think this may be an underestimate of the actual peak demand. This is because customers reportedly shift some of their consumption to private generators, many of which are not metered. The load factor estimated on the basis of EDL data is 74%, whereas nearby Jordan has a load factor of 67% which is more in line with other international benchmarks.

We understand that during late 2018, when most private generators began to be metered, EDL saw significant increases in demand. This appears to confirm our expectations – customers had been shifting consumption away from EDL because most private generators had been unmetered, whereas once private generators were metered customers began shifting consumption back to EDL. Overall, it is difficult to form a reliable estimate of demand until all consumption is metered and reported. We discuss this further in Section 3.1.

The supply shortfall is mostly due to the shortage of generating capacity

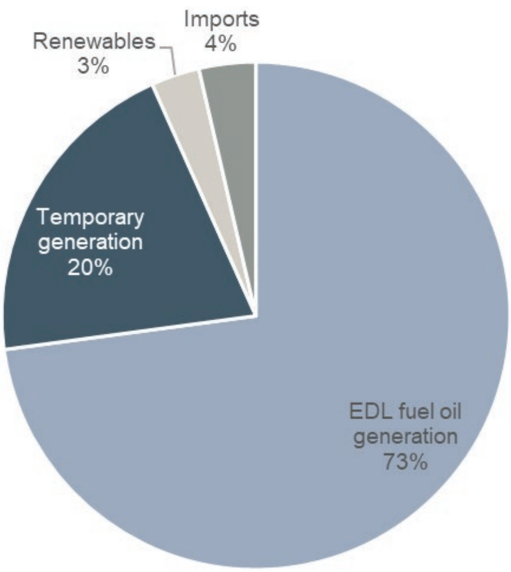
In total, EDL has approximately 2,200 MW of generating capacity whereas EDL's estimated peak demand is around 3,500 MW (and is likely even higher). This results in significant shortage of generating capacity. The supply shortfall is also partly because of generation curtailment to reduce the fuel bill, in particular by running inefficient OCGT plants at below capacity.

2.2 Reliance on oil-based fuels

EDL's generation is predominantly from expensive fuel oils

EDL's 2017 power mix is depicted in Figure 3. The majority of EDL's generation capacity is produced using expensive fuel oil[6] (73% in 2017), followed by temporary generation, also running on fuel oil (20%), imports (4%) and renewables – mostly hydro (3%).

Figure 3 Mix of 2017 EDL generation by source



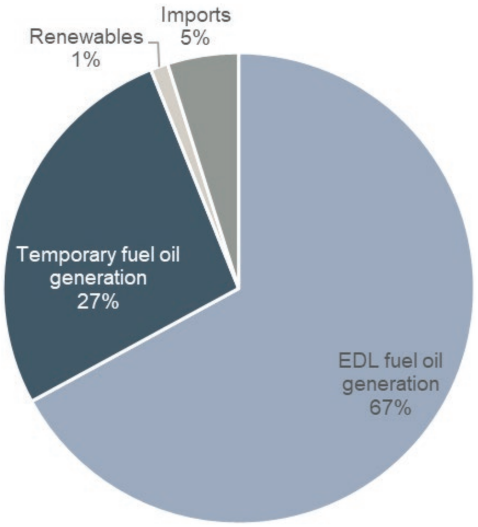
Source: ECA analysis based on EDL and MEW data

5 3,458 MW as measured at the exit of the high-voltage system, grossed up for EDL's estimated losses on the high-voltage system (1.5%)

6 Both heavy fuel oil and light fuel oil (diesel)

The split of generation costs is shown in Figure 4. The cost of fuel oil generation accounts for 67% of total generation costs, followed by temporary fuel oil generation costs (27%), imports (5%) and renewables (1%). Temporary generation is therefore relatively the most expensive source of power – it accounts for approximately 27% of EDL's generation costs but contributes only 20% to the total 2017 power generation. Comparing generation sources in this manner is not strictly fair – the cost of temporary generation includes rental/capital/energy costs, whereas the other generator per unit costs do not (the capital costs of those plants are either not included in EDL books or are mostly fully paid off). Renewables, on the other hand, are the cheapest source of power in relative terms – they contribute 3% to the total power generation but incur only 1% of total costs.

Figure 4 Mix of 2017 EDL fuel and IPP costs by source



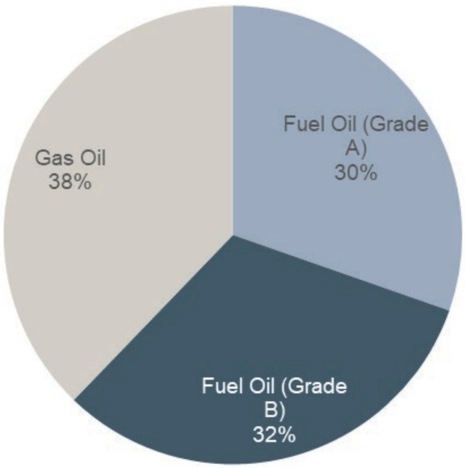
Source: ECA analysis based on EDL and MEW data

Figure 3 and Figure 4 focus on variable costs and hence only fuel and Independent Power Producer (IPP) costs (including energy conversion works for the temporary power barges) are included. Capital expenditure (capex) of EDL owned generation and operation and maintenance (O&M) costs are not considered here.

Many of EDL's plants are old and EDL has been reliant on temporary generation for several years now

Figure 5 shows fuel consumption by type of fuel in 2017. The majority of EDL's power plants operate on gas oil (38%), followed by fuel oil (grade B, 32%) and fuel oil (grade A, 30%).

Figure 5 Fuel consumption by type of fuel, 2017



Source: ECA analysis based on EDL and MEW data

Power plants running on fuel oil include Zouk, Jieh, Zouk Recip and Jieh Recip. The former two are older units, commissioned in the 1980's with the availability factor of around 65% and derated capacity of 440 MW in total. Both use steam turbines and it is not possible to switch them to LNG when it becomes available.

The latter two units are reciprocating engines which were commissioned in 2017. The total design capacity of both units is 272 MW and the availability factor is 88%. Despite currently operating on fuel oil, they can be switched to LNG in the future.

Zahrani and Deir Amar are CCGT units which currently operate on gas oil but can operate on LNG as well. The total derated capacity of the two power plants is 870 MW and their availability factors average around 81%. They were both commissioned in early 2000's.

Baalbak and Sour (Tyr) have a total derated capacity of 120 MW and an average availability factor of around 40%. They are both OCGT units currently operating on gas oil, but they can be switched to LNG when it becomes available. The remainder of EDL's generating capacity comes from one hydro power plant (capacity of 12 MW) and a biomass power plant (capacity of 7 MW).

One fifth of EDL's power generation is produced using temporary power barges. EDL has been incurring the Energy Conversion Works for several years now, which means that with hindsight, it would likely have been cheaper to have invested in permanent capacity, rather than keep paying high take-or-pay charges. KPS Zouk and KPS Jieh have a total design capacity of 370 MW and an availability factor of around 95%. In 2017, Lebanon also imported power from Syria which constituted 4% of total power generation.

The Independent Power Producers (IPPs) operate 4 hydro power plants with a total design capacity of around 270 MW. The availability factor and averages around 14% of design capacity. The Hrayche steam turbine is the only IPP that operates on fuel oil. Its derated capacity is 45 MW and the availability factor of around 50%.

The table and figure below provide a summary of existing generating units in Lebanon. The summary includes EDL's own generating units, temporary generation (power barges) and IPPs. More information is available in Annex A2.

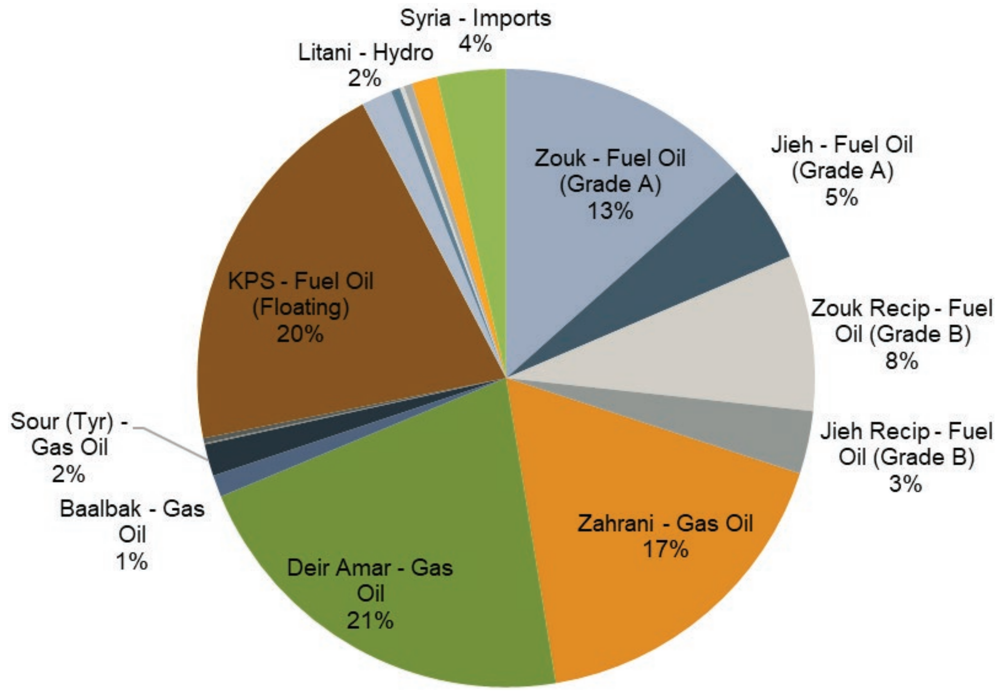
Table 1 Summary of current generating units

Name	Current fuel type	Technology	Design capacity (MW)	Derated capacity (MW)	Avg capacity factor (%)	MWh generated in 2017	Heat rate (metric T/MWh)	IPP energy charge ($/MWh)
Existing EDL								
Zouk	Fuel Oil (Grade A)	Steam Turbine	607	300	65%	2,018,973	0.26	
Jieh	Fuel Oil (Grade A)	Steam Turbine	343	140	68%	774,518	0.34	
Zouk Recip	Fuel Oil (Grade B)	Recip	194	194	88%	1,225,320	0.18	
Jieh Recip	Fuel Oil (Grade B)	Recip	78	78	87%	495,973	0.18	
Zahrani	Gas Oil	CCGT	469	435	89%	2,618,972	0.16	
Deir Amar	Gas Oil	CCGT	464	435	73%	3,207,727	0.19	
Baalbak	Gas Oil	OCGT	64	60	36%	170,708	0.26	
Sour (Tyr)	Gas Oil	OCGT	72	60	44%	250,818	0.28	
Safa (Richmaya)	Hydro	Hydro	13	12	9%	10,533		
Naameh	Biogas	Biogas	7	7	105%	40,937		
Existing - Barges[7]								
KPS Zouk	Fuel Oil (Floating)	Recip	187	185	95%	1,536,262	0.19	49
KPS Jieh	Fuel Oil (Floating)	Recip	187	185	95%	1,536,262	0.20	49
Existing - IPPs								
Litani	Hydro	Hydro	199	47	45%	242,564		40
Nahr Ibrahim	Hydro	Hydro	32	17	44%	72,548		26
Bared	Hydro	Hydro	17	6	56%	33,214		26
Kadisha hydro	Hydro	Hydro	21	15	45%	65,425		26
Hrayche	Fuel Oil (Grade A)	Steam Turbine	75	45	51%	200,461	0.30	54
Imports								
Syria				240	26%	542,630		

Source: ECA analysis based on EDL and MEW data

7 The table assumes a 50% split between the two power barges as only the total value for temporary generation was provided

Figure 6 Share of EDL energy generated in 2017



Source: ECA analysis based on EDL and MEW data

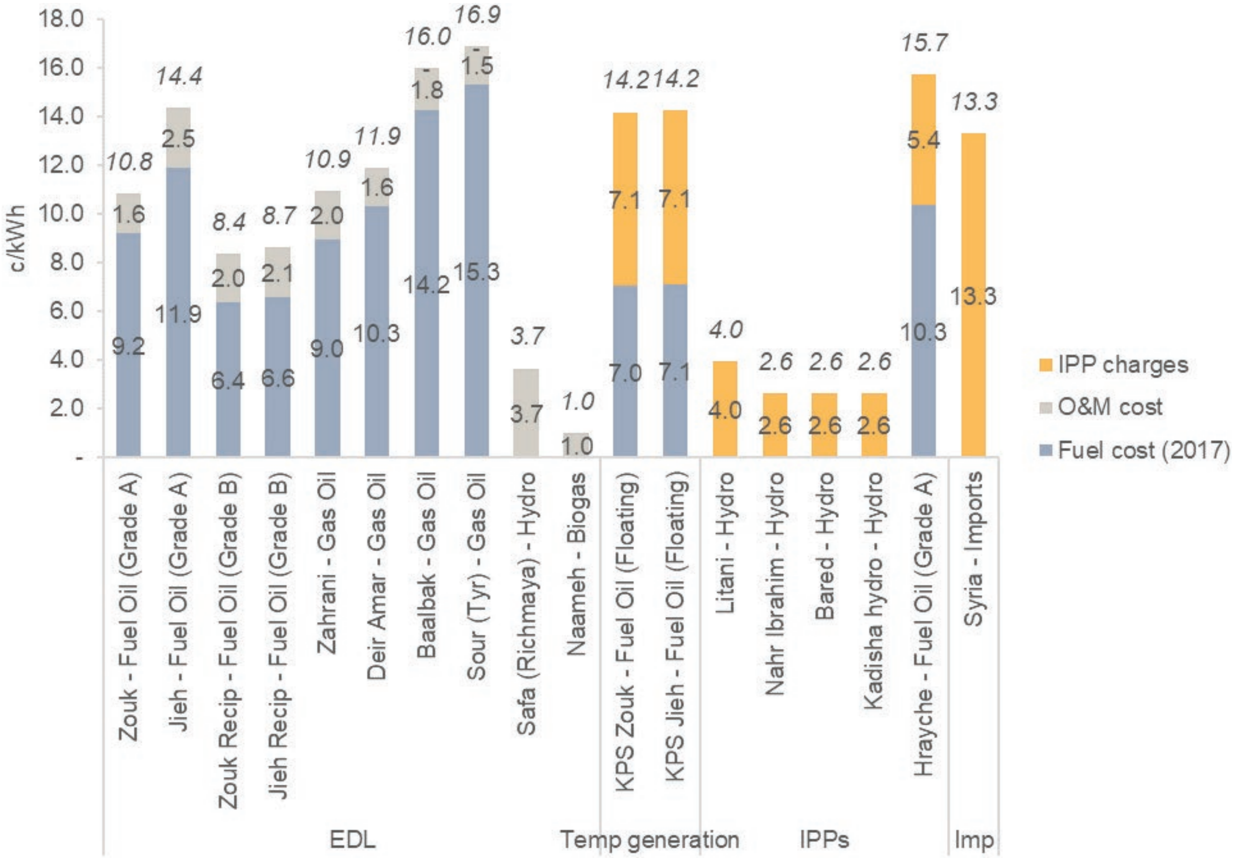
EDL has a mix of reasonably efficient plants and very old inefficient plants

Figure 7 and Figure 8 provide more detail on average fuel cost by power plant, based on 2017 data. Among EDL's power plants, Sour (Tyr) and Baalbak are most expensive with the average cost of \$0.167 per kWh. High fuel costs and inefficient running of power plants led EDL to curtailing their output in order to keep fuel costs down.

The average cost of running the old steam turbines (Jieh, Zouk and Hrayche) is between \$0.108 and \$0.157 per kWh. This is despite the power plants running on relatively inexpensive fuel oil, suggesting the efficiency of these power plants is very low.

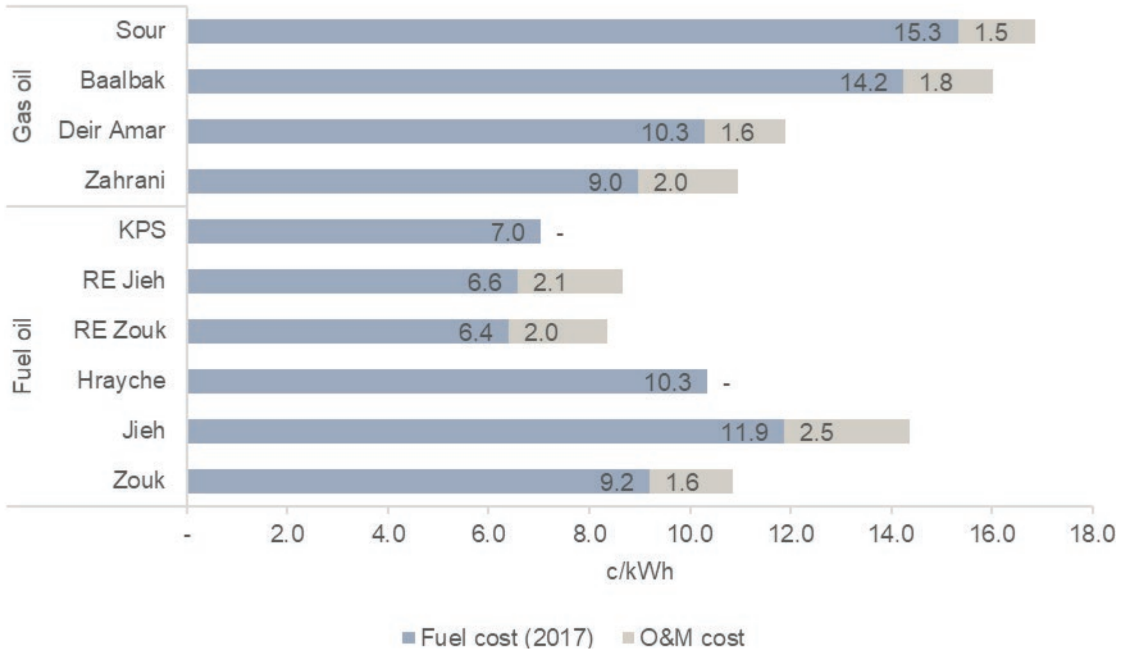
Deir Ammar and Zahrani gas turbines are among EDL's most efficient plants (average cost of \$0.115 per kWh) but they are running on expensive gas oil which increases average costs. The two new recips (Jieh and Zouk) operate efficiently on fuel oil and are the cheapest source of power (\$0.085 per kWh). The power barges (KPS) have similar fuel costs as the new recips (Jieh and Zouk), although their fuel price includes a small margin to cover transport and insurance.

Figure 7 Fuel, O&M, and IPP costs by plant, 2017 (at crude price of $54/bbl)



Source: ECA analysis based on EDL and MEW data

Figure 8 Fuel and O&M costs by EDL plant, 2017 (at crude price of $54/bbl)



Source: ECA analysis based on EDL and MEW data

2.3 High network losses

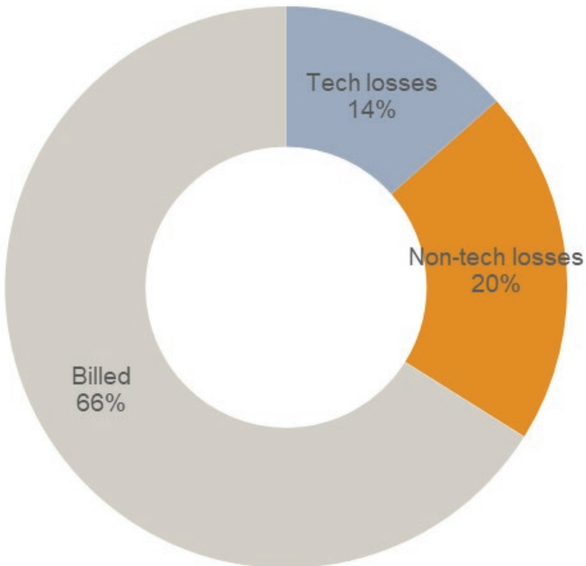
Around a third of EDL's energy produced/purchased is lost

- EDL network suffers from high technical and non-technical losses which sum up to 34% of total energy sent-out (ie, produced or purchased). Based on EDL data, transmission technical losses were estimated to be around 609 GWh in 2017 (4% of total energy entering the transmission system) while distribution technical losses amounted to 1,421 GWh (13% of energy entering the distribution system).
- After deducting technical losses, commercial/non-technical losses account for around 20% of energy sent out (28% of energy entering the distribution system), which is exceptionally high. As a comparison, nearby Jordan has total distribution losses (including both commercial and technical losses) of 12.9% and transmission losses of 1.7%. And these losses are not especially good by international standards.

Theft and billing errors are the primary cause for concern

- High non-technical losses most likely result from theft and billing errors. MEW and EDL are planning to implement a smart meter programme to target illegal connections and irregular meter reading, which should help reduce these high numbers. The share of losses in total energy sent out is illustrated in Figure 9.

Figure 9 Share of energy produced/purchased, 2017

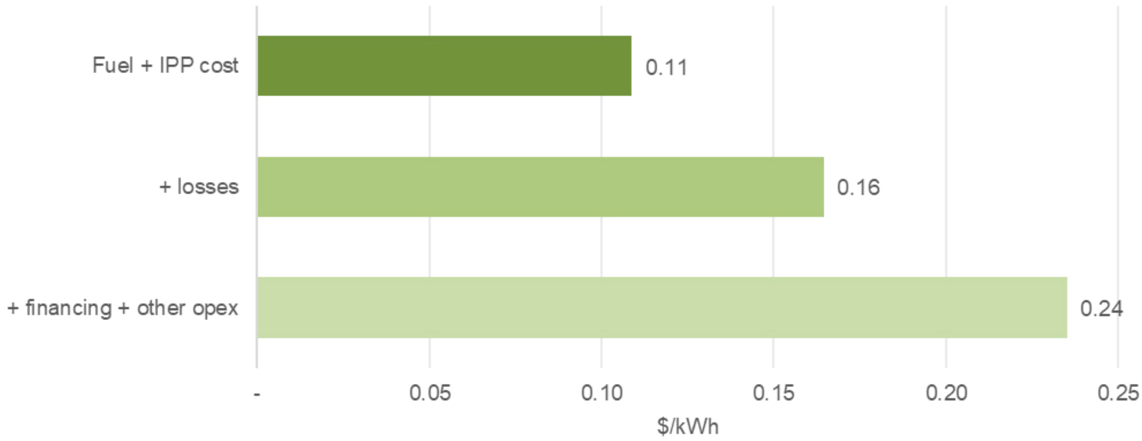


Source: ECA analysis based on EDL and MEW data

High losses result in high costs of supply

- EDL's fuel costs plus IPP costs sum up to $0.11 per kWh sent out. Once 34% losses are added, the cost goes up to $0.16 per kWh sold (billed). After accounting for EDL's other operating costs (including generation O&M, staffing costs, network repairs and maintenance) and financing costs (relating to past investments), the cost further increases to $0.24 per kWh sold[8]. This is the cost incurred by EDL before any profits are added and prior to any adjustments for the collection rates. The breakdown of costs is illustrated in Figure 10.

Figure 10 EDL's cost of supply, 2017



Source: ECA analysis based on EDL and MEW data

2.4 Collection issues

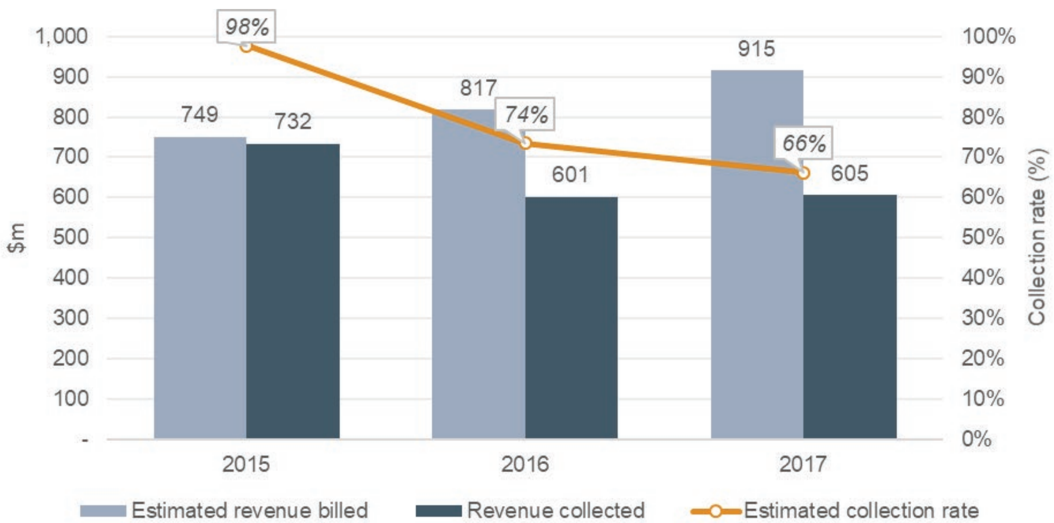
EDL had issues collecting revenues in 2016 and 2017, but these should now be resolved

EDL collected most (98%) of its billed revenues in 2015, which is apparently in line with historical collection rates. EDL's billing data in 2016 and 2017 is incomplete. However, the limited data that has been provided suggests that the collection rate was much poorer and as low as 66% in 2017.

According to EDL data, the energy sent out (i.e. energy produced and purchased) increased by around 21% from 2015 to 2017. EDL's tariffs did not change over this period, and assuming losses also remained unchanged, revenue billed ought to also have increased by around 21% from 2015 to 2017. Yet EDL data on revenue collected shows that revenue collected declined by 21% from 2015 to 2017. This implies a collection rate of only 66%, i.e. bad debts of over 30% (Figure 11).

We were informed that the sharp drop in collections is due to the Distribution System Providers (DSPs) pausing their collection activities during parts of 2016 and 2017. Apparently one DSP covering around 40% of EDL customers did not collect anything. As a result, in 2018, bills from 2016 and 2017 were still being collected. Going forward, EDL expects collection issues to be resolved. It is also possible that EDL will recover some of the 2016 and 2017 arrears in future years, as discussed later in this report.

Figure 11 Estimated revenue billed vs revenue collected

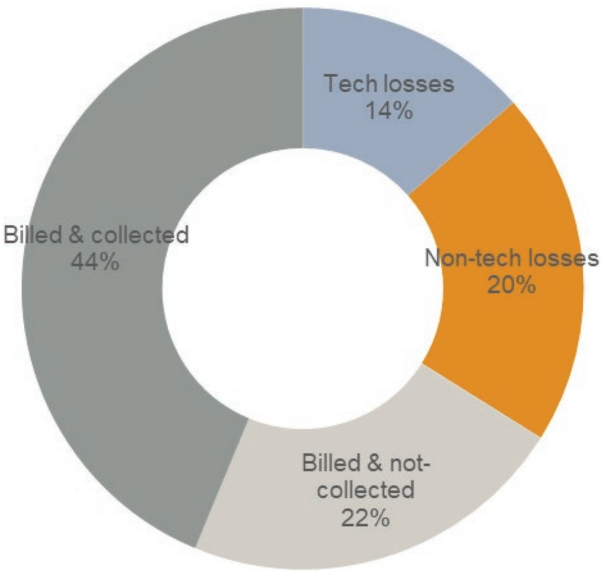


Source: ECA analysis based on EDL and MEW data

Poor collections further increased EDL's cost of supply in 2017

Figure 12 shows the percentage of revenue collected in 2017 using the latest available data. Revenue billed and not collected accounts for 22% of total energy entering EDL's system. Even though EDL expects to collect most of the remaining revenue, it should prioritise timely collection of bills in the future. This is important in ensuring the financial stability of EDL.

Figure 12 Share of energy produced/purchased (2017)



Source: ECA analysis based on EDL and MEW data

Poor collections combined with high network losses mean that EDL only collected cash revenues on 44% of the electricity it sent out and that its total cost of supply in 2017 was $0.36 per kWh collected. Going forward, EDL expects collection rates to return to the historical levels (98% in 2015), so the exceptionally high cost of service in 2017 should be an anomaly.

2.5 Significant private generation

The shortfall in EDL supply is mostly met by private generation providers

EDL estimates that it supplied only 59% of demand in 2016 and 67% of demand in 2017. The long-lasting undersupply of electricity has made room for private generation companies which over years have become EDL's competitor in Lebanon's electricity sector. By offering to supply power during the country's blackout hours, private generation companies have been able to charge high prices and earn significant profits.

Until recently private power generators were mostly unmetered, and subscribers were charged based on a flat fee which further incentivises the consumption of electricity supplied by private generators over the one supplied by EDL.

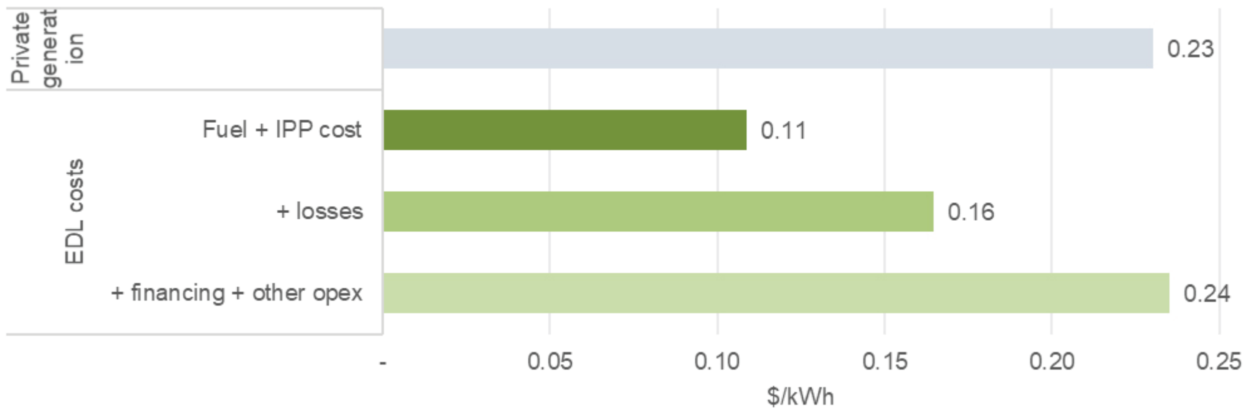
In late 2018 the Ministry began enforcing regulations that all private generation should be metered, and that customers should not be charged more than the Ministry's published rates (which vary based on the capacity of connection). As of late 2018, the average cost of private generation is reportedly around $0.30 per kWh which is estimated based on official charges imposed by the ministry.

EDL's inefficient networks results in a high cost of generation, similar to private generation tariffs

As discussed in section 2.2, EDL has a mix of reasonably efficient plants and very old inefficient plants running on expensive fuel. This results in high fuel costs which averaged $0.11 per kWh in 2017 (Figure 13). EDL's networks are inefficient with total losses of around 34% (section 2.3). This increases the average cost of supply to $0.16 per kWh. On top of that, EDL also incurs financing and opex costs which further increase the cost of supply to $0.24 per kWh

This compares with the cost of private generators of around $0.23 per kWh, at 2017 oil prices[9]. Private generator owners use small units which run on relatively expensive diesel and the tariff must also recover capital costs. The fact that EDL's costs are not significantly lower than private generation illustrates how efficient EDL's supply is.

Figure 13 EDL's operating costs vs private generation, 2017



Source: ECA analysis based on EDL and MEW data

Private generation tariffs are not directly comparable with EDL tariffs

There are however reasons why tariff for private generation is not directly comparable with EDL tariffs:

- Providers rely to a large extent on foreign labour at low wage rates, which significantly cuts the operating costs.
- They use EDL power poles, thereby avoiding investments.
- The private networks are of lower quality standard (e.g. aluminium cables).

The requirement to meter private generation will result in load shifting onto EDL

The recent requirement to meter private generation has significant implications for the sector. Customers no longer have an incentive to shift load onto private generation. In fact, they will now be inclined to shift load onto EDL (with whom they pay lower tariffs). This effect appears to be showing up in the latest EDL demand data where EDL's average demand was 9% higher in November 2018 than in November 2017.

2.6 Reliance on Government subsidies

Reliance on fuel oils, high losses, and low tariffs results in high Government subsidies

The Lebanon power sector has relied on Government subsidies for decades. The majority of EDL's power plants are old and inefficient and run on relatively expensive fuels, which results in total fuel expenses of around $1,317m in 2017. Power purchases were the second highest expenditure and were $320m in 2017. In this subsidy calculation we only detail cash costs, including other operating costs of $274m, but accordingly to EDL there is another $400m (or thereabouts) unaccounted for[10]. In total, the cash operating costs for 2017 were around $1,900m while revenue collected by EDL was only $640m.

According to 2015 billing data, EDL's average tariff is around $0.09 per kWh sold (billed) while the operating costs were around $0.20 per kWh sold. We rely here on 2015 billing data as advised by EDL, since the 2016 and 2017 meter reading and billing activities have been disrupted by Distribution Service Provider and EDL strikes. This means that in 2017, EDL's

9 Based on 2018 regulation methodology, adjusted for the price of crude oil ($54 per barrel in 2017 vs $71/bbl for 2018)

10 EDL recorded cash costs of $274m related to other operating costs such as generation O&M costs, staff costs, and admin costs. However apparently some costs were not paid or recorded and EDL's estimate of the true accounting cost is approximately $670m.

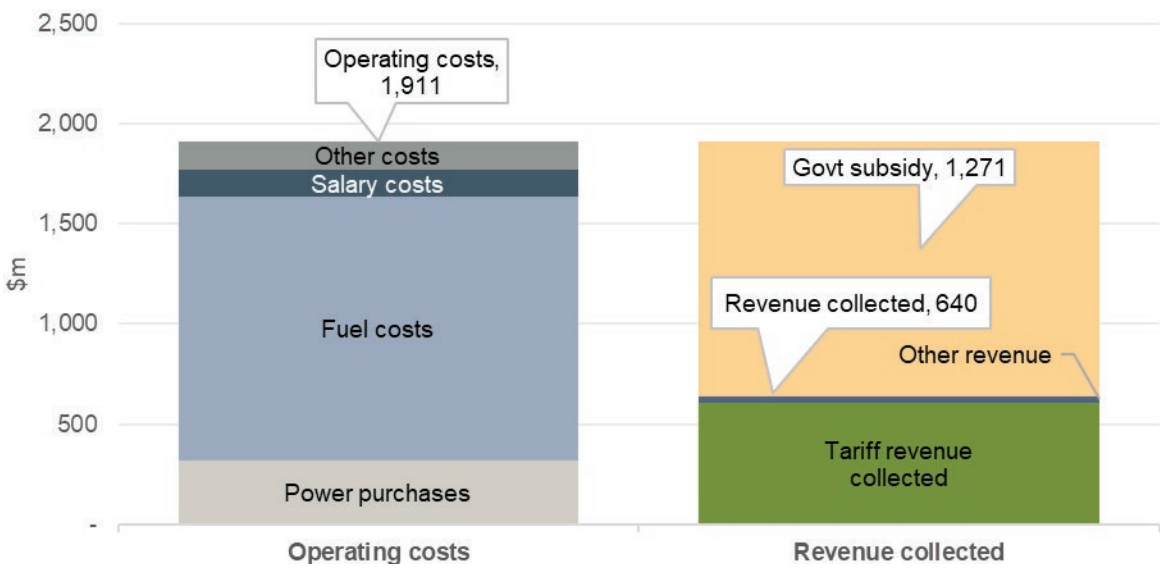
tariff billings only covered around 45% of its average operating costs. Tariffs have not changed since 1996 when oil prices were around $21 per barrel, which, with Brent prices being around $60 per barrel at the time of writing, leaves tariffs far below cost recovery levels. EDL has been reluctant to increase the tariffs while not being able to offer 24/7 electricity supply, fearing it might face strong opposition from the public.

EDL's apparent poor collection rate further reduces coverage of costs

Because the collection rate was only 66% in 2017, EDL's operating costs were around $0.36 per kWh collected, suggesting that EDL only covered about a third of its operating costs in 2017. We were informed that the poor collection rate should be considered as an anomaly and we expect that the cost per kWh sold will decrease as EDL collects the remaining bills.

Low collection rates mean that in 2017, EDL had to rely on the government subsidy of around $1.3bn to cover the difference between EDL's operating costs of 1.9$ bn and revenues collected of $0.6bn (Figure 14).

Figure 14 Government subsidy provided (2017)



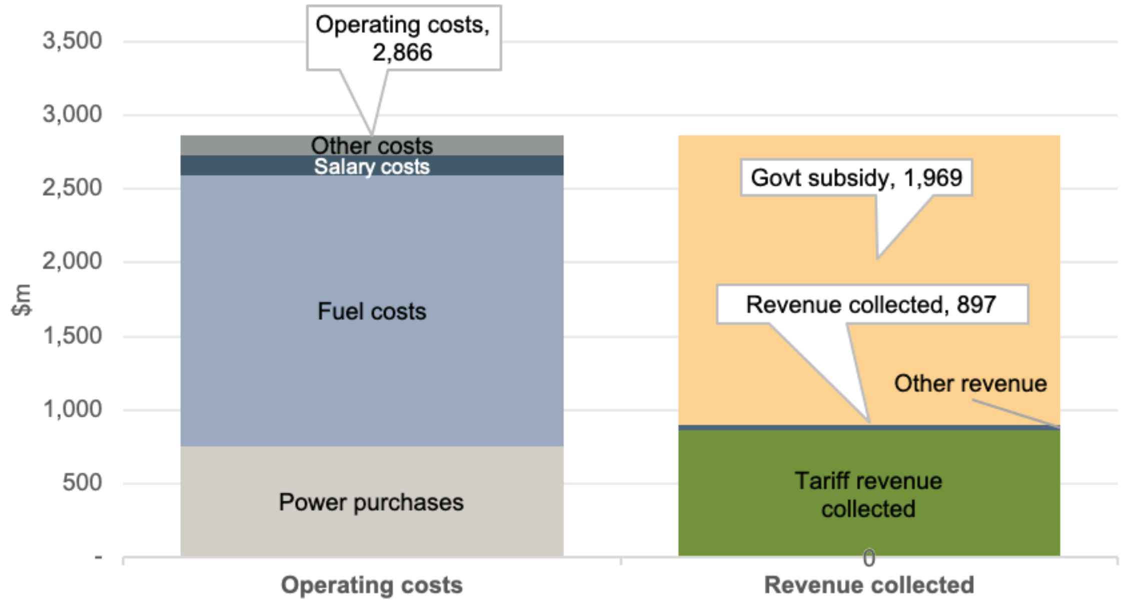
Source: ECA analysis based on EDL and MEW data

The use of additional temporary generation to meet demand would have increased the subsidy

As an exercise, we investigated what would happen to EDL's accounts if it had used additional temporary generation to meet the existing supply shortage. For this simple analysis, we assume that fuel and energy costs of additional power barges would have been the same as the existing barges. And we calculate power purchase costs by multiplying unmet demand (~7,400 GWh, including network losses) by average KPS power purchase costs ($58/MWh) and fuel costs ($70/MWh). We assume that all of EDL's other costs would remain constant. The result is additional generation costs of approximately $1bn, as illustrated in the figure below.

To calculate EDL's revenue from additional power sales, we assume tariffs remain at the same level and scale up 2017 revenue by the demand met by additional power barges (ie, we assume the same collection rate). This results in additional $0.3bn revenue collected[11] and therefore an increase in the subsidy of around $0.7bn.

Figure 15 Government subsidy if power barges had been used to meet demand (2017)



Source: ECA analysis based on EDL and MEW data

3. DEMAND AND SUPPLY OF ELECTRICITY

In this section we describe our estimate of demand for electricity in Lebanon and provide an overview of the Ministry of Energy and Water (MEW) plans to meet that demand. We forecast demand and supply under two cases – a base case as provided by MEW and an alternative case that is more conservative.

3.1 Demand forecast – base case

In the base case, we adopt MEW's demand forecast, as detailed in the sub-sections below.

3.1.1 Current demand

EDL estimates peak demand of 3,511 MW in 2017

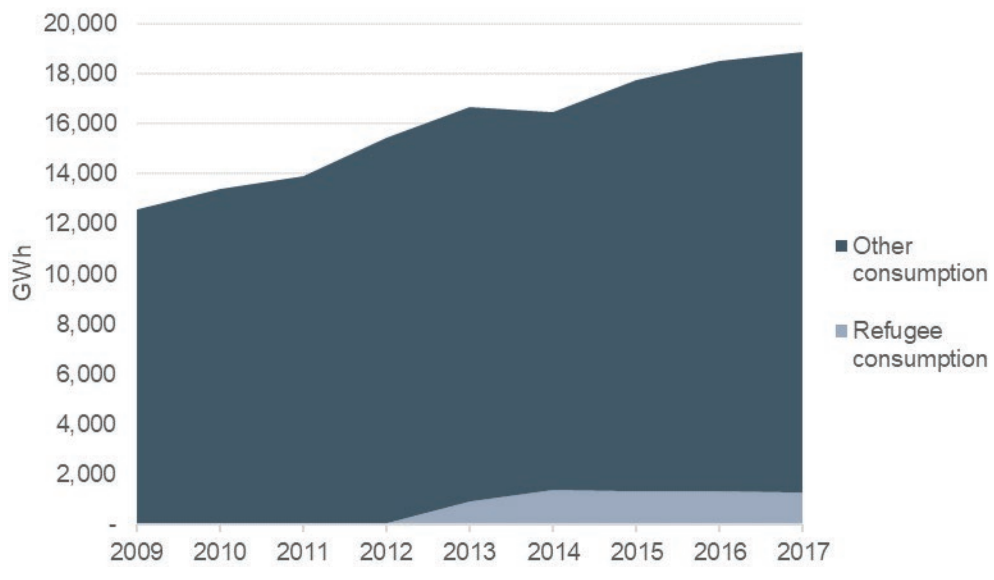
As described in Section 2.1, EDL estimated its peak demand to be around 3,511 MW in 2017. The estimation was carried out by substituting load-shed feeder data with supply data in the same hour on previous days. As noted earlier, customers likely had shifted some of their demand to private generators that were not metered. However, there is no reliable estimate of the extent of this load-shifting and therefore MEW prefer to rely on EDL's estimate of 3,511 MW.

Displaced Syrians contribute around 400MW of peak demand

The presence of Syrians displaced by the civil war further increases the gap between the demand and supply of electricity in Lebanon. A recent report by UNDP and MEW on the impact of the Syrian crisis on Lebanon's power sector suggests the influx of displaced Syrians has increased peak demand in Lebanon by 348-486 MW.[12]

Figure 16 shows the impact of displaced Syrians on the national grid. In 2012, the total electricity consumption of displaced Syrians was estimated to be around 32 GWh and has significantly increased over the past few years. In the figure below, we assume the current impact of demand generated by displaced Syrians is 477 MW and 1,511 GWh in 2017.

Figure 16 Electricity consumption in Lebanon, 2009-2017



Source: ECA analysis based on EDL and MEW data

12 AEMS, 2017, 'The Impact of the Syrian Crisis on the Lebanese Power Sector and Priority Recommendations', report prepared for the Ministry of Energy and Water and the United Nations Development Programme (UNDP), February.

Demand is inherently uncertain, given the current situation in Lebanon

Forecasts of future electricity demand are heavily dependent on the estimates of current electricity demand, which are inherently uncertain due to power generation shortages and shifting demand to private generators.

3.1.2 Future demand

MEW forecasts 3% demand growth, plus a one-off reduction when tariffs are increased to cost-recovery levels

In the base case, we adopt MEW's growth assumptions of:

- 3% growth in electricity demanded (at the point of supply, including non-technical losses) per annum from 2017 onwards.
- A one-off reduction in demand of 8% in 2021 following a substantial tariff increase (as detailed in Section 4.10).

MEW forecasts that losses can be reduced by around 23% over the next four years

In the base case we also adopt MEW's aggressive loss reduction forecasts of:

- Reduction of total losses from 34% in 2018 to 10.6% in 2022, with most of these reductions happening from 2019 to 2021.

A breakdown of assumed losses is provided in the table below.

Table 2 Base case - forecast of system losses

Loss type	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Non-technical losses	% of energy sent out	20.4%	20.6%	14.5%	7.5%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%
Technical losses	% of energy sent out	13.5%	13.4%	10.6%	9.3%	8.2%	7.0%	7.0%	7.0%	7.0%	7.0%
Total losses	% of energy sent out	33.9%	34.0%	25.1%	16.7%	11.9%	10.6%	10.6%	10.6%	10.6%	10.6%

Source: MEW

The result is that the total energy that needs to be sent out does not grow significantly from 2017 to 2023

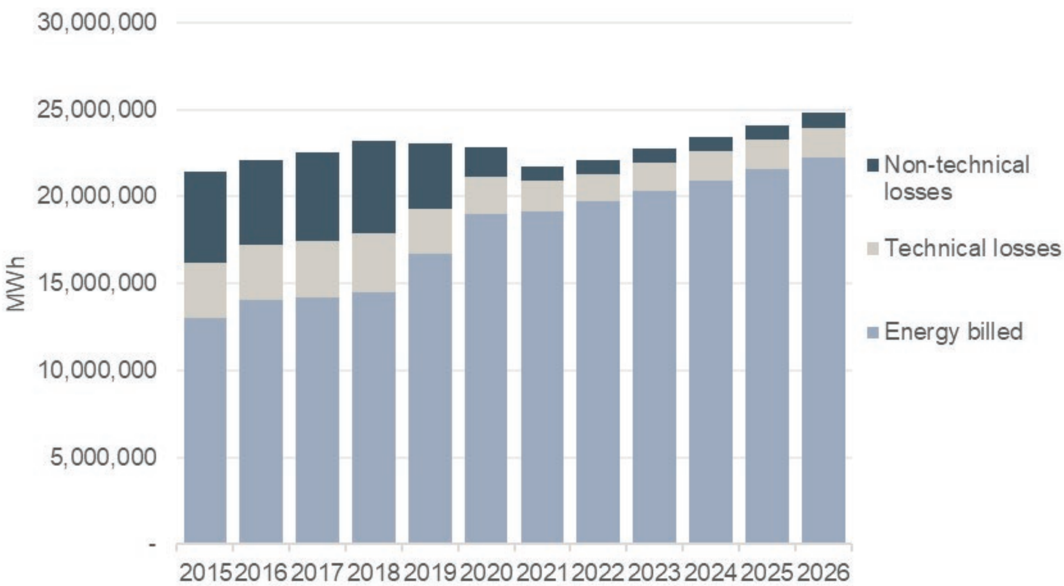
Forecast demand growth is largely offset by the reduction in losses, such that the resulting forecast of energy that needs to be generated or 'sent out' in 2023 is similar to 2017, as illustrated in the table and figure below. Only after 2023 does the required energy sent out start to grow by 3% per year.

Table 3 Base case - forecast of demand energy balance

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy billed (GWh)	14,162	14,503	16,701	19,004	19,125	19,734	20,326	20,936	21,564	22,211
Non-technical losses (GWh)	5,084	5,319	3,717	1,719	803	792	816	840	865	891
Technical losses (GWh)	3,263	3,361	2,615	2,129	1,795	1,541	1,587	1,635	1,684	1,735
Required energy sent out (GWh)	22,509	23,184	23,032	22,852	21,723	22,067	22,729	23,411	24,113	24,837
Peak load (MW)	3,511	3,616	3,592	3,564	3,388	3,442	3,545	3,652	3,761	3,874

Source: ECA analysis based on EDL and MEW data

Figure 17 Base case - forecast of demand energy balance



Source: ECA analysis based on EDL and MEW data

3.2 Demand forecast – alternative case

Our alternative demand forecast relies on consultant assumptions, rather than MEW assumptions

In our alternative case, we prepare our own forecasts of demand, as detailed in the sub-section below. The key differences can be summarised as:

- Current peak demand is higher than EDL/MEW estimates, because load is being shifted to private generation.
- Growth in energy demand is lower than MEW forecasts, based on IMF GDP forecasts and analysis of historical growth rates.
- System loss reductions are slower / less aggressive than MEW forecasts.

3.2.1 Current demand

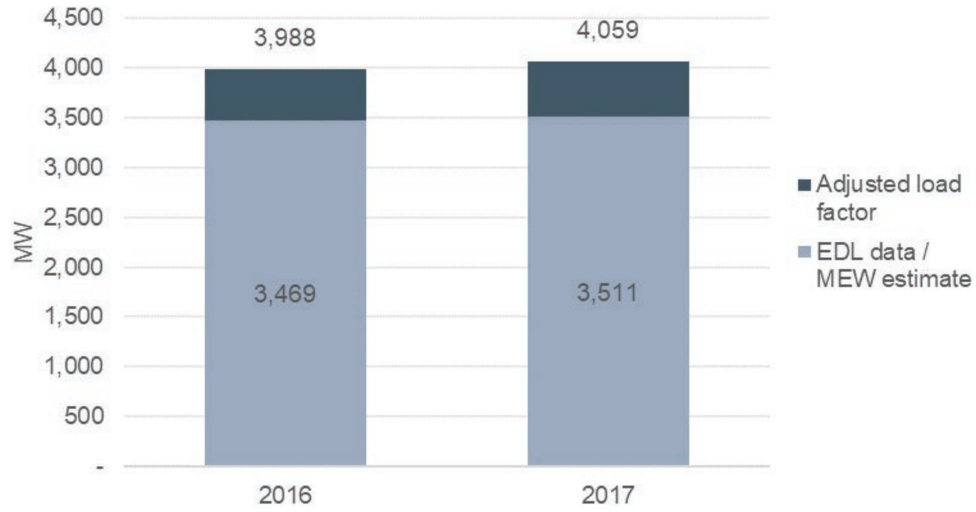
Using a lower load factor increases estimated peak demand to over 4,000 MW

The load factor calculated based on EDL data is 73%. If demand generated by displaced Syrians – which have a low load factor due to being largely residential – is stripped out, this figure rises to 81%. A load factor of 81% is exceptionally high for an economy with no significant industrial sector.

Therefore, it may be more appropriate to assume a lower load factor, such as that of nearby Jordan (67%), which is more in line with other international benchmarks. If one assumes a load factor of 67% (for non-displaced persons[13]), the peak load is estimated to be around 4,060 MW in 2017.

It is likely that both peak demand and the total energy demand are being underestimated by EDL. However, we only adjust peak demand, as there is no data available that would allow us to make a reasonable adjustment to energy demand.

Figure 18 Peak load, EDL vs alternative estimate, 2016 and 2017



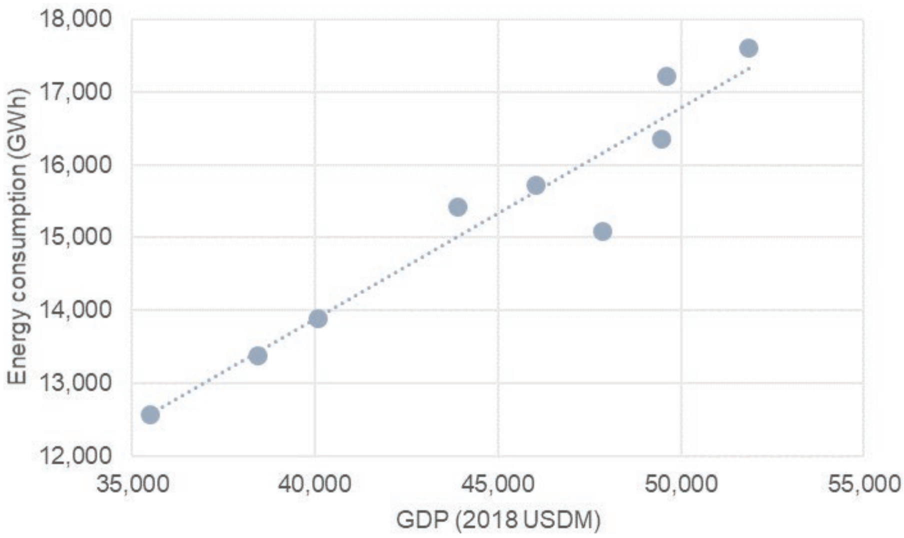
Source: ECA analysis based on EDL and MEW data

3.2.2 Future demand

We estimate that a 1% increase in GDP is associated with a 0.84% increase in final electricity consumption

We have constructed a forecast of electricity demand using GDP-based regression. Our regression suggests a 1% increase in GDP results in a 0.84% increase in electricity consumption. The strong historical relationship between GDP and electricity consumption[14] (R^2 = 0.93) is shown in Figure 19.

Figure 19 GDP and final electricity consumption, 2009-2017



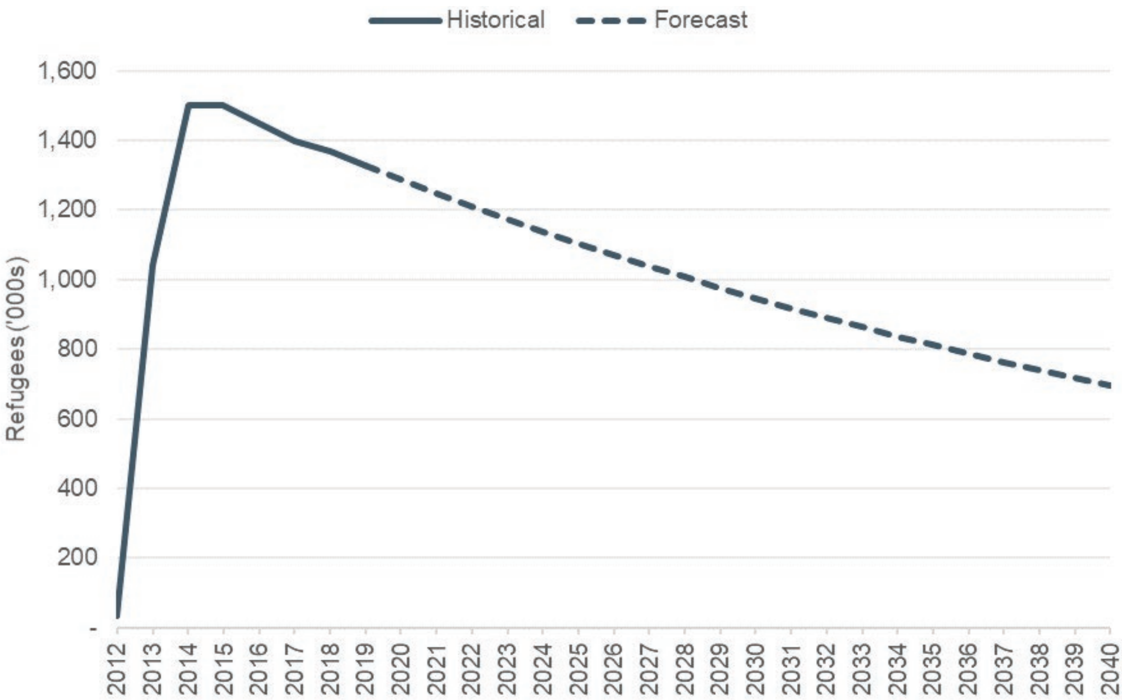
Source: ECA analysis based on EDL and MEW data; EDL data; World Bank, 'Hydropower Development in Lebanon', Report No: ACS22249, 13 June 2017. Note that energy consumption in this chart does not include estimated demand generated by displaced Syrians

Our regression analysis takes account of the influx of displaced persons in recent years

Our demand forecast is based on the regression of log (GDP) and historical electricity demand (net of demand generated by displaced persons). Electricity demand will be affected by displaced Syrians whose demand will have different characteristics to the demand of Lebanese residents. To capture the differences, we isolate the impact of displaced Syrians on overall electricity demand so that our regression is based on final electricity consumption of Lebanese residents only.

We then add demand generated by displaced Syrians exogenously to our regression-based forecast. We use the demand per displaced person from the recent report by AEMS on the impact of displaced Syrians on Lebanon's power sector. We also forecast the population of displaced Syrians – we take the GDGS's estimate of 1,500,000 displaced Syrians in 2015 as the starting point and assume that the 3% average annual decline in the number of displaced Syrians registered by UNHCR applies to the whole displaced population going forward. The result is a decline to approximately 700,000 by 2040 (Figure 20). Altogether we estimate the current impact of demand generated by displaced Syrians to be 477 MW and 1,511 GWh in 2017. These numbers are forecast to fall to 227 MW and 706 GWh, respectively, by 2040.

Figure 20 Population projection of displaced Syrians, 2018-40



Source: DGGS, UNHCR, ECA analysis.

IMF forecasts GDP growth of 1% in 2018, increasing to 2.9% by 2022. This leads to electricity demand growth of 1% increasing to 2.3%

Historical Lebanon GDP data for 2009 to 2017 is sourced from the World Bank database. The GDP forecast comes from the IMF World Economic Outlook Database, October 2018. IMF forecasts GDP growth of 1% in 2018, increasing to 2.9% by 2022. The growth rate is assumed to stay constant from 2022 onwards.

Our resulting forecast growth in electricity consumption is 1% per year for the next few years, increasing to 2.3% per year by 2022

We assume a reduction in demand due to tariff increases, as per the MEW assumption

In the alternative case, we adopt a similar assumption to MEW with respect to the effect of tariff increases on demand – that there will be decrease in demand of 8% due to a tariff increase of 74% (as advised by MEW and described in Section 4.10.1). Although we have not assessed this MEW's assumption in detail, this estimate appears within the plausible range of demand price elasticities, bearing in mind they will always be inherently uncertain given the unique situation in Lebanon (two electricity suppliers, historically low tariff, poor quality of grid supply etc). The only change we make to MEW's assumption is that we spread out the reduction over two years, because we assume the tariff increase is also spread over two years (as detailed in Section 4.10.2).

We make more conservative assumptions about loss reductions

As discussed in section 2.3, losses are a major issue in Lebanon, and currently account for approximately a third of the energy sent-out. We derive the energy requirement (i.e. the power that needs to be produced and purchased) by assuming reductions in losses.

In the alternative case, we make less aggressive assumptions about loss reductions than in the base case. We assume losses are reduced from 34% in 2017 to 14.6% in 2023, compared to losses of 10.6% in 2022/2023 in the base case. Our alternative case assumptions are based on discussions with advisors to the World Bank team in Beirut.

Table 4 Alternative case forecast of system losses

Loss type	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Non-technical losses	% of energy sent out	20.4%	22.6%	21.6%	19.6%	16.3%	12.1%	7.6%	7.6%	7.6%	7.6%
Technical losses	% of energy sent out	13.5%	13.4%	10.6%	8.7%	8.2%	6.8%	7.0%	7.0%	7.0%	7.0%
Total losses	% of energy sent out	33.9%	36.1%	32.2%	28.3%	24.4%	19.0%	14.6%	14.6%	14.6%	14.6%

Source: MEW

The result is that energy billed is around 10% lower in the alternative case, compared to the base case

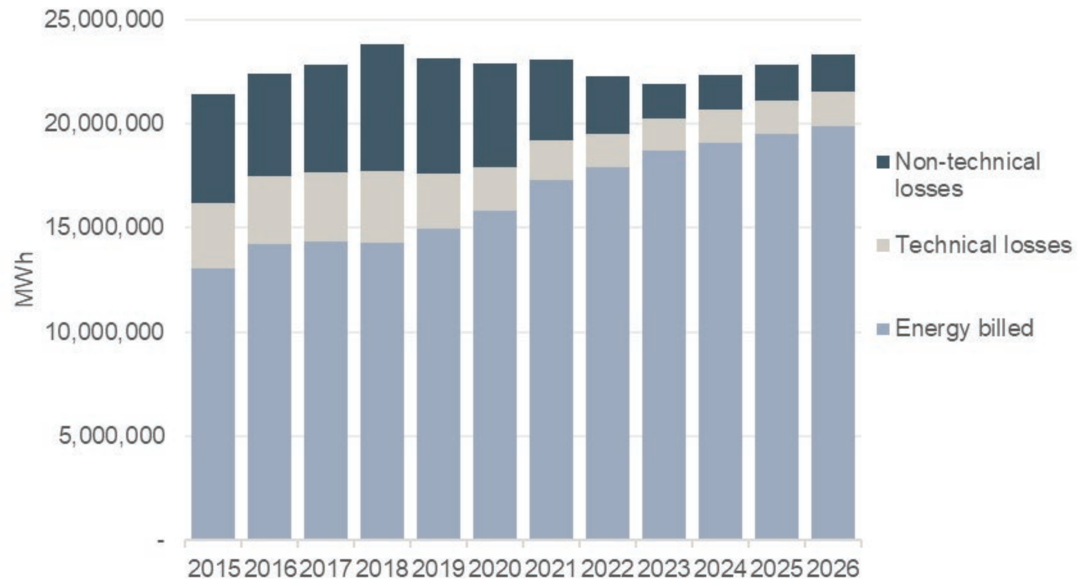
The result is that forecast required energy sent out is quite similar in the alternative case and base case, at least until 2023. But the energy billed is around 10% lower in the alternative case from 2018 onwards, primarily due to smaller loss reductions. The forecasts are summarised in the table and figures below.

Table 5 Alternative case forecast of demand energy balance

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy billed (GWh)	14,356	14,295	14,976	15,819	17,320	17,925	18,694	19,089	19,494	19,911
Non-technical losses (GWh)	5,176	6,035	5,536	4,976	3,831	2,820	1,656	1,691	1,727	1,764
Technical losses (GWh)	3,320	3,461	2,637	2,123	1,912	1,563	1,533	1,565	1,599	1,633
Required energy sent out (GWh)	22,852	23,791	23,149	22,919	23,063	22,308	21,883	22,345	22,820	23,308
Peak load (MW)	4,121	4,288	4,173	4,131	4,157	4,021	3,944	4,028	4,113	4,201

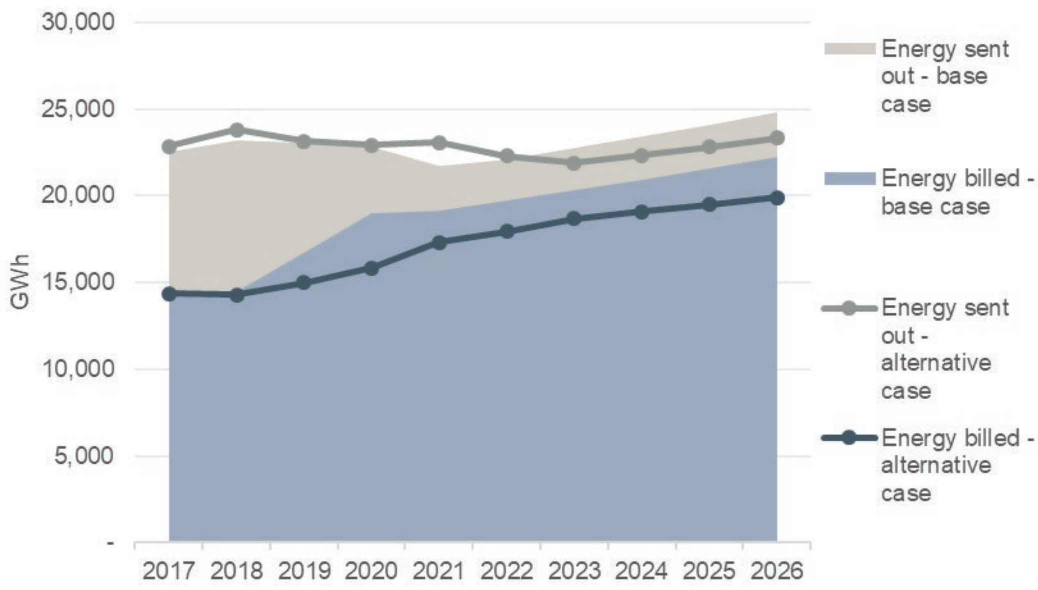
Source: ECA analysis based on MEW inputs

Figure 21 Alternative case forecast of demand energy balance



Source: ECA

Figure 22 Base case vs alternative case demand energy balance



Source: ECA

3.3 Supply forecast – base case

MEW expects LNG to be available from 2022 and plans to add significant new gas-fired generating capacity

The arrival of LNG in Lebanon will shape the electricity sector in the country for many years. MEW expects LNG to be available in three years from now, meaning that new gas-fired generators could start generating in 2022.

The investment plan used in this study is based on MEW's plan as of end July 2019. This plan is detailed in Table 6. It shows that MEW plans to commission:

- Approximately 2,600 MW of new LNG-fired CCGT plants over the next 10 years.
- 1,050 MW of 'fast-track' generation, such as LNG-fired containerised reciprocating engines. This fast-track generation can theoretically be commissioned in 2020 (initially running on fuel oil) and be in place till around 2024, once most of the CCGT is commissioned.
- Approximately 1,500 MW of new renewable capacity, comprising mostly solar PV and wind, but also a small amount of new hydro.

MEW expects refine this plan over time, as demand and realistic timeframes for LNG and plant commissioning are better understood.

Table 6 Base case – planned generation expansion

Name	Design capacity (MW)	Max capacity factor (%)	Technology	First year	End year
Fast-track generation					
Fast Track Deir Amar	450	90%	Recip	2020	2024
Fast Track Jieh	100	90%	Recip	2020	2024
Fast Track Zahrani	400	90%	Recip	2020	2024
Fast Track Bint Jbeil	50	90%	Recip	2020	2024
Fast Track Jib Jannine	50	90%	Recip	2020	2024
Gas turbines					
DAPPII PPA (OC)	360	89%	OCGT	2022	2022
DAPPII PPA (CC)	550	89%	CCGT	2023	2028
Zahrani II CCPP (OC)	430	89%	OCGT	2022	2022
Zahrani II CCPP (CC)	650	89%	CCGT	2023	2028
Selaata I CCPP (OC)	500	89%	OCGT	2022	2022
Selaata I CCPP (CC)	740	89%	CCGT	2023	2028
Jieh New CCPP (OC)	360	89%	OCGT	2025	2028
Zouk New CCPP (OC)	360	89%	OCGT	2024	2028
Renewables					
New wind 1	200	40%	Wind	2021	2028
New wind 2	400	40%	Wind	2024	2028
New PV 1	180	18%	Solar	2020	2028
New PV 2	300	18%	Solar	2023	2028
New PV 3	360	18%	Solar	2024	2028
Janneh Hydro	54	58%	Hydro	2022	2028
New Hydro (Daraya, Chamra, Yamouneh, Blat)	33	50%	Hydro	2021	2028

Source: MEW

The fast-track generation is planned to alleviate capacity shortages until CCGT is built and LNG arrives

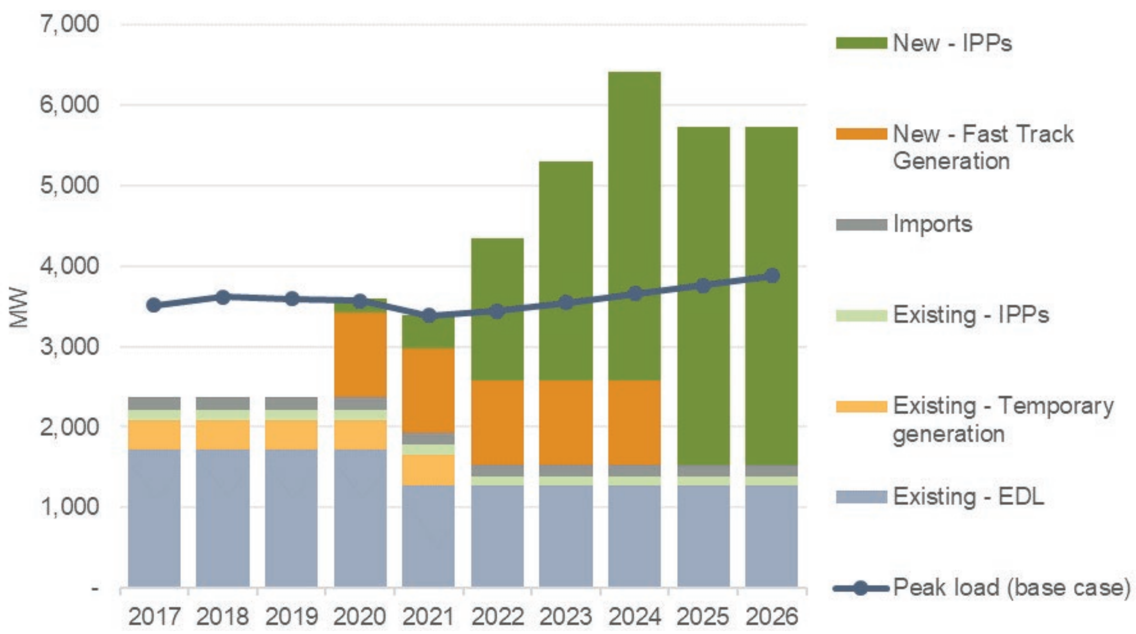
At the time of writing, MEW expects LNG to be available in 2022 in Deir Amar and Zahrani, and in 2023 in Jieh and Zouk. Until that time, the fast-track generation will run on fuel oil. The units will be duel fuel and therefore can be switched to LNG as soon as that becomes available.

MEW's planned capacity additions will probably still not be enough to meet all future demand

Figure 23 shows available capacity against the forecast peak load between 2017 and 2026. MEW's planned investments appear to have been calibrated to meet peak demand in 2020 and 2021, although it is likely that there will still be some unserved demand in these years, because:

- According to MEW's plan, there is insufficient reserve margin (typically around 20% internationally). This means that in peak hours there will often not be enough capacity to meet load because some plants will not be operational (around 10% of the time in the case of thermal plants, due to maintenance and unplanned outages).
- The renewable capacity, in particular solar and wind, cannot be fully relied on during peak hours.
- Demand is uncertain, as discussed in Sections 3.1 and 3.2.

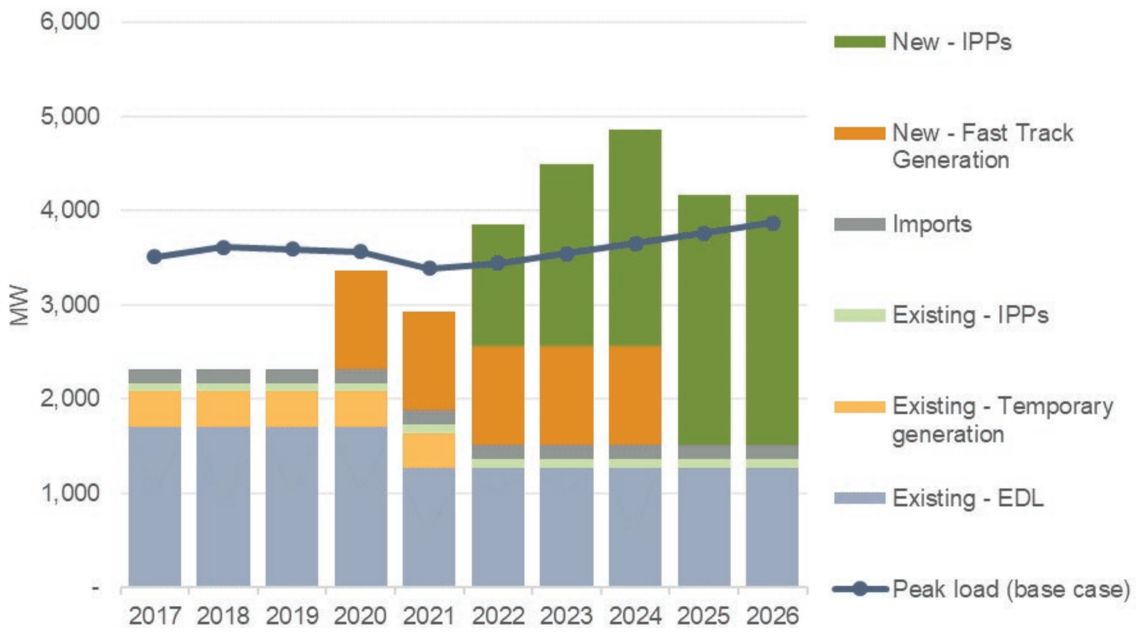
Figure 23 Base case - available capacity vs peak load, 2017-2026



Source: ECA analysis based on MEW and EDL data

Figure 24 compares firm capacity (i.e., capacity that can be relied on, which excludes renewables) against the peak load.

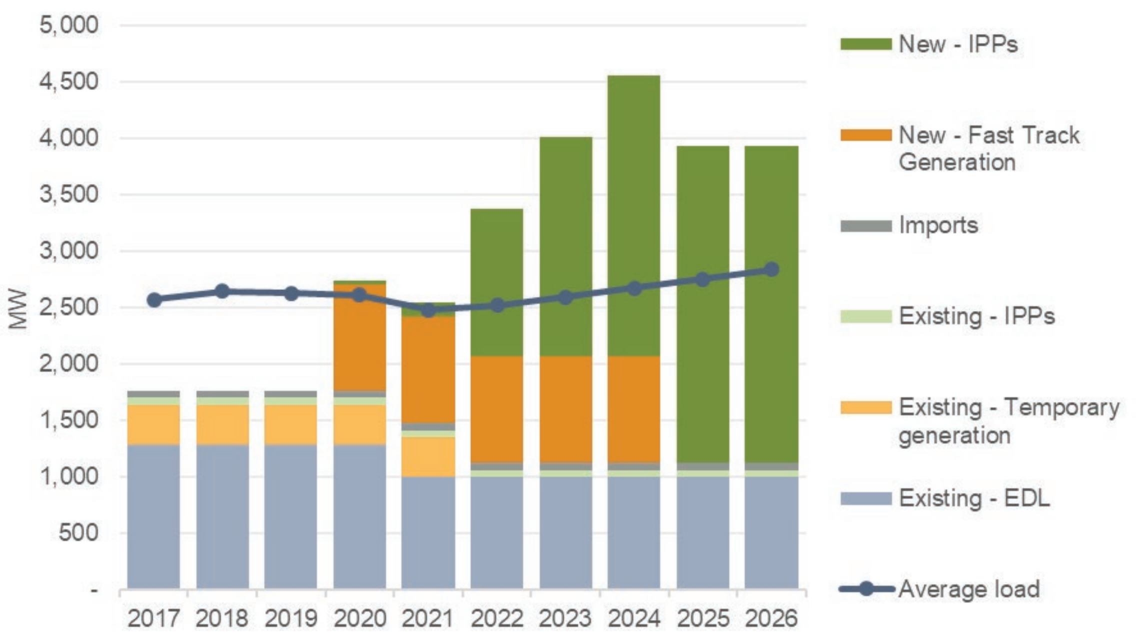
Figure 24 Base case - firm capacity vs peak load



Source: ECA analysis based on MEW and EDL data

Figure 25 compares average available capacity (capacity multiplied by the maximum capacity factor of each plant) against average load. This is slightly misleading in that while there might be surplus energy available across the whole year, there will be some hours when demand is less than available energy, and other hours when demand is higher than the maximum output of the generators.

Figure 25 Base case - average available capacity vs average load



Source: ECA analysis based on MEW and EDL data

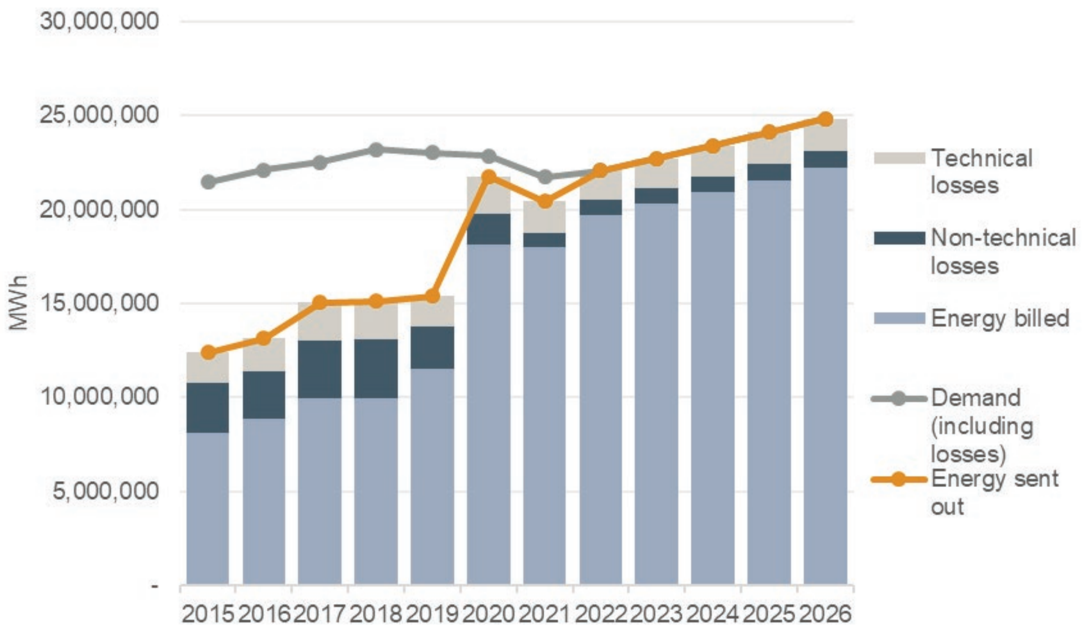
Our forecast energy balance, based on a simulation of system dispatch for every hour of each year, is provided in the table and figure below.

Table 7 Base case - forecast energy supply balance, 2015-2026

Energy		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy supplied													
Energy generated (EDL)	MWh	8,817,374	9,522,130	10,814,478	11,294,964	11,262,099	10,224,033	8,054,332	8,154,058	4,560,046	4,127,068	5,733,673	6,043,749
Energy generated (Temporary and Fast Track)	MWh	2,689,838	3,096,900	3,072,523	3,288,033	3,082,417	10,519,358	10,490,659	7,975,765	1,891,305	1,502,835	-	-
Energy purchased (IPPs)	MWh	643,385	448,121	614,212	535,572	525,004	719,065	1,575,804	5,934,407	16,277,579	17,780,895	18,379,449	18,792,606
Energy imported	MWh	261,501	69,756	542,630	11,627	524,997	290,138	320,811	2,295	-	-	-	160
Energy entering the transmission system	MWh	12,412,098	13,136,907	15,043,843	15,130,196	15,394,518	21,752,593	20,441,605	22,066,525	22,728,930	23,410,798	24,113,122	24,836,516
Transmission technical losses	MWh	502,398	531,736	608,922	612,417	534,959	755,903	710,346	657,582	677,322	697,642	718,571	740,128
Transmission energy billed	MWh	3,241,579	3,401,913	3,503,970	3,609,089	3,717,362	3,522,572	3,628,250	3,737,097	3,849,210	3,964,686	4,083,627	4,206,136
Energy entering the distribution system	MWh	8,668,121	9,203,258	10,930,950	10,908,689	11,142,196	17,474,119	16,103,010	17,671,845	18,202,398	18,748,470	19,310,924	19,890,252
Distribution technical losses	MWh	1,126,856	1,196,423	1,421,024	1,418,130	1,091,935	1,258,137	966,181	883,592	910,120	937,424	965,546	994,513
Distribution energy consumed	MWh	7,541,265	8,006,834	9,509,927	9,490,559	10,050,261	16,215,982	15,136,829	16,788,253	17,292,278	17,811,047	18,345,378	18,895,739
Non-technical losses	MWh	2,641,120	2,523,520	3,071,164	3,113,749	2,236,796	1,620,645	745,968	791,753	815,523	839,989	865,188	891,144
Distribution energy billed	MWh	4,900,145	5,483,314	6,438,763	6,376,810	7,813,465	14,595,337	14,390,861	15,996,500	16,476,755	16,971,058	17,480,190	18,004,595
Distribution energy billed but not collected	MWh	187,365	2,353,857	3,361,660	499,295	576,541	905,895	900,956	986,680	1,016,298	1,046,787	1,078,191	1,110,537
Distribution energy collected	MWh	4,712,779	3,129,457	3,077,103	5,877,515	7,236,924	13,689,442	13,489,906	15,009,820	15,460,457	15,924,271	16,401,999	16,894,059
Unmet demand													
Total energy consumed	MWh	10,782,844	11,408,747	13,013,897	13,099,649	13,767,623	19,738,554	18,765,079	20,525,350	21,141,488	21,775,733	22,429,005	23,101,875
Total energy demand	MWh	18,326,494	18,901,482	19,245,286	19,822,645	20,417,324	20,723,533	19,927,880	20,525,717	21,141,488	21,775,733	22,429,005	23,101,875
Unmet energy demand	MWh	7,543,650	7,492,735	6,231,389	6,722,996	6,649,701	984,979	1,162,801	367	-	-	-	-
Energy requirement shortfall	MWh	9,036,633	8,975,642	7,464,660	8,053,562	7,637,580	1,099,611	1,281,557	398	-	-	-	-

Source: ECA

Figure 26 Base case - forecast energy supply balance, 2015-2026

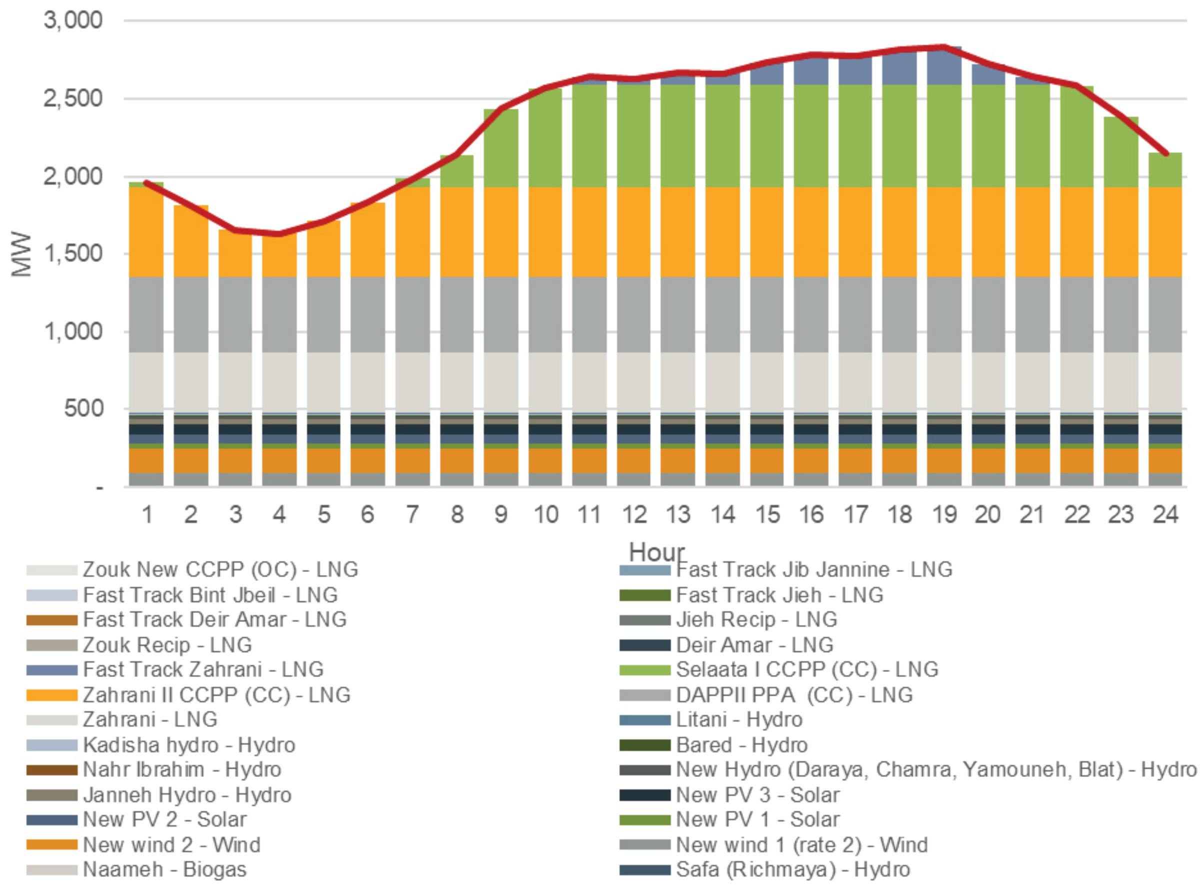


Source: ECA analysis based on EDL and MEW data

In preparing the above energy balance, we simulated the hourly dispatch of EDL generation. It is important to note that despite EDL's current shortfall in generating capacity, in some hours demand is low enough that EDL does not have to run its generators at 100%. This is why dispatch simulations are needed to develop reliable estimates of future generation levels (and costs, as described in Section 4.2).

Dispatch of EDL's generation is illustrated in the figure below, for an example day in February 2024.

Figure 27 Base case - simulated dispatch of system, first 24 hours of February 2024



Source: ECA analysis based on EDL and MEW data

3.4 Supply forecast – alternative case

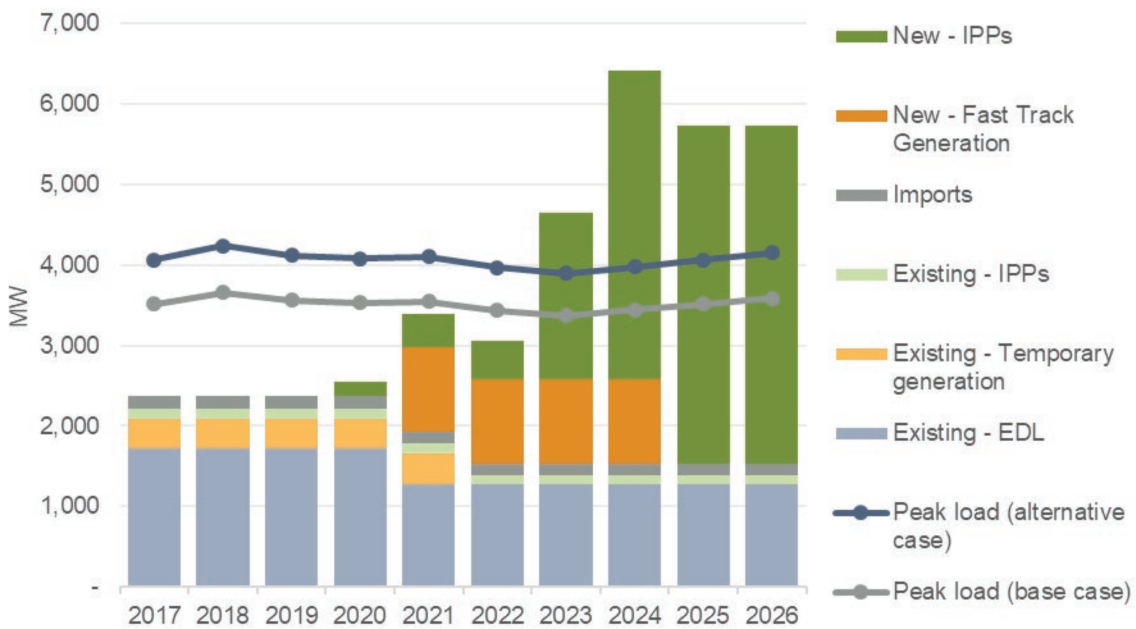
In the alternative case we delay fast-track generation and some CCGTs by one year

It was not part of the scope of this study to critically review MEW's generation expansion plan. Therefore, we only make minimal adjustments in our alternative case to reflect less optimistic commissioning dates. These adjustments are as follows:

- Fast-track generation is commissioned in 2021, rather than 2020 in the base case
- The new Deir Ammar, Zahrani, and Selaata CCGT plants are delayed by one year from the base case

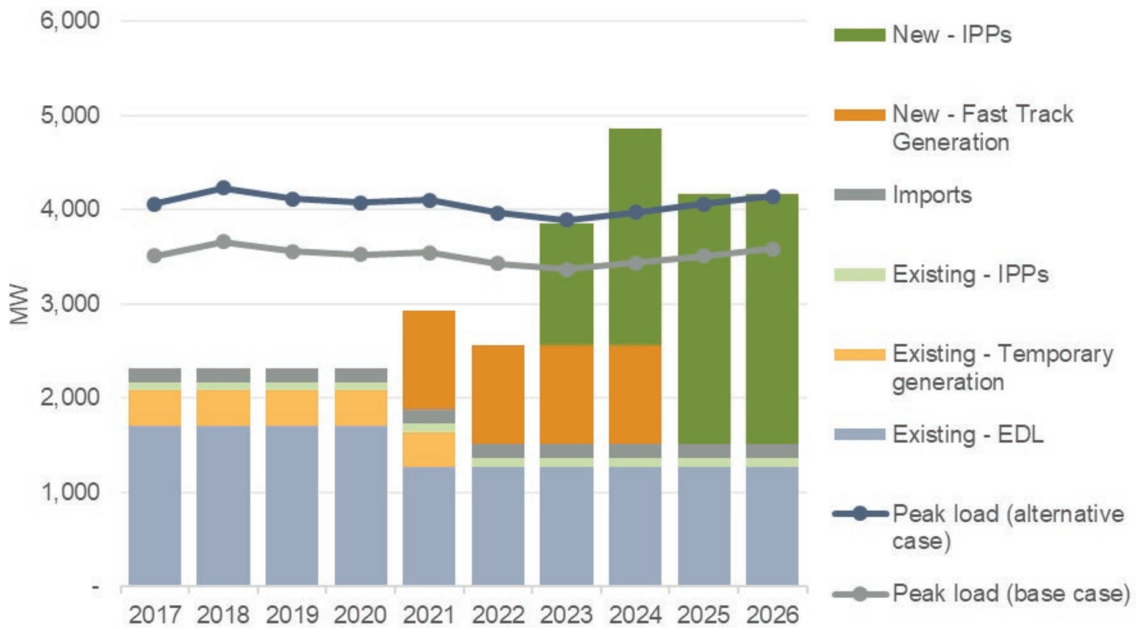
The resulting forecasts of capacity and energy supplied, when pairing the alternative case demand and supply forecasts, are shown in the figures and tables below.

Figure 28 Alternative case – available capacity vs peak load, 2017-2026



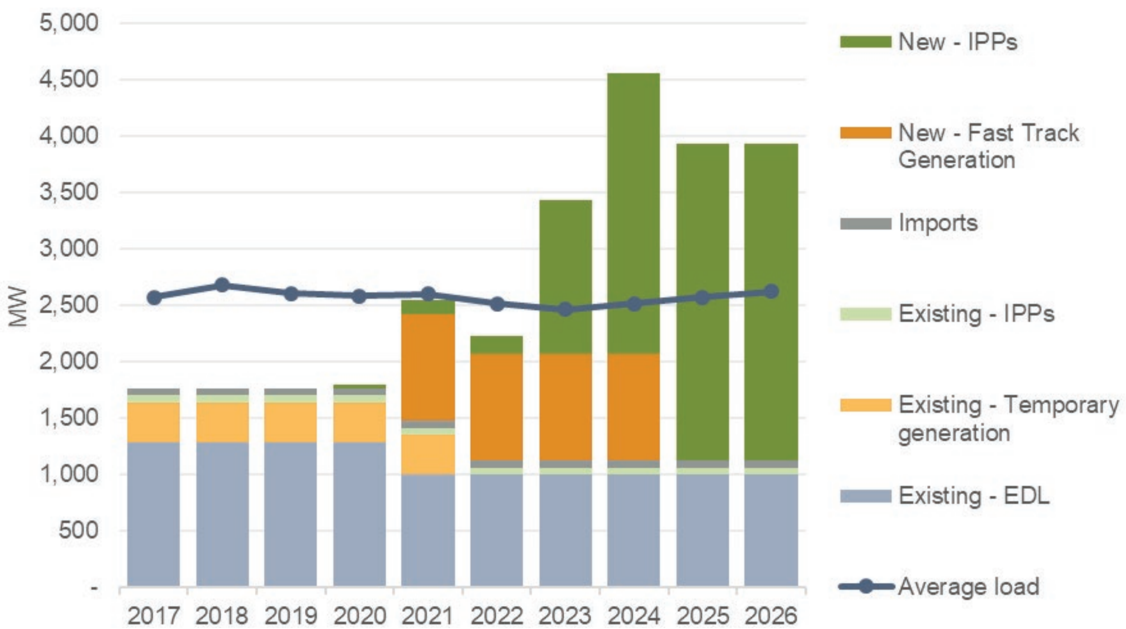
Source: ECA analysis based on MEW and EDL data

Figure 29 Alternative case - firm capacity vs peak load



Source: ECA analysis based on MEW and EDL data

Figure 30 Alternative case - average available capacity vs average load



Source: ECA analysis based on MEW and EDL data

Energy		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy supplied													
Energy generated (EDL)	MWh	8,817,374	9,522,130	10,814,478	11,294,964	11,257,823	11,241,081	8,227,988	8,476,728	8,322,739	3,710,861	4,955,105	5,194,142
Energy generated (Temporary and Fast Track)	MWh	2,689,838	3,096,900	3,072,523	3,288,033	3,081,951	3,078,002	10,638,034	7,969,664	7,620,372	1,046,195	-	-
Energy purchased (IPPs)	MWh	643,385	448,121	614,212	535,572	523,990	809,339	1,594,966	1,788,348	5,639,410	17,281,232	17,551,597	17,793,999
Energy imported	MWh	261,501	69,756	542,630	11,627	522,414	513,702	363,516	417,108	133	-	-	-
Energy entering the transmission system	MWh	12,412,098	13,136,907	15,043,843	15,130,196	15,386,177	15,642,124	20,824,504	18,651,847	21,582,654	22,038,289	22,506,701	22,988,141
Transmission technical losses	MWh	502,398	531,736	608,922	612,417	534,670	543,564	723,652	555,825	643,163	656,741	670,700	685,047
Transmission energy billed	MWh	3,241,579	3,401,913	3,503,970	3,609,089	3,641,535	3,691,856	3,754,998	3,682,912	3,612,792	3,689,063	3,767,472	3,848,061
Energy entering the distribution system	MWh	8,668,121	9,203,258	10,930,950	10,908,689	11,209,972	11,406,704	16,345,854	14,413,110	17,326,699	17,692,485	18,068,530	18,455,033
Distribution technical losses	MWh	1,126,856	1,196,423	1,421,024	1,418,130	1,098,577	821,283	980,751	720,655	866,335	884,624	903,427	922,752
Distribution energy consumed	MWh	7,541,265	8,006,834	9,509,927	9,490,559	10,111,395	10,585,421	15,365,103	13,692,454	16,460,364	16,807,861	17,165,104	17,532,281
Non-technical losses	MWh	2,641,120	2,523,520	3,071,164	3,425,328	3,318,152	3,079,810	3,383,592	2,262,858	1,628,710	1,663,094	1,698,442	1,734,773
Distribution energy billed	MWh	4,900,145	5,483,314	6,438,763	6,065,231	6,793,243	7,505,611	11,981,511	11,429,596	14,831,654	15,144,768	15,466,662	15,797,508
Distribution energy billed but not collected	MWh	187,365	2,353,857	3,361,660	483,716	521,739	447,899	629,460	604,500	737,778	753,353	769,365	785,823
Distribution energy collected	MWh	4,712,779	3,129,457	3,077,103	5,581,515	6,271,504	7,057,712	11,352,051	10,825,096	14,093,876	14,391,414	14,697,296	15,011,686
Unmet demand													
Total energy consumed	MWh	10,782,844	11,408,747	13,013,897	13,099,649	13,752,930	14,277,277	19,120,101	17,375,367	20,073,156	20,496,924	20,932,575	21,380,343
Total energy demand	MWh	18,326,494	18,901,482	19,245,286	20,052,582	20,232,853	20,512,445	20,863,270	20,462,753	20,073,156	20,496,924	20,932,575	21,380,343
Unmet energy demand	MWh	7,543,650	7,492,735	6,231,389	6,952,934	6,479,924	6,235,168	1,743,169	3,087,386	-	-	-	-
Energy requirement shortfall	MWh	9,036,633	8,975,642	7,464,660	8,329,007	7,442,581	6,960,819	1,921,197	3,349,701	-	-	-	-

Table 8 Alternative case - forecast energy supply balance, 2015-2026

Energy		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy supplied													
Energy generated (EDL)	MWh	8,817,374	9,522,130	10,814,478	11,294,964	11,257,823	11,241,081	8,227,988	8,476,728	8,322,739	3,710,861	4,955,105	5,194,142
Energy generated (Temporary and Fast Track)	MWh	2,689,838	3,096,900	3,072,523	3,288,033	3,081,951	3,078,002	10,638,034	7,969,664	7,620,372	1,046,195	-	-
Energy purchased (IPPs)	MWh	643,385	448,121	614,212	535,572	523,990	809,339	1,594,966	1,788,348	5,639,410	17,281,232	17,551,597	17,793,999
Energy imported	MWh	261,501	69,756	542,630	11,627	522,414	513,702	363,516	417,108	133	-	-	-
Energy entering the transmission system	MWh	12,412,098	13,136,907	15,043,843	15,130,196	15,386,177	15,642,124	20,824,504	18,651,847	21,582,654	22,038,289	22,506,701	22,988,141
Transmission technical losses	MWh	502,398	531,736	608,922	612,417	534,670	543,564	723,652	555,825	643,163	656,741	670,700	685,047
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Energy entering the distribution system	MWh	8,668,121	9,203,258	10,930,950	10,908,689	11,209,972	11,406,704	16,345,854	14,413,110	17,326,699	17,692,485	18,068,530	18,455,033
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Distribution energy consumed	MWh	7,541,265	8,006,834	9,509,927	9,490,559	10,111,395	10,585,421	15,365,103	13,692,454	16,460,364	16,807,861	17,165,104	17,532,281
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Distribution energy billed	MWh	4,900,145	5,483,314	6,438,763	6,065,231	6,793,243	7,505,611	11,981,511	11,429,596	14,831,654	15,144,768	15,466,662	15,797,508
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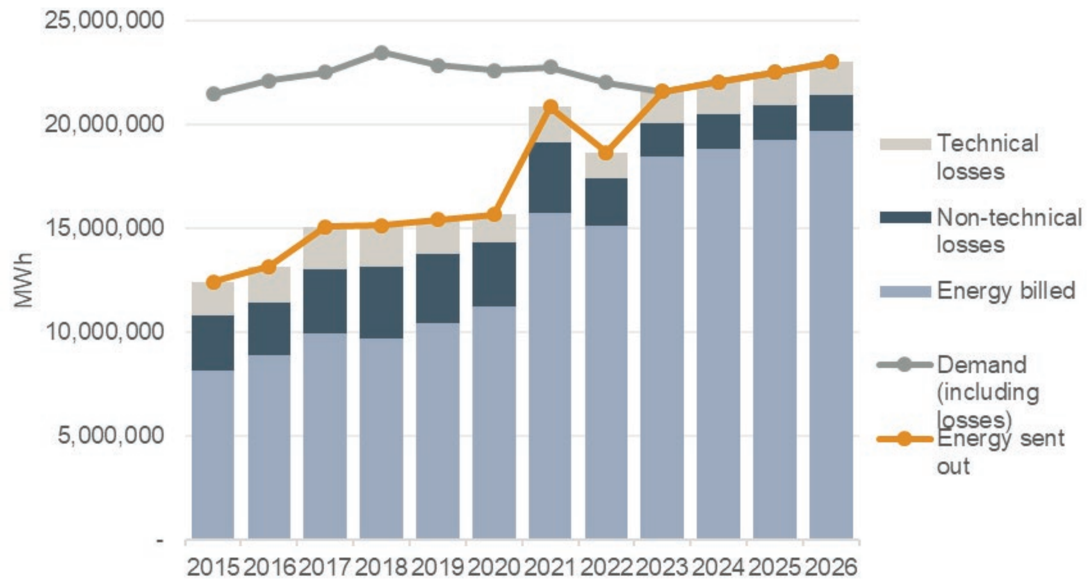
Unmet demand													
Total energy consumed	MWh	10,782,844	11,408,747	13,013,897	13,099,649	13,752,930	14,277,277	19,120,101	17,375,367	20,073,156	20,496,924	20,932,575	21,380,343
Total energy demand	MWh	18,326,494	18,901,482	19,245,286	20,052,582	20,232,853	20,512,445	20,863,270	20,462,753	20,073,156	20,496,924	20,932,575	21,380,343
Unmet energy demand	MWh	7,543,650	7,492,735	6,231,389	6,952,934	6,479,924	6,235,168	1,743,169	3,087,386	-	-	-	-
Energy requirement shortfall	MWh	9,036,633	8,975,642	7,464,660	8,329,007	7,442,581	6,960,819	1,921,197	3,349,701	-	-	-	-

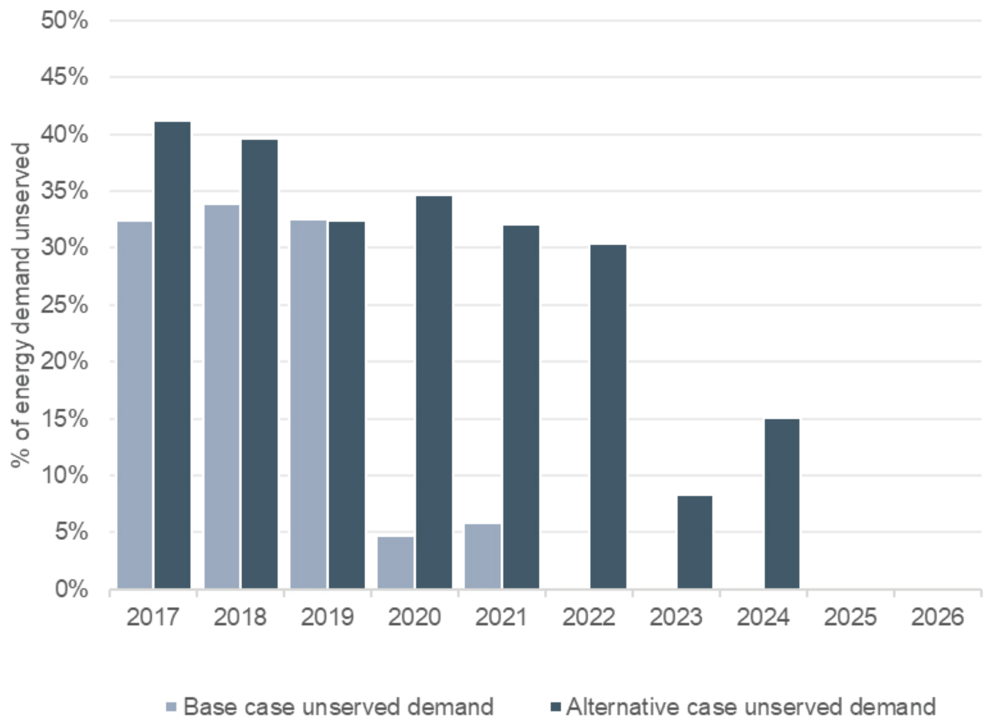
Source: ECA

Figure 31 Alternative case - forecast energy supply balance, 2015-2026



Source: ECA analysis based on EDL and MEW data

Figure 32 Base case vs alternative case – unserved demand, 2015-2026



Source: ECA analysis based on EDL and MEW data

4. COST OF SERVICE / REVENUE REQUIREMENT

In this section we describe our estimate of EDL's future costs and the revenue that it needs to earn to cover those costs, given various assumptions about the future. We also estimate the likely impacts on required Government subsidies, given assumptions about future tariff increases.

4.1 Methodology

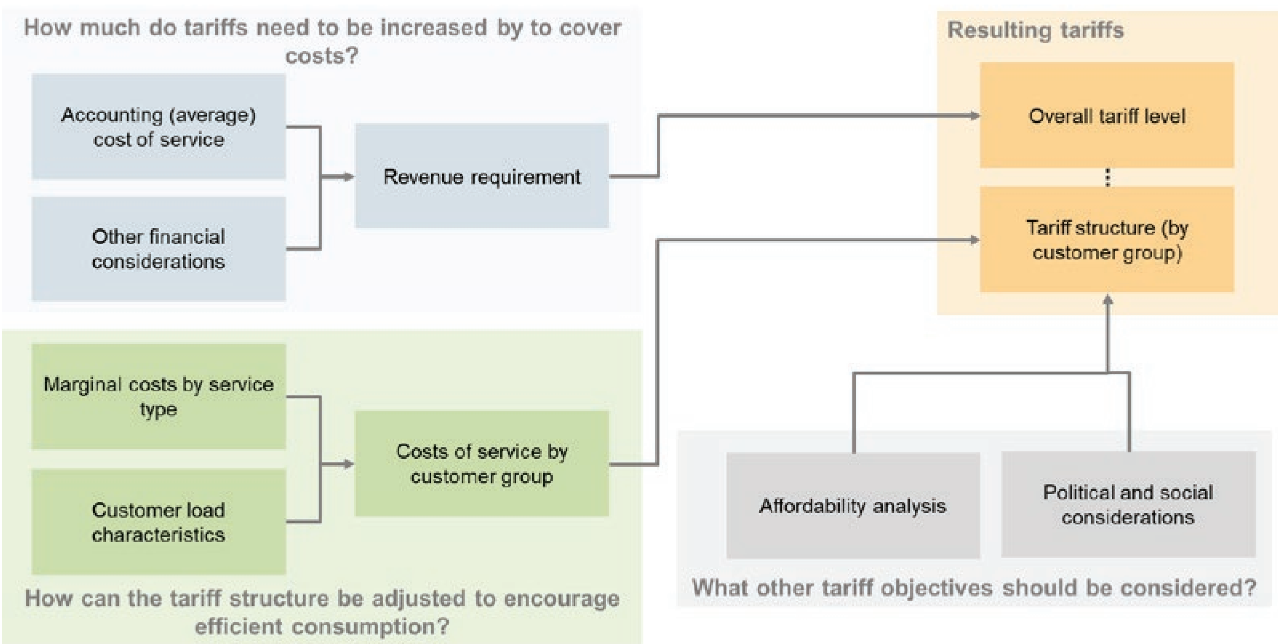
4.1.1 Defining the revenue requirement

Determining the future cost of supply is one key aspect of setting electricity tariffs

A review of electricity tariffs typically answers three key questions, as summarised in the figure below.

1. **How much do tariffs need to be increased by to cover costs?** This part of the tariff study aims to calculate the overall revenue requirement. It is a purely accounting exercise which does not take tariff design/structure into account.
2. **How can the tariff structure be adjusted to encourage efficient consumption?** This part of the study focuses on designing tariffs in a way that encourages efficient consumption across customers. It involves the calculation of approximate marginal costs by service type to ensure that customers are provided with the right price signals.
3. **What other tariff objectives should be considered?** This part of the study provides an analysis of the resulting tariff levels from a more qualitative perspective. Rather than being a strictly quantitative calculation, it aims to take social and political considerations into account. Often it will involve affordability analysis to make sure most vulnerable customers can afford the tariff increase.

Figure 33 Overall approach to setting tariffs



Source: ECA

This section of our report answers the first question (how much do tariffs need to be increased by to cover costs?).

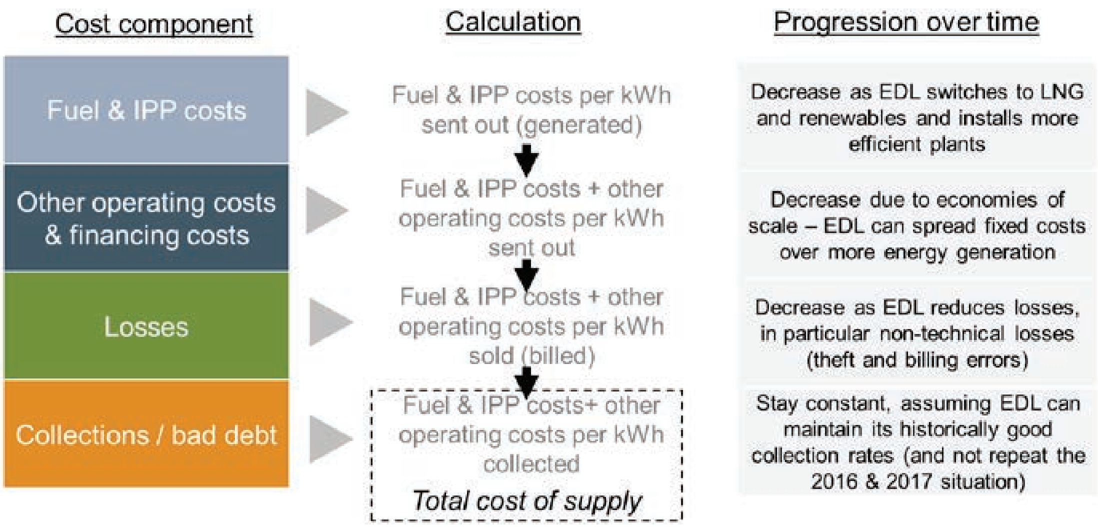
The second question (related to tariff structure) is answered in Section 5.

The third question (related to other tariff objectives) is outside the scope of this study and is largely a political consideration, although we do offer strategies in Section 5 that may help minimise the political and social implications of tariff increases.

The revenue requirement is the amount of revenue that EDL needs to collect to cover its costs and eliminate Government subsidies

EDL's revenue requirement is the amount that EDL needs to collect to cover its overall costs and to eliminate Government subsidies. Our approach to calculating the revenue requirement is summarised in the figure below.

Figure 34 Overview of the revenue requirement calculations



Note: The terms 'financing costs' and 'network financing costs' are used interchangeable through this report

Source: ECA

Our revenue requirement model covers the forecast period of 10 years, from 2017 to 2026. The costs are forecast in 2017 real terms (excluding inflation), in US$. The exchange rate applied throughout the model is 1,510 LBP per 1 US$.

The revenue requirement is calculated as the sum of four components: fuel and IPP costs, other operating and financing costs, losses and collections (or bad debt). We elaborate on our calculations in the following sub-sections, but in summary:

- **Fuel and IPP costs** are estimated by calculating fuel and IPP costs **per kWh sent out** using our in-house dispatch simulation modelling tool, Wairoa. Wairoa is an Excel based dispatch model developed by ECA power system experts that simulates system dispatch on an hourly basis (across the whole modelling period) and takes account of the average output of generators (after accounting for intermittency of resource, seasonality of output, maintenance, forced outages etc). Inputs to the model include existing generation, new generation contracts, loss forecasts, demand forecasts and fuel price forecasts. Fuel and IPP costs will decrease as EDL switches to LNG and renewables and installs more efficient power plants.
- We add **other operating costs** which are estimated by calculating fuel and IPP costs and other operating costs **per kWh sent out**. Other operating costs include generation O&M costs, staff costs, administration costs, network repairs and maintenance costs, etc[15]. Financing costs include existing interest and repayment costs borne by both MEW and MOF on behalf of EDL and the costs of financing new transmission and distribution investments.
- Then we adjust our calculation for network losses by calculating the costs **per kWh sold (billed).** These costs will decrease as EDL reduces network losses (and non-technical losses consisting of theft and billing errors in particular).
- Finally, we take account of the collection rate by calculating the costs **per kWh collected** which determines the total cost of supply. We assume a constant collection rate, on the basis that EDL is confident it can maintain its historically good collections (and not repeat the decrease in collection rates that happened in 2016 and 2017).

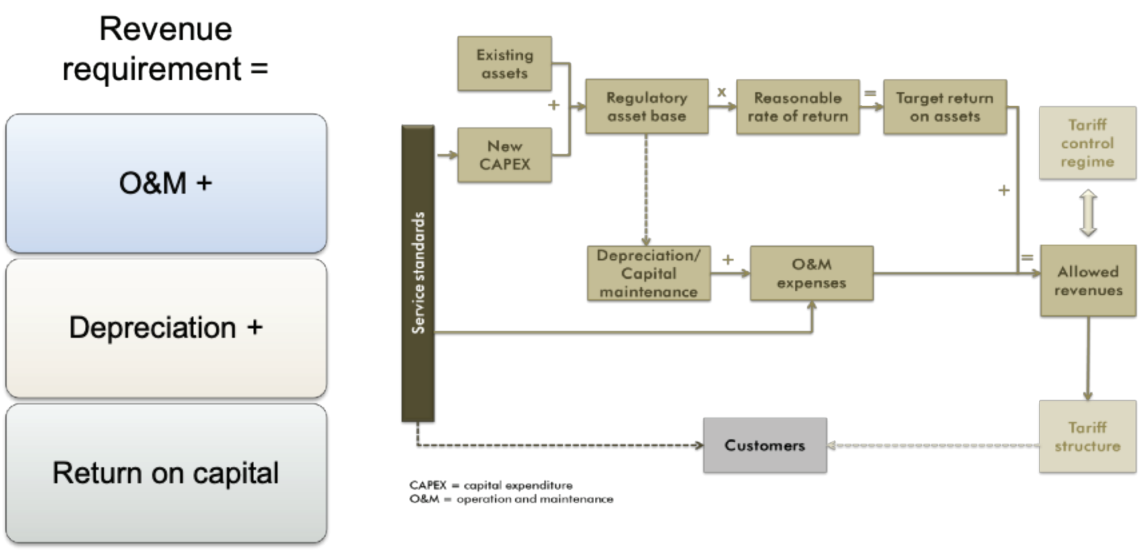
Our approach differs from a typical building blocks calculation

Our above approach is slightly different to revenue requirement formulas applied in mature power markets where tariffs already cover costs. In those markets, the 'building blocks' approach or similar is used.

Our approach to calculating the revenue requirement for EDL is cash-based. The key difference is that cash-based uses actual debt costs (i.e., interest costs + debt repayment) rather than depreciation + return on capital under the building blocks approach. Calculated debt repayments will be higher than depreciation, because we assume repayment periods that are shorter than asset lives. But calculated interest costs are based on assumed concessionary terms – 3% real – and are only applied to new network investments. Under the building blocks model, return on capital is typically calculated using a fully commercial cost-of-capital (e.g., 10%) and is applied to all assets regardless of how they were funded. We believe the cash-based approach is more suitable to Lebanon right now because it better reflects the true cash costs to EDL and the Government. When Lebanon transitions to cost-recovery tariffs, we recommend shifting to a building blocks approach (Figure 35).

Another reason for using the cash-based approach is that EDL does not have a complete record of the book value of the power sector assets that is operates. It appears that some assets have been financed by the Government but not added to EDL's books.

Figure 35 Revenue requirement – the 'Building blocks' model



Source: ECA

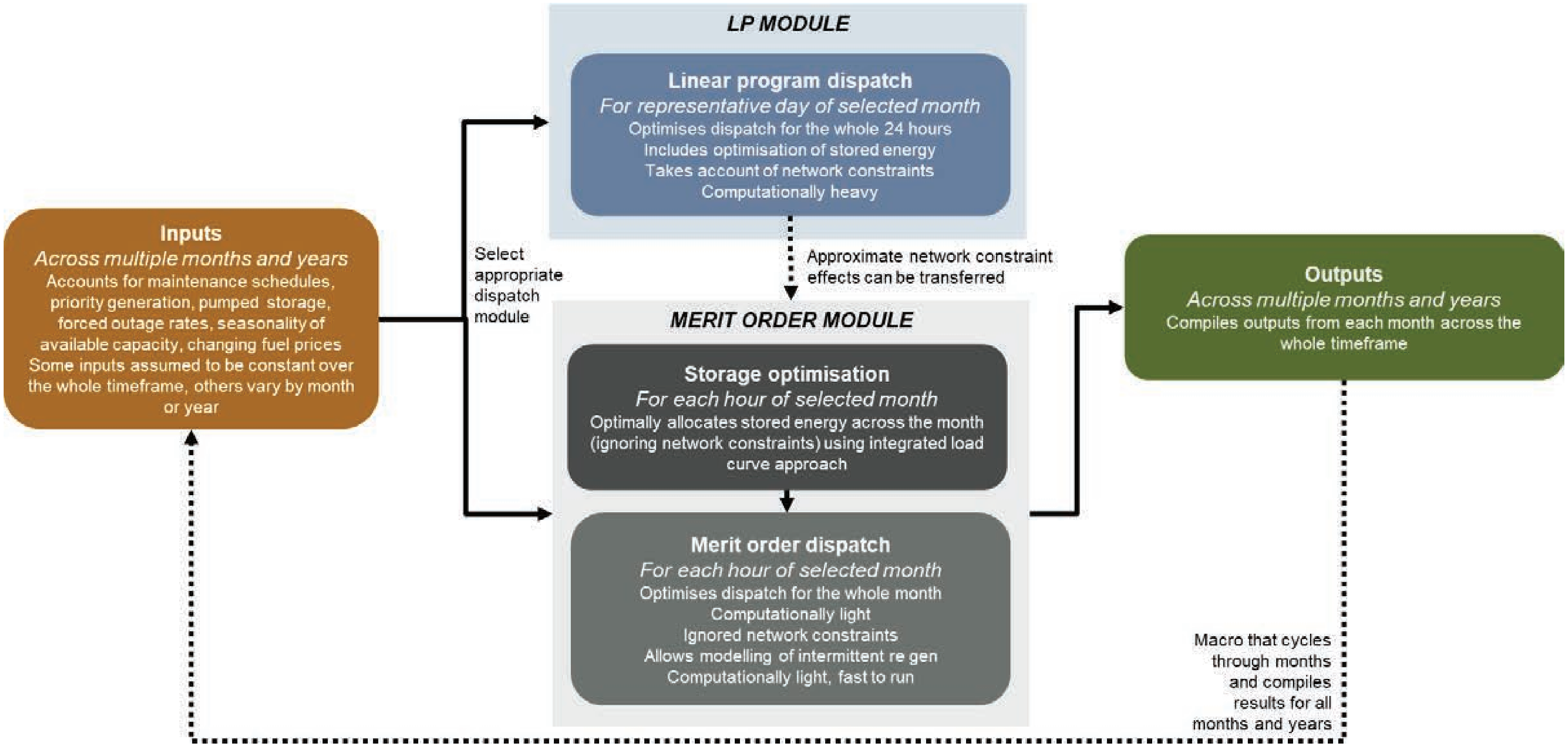
4.1.2 Simulation of future generation

We use a dispatch model to simulate future fuel costs and IPP costs

In this study, we have used data on existing generators, planned investments, as well as loss, demand and fuel price forecasts to optimise generation dispatch over the forecast horizon. Using the dispatch model, we simulate every hour of the year between 2017 and 2026 to arrive at the optimal solution. In our simulation, we use the 2016 load profile with missing data substituted, as described in Section 2.1. As mentioned earlier, it is important to note that despite EDL's current shortfall in generating capacity, in some hours demand is low enough that EDL does not have to run its generators at 100%. Therefore, dispatch simulations are needed to develop reliable estimates of future generation costs.

ECA has recently used Wairoa in a range of power plant investment, market pricing and due diligence assignments in Turkey, Albania, Papua New Guinea, Sri Lanka, and Indonesia. Wairoa's model structure is summarised in the figure below.

Figure 36 Wairoa's model structure



Source: ECA

4.2 Fuel and IPP costs – base case

4.2.1 Key inputs and assumptions

We assume that oil prices remain constant at $66/bbl

To forecast fuel and IPP costs, we assume that the price of Brent Crude Oil remains at $66/bbl from 2018 onwards, as advised by MEW. This is obviously an important assumption that has a huge bearing on resulting costs and required sector subsidies.

The resulting assumed costs of different fuel types in Lebanon are as follows[16]:

Table 9 Assumed fuel prices, by fuel type

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fuel Oil (Grade A)	$/Metric Ton	339	288	350	450	420	420	420	420	420	420	420	420
Fuel Oil (Grade B)	$/Metric Ton	339	288	350	450	420	420	420	420	420	420	420	420
Fuel Oil (Floating)	$/Metric Ton	341	290	352	452	422	422	422	422	422	422	422	422
Gas Oil	$/Metric Ton	533	451	550	709	662	662	662	662	662	662	662	662

Source: ECA analysis based on EDL and MEW data

A fuel-cost pass-through mechanism should be introduced

The cost of generation in Lebanon is heavily dependent on international oil prices. The increase in the oil price was largely responsible for the cost per kWh in 2018 being approximately 27% higher than 2017 levels. To reduce EDL and the Government's exposure to costs outside of its control, the Government should introduce a fuel price indexation.

Without such a pass-through, Government could increase tariffs to cost-recovery tariffs (ie, as calculated in this report), a few days or weeks later the oil price could change, and the sector may be again be running a large deficit (or surplus). Such mechanisms are widespread internationally for power sectors that have significant exposure to international oil prices.

In the base case, we use MEW's forecast of LNG prices

In the base case scenario, we assume a LNG price in Lebanon of $9.8/mmbtu. This is based on MEW assumptions – 12.5% multiplied by the price of Brent Crude plus $1.5/mmbtu to cover opex and capex.

We use MEW assumptions regarding fuel efficiencies of thermal plants

Our assumptions regarding fuel efficiency of existing and future thermals plants are summarised in the table below, as provided by MEW.

Table 10 Assumed fuel efficiency of thermal plants

Name	Current Fuel Type	Technology	Year switch to LNG	Fuel efficiency with current fuel (GJ/MWh)	Fuel efficiency with current fuel (Metric Ton/MWh)	Fuel efficiency with LNG (GJ/MWh)
Existing - EDL						
Zouk	Fuel Oil (Grade A)	Steam Turbine		11.6	0.26	
Jieh	Fuel Oil (Grade A)	Steam Turbine		15.0	0.34	
Zouk Recip	Fuel Oil (Grade B)	Recip	2023	7.8	0.18	7.6
Jieh Recip	Fuel Oil (Grade B)	Recip	2023	8.1	0.18	7.8
Zahrani	Gas Oil	CCGT	2022	7.3	0.16	6.4
Deir Amar	Gas Oil	CCGT	2022	8.4	0.19	7.4
Baalbak	Gas Oil	OCGT	2022	11.6	0.26	11.1
Sour (Tyr)	Gas Oil	OCGT	2022	12.5	0.28	11.9
Existing - Temporary generation						
KPS Zouk	Fuel Oil (Floating)	Recip	n/a	8.6	0.19	8.9
KPS Jieh	Fuel Oil (Floating)	Recip	n/a	8.6	0.20	8.9
Existing - IPPs						
Hrayche	Fuel Oil (Grade A)	Steam Turbine		13.0	0.30	
New - Fast Track Generation						
Fast Track Deir Amar	Fuel Oil (Grade B)	Recip	2022	8.6		8.3
Fast Track Jieh	Fuel Oil (Grade B)	Recip	2023	8.6		8.3
Fast Track Zahrani	Fuel Oil (Grade B)	Recip	2022	8.6		7.2
Fast Track Bint Jbeil	Fuel Oil (Grade B)	Recip	2022	10.3		9.9
Fast Track Jib Jannine	Fuel Oil (Grade B)	Recip	2022	10.3		9.9
New - IPPs						
DAPPII PPA (OC)	Fuel Oil (Grade B)	OCGT	2022	10.8		10.8
DAPPII PPA (CC)	Fuel Oil (Grade B)	CCGT	2022	7.2		7.1
Zahrani II CCPP (OC)	Fuel Oil (Grade B)	OCGT	2022	10.8		10.8
Zahrani II CCPP (CC)	Fuel Oil (Grade B)	CCGT	2022	7.2		7.1
Selaata I CCPP (OC)	Fuel Oil (Grade B)	OCGT	2022	10.8		10.8
Selaata I CCPP (CC)	Fuel Oil (Grade B)	CCGT	2022	7.2		7.1
Jieh New CCPP (OC)	Fuel Oil (Grade B)	OCGT	2023	10.8		10.8
Jieh New CCPP (CC)	Fuel Oil (Grade B)	CCGT	2023	7.2		7.1
Zouk New CCPP (OC)	Fuel Oil (Grade B)	OCGT	2023	10.8		10.8

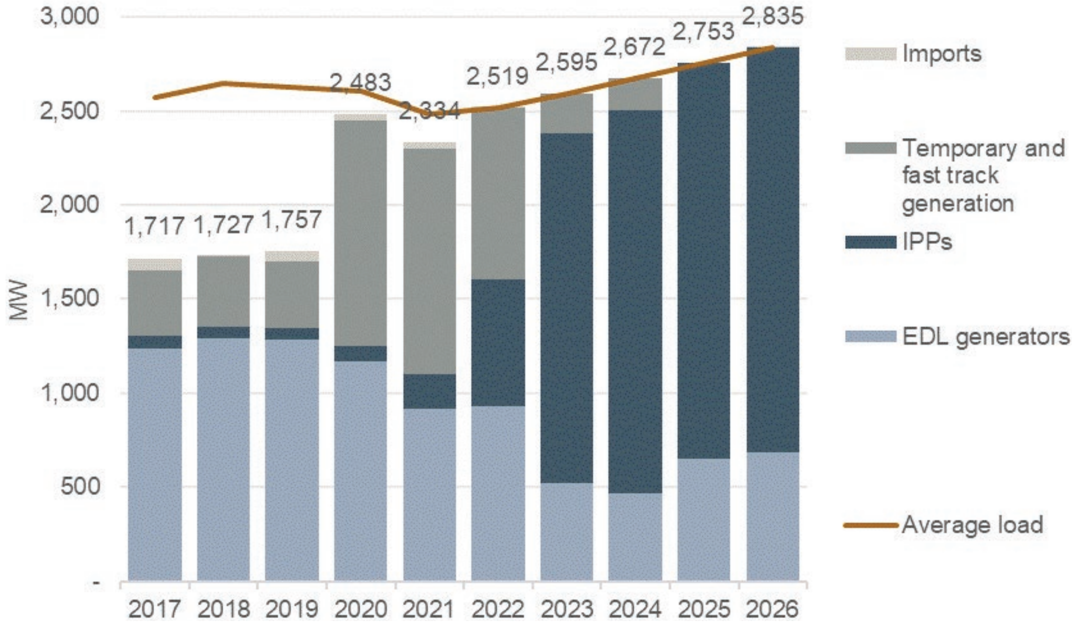
Source: ECA analysis based on MEW and EDL data

The generation mix will change significantly over the next five years

Based our simulation of system dispatch, as described in Section 3.3 above, we can see the expected shift in EDL's generation mix. Figure 37 shows a clear shift from EDL generators to IPPs. It implies that:

- All else being equal, IPPs should have significant lower fuel costs than EDL's older existing generators.
- EDL will have to pay charges that cover the capital costs of the new IPPs (EDL no longer bears any capital costs relating to its older existing generators). So contracting new IPPs essentially trades off lower fuel prices against higher capacity costs.

Figure 37 Base case – annual average dispatch by generation type



Source: ECA based on EDL and MEW data

The approximate capacity cost of new CCGTs is around $0.02 per kWh

To calculate IPP costs for new thermal IPPs, we assume that EDL will pay IPP capacity charges for all thermal capacity – in other words, they will pay per kW of installed capacity rather than per kWh of output. We assume this to ensure that lower simulated utilisation of new IPPs does not lead to lower IPP costs. If power purchase agreements are instead structured based on per kWh energy charges, they will almost certainly also come with take-or-pay provisions that mean EDL pays IPP costs regardless. We convert MEW provided energy charges for new thermal IPPs to capacity charges by assuming take-or-pay provisions of 70%.

The resulting charges are shown in the table below.

Table 11 Assumed IPP charges

Name	Technology	IPP energy charge ($/MWh)	IPP capacity charge ($/MW/year)	IPP take or pay %
Existing - Temporary generation				
KPS Zouk	Recip	49		
KPS Jieh	Recip	49		
Existing - IPPs				
Litani	Hydro	40		
Nahr Ibrahim	Hydro	26		
Bared	Hydro	26		
Kadisha hydro	Hydro	26		
Hrayche	Steam Turbine	54		
New - Fast Track Generation				
Fast Track Deir Amar	Recip		324,996	70%
Fast Track Zouk	Recip		324,996	70%
Fast Track Jieh	Recip		324,996	70%
Fast Track Zahrani	Recip		226,884	70%
Fast Track Bint Jbeil	Recip		251,412	70%
Fast Track Jib Jannine	Recip		251,412	70%
New - IPPs				
DAPPII PPA (OC)	OCGT		180,894	70%
DAPPII PPA (CC)	CCGT		180,894	70%
Zahrani II CCPP (OC)	OCGT		156,979	70%
Zahrani II CCPP (CC)	CCGT		156,979	70%
Selaata I CCPP (OC)	OCGT		156,979	70%
Selaata I CCPP (CC)	CCGT		156,979	70%
Jieh New CCPP (OC)	OCGT		156,979	70%
Jieh New CCPP (CC)	CCGT		156,979	70%
Zouk New CCPP (OC)	OCGT		156,979	70%
New wind 1 (rate 1)	Wind	105		
New wind 1 (rate 2)	Wind	96		
New wind 2	Wind	96		
New PV 1	Solar	70		
New PV 2	Solar	70		
New PV 3	Solar	70		
Janneh Hydro	Hydro	70		
New Hydro (Daraya, Chamra, Yamouneh, Blat)	Hydro	70		

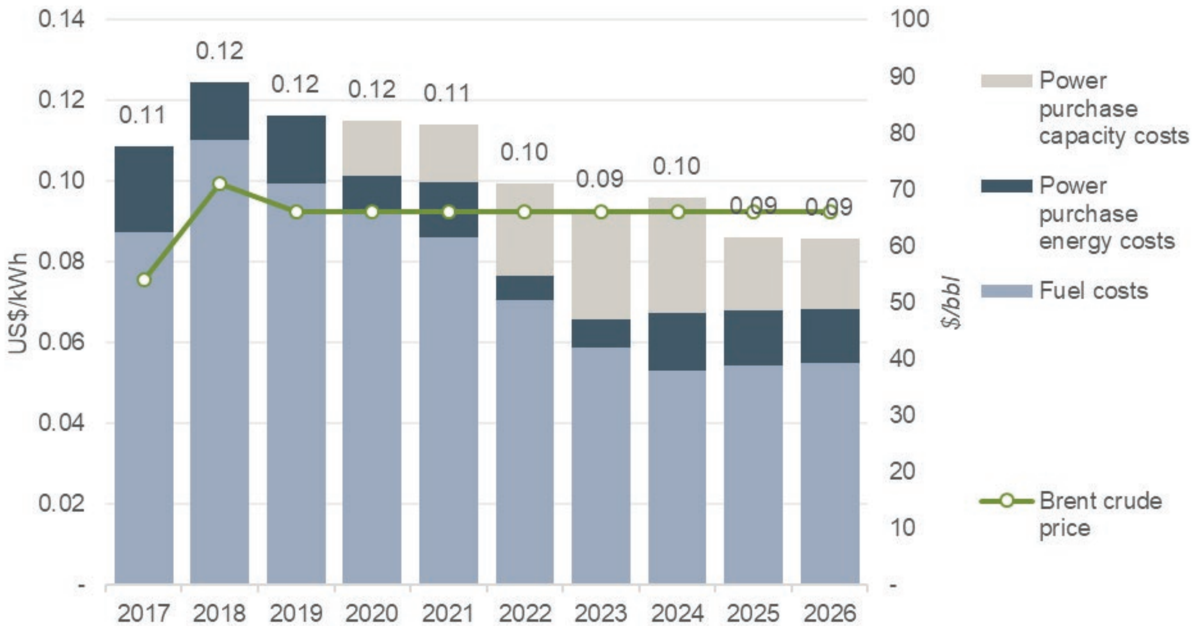
Source: ECA analysis based on MEW data

4.2.2 Forecast costs

Switching to LNG will reduce fuel & IPP costs on a per kWh basis

We forecast that the average fuel & IPP cost per kWh sent out will be 22% lower in 2023 than 2018 levels (a decrease from $0.12 per kWh sent out in 2018 to $0.09 per kWh sent out in 2023), as shown in the figure below. Note that all values are also shown in real terms, excluding inflation and that these costs include fuel and IPP costs only (they exclude other operating costs such as generation O&M costs). The key insight here is that the fuel cost savings from introducing LNG in 2022 and 2023 are expected to outweigh the new IPP costs.

Figure 38 Base case - forecast fuel and IPP costs per kWh sent out

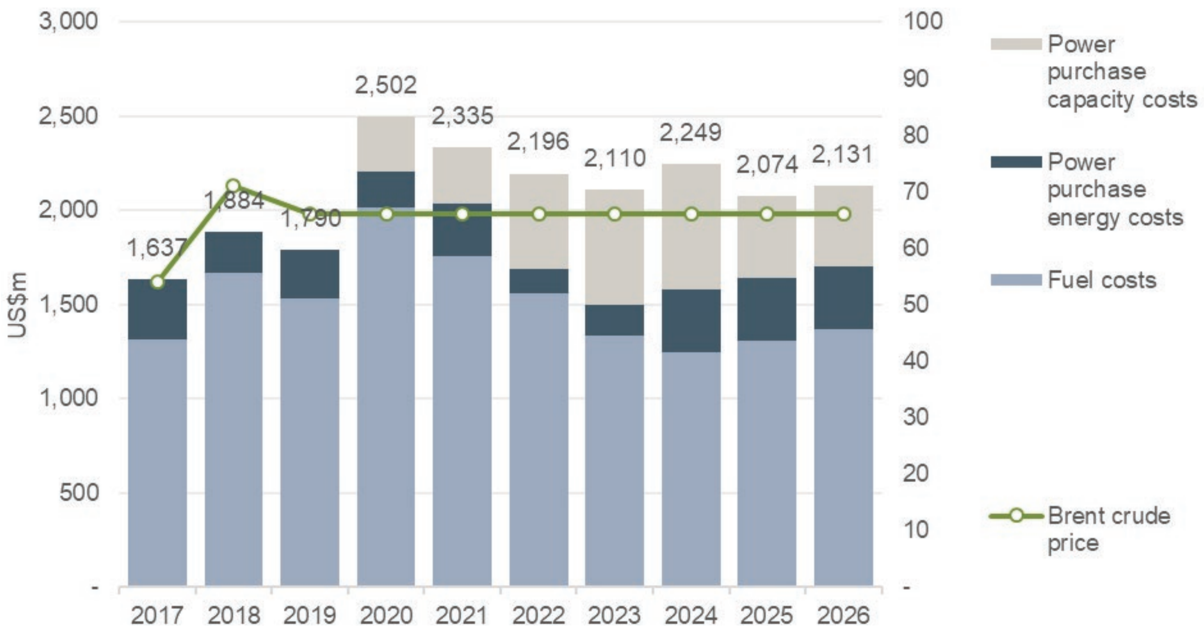


Source: ECA analysis based on EDL and MEW data

Total fuel & IPP costs will increase because volumes generated increase significantly

The figure below shows that while the per unit cost is expected to come down over time, total costs are expected to increase because the volume of energy sent out increases significantly.

Figure 39 Base case - forecast fuel and IPP costs



Source: ECA analysis based on EDL and MEW data

4.3 Fuel and IPP costs – alternative case

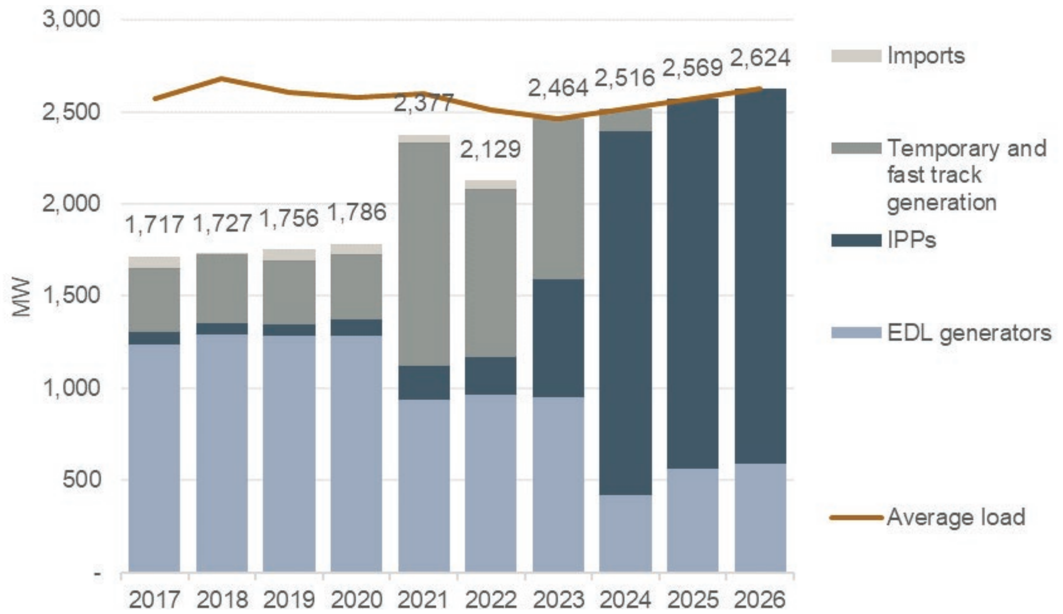
4.3.1 Key inputs and assumptions

We assume the same fuel prices and plant efficiencies. But different loss reduction and generation expansion assumptions means different volumes

In the alternative case, we use all the same fuel and IPP cost assumptions as the base case. The only difference is that the volumes of energy generated by plant are different, as detailed in Section 3.4 above. In particular, loss reductions are smaller (and therefore generation is higher) and some new IPPs are delayed by one year.

The resulting generation mix is summarised in the figure below. The key insight is that in the alternative case EDL relies on its existing generators for longer and therefore total volumes generated are lower.

Figure 40 Alternative case - annual average dispatch by generation type



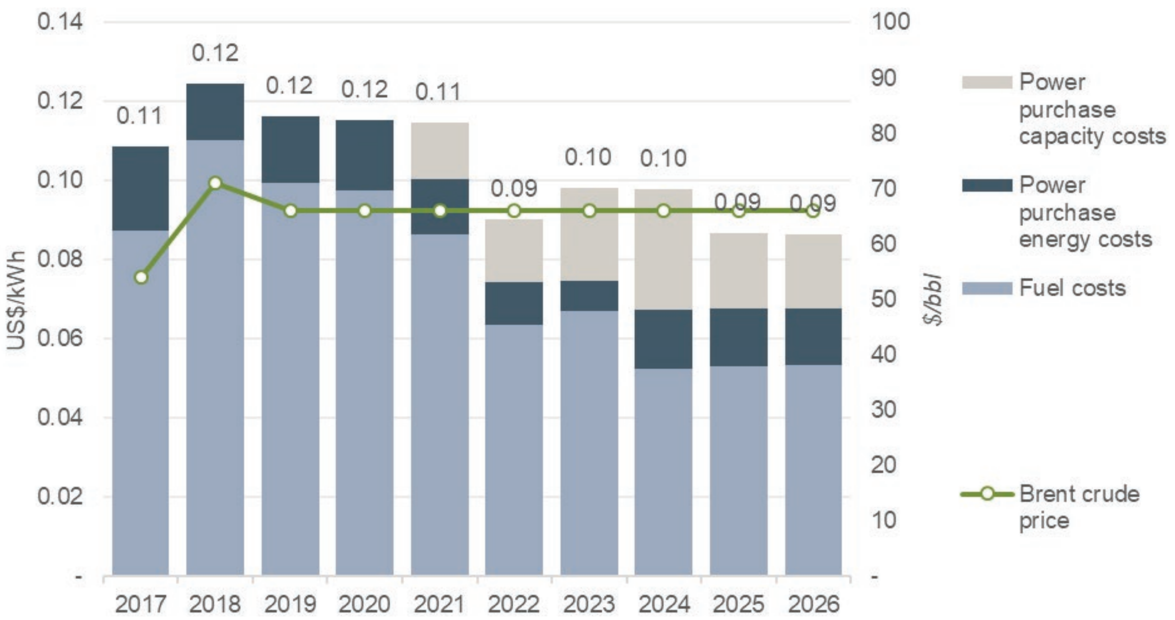
Source: ECA based on EDL and MEW data

4.3.2 Forecast costs

In the alternative case, fuel and IPP costs are lower due to less generation (and more unserved demand)

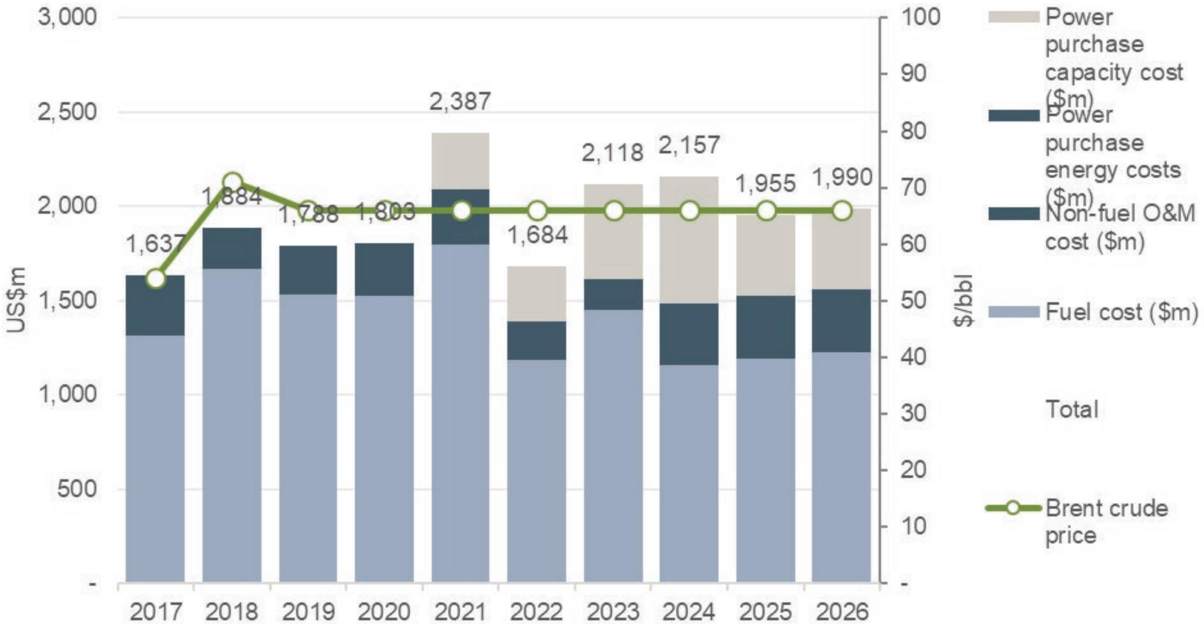
The resulting forecast fuel and IPP costs in the alternative case are similar in per kWh terms to the base case, despite some new IPPs being delayed. This shows that it is the arrival of LNG that is most critical bringing down per unit costs, rather than the commissioning of new plants. Total fuel and IPP costs decrease in the alternative case because a smaller volume is generated (due to capacity constraints). The obvious downside to this is more load shedding / unserved demand.

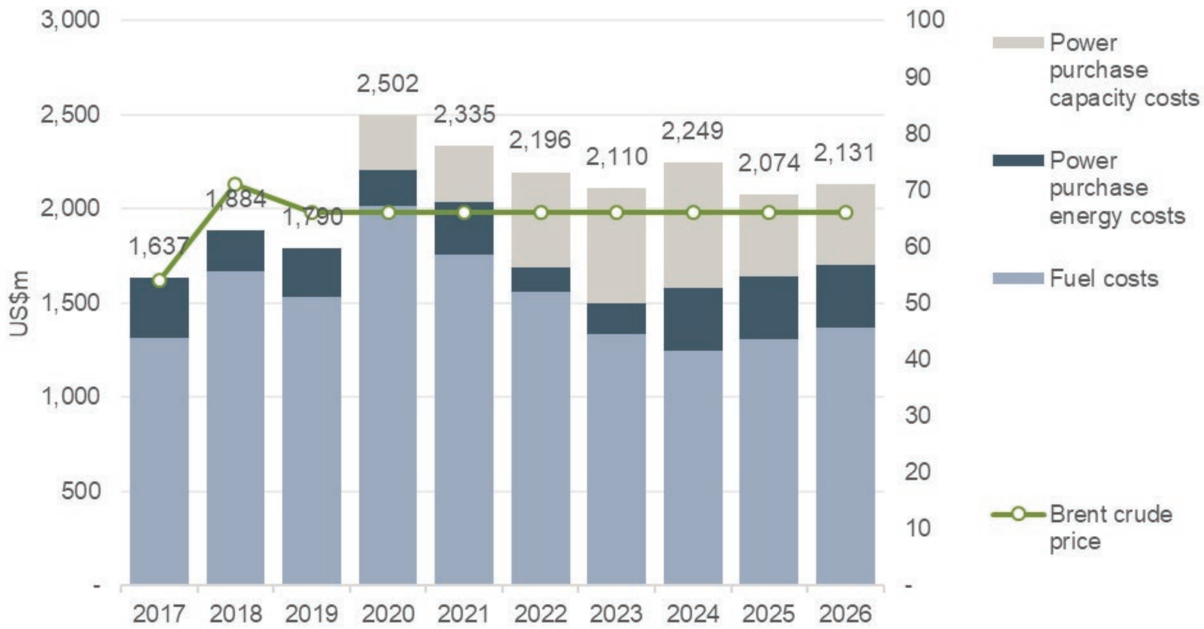
Figure 41 Alternative case - forecast fuel and IPP costs per kWh sent out



Source: ECA analysis based on EDL and MEW data

Figure 42 Alternative case - forecast fuel and IPP costs





Source: ECA analysis based on EDL and MEW data

4.4 Other operating costs

4.4.1 Key inputs and assumptions

Other operating costs are forecast by starting from EDL's 2017 estimate and escalating some costs

Other operating costs comprise the following:

- Generation O&M costs[17]
- Non-generation O&M costs
- Salaries
- Administration costs
- EDL estimates that its other operating costs were $672m in 2017[18]. Around $210m of this relates to generation O&M costs.

We forecast other operating costs by keeping generation O&M costs fixed (in real terms) and by escalating all other operating costs by two percent per annum, as advised by MEW.

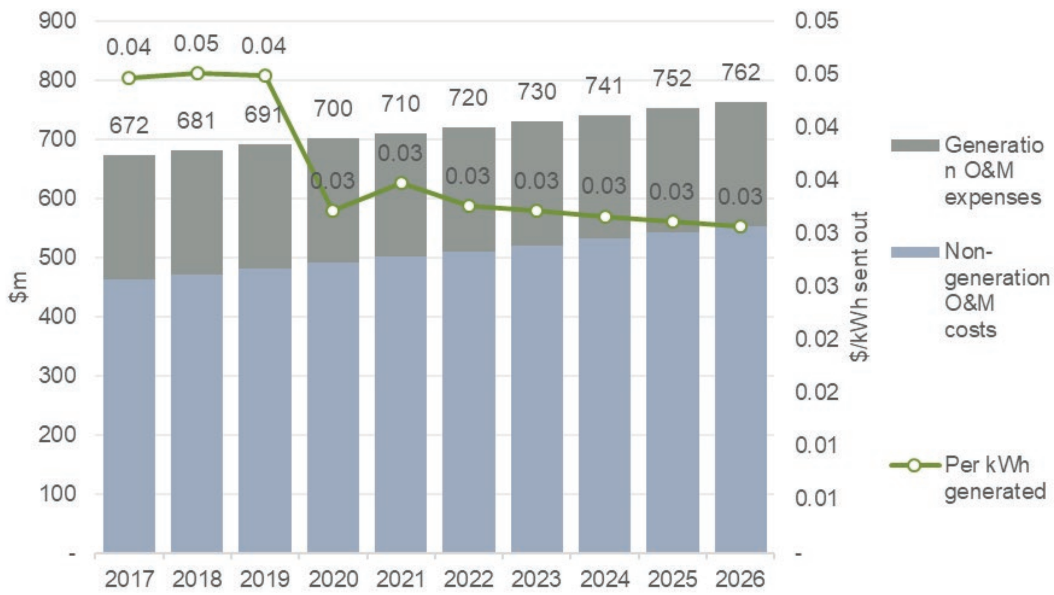
4.4.2 Forecast costs

EDL's other operating costs will increase to around $760m per year

Figure 43 shows forecast other operating costs between 2017 and 2026. EDL's other operating costs are currently around $672m per year, out of which generation O&M costs account for approximately 30%.

In terms of cost per kWh generated/sent-out, other operating costs will decrease to around 3c per kWh once new generating capacity is added. This compares to fuel and IPP costs of around 10c per kWh. While we have not critically reviewed EDL's estimate of other operating costs, there does appear to be significant scope to improve efficiency.

Figure 43 Forecast of EDL's other operating costs between 2017 and 2026



Source: ECA analysis based on EDL and MEW data

17 Generation O&M costs are both fixed and variable in nature, but data limitations with respect to variable costs by plant meant that we could not reliably link variable O&M costs to the dispatch simulation, and therefore had to estimate them separately

18 In 2017, EDL reported non-fuel and non-IPP operating costs of $268m were paid. However, we understand that this is a significant underestimate of costs because not all costs were actually paid or properly recorded. We did not get full clarity on how this large difference arose, but we have been assured by EDL and MEW that the $672m value is a better estimate.

4.5 Financing costs

4.5.1 Key inputs and assumptions

Existing financing costs are based on existing MEW and EDL electricity sector debt

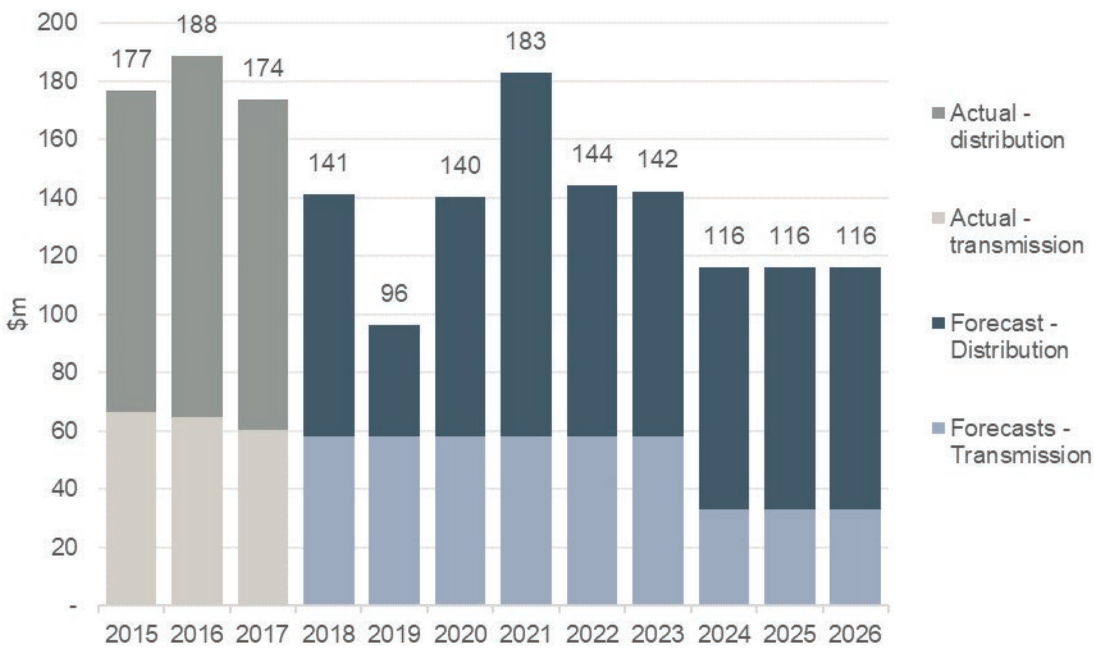
We have calculated existing and future financing costs using loan data provided by MEW. These include debt on EDL's books, as well as MEW's debt on projects which relate to the energy sector. It should be noted that some of the loans are currently being repaid by the Ministry of Finance (MOF) as EDL does not earn enough revenue to cover all its financing costs.

New network financing costs are based on the EDF transmission plan and DSP investment plans

Network capex consists of transmission and distribution capex. Our cost forecast assumes transmission capex of around $58m per year until 2024 and then $33m per year until 2026. The figure is based on the 2017 Electricité de France (EDF) Transmission Master Plan[19] which assumes approximately $353m will be spent between 2017 and 2023 with further $201m spent between 2024 and 2030.

The forecast of distribution capex is based on estimates by the Distribution Service Providers that were provided to MEW. The forecasts average $83m per year out till 2026.

Figure 44 Forecast network capex, 2015-2026



Source: ECA analysis based on EDL and MEW data

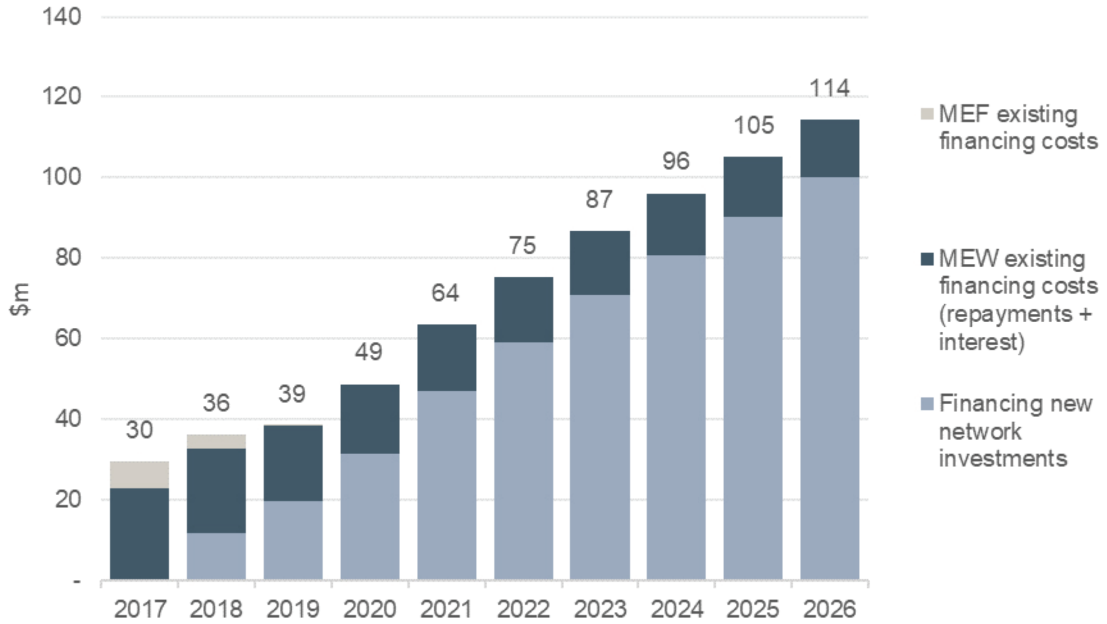
To convert capex costs into financing costs, we assume that new loans will be serviced at concessionary rates (3% interest and 15 years repayment schedule).

4.5.2 Forecast costs

The cost of financing network investments is expected to rise to around $114m per year by 2025.

Figure 45 shows a forecast of EDL's financing costs until 2026. The cost of financing investments was approximately $30m in 2017 (1% of total costs) and is expected to rise to around $114m (4% of total forecast cost of supply) by 2026. This increase is caused by the fact that EDL's existing network is aging and needs heavy new investment. It also potentially reflects the fact that not all historical investment has been recorded as debts to MEW, MOF, or EDL.

Figure 45 Forecast financing costs, 2017-2026



Source: ECA analysis based on EDL and MEW data

In per kWh terms, network financing costs are still small, approaching half a cent per kWh sent out by 2026.

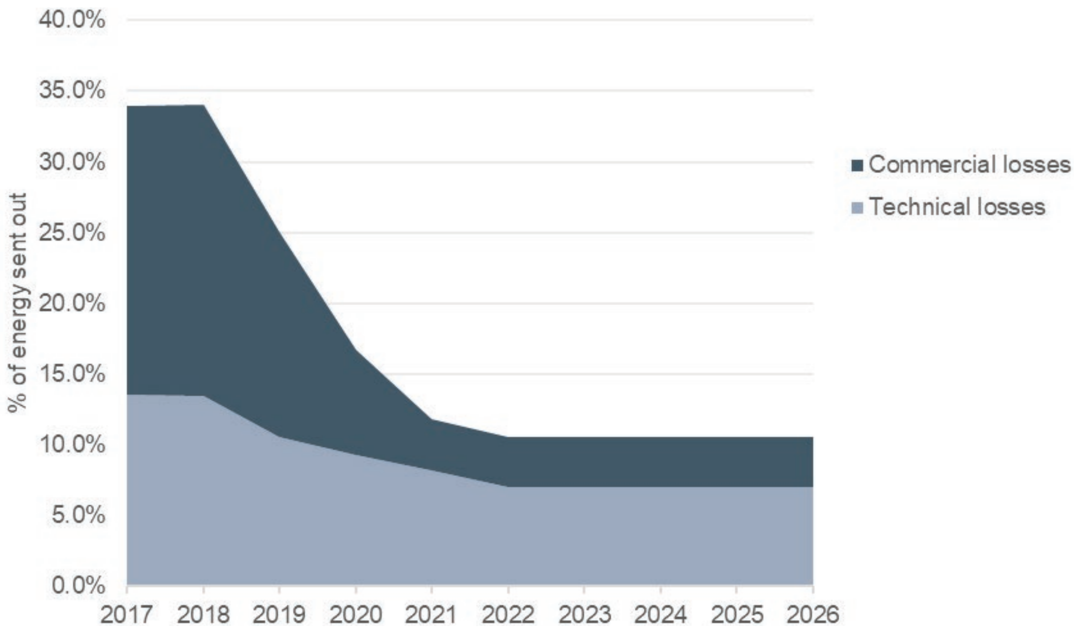
4.6 Cost of network losses – base case

4.6.1 Key inputs and assumptions

To forecast the cost of supply in the base case we use MEW's assumption that total losses are reduced to 10.6% by 2022

In the base case, we adopt MEW's assumption that total losses are reduced to 10.6% by 2022, as discussed in Section 3.1.2 and illustrated in the figure below. The decrease is a result of an assumed decrease in commercial/non-technical losses from 20.4% in 2017 to 3.6% in 2021, and an assumed decrease in technical losses from 13.5% in 2017 to 7% in 2022. The investment plans associated with these losses, as provided by DSPs, are detailed in Section 4.5 and are therefore included in the overall cost.

Figure 46 Base case - forecast losses (%)



Source: ECA analysis based on EDL and MEW data

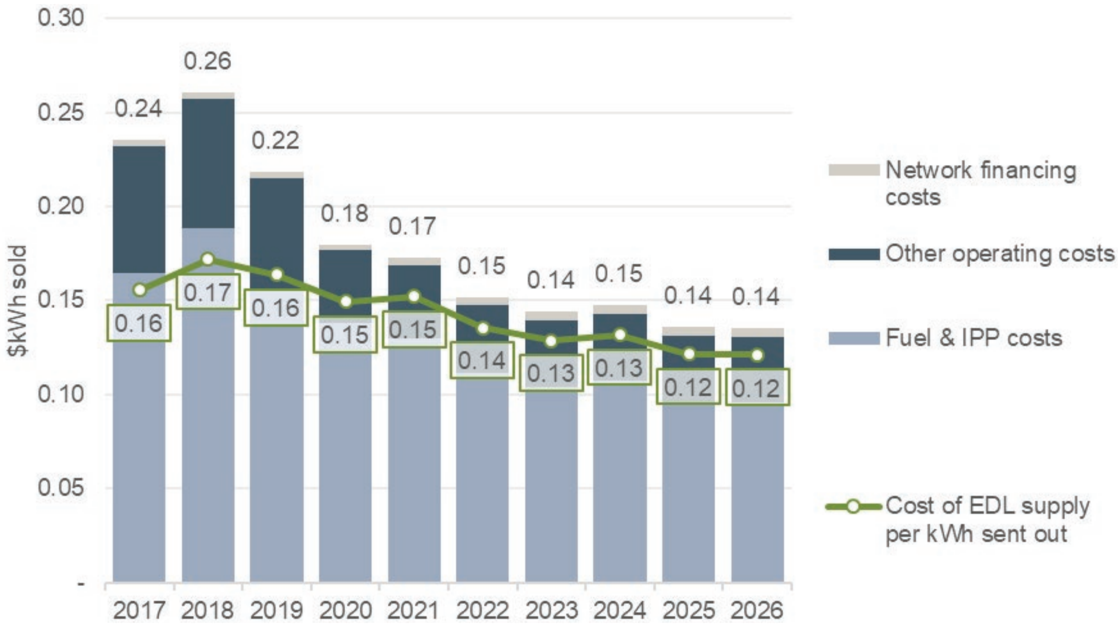
4.6.2 Forecast costs

Losses add 8c per kWh in 2017, but less than 2c per kWh by 2022

High network losses significantly increase the cost of EDL's supply – from $0.16 per kWh sent out (covering fuel & IPP costs, other operating costs, and network financing costs) to $0.24 per kWh sold in 2017 (Figure 47). This implies a $0.08 per kWh sold cost of losses in 2017.

By 2022 losses have reduced such that the implied cost of losses is only $0.015 per kWh, as illustrated in the figure below.

Figure 47 Base case - forecast cost of supply per kWh sold



Source: ECA analysis based on EDL and MEW data

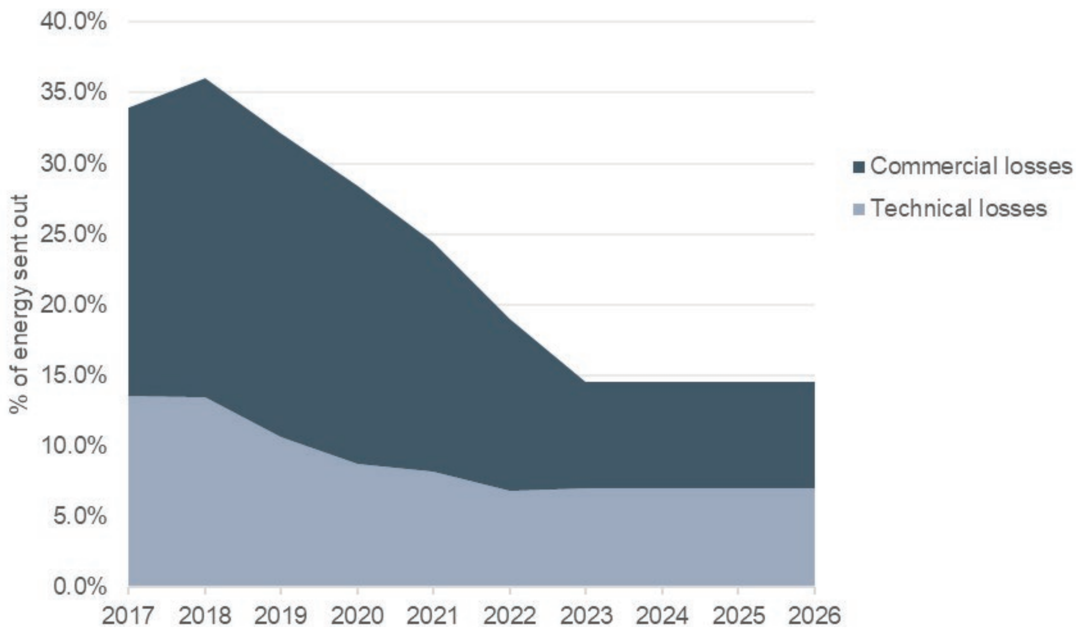
4.7 Cost of network losses – alternative case

4.7.1 Key inputs and assumptions

To forecast the cost of supply in the alternative case we use the more conservative assumption that total losses are reduced to 14.5% by 2023

In the alternative case, we use a more conservative assumption that total losses are reduced to 14.5% by 2023, rather than 10.6% by 2022 in the base case, as discussed in Section 3.2.2 and illustrated in the figure below. This difference is due to assumptions about non-technical loss reductions (assumed technical loss reductions are the same in both scenarios). The investment plans associated with these losses, as provided by DSPs, are detailed in Section 4.5 and are therefore included in the overall cost.

Figure 48 Alternative case - forecast losses, 2017-2026



Source: ECA analysis based on EDL and MEW data

4.7.2 Forecast costs

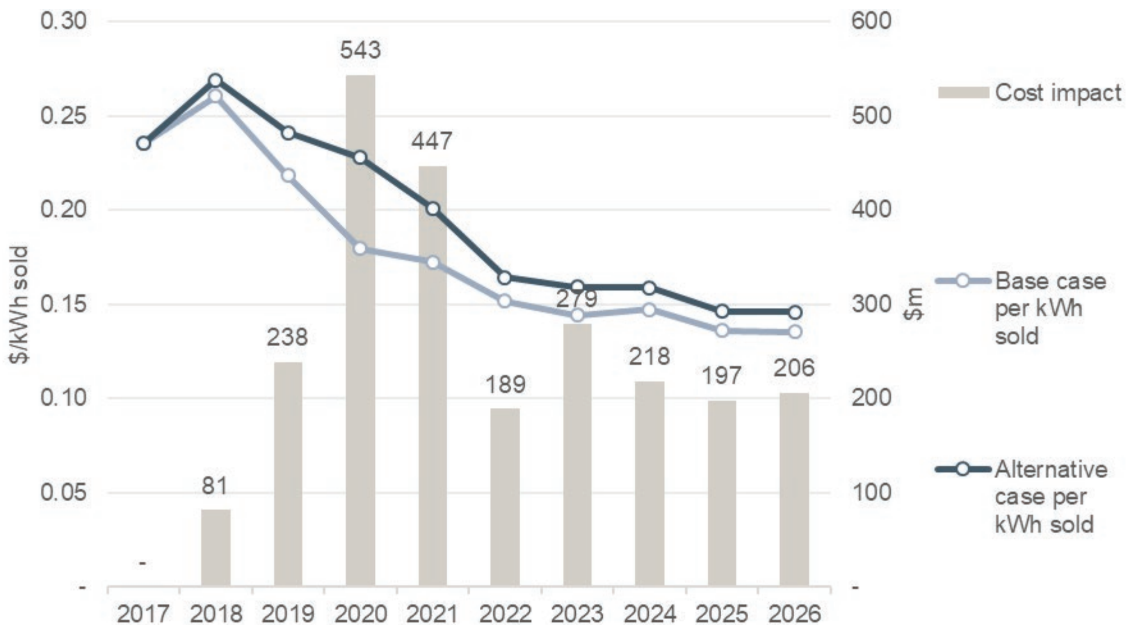
In the alternative case, losses add around 3c per kWh to the cost of supply from 2022 onwards

In the alternative case the smaller loss reductions means that the cost of losses is much more significant – around $0.05 per kWh in 2021 and $0.03 per kWh in 2026, as illustrated in the figures below. The cost implications of the difference between the base case and alternative case peaks at over $500m in 2020, although the exact cost of losses depends on other assumptions such as the timing of generation expansion.

Figure 49 Alternative case - forecast cost of supply per kWh sold

Source: ECA analysis based on EDL and MEW data

Figure 50 Base case vs alternative case - forecast cost of supply per kWh sold and cost implication



Source: ECA analysis based on EDL and MEW data

4.8 Collection improvement

4.8.1 Key inputs and assumptions

EDL only collected cash revenues on approximately 44% of the electricity it produced & purchased in 2017, due to DSP strikes

The underlying data suggests that EDL only collected cash revenues on approximately 44% of the electricity it produced and purchased in 2017, as detailed in Section 2.4.

Exceptionally low collection rates in 2017 have significantly increased EDL's costs for that year. The cost per kWh sent out (i.e. before adjusting for losses and collections) was $0.16 per kWh in 2017. After the adjustment for losses is made (but before we account for collection rates), the cost per kWh sold increases to $0.24 per kWh. Once EDL's losses and collection rates are accounted for, the cost per kWh collected increases further to $0.36 per kWh.

MEW and EDL expect these issues to be resolved and collections to return to historical levels of ~95%

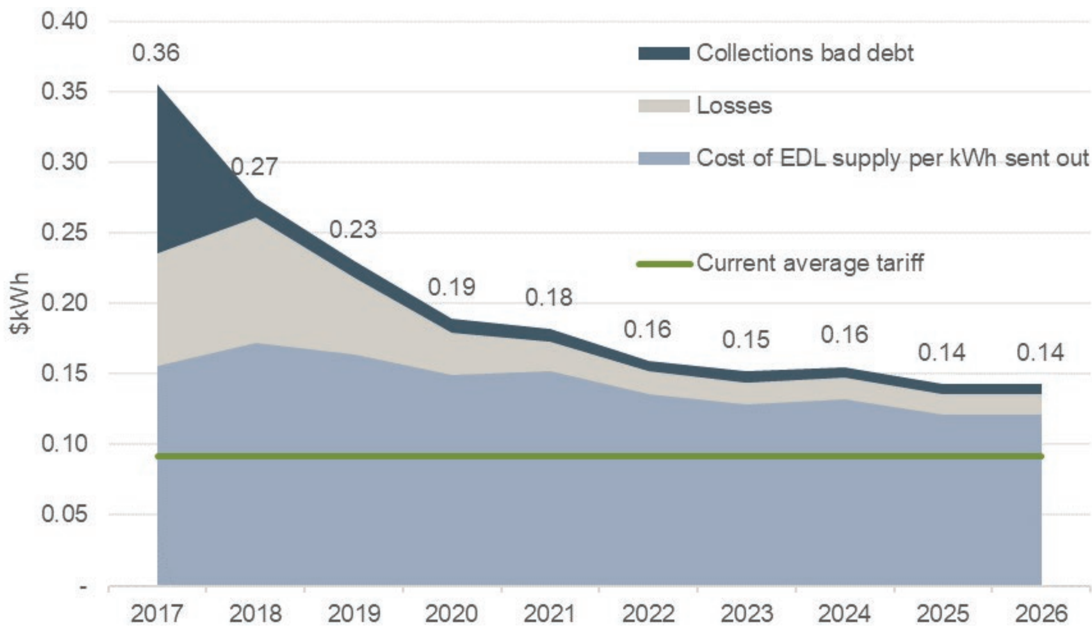
MEW and EDL expect to collect the remaining 2017 revenues bringing the share of revenue collected close to the historical levels of 95%. Therefore, in our cost forecast beyond 2018, we have assumed that collections increase EDL's cost of supply only by a small percentage (approximately 5%).

4.8.2 Forecast costs

Bad debt only adds small increases (~5%) to EDL's cost of supply from 2018 onwards

Because we assume only 5% bad debt in future years, the collection rate only adds slightly more than 5% to EDL's cost of supply, as illustrated in the figure below.

Figure 51 Base case - Forecast cost of supply per kWh sent out, sold out and collected



Source: ECA analysis based on EDL and MEW data

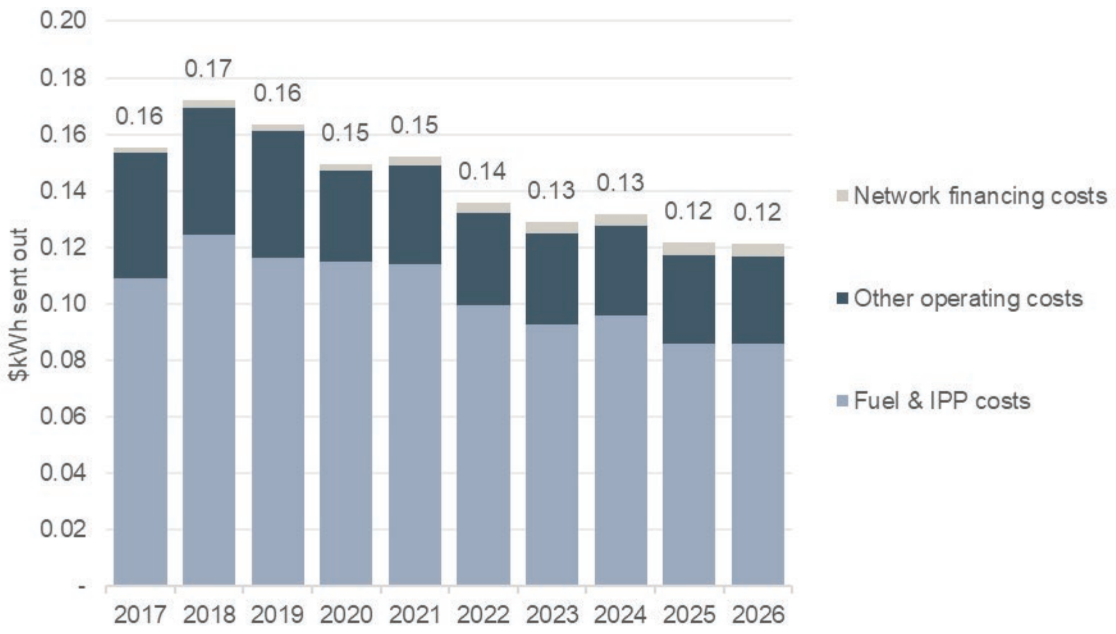
4.9 Total costs / revenue requirement

4.9.1 Base case

The introduction of LNG and new CCGTs should reduce costs by around 3c per kWh

Figure 52 presents a summary of future estimated costs of supply, before losses and collections are considered. It includes fuel & IPP costs, other operating costs, and network financing costs. In 2017, these costs are equal $0.16 per kWh sent out. with fuel and IPP costs accounting for approximately 70% of the total. From 2022 onwards, when LNG is expected to arrive and new CCGTs begin being commissioned, total costs are forecast to drop to around $0.13 per kWh sent out. In other words, the fuel cost savings from using LNG are expected to outweigh the cost of new IPP payments, to the extent that total costs are expected to reduce by around $0.03 per kWh.

Figure 52 Base case - forecast cost of supply per kWh sent out (excluding losses and collections), including other operating costs and network investment costs

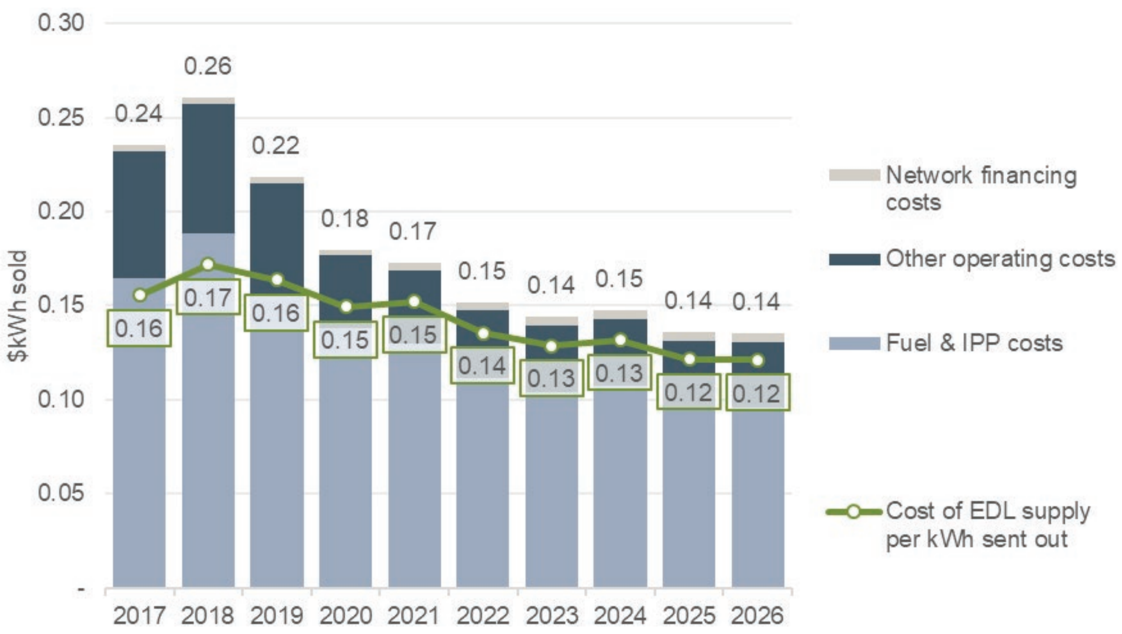


Source: ECA analysis based on EDL and MEW data

Large loss reductions will bring about cost savings of around 6c per kWh

EDL's 34% losses means that its cost of supply of $0.16 per kWh **sent out** becomes $0.24 per kWh **sold**, as shown in the figure below. In the base case, we assume aggressive loss reductions in line with MEW assumptions. The result is a reduction in the cost of supply per kWh sold of around $0.06 per kWh (in 2017 losses cost $0.08 per kWh and by 2021 losses they cost $0.02 per kWh).

Figure 53 Base case - forecast cost of supply per kWh sold

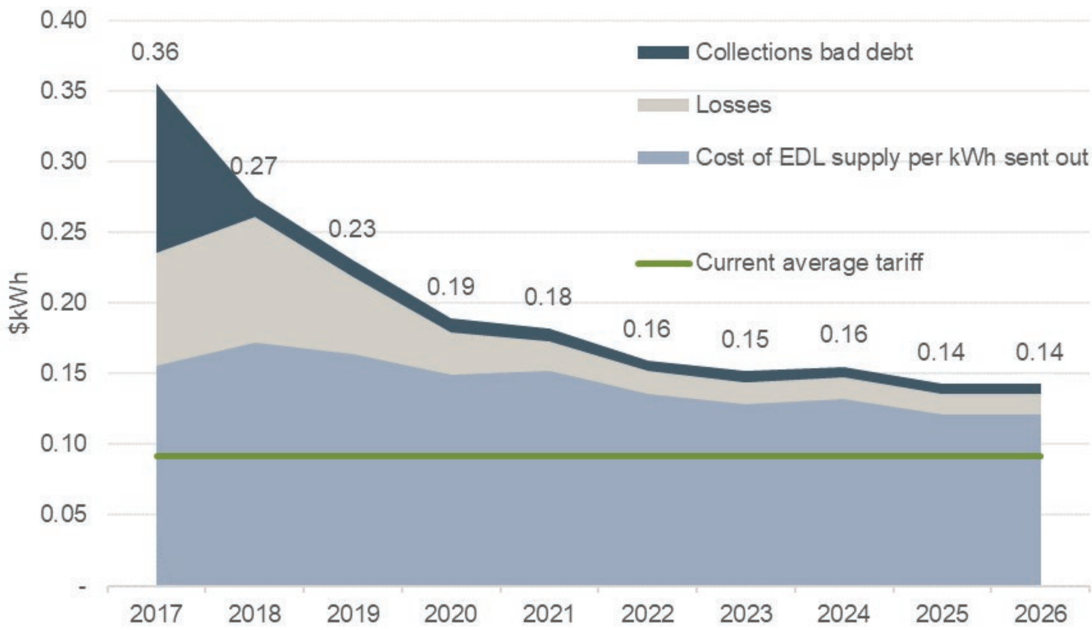


Source: ECA analysis based on EDL and MEW data

The total cost reflective tariff is around 0.16$ per kWh from 2022 onwards

As above, collection rates were poor in 2016 and 2017, but are expected to be high from 2018 onwards, and therefore only have a small effect on the total revenue requirement, as shown in the figure below. The final a cost of supply per kWh collected that reduces from around 0.27$ per kWh in 2018 down to 10.6$ per kWh in 2022 as losses are reduced, new generating capacity is added, and LNG is used to fuel generators.

Figure 54 Base case - forecast cost of supply per kWh collected

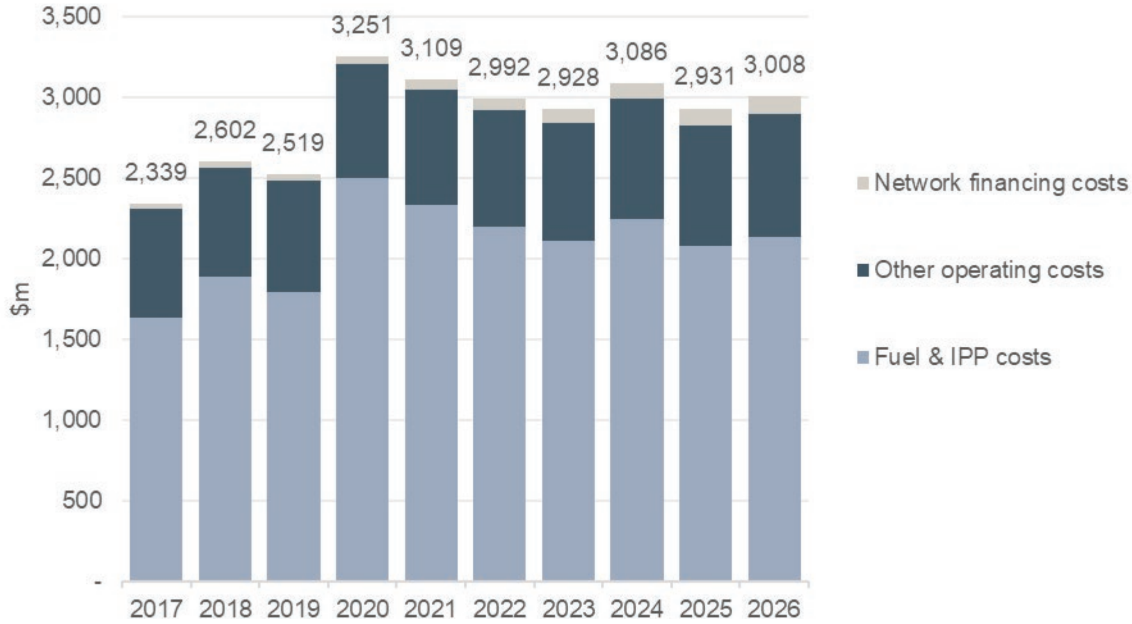


Source: ECA analysis based on EDL and MEW data

The total cost of supply increases by up to $1bn due to increased volumes generated

Although the per unit cost decreases significantly over time, as illustrated above, the total cost of supply increases significantly over the same period due to EDL generating more power. The forecast cost peaks at about $3.25bn in 2020 and levels out at around $3bn from 2022 onwards. As discussed previously, this assume the oil price stays constant at $66/bbl.

Figure 55 Base case - forecast cost of supply



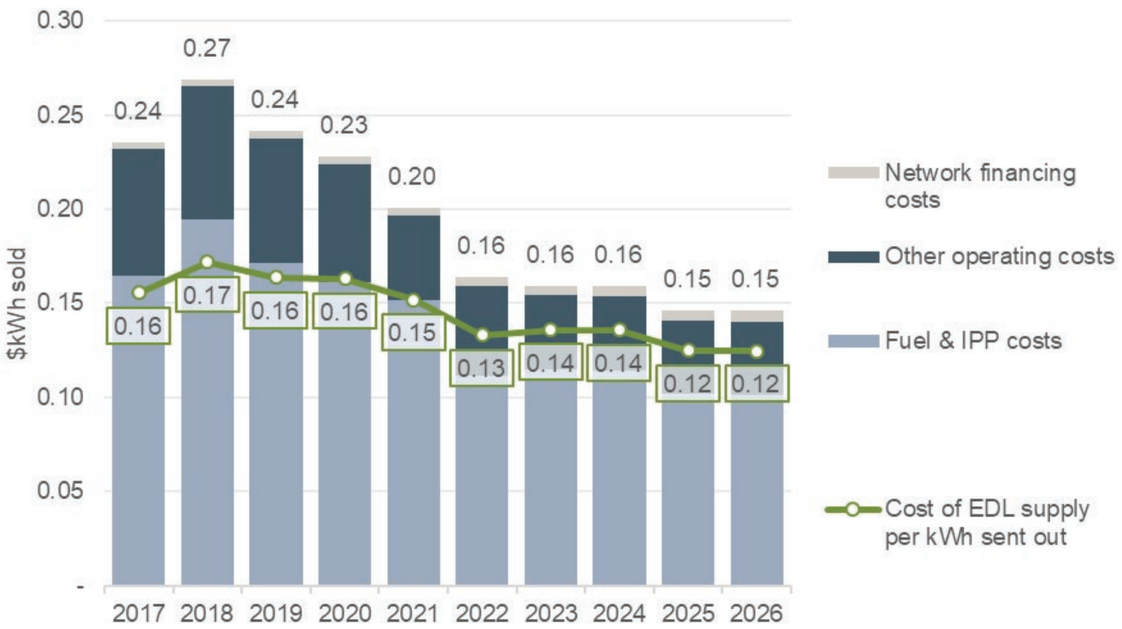
Source: ECA analysis based on EDL and MEW data

4.9.2 Alternative case

In the alternative case the per kWh costs are higher. The 2022 cost-reflective tariff is around $0.17 per kWh

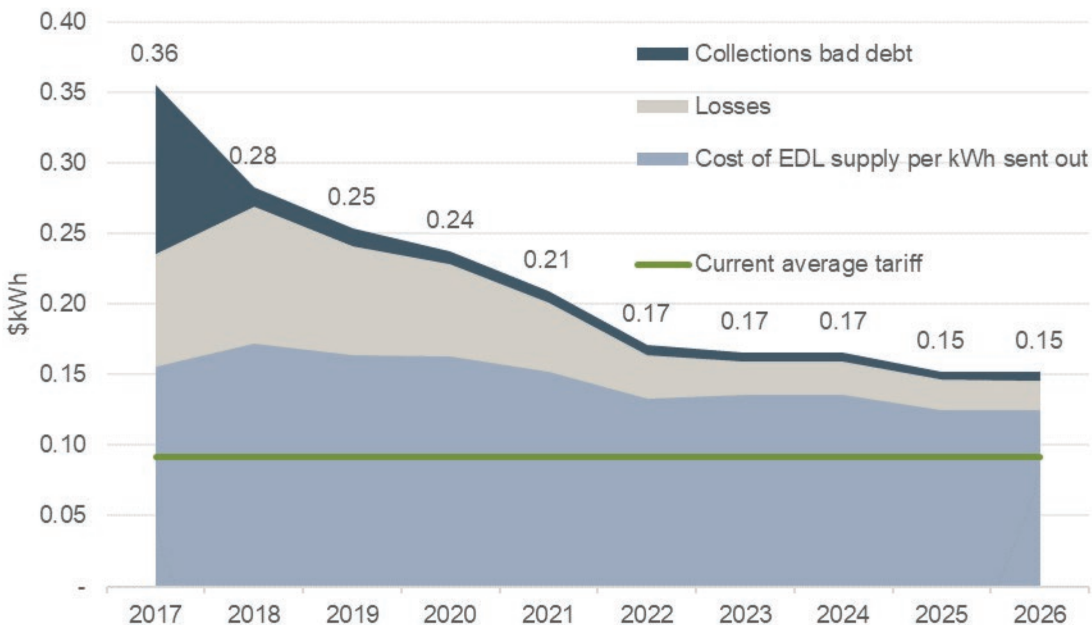
In the alternative case, the per unit costs of supply remain higher for longer, as illustrated in the figures below. Before 2022 the cost-reflective tariff is significantly higher in the alternative case – e.g., in 2021 it is $0.21 per kWh versus $0.18 per kWh in the base case. From 2022 the cost of supply in the alternative case levels out at around $0.17 per kWh (rather than $0.16 per kWh in the base case). This difference is caused primarily by smaller loss reductions.

Figure 56 Alternative case - forecast cost of supply per kWh sold



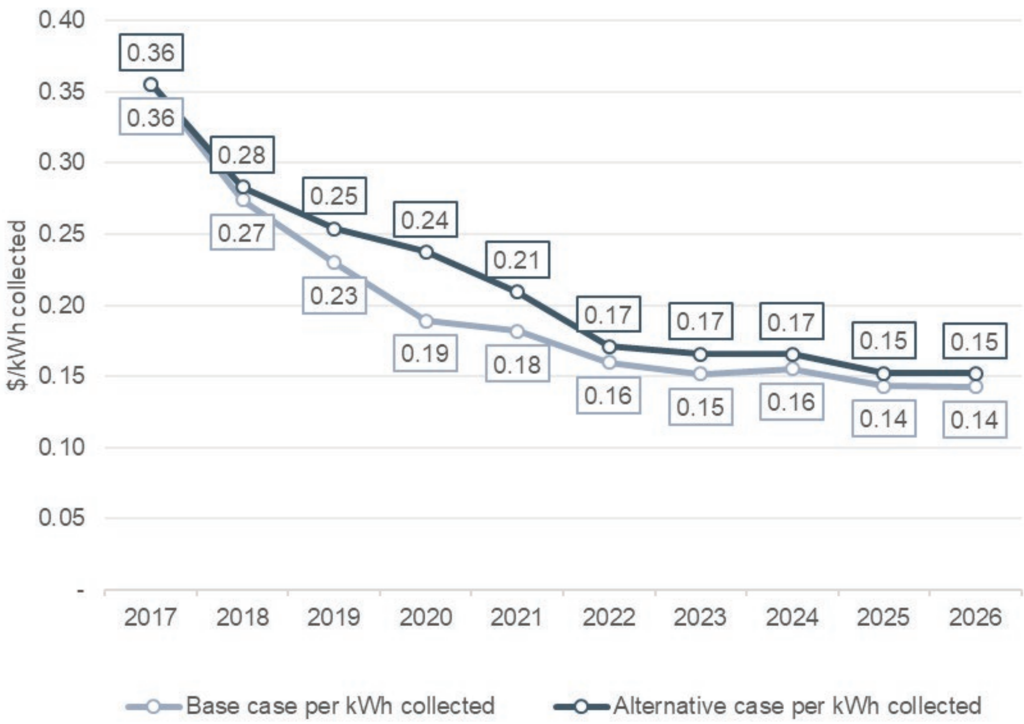
Source: ECA analysis based on EDL and MEW data

Figure 57 Alternative case - forecast cost of supply per kWh collected



Source: ECA analysis based on EDL and MEW data

Figure 58 Base case vs alternative case - forecast cost of supply per kWh collected

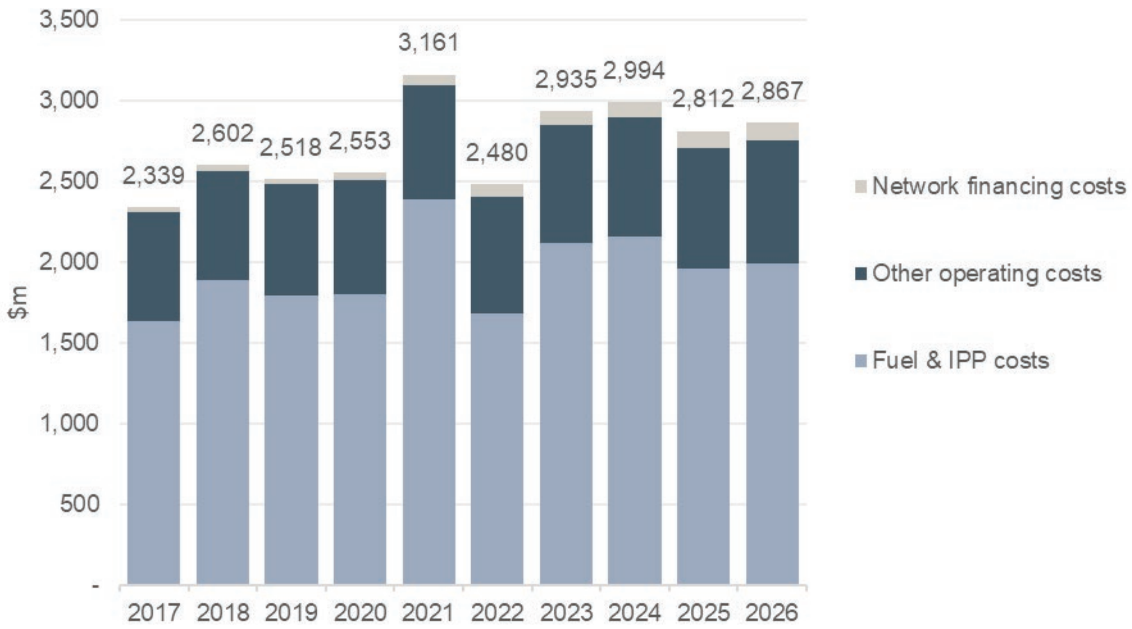


Source: ECA analysis based on EDL and MEW data

Total costs are generally lower in the alternative case, due to less generation, but unserved demand is higher

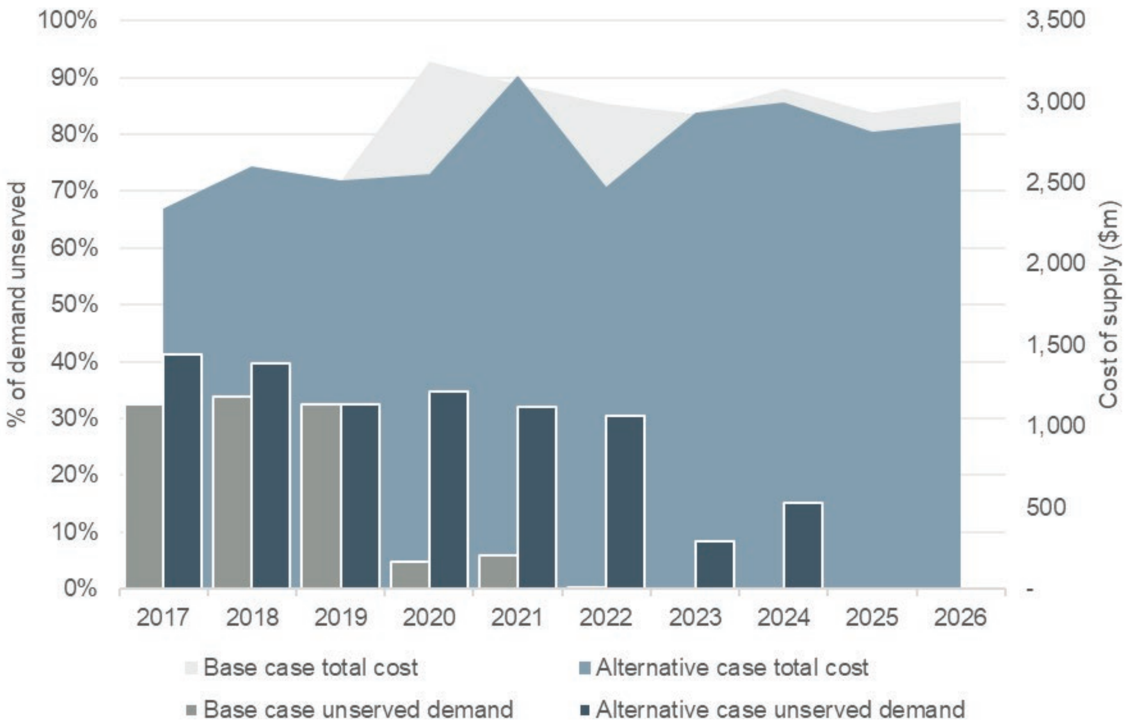
Despite the higher unit costs, the total costs of supply in the alternative case are lower than in the base case because less energy is generated, due to delays in commissioning new IPPs. This however comes at an obvious economic cost, due to higher unserved demand in the alternative case. This is illustrated in the figures below.

Figure 59 Alternative case - forecast cost of supply



Source: ECA analysis based on EDL and MEW data

Figure 60 Base case vs alternative case - forecast cost of supply and unserved demand



Source: ECA analysis based on EDL and MEW data

4.10 Subsidy impacts

4.10.1 Base case

We assume that historical sector arrears are recovered and that tariffs will be increased to cost-recovery levels of $0.16 per kWh in 2020

We calculate the required subsidy sector as the difference between EDL's total cost of supply and EDL's total revenues.

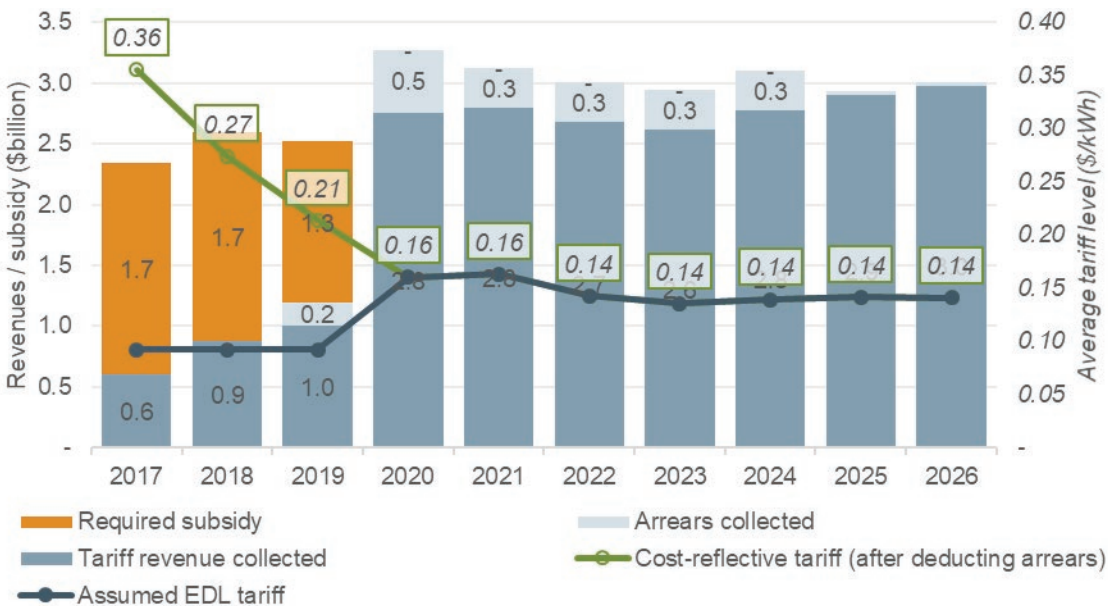
To forecast EDL revenues, we adopt MEW's assumptions in the base case:

- **Sector arrears, totalling ~$2bn, are collected between 2019 and 2024**. These arrears include collection arrears related to the DSP strikes (~$209m), DSP enhancement arrears ($368m), and public administration and Palestinian refugee arrears ($1,500m). In total, this translates to average arrear recovery of $340m per year.
- **From 2020 onwards, tariffs will be set at a level that will eliminate the subsidy (16c per kWh in 2020, a 74% tariff increase)**, which coincides with the commissioning of fast-track generation and therefore most demand being met by EDL supply.

The subsidy is forecast to be $1.7bn in 2018 and $1.3 in 2019, and reduced to zero in 2020

The resulting sector subsidies that are required to cover EDL's costs of supply until tariffs are increased are $1.7bn in 2018 and $1.3 in 2019, as shown in the figure below. As noted elsewhere, this assumes that oil prices remain fixed at $66/bbl. Without a fuel cost pass-through mechanism, subsidies will be very sensitive to oil price changes.

Figure 61 Base case – forecast subsidy and cost-reflective tariff



Source: ECA analysis based on EDL and MEW data

4.10.2 Alternative case

In the alternative case, we assume that most arrears are not recovered and that tariff increases are phased – $0.13 per kWh in 2022 and $0.17 per kWh in 2023

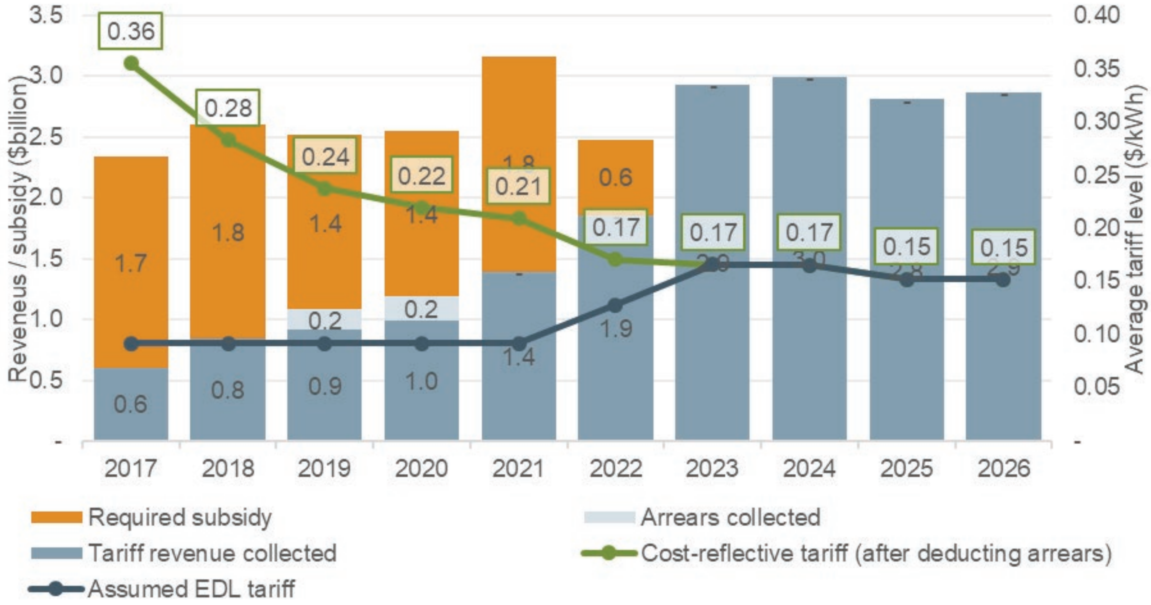
To forecast EDL revenues in the alternative case, we assume the following:

- **Most sector arrears are not recovered.** Only $200m per year is collected in 2019 and 2020 respectively, related to DSP enhancement payments.
- **Tariffs are increased by 40% in 2022 (to $0.13/kWh) and 30% in 2023 (to $0.17/kWh),** such that 75% of costs are met in 2022 and 100% in 2023.

Under these more conservative assumptions, the subsidy is between $1.4bn and $1.8bn till 2022 when LNG arrives and tariffs are increased

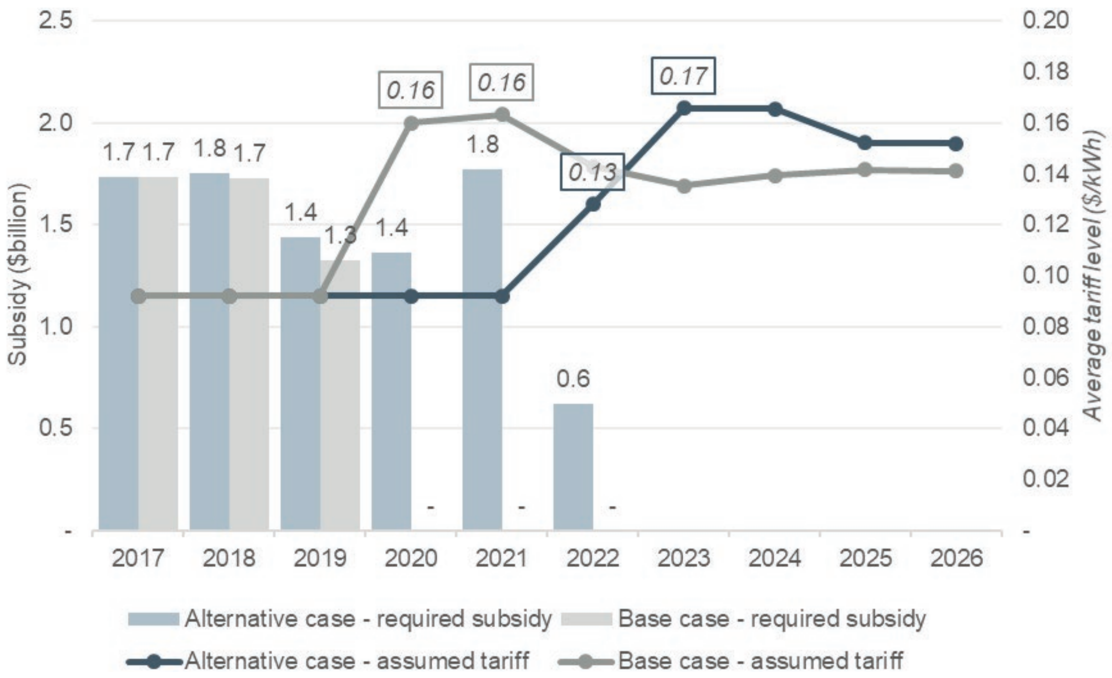
The resulting sector subsidies that are required to cover EDL's costs of supply are $1.8bn in 2018, $1.4bn in 2019 and 2020, and $1.8bn in 2021. In 2022 LNG arrives and the first tariff increase kicks in, which reduces the subsidy to $0.6bn. In 2023 the second tariff increase eliminates the subsidy altogether. As noted elsewhere, this assumes that oil prices remain fixed at $66/bbl. Without a fuel cost pass-through mechanism, subsidies will be very sensitive to oil price changes.

Figure 62 Alternative case – forecast subsidy and cost-reflective tariff



Source: ECA analysis based on EDL and MEW data

Figure 63 Base case vs alternative case – forecast subsidy and cost-reflective tariff



Source: ECA analysis based on EDL and MEW data

5. TARIFF DESIGN AND REVISION

In this section we set out our recommendations for revising the structure of EDL's tariffs, to increase revenue in the short term and improve the efficiency of price signals in the medium to long term.

5.1 Current tariff structure

The current tariff structure is described in the two tables below.

Table 12 EDL energy charge

Voltage	Customer category / block	LBP/kWh	USc/kWh
LV	Residential and commercial		
	1 - 100 kWh	35	2.3
	101 - 300 kWh	55	3.7
	301 - 400 kWh	80	5.3
	401 - 500 kWh	120	8.0
	Over 500 kWh	200	13.3
	Government and Public Admin	115	7.7
	Agriculture and Industrial	115	7.7
	Public lighting	115	7.7
MV (<100 kVA)	Residential and commercial	130	8.7
	Government and Public Admin	140	9.3
	Agriculture and Industrial	140	9.3
	Palestinian Camps	130	8.7
MV & HV (>100 kVA)	All		
	Night	80	5.3
	Day	112	7.5
	Peak	320	21.3
Concessions	Jbeil	75	5.0
	Zahle	50	3.3
	Bhamdoun	75	5.0
	Kadisha	61	4.1

Source: EDL sources, summarised by ECA

Table 13 EDL other charges

Charge	LBP	US$
Reverse energy charge (LBP/kVARh, >0.75)	50	0.03
Standing charge (LBP/A/month, 220V customers)	240	0.16
Standing charge (LBP/kVA/month, >220V customers)	1,200	0.80
Meter charge (per meter/month, <9kVA customers)	5,000	3.3
Meter charge (per meter/month, >9kVA customers)	100,000	66.7

Source: EDL sources, summarised by ECA

The current tariff structure is characterised by the following key features:

- **Low voltage customers are separated into the following customer categories**: (i) Residential and Commercial, (ii) Agriculture and Industry, (iii) Government and Public Admin, (iv) Street Lighting[20].
- **Residential and commercial customers pay the same tariffs** and are not distinguished in EDL's billing database.
- **Residential and commercial pay for energy under a rising block tariff structure**, which has five bands, the charge for which rises from $0.02 to $0.13 per kWh.
- **Other low-voltage customers pay a flat-rate energy charge.**
- **Medium voltage customers are separated into similar customer categories, with the main difference being separate categories for Palestinian camps and distribution concessions**: (i) Residential and Commercial, (ii) Agriculture and Industry, (iii) Government and Public Admin, (iv) Palestinian Camps, (v) Concessions.
- **All medium voltage customers pay a flat-rate energy charge**, except for those which pay a Time-Of-Use (TOU) tariff.
- **The TOU tariff applies to high demand customers (>100 kVA) and is in three-parts**: (i) night rate, (ii) day rate, and (iii) peak rate. It varies from $0.05 to $0.21 per kWh. The three-part rate is the same year-round.
- **The distribution concessions pay a lower (bulk) charge than customers** who are directly supplied by EDL.
- **All customers pay a fixed monthly metering charge**, which is either $3 per month if the capacity of the connection is less than 9 kVA, or $66 per month if the capacity is greater than 9 kVA.
- **All customers pay a fixed monthly charge based on the capacity** of their connection, which is $0.16 per A per month for low voltage customers and $0.80 for all other customers.
- **Medium voltage customers pay a reactive power charge** if their kVARh exceeds 0.75.

5.2 Approach to revising tariff structures

5.2.1 Overall approach

First cost-recovery, then more efficient price signals

EDL's tariffs are currently far below cost recovery levels. This means that consumers currently face prices that do not reflect either average or marginal costs of supply.

To encourage efficient consumption, EDL's first order of priority should be to increase tariffs to something approaching average cost-recovery levels. Once cost-recovery is achieved, EDL can turn its attention to the detail of the tariff structure and how it can be tweaked to better reflect marginal costs. Without cost-recovery, EDL will remain reliant on high Government subsidies, which puts the sustainability of the whole sector at risk.

20 The information we received for EDL regarding the tariff structure varied in its definition of tariff categories, perhaps due to translation from Arabic. Some sources showed an additional category of Schools and Churches.

Therefore, in the following sections we make two different sets of recommendations, each with a different objective:

- **In the short term, how can the tariff structure be adjusted to improve cost-recovery?** Lebanon's Government appears committed to tariff increases, but there are numerous options for applying those increases, i.e. will they be applied uniformly (all charges increase by the same amount) or targeted to particular customer types? Targeted increases may help minimise the political ramifications of increases.

- **In the medium to long term, once cost-recovery is achieved, how can the tariff structure be adjusted to improve economic efficiency?** This is informed by calculations of the marginal cost of supplying different types of customers.

The importance of economic price signals

As above, once EDL achieves cost-recovery, its focus should turn to designing tariff structures that encourage economic efficiency. Tariffs encourage economic efficiency if customers pay prices for electricity that equal the marginal cost of supplying electricity at different voltages, and at different times of the day or different seasons of the year.

When setting economically efficient tariffs, one must, however, recognise the practical constraints of metering. Fully cost reflective tariffs would be complex and complex tariffs require meters that allow consumption to be read by time of day and season of the year. Such meters are more expensive than conventional kWh-only meters and the benefits (cost savings) from introducing complex tariffs together with more complex meters can outweigh the costs of those meters. Falling costs of electronic smart meters over the past few years has meant that it is now more attractive than before to introduce complex tariffs and electronic meters for smaller customers.

The other practical constraint on introducing complex cost-reflective tariffs is that small electricity users will often not be willing to spend enough time and effort to understand complex prices. The benefits of smart meters and complex tariffs are therefore lessened for small users. Despite a growing trend internationally toward smart meters for residential users, the cost-benefit balance in relation to smart meters for households is still debatable.

5.2.2 Economically efficient tariff structures

Different types of charges should be applied to reflect different types of marginal costs

Ideally, tariff structures should reflect the drivers of costs. This implies that an ideal tariff structure will comprise the following elements:

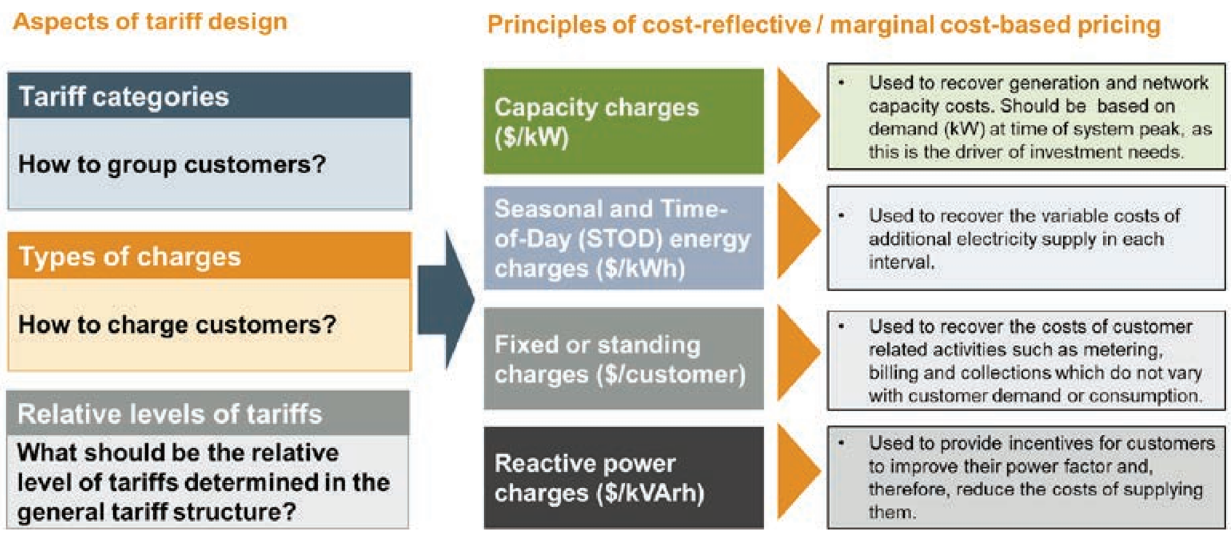
- The fixed costs of generation and network capacity should be recovered through charges based on **demand (kW)** at time of system peak demand, as this is the driver of investment needs.

- Time-varying **energy (kWh)** charges should be used to recover the variable costs of electricity supply in each interval.

- Fixed or **standing charges (per customer)** should be used to recover the costs of customer-related activities such as metering, billing and collections which do not vary with customer demand or consumption.

- Reactive **power charges (kVArh)** should be used to provide incentives for customers to improve their power factor and, therefore, reduce the costs of supplying them.

Figure 64 Theory of tariff design



Source: ECA

In practice, tariffs will deviate from this ideal structure for many reasons including issues of acceptability, simplicity and cost of metering relative to the benefits achieved from more complex tariff structures.

Customer categories should reflect the costs of supply

Customer categories should ideally be based on the principles of minimising the numbers of classes as far as possible, for reasons of transparency and simplicity, while still capturing major differences as regards cost drivers. In addition, the definitions should be capable of easy verification in order to avoid the risk of classifying customers in categories they do not actually belong.

The two cost drivers that we typically focus on are:

- **Voltage level of connection**. This is both a key determinant of costs and is a readily observable means of classifying customers.
- **Consumption profile.** Costs of service to individual customer classes are driven by their contribution to system peak demand and energy consumed in peak hours.

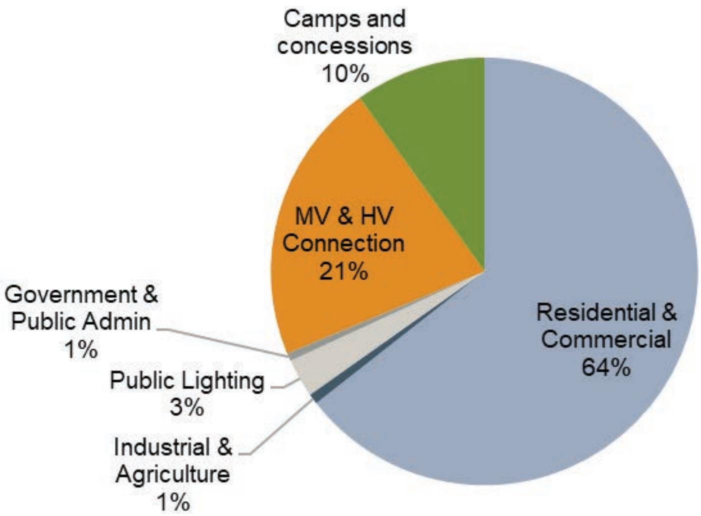
5.3 Recommendations to improve cost-recovery

5.3.1 Target high consumption blocks

Residential and commercial customers make around two-thirds of EDL's revenues

Figure 65 shows the share of EDL's billed revenues by customer category. Around two thirds of EDL's revenue comes from residential and commercial customers, who pay for energy under a rising block tariff. The second highest share in billed revenues comes from medium and high voltage connections (21%).

Figure 65 Share of EDL's billed revenues by customer category, 2015

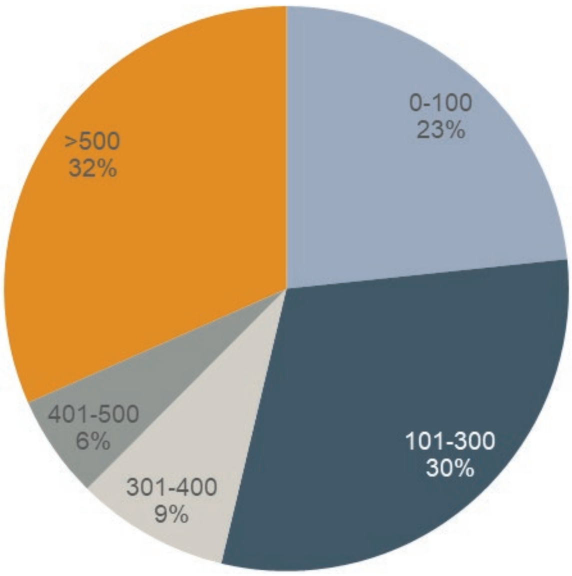


Source: ECA analysis based on EDL and MEW data

The high consumption block is where EDL earns most of its revenues, but most households likely fall in the low consumption blocks

Figure 66 presents the share of energy consumption by block, taking into account residential and commercial customers only. The graph shows that customers in the last tariff block (>500 kWh) consume 32% of energy, followed by customers in the middle block (101-300 kWh, 30%) and lowest block (0-100 kWh, 23%).

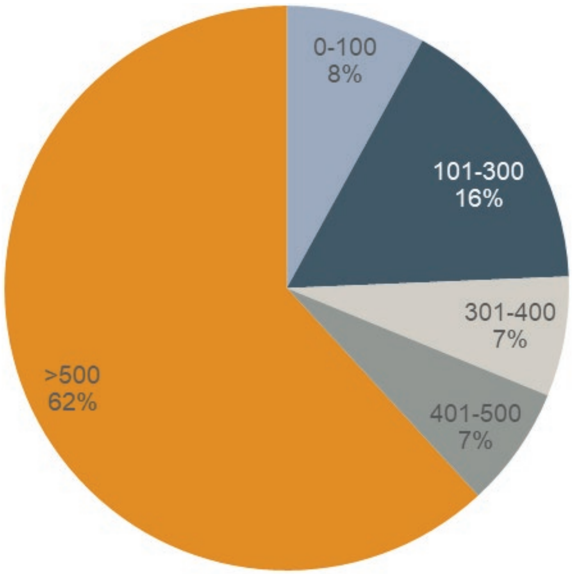
Figure 66 Share of residential and commercial energy consumption by block (2016)



Source: ECA analysis based on EDL and MEW data

Figure 67 presents revenues charged to each of the customer category. Even though the highest tariff block consumes only 32% of energy, the revenue charged accounts for 62% of total revenues in the residential and commercial category. The middle block category (101-300 MWh) accounts for 16% of revenue charged while the remaining categories are charged less than 10% of variable charge revenue each.

Figure 67 Share of residential and commercial variable charge revenue by block (2016)



Source: ECA analysis based on EDL and MEW data

A full breakdown of energy billings and associated revenues in provided in Table 14 below.

Table 14 Energy consumption and revenue by tariff category in 2016

MWh consumption by block	Tariff block	Consumption (MWh)	Energy charge ($/kWh)	Revenue ($m)	% MWh	% Revenue from Energy Charges
Residential and commercial	1-100	1,124,261	0.023	26	15%	5%
Residential and commercial	101-300	1,463,934	0.037	54	19%	10%
Residential and commercial	301-400	422,417	0.053	23	5%	4%
Residential and commercial	401-500	285,305	0.080	23	4%	4%
Residential and commercial	>500	1,522,715	0.133	203	20%	37%
Residential and commercial	Medium tension	46,599	0.09	4	1%	1%
Agriculture and industrial	-	66,050	0.08	5	1%	1%
Government and public admin	Low tension	7,258	0.08	1	0%	0%
Government and public admin	Medium tension	37,015	0.09	3	0%	1%
Public lighting		226,043	0.08	17	3%	3%
MV & HV connections		2,506,798	0.08	192	33%	35%

Source: ECA analysis based on EDL and MEW data

EDL was unable to provide information on the number of customers consuming within each consumption block. It is safe to assume that the majority of households consume within the first two consumption blocks. This is because those blocks account for 53% of residential and commercial consumption, despite spanning a consumption range of only 300 kWh per month. The highest consumption block (>500 kWh per month) is open ended and it is likely that a comparatively small number of connections are responsible for a large share of this consumption (32% of residential and commercial consumption).

Significant subsidy reductions require widespread tariff increases

To illustrate impact of different strategies for increasing EDL's revenue, the table below shows the estimated increase in EDL's total revenue arising from different types of tariff increases. For example, it shows that:

- EDL could leave the first two consumption blocks untouched and increase all other tariffs by 50% (scenario 5 in the table below) and achieve a revenue increase / subsidy decrease of ~$0.6bn.
- EDL could leave the first two consumption blocks untouched and increase all other tariffs by 94% (scenario 6 in the table below) and achieve a decrease in Government subsidy in 2020 of ~$1.2bn, which under the base case assumptions should be enough to eliminate the subsidy altogether.

Table 15 Example tariff increase scenarios

	Tariff adjustment scenario	% increase in total EDL revenues billed	Increase in 2020 revenue ($bn)	Average tariff level ($/kWh)
1	First four residential & commercial consumption blocks combined into a single block and the energy charge for that combined block set to $0.08 per kWh	17.5%	0.29	0.11
2	Residential & commercial energy charge increased by 50%, except the first two blocks	15.8%	0.26	0.11
3	Energy charge increased by 50% for all customers that are not LV residential & commercial	17.9%	0.30	0.11
4	All customers' energy charges increased by 50%, except the first two blocks	33.7%	0.55	0.12
5	All customers' tariffs (both energy and fixed) increased by 50%, except the first two blocks*	39.3%	0.64	0.13
6	All customers' tariffs (both per energy and fixed) increased by 95%, except the first two blocks*	74.0%	1.19	0.16

*EDL was unable to provide a breakdown of connection numbers by customer type. For the purposes of calculating expected impacts on per connection revenues (related to fixed charges), we assume that 50% of connections fall within the first two blocks: Residential and Commercial: 1-100, Residential and Commercial: 101-300 categories.

Source: ECA analysis based on EDL and MEW data

5.3.2 Separating out commercial connections would allow better targeting

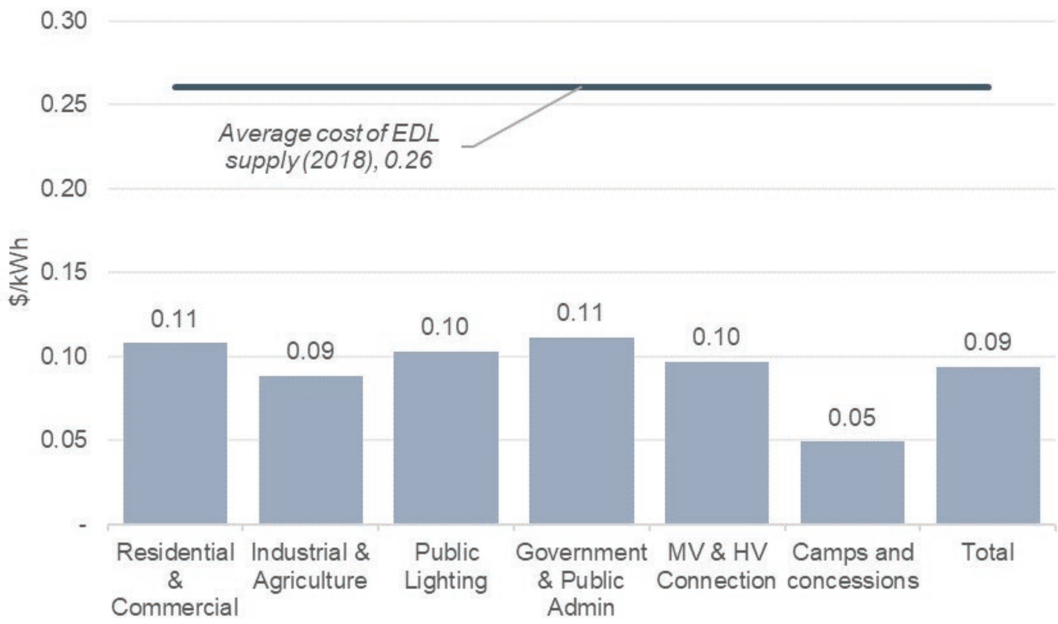
Commercial customers should not be receiving subsidised power

Another possible solution that could help increase EDL's revenue would be to separate residential and commercial customers, thereby allowing EDL to charge them different tariffs.

Currently residential and commercial customers pay the same tariff under a rising block tariff structure. This means that commercial customers pay low tariffs for the first increments of monthly consumption, which is rare by international standards. Some countries subsidise power to make it affordable for low-consumption / poor residential households. But those affordability reasons do not apply to commercial businesses and there are no strong reasons for commercial businesses to receive heavily subsidised power as is currently the practice in Lebanon.

Figure 68 shows average tariffs by customer category. A breakdown of residential and commercial customers is not available (because EDL does not classify them separately in its billing system), but it does show that average tariffs are actually very similar across the various tariff categories.

Figure 68 Average tariffs by customer category (2015 billing data)



Source: ECA analysis based on EDL and MEW data

Separating out residential and commercial customers may allow EDL to increase revenues without impacting residential households.

Ideally EDL would reclassify existing customers, perhaps as part of the smart meter rollout as there is currently no reliable record of residential vs commercial customers in EDL's billing database. But this will take significant time.

A quicker approach to differentiating commercial customers (and wealthier residential households) would be to set charges based on the capacity (rating of the circuit breaker) of a customer's connection. High capacity customers, for example those who run air conditioners or commercial equipment, could be charged higher tariffs. This approach might allow EDL to do away with the rising block tariff structure altogether.

An example tariff structure varying by capacity of connection is shown in the table below.

Table 16 Example tariff structure varying by capacity of connection

Connection capacity	Volumetric charge	Fixed charge
[ ] amp > [ ] amp	[ ] USc/kWh	[ ] $/amp/month
[ ] amp > [ ] amp	[ ] USc/kWh	[ ] $/amp/month
[ ] amp > [ ] amp	[ ] USc/kWh	[ ] $/amp/month
[ ] amp > [ ] amp	[ ] USc/kWh	[ ] $/amp/month
[ ] amp > [ ] amp	[ ] USc/kWh	[ ] $/amp/month

Source: ECA

In the absence of billing data on residential and commercial customers, we are unable to reliably estimate the effects of separating out residential and commercial customers.

5.3.3 Poor households could be targeted directly

Increasing social benefits under the National Poverty Targeting Program could mitigate the impact of tariff increases

In increasing tariff levels, we want to make sure that the most vulnerable households are not significantly affected by price increase. Currently all residential and commercial customers pay low tariffs for the first increments of monthly consumption. One way to increase tariffs while maintaining the social protection would be to increase tariffs in the first few consumption blocks, and instead protect poor households through other more direct mechanisms such as increasing the social assistance benefits under the National Poverty Targeting Program (NPTP) or similar. The NPTP database currently includes 60,000 households (~5% of the populations) who are classified as extremely poor.

An alternative solution would be to protect vulnerable households by classifying them within EDL's billing database and charging those household a lower tariff. However, consumption in the first two tariff blocks only makes up less than 15% of EDL's tariff revenue, so the impact would be limited. As an example, setting the tariff to $0.08 per kWh for the first four blocks would only increase total EDL revenues by approximately 18%.

5.4 Marginal cost of supply

5.4.1 Methodology

We estimate the marginal costs of energy, generation capacity, and network capacity, separately for each customer category

To estimate EDL's marginal cost of providing electricity for different customer groups, we follow four steps:

- Estimate the **marginal cost of generation**, both with respect to capacity ($/kW) and energy ($/kWh), and then use estimated network losses to estimate it by voltage level;
- Estimate the **marginal (incremental) cost of networks investment** ($/kW), by voltage level;
- Calculate the total marginal costs, i.e. for both generation and networks investment, **for each customer group** based on their voltage level, and load profile; and
- Allocate the total marginal costs to **different seasons and times of the day**, based on the annual and daily system load curves (i.e. when the annual peak occurs)

As per Section 5.3 above, EDL should first prioritise cost-recovery before improving the economic efficiency of its tariff structure. This means that marginal cost calculations are unlikely to be used till around the time that LNG arrives, i.e. when EDL is likely to be able to cover its costs. We therefore calculate marginal costs for the year 2022. In calculating marginal costs, we assume supply equals demand (i.e. there is no load shedding).

5.4.2 Marginal cost of generation

The marginal cost of generation capacity is $173 per kW, before adjusting for losses

We assume that future peaking generating capacity will be provided by open cycle gas turbine generators, given their relatively low capital costs and the future availability of LNG in Lebanon.

We assume a cost of $143,725 per MW of capacity. This is based on the following:

- Overnight cost of $1m per MW, based on MEW advice.
- Project development costs of $15,000 per MW.
- Interest during construction of 9.1% per year, with an assumed construction profile of 10% in year 1, 45% in year 2, and 45% in year 3.
- The resulting all-in cost is $1.174m per MW.
- Converted to an annualise cost at a discount rate of 9.1% and a life of 25 years, gives $120,525 per MW.
- Plus $23,200 per MW for annual fixed O&M costs.

On top of the $143,725 per MW per year for generating capacity, we add 20% as a reserve margin. This gives a total cost of $172,570 per MW of capacity.

To allocate this by voltage level, we assume the following split of network losses in 2022.[21]

Table 17 Assumed split of technical network losses for year 2022

Network (voltage level)	At system peak (% of total sent out demand)	Average (% of total sent out demand)
HV	4.0%	3.0%
MV	2.8%	2.1%
LV	6.5%	4.9%
All	13.3%	10.0%

Source: EDL data and ECA assumptions

The resulting marginal cost of generating capacity is summarised in the table below.

Table 18 Marginal cost of generating capacity by voltage level ($/kW of capacity)

Voltage level of supply	MC of generation capacity (US$/kW)
Sent out	172.5
HV	176.0
MV	183.3
LV	191.0

Source: ECA

The marginal cost of energy generated is around 11c per kWh, based on the variable cost of peaking generators

We assume that the cost of the marginal 'peaking' OCGT generator is $10.6 per MWh sent out. This is based on the forecast cost of LNG-fired OCGT generators at an LNG price of $9.8/mmbtu (and an oil price of $66/bbl).

Table 19 Marginal cost of energy generation by voltage level ($/kWh)

Voltage level of supply	MC of energy generation ($/kWh)
Sent out	0.106
HV	0.109
MV	0.112
LV	0.117

Source: ECA

5.4.3 Marginal cost of network investments

The marginal cost of network investments is calculated using the LRAIC method

The Long Run Average Incremental Cost (LRAIC) method is typically used to estimate the marginal cost of network investment. This method essentially calculates average cost of new investments required to meet additional demand over a period of 10 years or more. It is described in the following formula:

$$LRMC_T = \frac{\sum_{i=1}^{T} \frac{I_i}{(1+r)^i}}{\sum_{i=1}^{T} \frac{\Delta MW_i}{(1+r)^i}}$$

where:

I_i =investment cost in year i
T = planning horizon
ΔMW = incremental load relative to previous year
r = discount rate

The resulting marginal cost is expressed as the annualised[22] network capacity cost per kW per year. This cost is then subsequently adjusted upwards for incremental fixed O&M expenses.

The marginal cost of transmission network capacity is around $45 per kW per year, based on the EDF Masterplan

To estimate the marginal cost of HV network investments in Lebanon, we use the 2017 Updated of the Transmission Masterplan, prepared by EDF. The study estimates total capex of 353 million Euro between 2017 and 2023, and 201 million Euro between 2024 and 2030. Converting these to US dollars and spreading the cost evenly across the two periods, results in annual costs of $58m between 2017 and 2023, and $33 million between 2024 and 2030. EDF estimated that cost based on an increase in peak demand of 1,688 MW over the ten-year period from 2017 to 2026. The resulting long run cost is $38 per kW per year. To that we add fixed O&M expenses, which we assume are 2% of per kW investment costs (before they are converted to an annual amount). The resulting total LRAIC for the HV network is $44 per kW per year.

The marginal cost of distribution network capacity is around $77 per kW per year, based on DSP investment forecasts

To estimate the marginal cost of MV and LV network investments in Lebanon, we use the estimated costs of investment distribution networks, as provided by the DSPs to MEW. These costs are approximately $83m per year over the next ten years. We assume that 50% of these costs are attributable to the MV network and 50% to the LV network and that fixed O&M costs on the networks is 4%. The resulting LRAIC for MV and LV networks is $34 per kW per year and $29 per kW per year respectively.

The total network marginal cost applying to the whole network is $110 per kW per year

The resulting marginal costs are summarised in the table below. The costs differ by voltage level of supply due to different power losses at each level.

Table 20 Marginal cost of network investment

Voltage level of supply	MC of HV network ($/kW/yr)	MC of MV network ($/kW/yr)	MC of LV network ($/kW/yr)	Total ($/kW/yr)
HV	43.9			43.9
MV	45.7	33.6		79.3
LV	47.6	33.6	29.1	110.3

Source: ECA

5.4.4 Total marginal cost by customer category

Total marginal costs are $301 per kW per year for generation and network capacity plus 12c per kW for generation energy, after adjusting for losses

Summing the marginal generation costs and marginal network investment costs results in the total marginal costs shown in the table below.

Table 21 Total system marginal costs

Voltage level of supply	MC of generation ($/kW/yr)	MC of HV network ($/kW/yr)	MC of MV network ($/kW/yr)	MC of LV network ($/kW/yr)	Total MC of capacity ($/kW/yr)	MC of energy generation ($/kWh)
Sent out	172.5	-	-	-	172.5	0.106
HV	176.0	43.9	-	-	219.8	0.109
MV	183.3	45.7	33.6	-	262.6	0.112
LV	191.0	47.6	33.6	29.1	301.3	0.117

Source: ECA

To allocate marginal costs between different customer categories, we assume load characteristics

The marginal costs in the table above are the costs at the system peak. To convert this to marginal costs for each customer category, we need to adjust for each customer category's load characteristic (coincidence factor and diversity factor), which are summarised in the table below. In the absence of data from Lebanon, we assume values based on other countries in the region. These values assume that residential customers define the system peak (have a high coincidence factor), which is suggested by the evening peak in Lebanon.

Table 22 Assumed load characteristics by customer category

Customer category name	Coincidence Factor (%)	Diversity Factor (%)
Residential LV	98%	90%
Commercial LV	60%	90%
Commercial MV	65%	90%
Industrial MV	90%	90%
Industrial HV	90%	90%
Agriculture LV	65%	90%

Source: ECA

The resulting marginal costs show that residential households are the most expensive to supply, because they define the system peak and are connected to the LV network

The resulting marginal costs by category are shown in the table below.

Table 23 Marginal cost by customer category

Customer type	MC of energy generation (USc/kWh)	MC of capacity ($/kW/yr)
Residential LV	11.7	266
Commercial LV	11.7	163
Commercial MV	11.2	154
Industrial MV	11.2	213
Industrial HV	10.9	178
Agriculture LV	11.7	176

Source: ECA

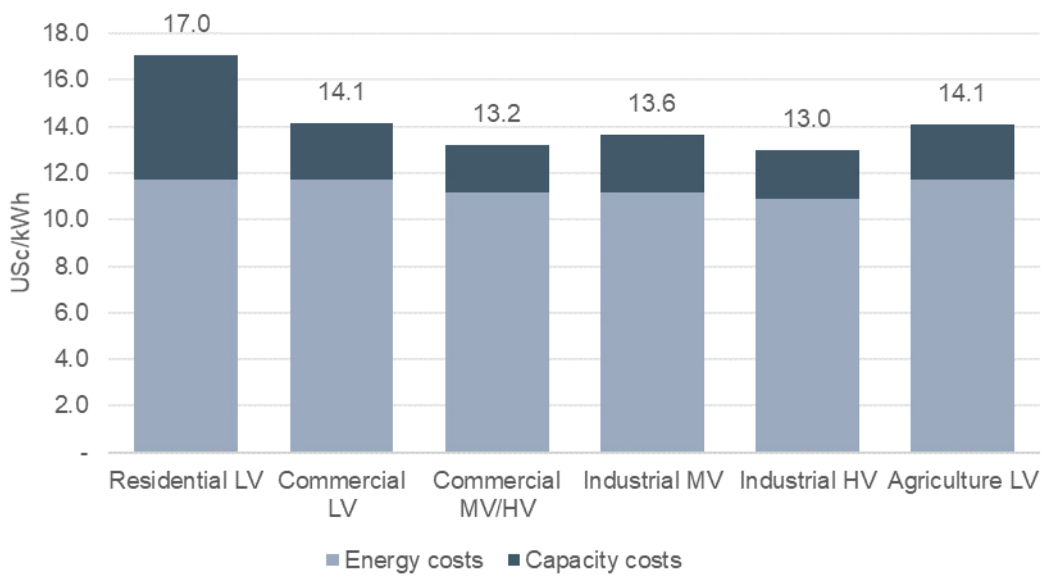
Table 24 Marginal cost by customer category, converted to per kWh

Customer type	MC of energy generation (USc/kWh)	MC of capacity (USc/kWh)	Total MC (USc/kWh)
Residential LV	11.7	5.3	17.0
Commercial LV	11.7	2.4	14.1
Commercial MV	11.2	2.1	13.2
Industrial MV	11.2	2.5	13.6
Industrial HV	10.9	2.1	13.0
Agriculture LV	11.7	2.4	14.1

Source: ECA

The figure below shows marginal costs by customer category, converted to a single per kWh charge for ease of comparison.

Figure 69 Marginal costs as annual average, in per kWh terms



Source: ECA analysis based on EDL and MEW data

The key results shown in the figure, which are in line with the results we would expect based on other countries in the region, are:

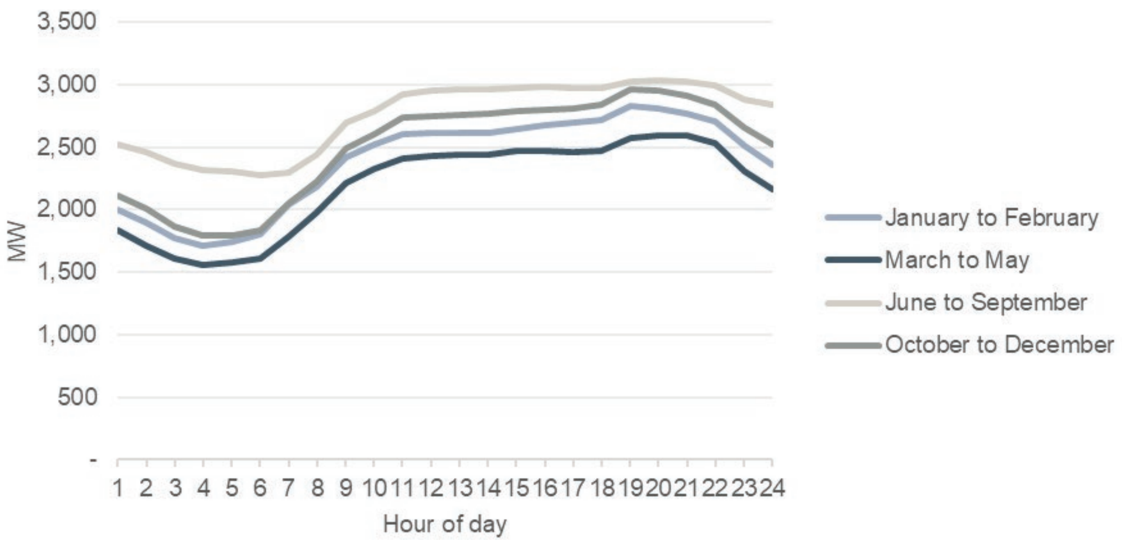
- **Residential households are the most expensive to supply**, because they are connected to the LV network (which has high technical losses) and because they define the system peak (and therefore the need for additional generation and network capacity).
- The **marginal cost of supplying residential customers** ($0.17 per kWh) is **similar to the expected average cost of supply** in 2022 ($0.16 per kWh). Unlike many countries, the difference is not significant because Lebanon does not have large legacy sources of cheap generation (e.g. hydro).

5.4.5 Seasonal and time of day variation

Peak demand occurs in the summer evenings

The figure below shows the average demand by season in 2016[23]. The demand starts increasing from 6am until noon and then it stays relatively flat (although there is a much smaller peak in the evening hours). It is likely that the evening peak is supressed due to load shifting to private generators (many of which do not meter).

Figure 70 Average demand by season in 2016



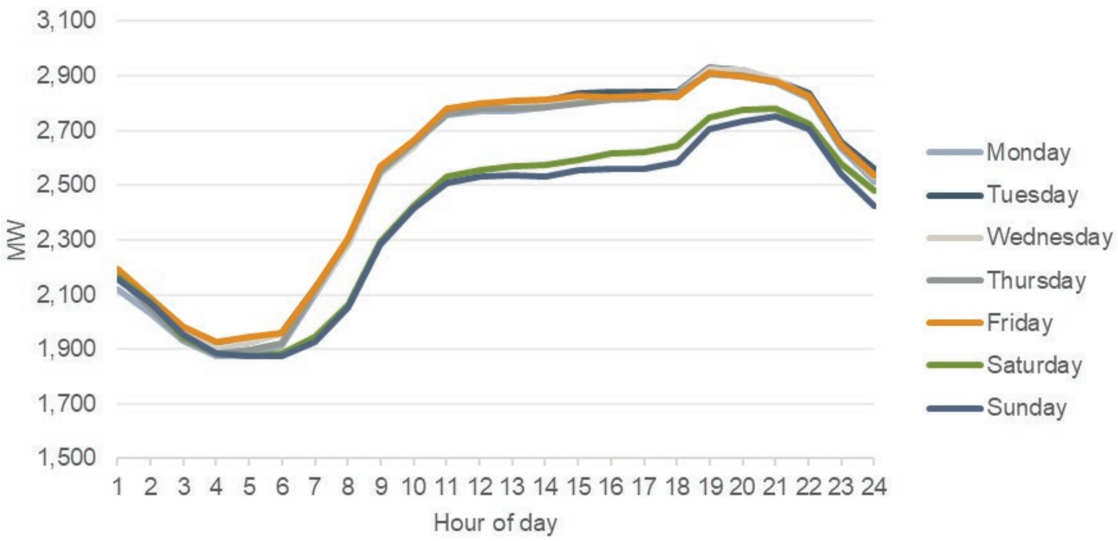
Source: ECA analysis based on EDL and MEW data

The highest demand occurs in the summer months and varies between 2,281 MW at 6am and 3,177 MW at 9pm (on average for 2017).

Demand on weekends is significantly lower

Figure 71 depicts average demand by day of the week in 2016. The highest demand occurs between Monday and Friday during the working week. On Saturday and Sunday demand is lower due to the commercial activity decreasing over the weekend.

Figure 71 Average demand by day of week in 2016



Source: ECA analysis based on EDL and MEW data

Increases in peak demand require EDL to invest in new capacity, which raises costs of supply

As shown above, demand typically starts increasing from 6am until noon and then it stays relatively flat with a small peak in the evening hours. It is likely that the evening peak is supressed due to load shifting to private generators (many of which do not meter), as discussed in Section 3. Increases in demand during peak hours require EDL to invest in new generation and network capacity. This means that it is much more expensive for EDL to supply energy during peak hours than during off peak hours. The same logic applies to seasonal effects – capacity costs are mostly incurred during June to September.

Therefore, all customers for whom the costs installing a smart meter are justified and whom have significant ability to shift demand, should pay demand/capacity charges that vary by time of day (peak and off-peak) and by season. At present EDL does apply time of day pricing, but only to the largest customers and there is no seasonal variation.

Marginal costs of energy generation are unlikely vary significantly by time of day or season

EDL's hourly short-run marginal costs are not likely to fluctuate significantly by hour, given future reliance on LNG. Therefore time-of-day and season tariffs only need to vary based on capacity costs (as discussed above), rather than based on energy costs.

5.5 Recommendations to improve economic efficiency

First cost-recovery, then cost-reflectivity

Cost-recovery of tariffs should be the first and foremost priority in achieving the sustainability of the power sector. Once total revenue covers all EDL's costs, EDL can focus on cost-reflectivity, that is designing the tariff structure in a way that reflects the true costs of supply.

Cost reflectivity is achieved when customers pay different types of charges (energy, demand, standing, etc.) that reflect the different costs of supply. The price-setting mechanism should be based on the marginal cost of supplying more power so that customers decision whether to consume more power are based on the underlying cost of supplying that increment in consumption.

All MW and HV customers should pay demand charges, to better signal marginal capacity costs

A demand charge is based on the highest power demand in a specified time period. Increased peak demand requires EDL to invest in new generation capacity and power network, making it more expensive to supply power. Therefore, we recommend that all MV and HV customers pay demand charges, to better signal marginal capacity costs.

There should be seasonal demand charges to reflect that peak load in summer is significantly higher than other months

High peak load in the summer (and to a lesser extent winter months) increases the costs for EDL as it needs to switch on the peaking power plants to meet the additional demand. Introducing seasonal capacity charges would reflect the increased costs of supply in the summer months and would encourage customers to shift their demand where possible.

Time-of-day tariffs should be implemented for larger customers to encourage them to shift demand to off-peak hours

EDL's hourly short-run marginal costs are not likely to fluctuate widely by hour – at most the difference between CCGT and OCGT fuel costs – given the sectors future reliance on LNG-fired thermal plants. Nevertheless, time-of-day tariffs should still be implemented for large customers to encourage them to shift demand to off-peak hours, thereby saving EDL capacity costs.

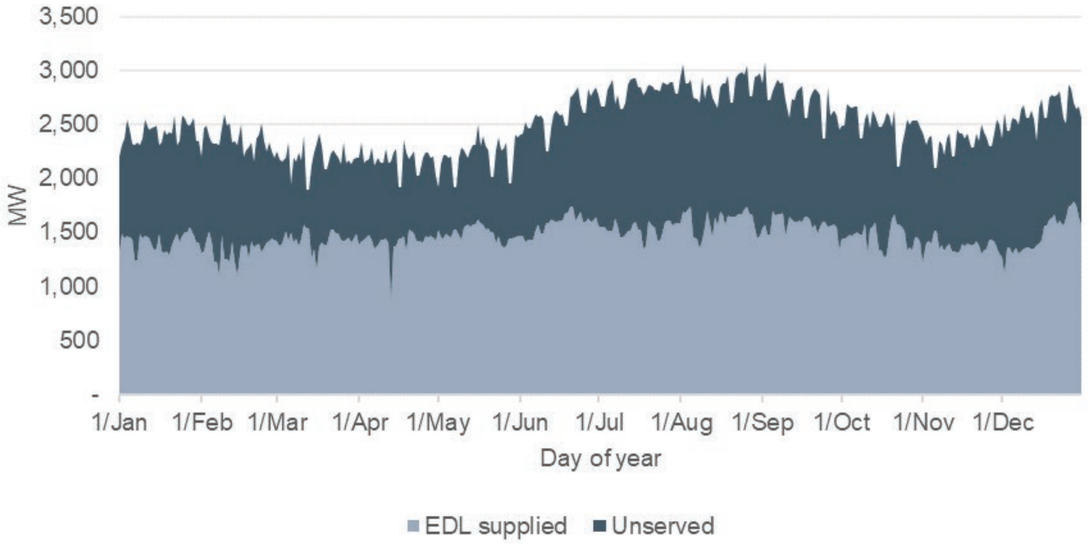
EDL should distinguish between commercial and residential customers at different voltage levels

The costs of supply at different voltage levels will vary significantly. To reflect those differences, EDL should reclassify its customers (potentially as part of the smart meter rollout) and base its charges on the customer category and voltage levels.

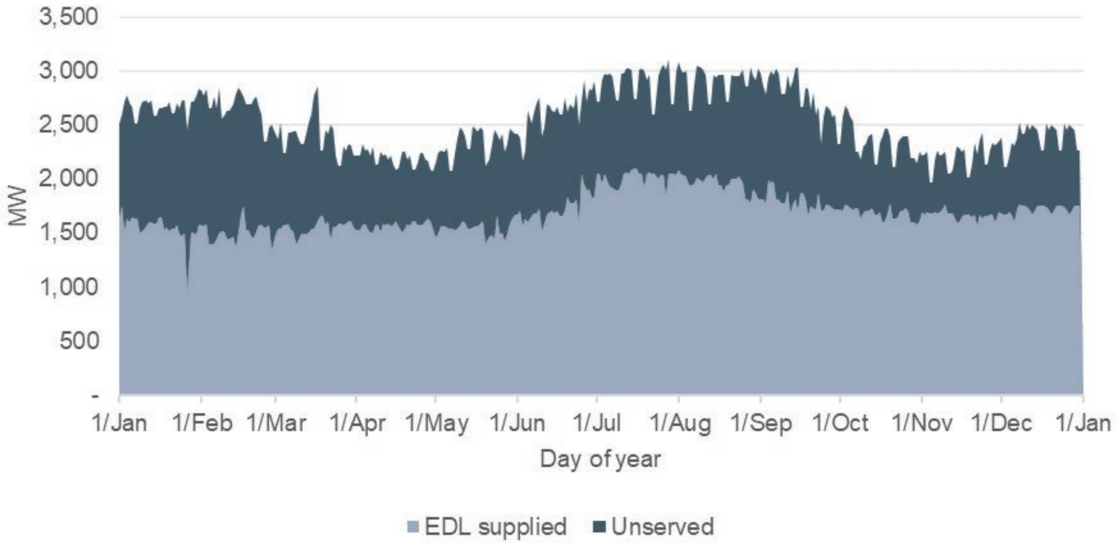
ANNEXES

A1. EDL DATA ON SUPPLY AND DEMAND

A1.1 Average demand/supply over year, 2016



A1.2 Average demand/supply over year, 2017



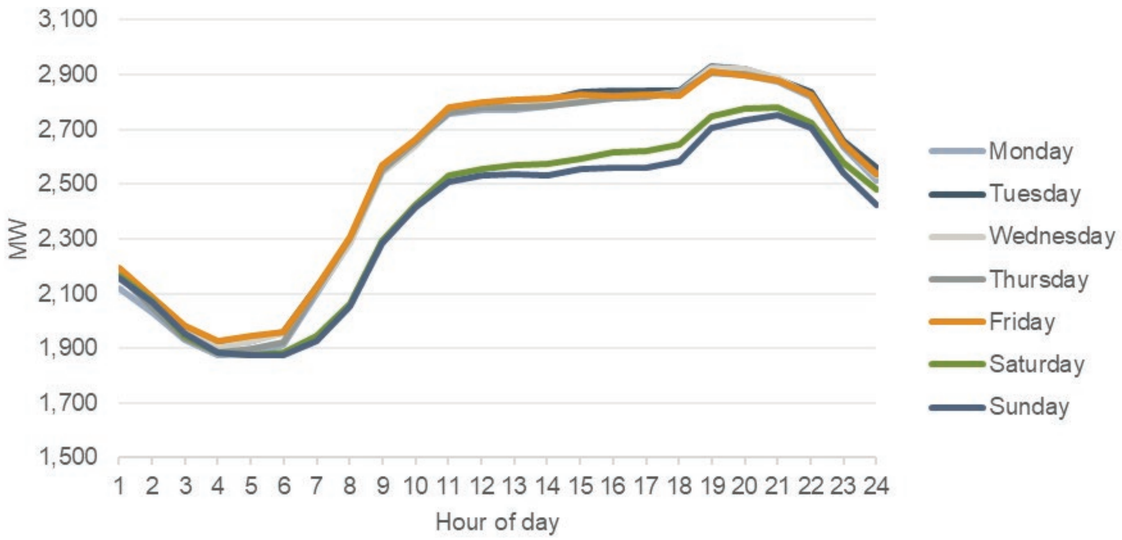
A1.3 Estimated average demand by month from EDL data, 2016

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 January	2,057	1,938	1,802	1,722	1,765	1,822	2,057	2,213	2,468	2,574	2,652	2,652	2,645	2,645	2,657	2,686	2,707	2,738	2,838	2,827	2,800	2,747	2,571	2,418
2 February	1,945	1,848	1,741	1,695	1,729	1,786	2,013	2,151	2,377	2,467	2,558	2,573	2,575	2,588	2,636	2,662	2,684	2,705	2,813	2,785	2,742	2,667	2,456	2,299
3 March	1,790	1,657	1,551	1,513	1,531	1,588	1,789	1,994	2,224	2,345	2,406	2,425	2,423	2,421	2,461	2,467	2,459	2,482	2,673	2,660	2,624	2,557	2,317	2,141
4 April	1,845	1,710	1,592	1,547	1,559	1,600	1,774	1,973	2,197	2,319	2,399	2,408	2,413	2,417	2,447	2,436	2,436	2,428	2,548	2,598	2,598	2,518	2,285	2,140
5 May	1,879	1,774	1,678	1,618	1,643	1,649	1,798	1,973	2,212	2,334	2,428	2,461	2,492	2,488	2,495	2,502	2,495	2,497	2,502	2,532	2,575	2,525	2,316	2,209
6 June	2,333	2,279	2,213	2,137	2,116	2,061	2,100	2,276	2,536	2,624	2,785	2,804	2,819	2,823	2,854	2,846	2,839	2,841	2,874	2,896	2,902	2,870	2,716	2,660
7 July	2,568	2,493	2,433	2,390	2,392	2,378	2,356	2,524	2,787	2,882	3,000	3,022	3,025	3,045	3,044	3,042	3,042	3,037	3,088	3,078	3,066	3,045	2,906	2,879
8 August	2,653	2,596	2,511	2,458	2,471	2,465	2,453	2,549	2,785	2,884	3,007	3,039	3,034	3,031	3,051	3,070	3,068	3,068	3,113	3,107	3,122	3,093	3,005	2,956
9 September	2,521	2,454	2,331	2,278	2,232	2,210	2,272	2,393	2,689	2,777	2,912	2,938	2,960	2,957	2,964	2,957	2,940	2,938	3,017	3,040	3,021	2,968	2,907	2,865
10 October	2,213	2,126	1,988	1,907	1,885	1,907	2,081	2,215	2,491	2,588	2,707	2,735	2,752	2,757	2,790	2,765	2,762	2,751	2,916	2,913	2,882	2,809	2,691	2,554
11 November	1,886	1,783	1,653	1,604	1,634	1,686	1,914	2,131	2,382	2,486	2,634	2,634	2,641	2,636	2,644	2,679	2,700	2,768	2,869	2,838	2,779	2,704	2,461	2,324
12 December	2,224	2,104	1,952	1,865	1,864	1,913	2,148	2,314	2,603	2,726	2,858	2,883	2,887	2,901	2,918	2,940	2,969	3,007	3,093	3,095	3,059	3,005	2,810	2,681

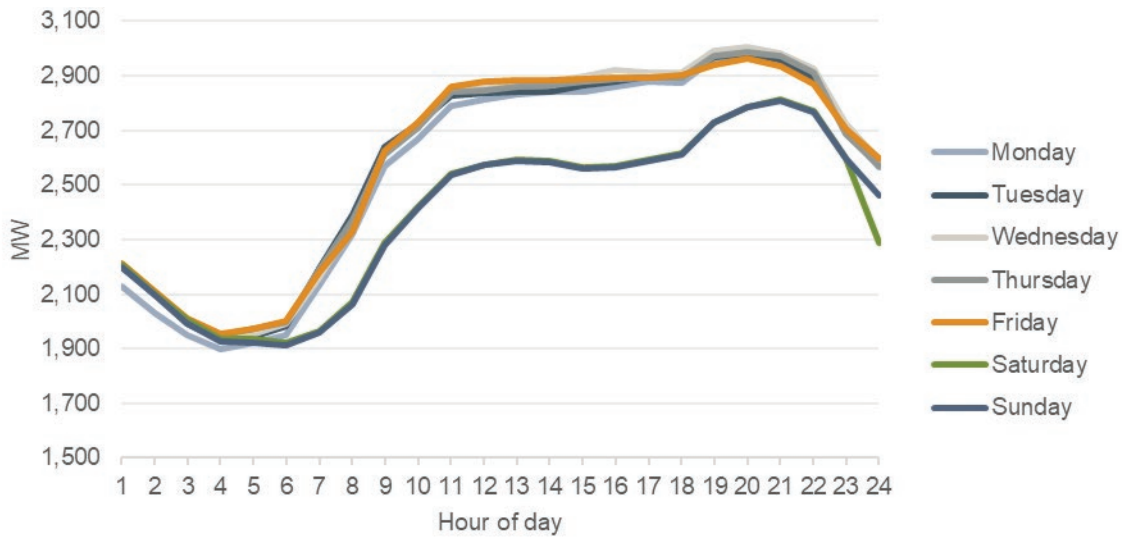
A1.4 Estimated average demand by month from EDL data, 2017

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 January	2,294	2,190	2,040	1,962	1,996	2,057	2,276	2,449	2,698	2,782	2,874	2,892	2,879	2,908	2,899	2,917	2,930	2,975	3,102	3,098	3,070	3,026	2,852	2,725
2 February	2,250	2,181	2,065	1,978	2,024	2,079	2,366	2,491	2,752	2,809	2,893	2,910	2,914	2,903	2,904	2,915	2,926	2,945	3,106	3,088	3,050	3,037	2,838	2,659
3 March	1,974	1,854	1,777	1,708	1,737	1,792	1,994	2,186	2,418	2,523	2,624	2,629	2,635	2,637	2,645	2,643	2,644	2,659	2,821	2,848	2,833	2,755	2,545	2,360
4 April	1,839	1,727	1,648	1,600	1,597	1,640	1,808	1,953	2,222	2,332	2,436	2,446	2,459	2,463	2,457	2,458	2,441	2,400	2,443	2,586	2,619	2,513	2,329	2,146
5 May	1,997	1,871	1,746	1,701	1,704	1,707	1,860	2,044	2,295	2,447	2,620	2,632	2,638	2,639	2,657	2,650	2,638	2,616	2,657	2,712	2,760	2,690	2,459	2,216
6 June	2,418	2,343	2,237	2,158	2,108	2,038	2,067	2,255	2,520	2,652	2,814	2,844	2,866	2,872	2,889	2,885	2,892	2,890	2,934	2,934	2,957	2,944	2,832	2,580
7 July	2,686	2,615	2,515	2,463	2,465	2,410	2,435	2,583	2,833	2,912	3,044	3,076	3,101	3,086	3,117	3,129	3,135	3,126	3,118	3,149	3,177	3,179	3,067	3,034
8 August	2,705	2,629	2,532	2,470	2,470	2,438	2,449	2,589	2,836	2,924	3,068	3,062	3,107	3,117	3,139	3,142	3,141	3,123	3,166	3,200	3,224	3,212	3,103	3,056
9 September	2,504	2,418	2,326	2,270	2,282	2,286	2,321	2,449	2,710	2,835	2,979	3,004	3,027	3,027	2,995	3,011	3,020	2,988	3,089	3,147	3,128	3,082	2,897	2,823
10 October	1,929	1,832	1,757	1,718	1,731	1,778	1,929	2,076	2,317	2,442	2,601	2,630	2,632	2,636	2,643	2,642	2,646	2,651	2,815	2,814	2,740	2,624	2,392	2,229
11 November	1,759	1,640	1,568	1,527	1,557	1,624	1,851	2,026	2,232	2,361	2,435	2,473	2,467	2,459	2,475	2,514	2,556	2,641	2,680	2,659	2,609	2,486	2,234	2,051
12 December	1,956	1,797	1,709	1,659	1,693	1,753	1,984	2,172	2,405	2,512	2,595	2,632	2,649	2,645	2,610	2,646	2,712	2,774	2,875	2,889	2,859	2,788	2,550	2,385

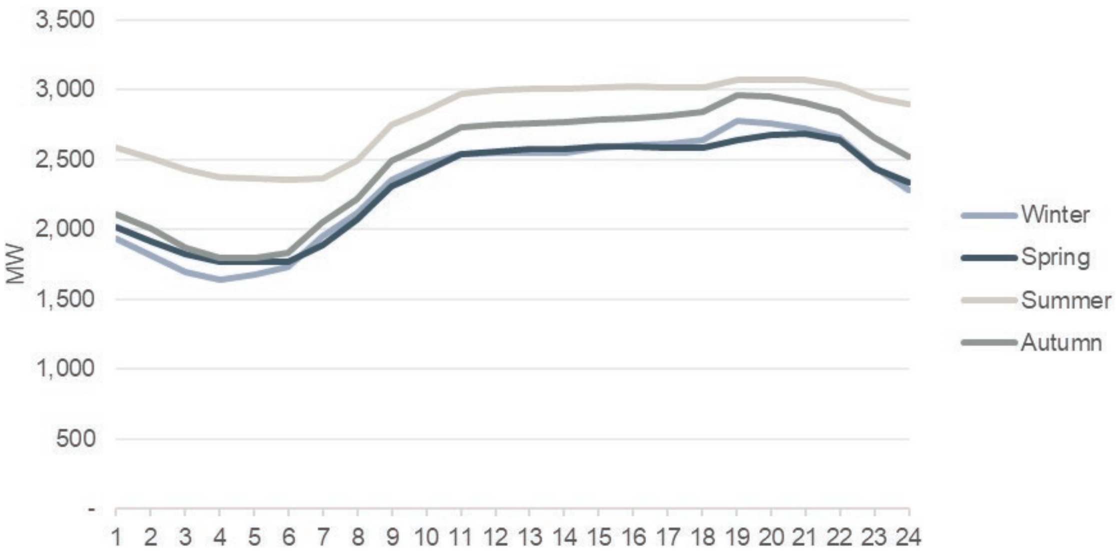
A1.5 Estimated average demand by day of the week, 2016



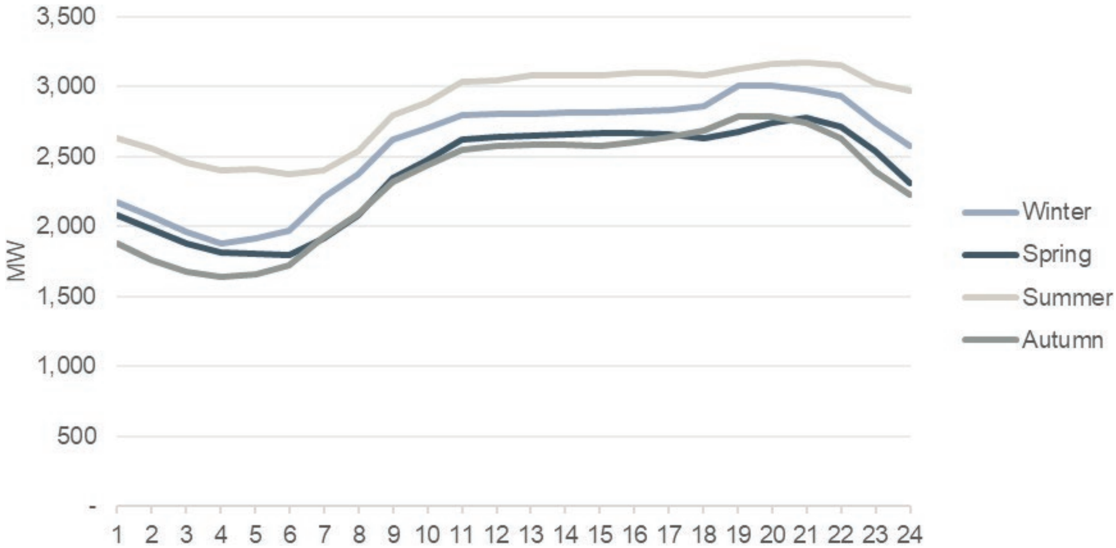
A1.6 Estimated average demand by day of the week, 2017



A1.7 Estimated average demand by season, 2016



A1.8 Estimated average demand by season, 2017



A2. EDL DATA ON GENERATION

A2.1 Existing generation

Name	Current Fuel type	Technology	Firm capacity	Year switch to LNG	End year	Design capacity (MW)	De-rated capacity (MW)	Availability factor/Capacity factor for RE (%)	Fuel efficiency with current fuel (GJ/MWh)	Fuel efficiency with LNG (GJ/MWh)	IPP energy charge ($/MWh)
Existing EDL											
Zouk	Fuel Oil (Grade A)	Steam Turbine	Yes		2020	607	300	65%	11.6		
Jieh	Fuel Oil (Grade A)	Steam Turbine	Yes		2020	343	140	68%	15.0		
Zouk Recip	Fuel Oil (Grade B)	Recip	Yes	2023	2046	194	194	88%	7.8	7.6	
Jieh Recip	Fuel Oil (Grade B)	Recip	Yes	2023	2046	78	78	87%	8.1	7.8	
Zahrani	Gas Oil	CCGT	Yes	2022	2028	469	435	89%	7.3	6.4	
Deir Amar	Gas Oil	CCGT	Yes	2022	2028	464	435	73%	8.4	7.4	
Baalbak	Gas Oil	OCGT	Yes	2022	2028	64	60	36%	11.6	11.1	
Sour (Tyr)	Gas Oil	OCGT	Yes	2022	2028	72	60	44%	12.5	11.9	
Safa (Richmaya)	Hydro	Hydro				13	12	9%			
Naameh	Biogas	Biogas	Yes			7	7	105%			
Existing - Barges											
KPS Zouk	Fuel Oil (Floating)	Recip	Yes	n/a	2021	187	185	95%	8.6	8.9	49
KPS Jieh	Fuel Oil (Floating)	Recip	Yes	n/a	2021	187	185	95%	8.6	8.9	49
Existing - IPPs											
Litani	Hydro	Hydro	Yes			199	47	45%			40
Nahr Ibrahim	Hydro	Hydro				32	17	44%			26
Bared	Hydro	Hydro				17	6	56%			26
Kadisha hydro	Hydro	Hydro				21	15	45%			26
Hrayche	Fuel Oil (Grade A)	Steam Turbine	Yes			75	45	51%	13.0		54
Imports											
Syria	Imports		Yes				150	41%	1.0		

Source: ECA

A2.2 Planned generation (base case)

Name	Current Fuel type	Tech-nology	Firm capacity	Year switch to LNG	End year	Design capacity (MW)	De-rated capacity (MW)	Availability factor/ Capacity factor for RE (%)	Fuel efficiency with current fuel (GJ/MWh)	Fuel efficiency with LNG (GJ/MWh)	IPP energy charge ($/MWh)	IPP capacity charge ($/MW)
New - Fast Track Generation												
Fast Track Deir Amar	Fuel Oil (Grade B)	Recip	Yes	2022	2024	450	450	90%	8.6	8.3		324,996
Fast Track Jieh	Fuel Oil (Grade B)	Recip	Yes	2023	2024	100	100	90%	8.6	8.3		324,996
Fast Track Zahrani	Fuel Oil (Grade B)	Recip	Yes	2022	2024	400	400	90%	8.6	7.2		226,884
Fast Track Bint Jbeil	Fuel Oil (Grade B)	Recip	Yes	2022	2024	50	50	90%	10.3	9.9		251,412
Fast Track Jib Jannine	Fuel Oil (Grade B)	Recip	Yes	2022	2024	50	50	90%	10.3	9.9		251,412
New - IPPs												
DAPPII PPA (OC)	Fuel Oil (Grade B)	OCGT	Yes	2022	2022	360	360	89%	10.8	10.8		180,894
DAPPII PPA (CC)	Fuel Oil (Grade B)	CCGT	Yes	2022	2028	550	550	89%	7.2	7.1		180,894
Zahrani II CCPP (OC)	Fuel Oil (Grade B)	OCGT	Yes	2022	2022	430	430	89%	10.8	10.8		156,979
Zahrani II CCPP (CC)	Fuel Oil (Grade B)	CCGT	Yes	2022	2028	650	650	89%	7.2	7.1		156,979
Selaata I CCPP (OC)	Fuel Oil (Grade B)	OCGT	Yes	2022	2022	500	500	89%	10.8	10.8		156,979
Selaata I CCPP (CC)	Fuel Oil (Grade B)	CCGT	Yes	2022	2028	740	740	89%	7.2	7.1		156,979
Jieh New CCPP (OC)	Fuel Oil (Grade B)	OCGT	Yes	2023	2028	360	360	89%	10.8	10.8		156,979
Jieh New CCPP (CC)	Fuel Oil (Grade B)	CCGT	Yes	2023				89%	7.2	7.1		156,979
Zouk New CCPP (OC)	Fuel Oil (Grade B)	OCGT	Yes	2023	2028	360	360	89%	10.8	10.8		156,979
New wind 1 (rate 1)	Wind	Wind			2023	200	200	40%			105	
New wind 1 (rate 2)	Wind	Wind			2028	200	200	40%			96	
New wind 2	Wind	Wind			2028	400	400	40%			96	
New PV 1	Solar	Solar			2028	180	180	18%			70	
New PV 2	Solar	Solar			2028	300	300	18%			70	
New PV 3	Solar	Solar			2028	360	360	18%			70	
Janneh Hydro	Hydro	Hydro			2028	54	54	58%			70	
New Hydro (Daraya, Chamra, Yamouneh, Blat)	Hydro	Hydro			2028	33	33	50%			70	

A3. FORECAST ENERGY BALANCE (BASE CASE)

A3.1 Forecast demand balance

		Actuals/Estimates						Forecasts					
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Summary of demand													
Demand for energy billed	MWh	13,043,418	14,016,471	14,161,740	14,503,154	16,700,564	19,004,448	19,124,607	19,733,947	20,325,965	20,935,744	21,563,816	22,210,731
Non-technical losses	MWh	5,283,075	4,885,011	5,083,547	5,319,491	3,716,760	1,719,085	803,273	791,770	815,523	839,989	865,188	891,144
Technical losses	MWh	3,122,237	3,211,066	3,263,216	3,361,113	2,614,774	2,128,671	1,795,282	1,541,206	1,587,442	1,635,065	1,684,117	1,734,641
Demand for energy sent out	MWh	21,448,731	22,112,548	22,508,502	23,183,758	23,032,098	22,852,205	21,723,162	22,066,922	22,728,930	23,410,798	24,113,122	24,836,516
Demand for energy collected	MWh	12,743,250	10,303,255	9,373,624	13,777,996	15,865,536	18,054,226	18,168,377	18,747,249	19,309,667	19,888,957	20,485,626	21,100,194
Peak load	MW	3,345	3,469	3,511	3,616	3,592	3,564	3,388	3,442	3,545	3,652	3,761	3,874
Growth in energy consumption	%		3.1%	1.8%	3.0%	3.0%	1.5%	-3.8%	3.0%	3.0%	3.0%	3.0%	3.0%
Summary of losses													
Non-technical losses	% of energy sent out	24.6%	22.1%	22.6%	22.9%	16.1%	7.5%	3.7%	3.6%	3.6%	3.6%	3.6%	3.6%
Technical losses	% of energy sent out	14.6%	14.5%	14.5%	14.5%	11.4%	9.3%	8.3%	7.0%	7.0%	7.0%	7.0%	7.0%
Total losses	% of energy sent out	39.2%	36.6%	37.1%	37.4%	27.5%	16.8%	12.0%	10.6%	10.6%	10.6%	10.6%	10.6%
Demand energy balance													
Estimated total system demand	MWh	21,448,731	22,112,548	22,508,502	23,183,758	23,032,098	22,852,205	21,723,162	22,066,922	22,728,930	23,410,798	24,113,122	24,836,516
Transmission technical losses	%	4.0%	4.0%	4.0%	4.0%	3.5%	3.5%	3.5%	3.0%	3.0%	3.0%	3.0%	3.0%

		Actuals/Estimates						Forecasts					
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Transmission technical losses	MWh	868,170	895,039	911,065	938,397	800,365	794,114	754,880	657,594	677,322	697,642	718,571	740,128
Transmission energy billed	MWh	3,241,579	3,401,913	3,503,970	3,609,089	3,717,362	3,522,572	3,628,250	3,737,097	3,849,210	3,964,686	4,083,627	4,206,136
Energy entering the distribution system	MWh	17,338,982	17,815,597	18,093,467	18,636,271	18,514,370	18,535,518	17,340,033	17,672,231	18,202,398	18,748,470	19,310,924	19,890,252
Distribution technical losses	%	13.0%	13.0%	13.0%	13.0%	9.8%	7.2%	6.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Distribution technical losses	MWh	2,254,068	2,316,028	2,352,151	2,422,715	1,814,408	1,334,557	1,040,402	883,612	910,120	937,424	965,546	994,513
Distribution energy consumed	MWh	15,084,915	15,499,569	15,741,316	16,213,556	16,699,962	17,200,961	16,299,631	16,788,620	17,292,278	17,811,047	18,345,378	18,895,739
Non-technical losses	%	30.5%	27.4%	28.1%	28.5%	20.1%	9.3%	4.6%	4.5%	4.5%	4.5%	4.5%	4.5%
Non-technical losses	MWh	5,283,075	4,885,011	5,083,547	5,319,491	3,716,760	1,719,085	803,273	791,770	815,523	839,989	865,188	891,144
Distribution energy billed	MWh	9,801,839	10,614,559	10,657,770	10,894,064	12,983,202	15,481,876	15,496,358	15,996,850	16,476,755	16,971,058	17,480,190	18,004,595
Distribution energy billed but not collected	%	2.3%	26.5%	33.8%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Distribution energy billed but not collected	MWh	300,168	3,713,216	4,788,116	725,158	835,028	950,222	956,230	986,697	1,016,298	1,046,787	1,078,191	1,110,537
Distribution energy collected	MWh	9,501,671	6,901,342	5,869,654	10,168,907	12,148,174	14,531,654	14,540,128	15,010,152	15,460,457	15,924,271	16,401,999	16,894,059
Peak load													
Load factor	%	73.2%	72.8%	73.2%	73.2%	73.2%	73.2%	73.2%	73.2%	73.2%	73.2%	73.2%	73.2%
Peak load	MWh	3,345	3,469	3,511	3,616	3,592	3,564	3,388	3,442	3,545	3,652	3,761	3,874
Growth	%		3.7%	1.2%	3.0%	-0.7%	-0.8%	-4.9%	1.6%	3.0%	3.0%	3.0%	3.0%

A3.2 Forecast supply balance

		Actuals/Estimates						Forecasts					
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Summary of supply													
Energy billed	MWh	8,141,724	8,885,227	9,942,734	9,985,900	11,530,827	18,117,909	18,019,111	19,733,597	20,325,965	20,935,744	21,563,816	22,210,731
Non-technical losses	MWh	2,641,120	2,523,520	3,071,164	3,113,749	2,236,796	1,620,645	745,968	791,753	815,523	839,989	865,188	891,144
Technical losses	MWh	1,629,254	1,728,159	2,029,946	2,030,547	1,626,895	2,014,039	1,676,526	1,541,175	1,587,442	1,635,065	1,684,117	1,734,641
Energy sent out	MWh	12,412,098	13,136,907	15,043,843	15,130,196	15,394,518	21,752,593	20,441,605	22,066,525	22,728,930	23,410,798	24,113,122	24,836,516
Energy collected	MWh	7,954,358	6,531,370	6,581,073	9,486,605	10,954,286	17,212,014	17,118,155	18,746,917	19,309,667	19,888,957	20,485,626	21,100,194
Summary of losses													
Non-technical losses	% of energy sent out	21.3%	19.2%	20.4%	20.6%	14.5%	7.5%	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%
Technical losses	% of energy sent out	13.1%	13.2%	13.5%	13.4%	10.6%	9.3%	8.2%	7.0%	7.0%	7.0%	7.0%	7.0%
Total losses	% of energy sent out	34.4%	32.4%	33.9%	34.0%	25.1%	16.7%	11.9%	10.6%	10.6%	10.6%	10.6%	10.6%
Supply energy balance													
Energy generated (EDL)	MWh	8,817,374	9,522,130	10,814,478	11,294,964	11,262,099	10,224,033	8,054,332	8,154,058	4,560,046	4,127,068	5,733,673	6,043,749
Energy generated (Temporary and Fast Track)	MWh	2,689,838	3,096,900	3,072,523	3,288,033	3,082,417	10,519,358	10,490,659	7,975,765	1,891,305	1,502,835	-	-
Energy purchased (IPPs)	MWh	643,385	448,121	614,212	535,572	525,004	719,065	1,575,804	5,934,407	16,277,579	17,780,895	18,379,449	18,792,606
Energy imported	MWh	261,501	69,756	542,630	11,627	524,997	290,138	320,811	2,295	-	-	-	160
Energy entering the transmission system	MWh	12,412,098	13,136,907	15,043,843	15,130,196	15,394,518	21,752,593	20,441,605	22,066,525	22,728,930	23,410,798	24,113,122	24,836,516
Transmission technical losses	%	4.0%	4.0%	4.0%	4.0%	3.5%	3.5%	3.5%	3.0%	3.0%	3.0%	3.0%	3.0%

		Actuals/Estimates						Forecasts					
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Transmission technical losses	MWh	502,398	531,736	608,922	612,417	534,959	755,903	710,346	657,582	677,322	697,642	718,571	740,128
Transmission energy billed	MWh	3,241,579	3,401,913	3,503,970	3,609,089	3,717,362	3,522,572	3,628,250	3,737,097	3,849,210	3,964,686	4,083,627	4,206,136
Energy entering the distribution system	MWh	8,668,121	9,203,258	10,930,950	10,908,689	11,142,196	17,474,119	16,103,010	17,671,845	18,202,398	18,748,470	19,310,924	19,890,252
Distribution technical losses	%	13.0%	13.0%	13.0%	13.0%	9.8%	7.2%	6.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Distribution technical losses	MWh	1,126,856	1,196,423	1,421,024	1,418,130	1,091,935	1,258,137	966,181	883,592	910,120	937,424	965,546	994,513
Distribution energy consumed	MWh	7,541,265	8,006,834	9,509,927	9,490,559	10,050,261	16,215,982	15,136,829	16,788,253	17,292,278	17,811,047	18,345,378	18,895,739
Non-technical losses	%	30.5%	27.4%	28.1%	28.5%	20.1%	9.3%	4.6%	4.5%	4.5%	4.5%	4.5%	4.5%
Non-technical losses	MWh	2,641,120	2,523,520	3,071,164	3,113,749	2,236,796	1,620,645	745,968	791,753	815,523	839,989	865,188	891,144
Distribution energy billed	MWh	4,900,145	5,483,314	6,438,763	6,376,810	7,813,465	14,595,337	14,390,861	15,996,500	16,476,755	16,971,058	17,480,190	18,004,595
Distribution energy billed but not collected	%	2.3%	26.5%	33.8%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Distribution energy billed but not collected	MWh	187,365	2,353,857	3,361,660	499,295	576,541	905,895	900,956	986,680	1,016,298	1,046,787	1,078,191	1,110,537
Distribution energy collected	MWh	4,712,779	3,129,457	3,077,103	5,877,515	7,236,924	13,689,442	13,489,906	15,009,820	15,460,457	15,924,271	16,401,999	16,894,059

A4. FORECAST COST OF SUPPLY (BASE CASE)

A4.1 Forecast fuel and IPP costs

A4.1.1 Forecast generation (MWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing - EDL										
Zouk - Fuel Oil (Grade A)	2,018,973	1,706,656	1,706,656	1,599,668	-	-	-	-	-	-
Jieh - Fuel Oil (Grade A)	774,518	828,320	818,359	497,485	-	-	-	-	-	-
Zouk Recip - Fuel Oil (Grade B)	1,225,320	1,496,737	1,496,737	1,496,737	1,496,737	1,375,774	-	-	-	-
Jieh Recip - Fuel Oil (Grade B)	495,973	595,728	595,728	595,728	595,728	526,193	-	-	-	-
Zahrani - Gas Oil	2,618,972	3,409,473	3,409,473	3,389,375	3,294,860	-	-	-	-	-
Deir Amar - Gas Oil	3,207,727	2,764,644	2,764,364	2,372,624	2,371,111	-	-	-	-	-
Baalbak - Gas Oil	170,708	190,947	182,102	94,585	106,109	-	-	-	-	-
Sour (Tyr) - Gas Oil	250,818	229,054	215,275	104,427	116,382	-	-	-	-	-
Safa (Richmaya) - Hydro	10,533	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059
Naameh - Biogas	40,937	64,346	64,346	64,346	64,346	64,346	64,346	64,346	64,346	64,346
Existing - Temporary generation										
KPS Zouk - Fuel Oil (Floating)	3,072,523	3,288,033	1,541,829	1,181,480	1,173,718	-	-	-	-	-
KPS Jieh - Fuel Oil (Floating)	-	-	1,540,588	1,060,216	1,039,890	-	-	-	-	-
Existing - IPPs										
Litani - Hydro	242,564	184,407	184,407	184,407	184,407	79,295	79,295	79,295	79,295	79,295
Nahr Ibrahim - Hydro	72,548	64,236	64,236	64,236	64,236	64,236	64,236	64,236	64,236	64,236
Bared - Hydro	33,214	29,386	29,386	29,386	29,386	29,386	29,386	29,386	29,386	29,386
Kadisha hydro - Hydro	65,425	58,203	58,203	58,203	58,203	58,203	58,203	58,203	58,203	58,203
Hrayche - Fuel Oil (Grade A)	200,461	199,340	188,772	94,833	106,232	230	-	-	-	-
Imports										
Syria - Imports	542,630	11,627	524,997	290,138	320,811	2,295	-	-	-	160
Egypt - Imports	-	-	-	-	-	-	-	-	-	-

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
New - Fast Track Generation										
Fast Track Deir Amar - HFO	-	-	-	3,547,800	3,547,800	-	-	-	-	-
Fast Track Zouk - HFO	-	-	-	-	-	-	-	-	-	-
Fast Track Jieh - HFO	-	-	-	788,400	788,400	674,684	-	-	-	-
Fast Track Zahrani - HFO	-	-	-	3,153,196	3,152,723	-	-	-	-	-
Fast Track Bint Jbeil - HFO	-	-	-	394,065	393,928	-	-	-	-	-
Fast Track Jib Jannine - HFO	-	-	-	394,200	394,200	-	-	-	-	-
New - IPPs										
DAPPII PPA (OC) - HFO	-	-	-	-	-	-	-	-	-	-
DAPPII PPA (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Zahrani II CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Zahrani II CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Selaata I CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Selaata I CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Jieh New CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Jieh New CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Zouk New CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Zouk New CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Hrayche New Thermal Plant - HFO	-	-	-	-	-	-	-	-	-	-
New wind 1 (rate 1) - Wind	-	-	-	-	700,800	700,800	700,800	-	-	-
New wind 1 (rate 2) - Wind	-	-	-	-	-	-	-	700,800	700,800	700,800
New wind 2 - Wind	-	-	-	-	-	-	-	1,401,600	1,401,600	1,401,600
New PV 1 - Solar	-	-	-	288,000	288,000	288,000	288,000	288,000	288,000	288,000
New PV 2 - Solar	-	-	-	-	-	-	480,000	480,000	480,000	480,000
New PV 3 - Solar	-	-	-	-	-	-	-	576,000	576,000	576,000
Janneh Hydro - Hydro	-	-	-	-	-	274,363	274,363	274,363	274,363	274,363
New Hydro (Daraya, Chamra, Yamouneh, Blat derated for CF) - Hydro	-	-	-	-	144,540	144,540	144,540	144,540	144,540	144,540

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing - EDL on LNG										
Zouk Recip - LNG	-	-	-	-	-	-	186,866	78,503	543,238	649,229
Jieh Recip - LNG	-	-	-	-	-	-	32,648	5,688	160,081	201,838
Zahrani - LNG	-	-	-	-	-	3,409,473	3,409,473	3,409,473	3,409,473	3,409,473
Deir Amar - LNG	-	-	-	-	-	2,764,003	857,654	559,999	1,547,476	1,709,519
Baalbak - LNG	-	-	-	-	-	2,854	-	-	-	165
Sour (Tyr) - LNG	-	-	-	-	-	2,356	-	-	-	120
Existing - Temporary Generation on LNG										
KPS Zouk - LNG	-	-	-	-	-	-	-	-	-	-
KPS Jieh - LNG	-	-	-	-	-	-	-	-	-	-
New - Fast Track Generation on LNG										
Fast Track Deir Amar - LNG	-	-	-	-	-	3,501,105	19,777	1,576	-	-
Fast Track Zouk - LNG	-	-	-	-	-	-	-	-	-	-
Fast Track Jieh - LNG	-	-	-	-	-	-	-	-	-	-
Fast Track Zahrani - LNG	-	-	-	-	-	3,153,600	1,871,528	1,501,259	-	-
Fast Track Bint Jbeil - LNG	-	-	-	-	-	326,908	-	-	-	-
Fast Track Jib Jannine - LNG	-	-	-	-	-	319,467	-	-	-	-
New - IPPs on LNG										
DAPPII PPA (OC) - LNG	-	-	-	-	-	2,061,663	-	-	-	-
DAPPII PPA (CC) - LNG	-	-	-	-	-	-	4,289,752	4,289,214	4,289,314	4,289,417
Zahrani II CCPP (OC) - LNG	-	-	-	-	-	1,645,754	-	-	-	-
Zahrani II CCPP (CC) - LNG	-	-	-	-	-	-	5,024,947	4,905,107	4,948,115	4,983,994
Selaata I CCPP (OC) - LNG	-	-	-	-	-	587,936	-	-	-	-
Selaata I CCPP (CC) - LNG	-	-	-	-	-	-	4,844,056	4,490,151	4,643,831	4,779,331
Jieh New CCPP (OC) - LNG	-	-	-	-	-	-	-	-	376,017	553,225
Jieh New CCPP (CC) - LNG	-	-	-	-	-	-	-	-	-	-
Zouk New CCPP (OC) - LNG	-	-	-	-	-	-	-	-	25,748	90,216
Zouk New CCPP (CC) - LNG	-	-	-	-	-	-	-	-	-	-
Hrayche New Thermal Plant - LNG	-	-	-	-	-	-	-	-	-	-
Total	**15,043,843**	**15,130,196**	**15,394,518**	**21,752,593**	**20,441,605**	**22,066,525**	**22,728,930**	**23,410,798**	**24,113,122**	**24,836,516**

A4.1.2 Forecast available capacity (MW)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing - EDL										
Zouk - Fuel Oil (Grade A)	300	300	300	300	-	-	-	-	-	-
Jieh - Fuel Oil (Grade A)	140	140	140	140	-	-	-	-	-	-
Zouk Recip - Fuel Oil (Grade B)	194	194	194	194	194	194	-	-	-	-
Jieh Recip - Fuel Oil (Grade B)	78	78	78	78	78	78	-	-	-	-
Zahrani - Gas Oil	435	435	435	435	435	-	-	-	-	-
Deir Amar - Gas Oil	435	435	435	435	435	-	-	-	-	-
Baalbak - Gas Oil	60	60	60	60	60	-	-	-	-	-
Sour (Tyr) - Gas Oil	60	60	60	60	60	-	-	-	-	-
Safa (Richmaya) - Hydro	12	12	12	12	12	12	12	12	12	12
Naameh - Biogas	7	7	7	7	7	7	7	7	7	7
Existing - Temporary generation										
KPS Zouk - Fuel Oil (Floating)	185	185	185	185	185	-	-	-	-	-
KPS Jieh - Fuel Oil (Floating)	185	185	185	185	185	-	-	-	-	-
Existing - IPPs										
Litani - Hydro	47	47	47	47	47	20	20	20	20	20
Nahr Ibrahim - Hydro	17	17	17	17	17	17	17	17	17	17
Bared - Hydro	6	6	6	6	6	6	6	6	6	6
Kadisha hydro - Hydro	15	15	15	15	15	15	15	15	15	15
Hrayche - Fuel Oil (Grade A)	45	45	45	45	45	45	45	45	45	45
Imports										
Syria - Imports	150	150	150	150	150	150	150	150	150	150
Egypt - Imports	-	-	-	-	-	-	-	-	-	-
New - Fast Track Generation										
Fast Track Deir Amar - HFO	-	-	-	450	450	-	-	-	-	-
Fast Track Zouk - HFO	-	-	-	-	-	-	-	-	-	-
Fast Track Jieh - HFO	-	-	-	100	100	100	-	-	-	-
Fast Track Zahrani - HFO	-	-	-	400	400	-	-	-	-	-
Fast Track Bint Jbeil - HFO	-	-	-	50	50	-	-	-	-	-
Fast Track Jib Jannine - HFO	-	-	-	50	50	-	-	-	-	-

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
New - IPPs										
DAPPII PPA (OC) - HFO	-	-	-	-	-	-	-	-	-	-
DAPPII PPA (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Zahrani II CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Zahrani II CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Selaata I CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Selaata I CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Jieh New CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Jieh New CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Zouk New CCPP (OC) - HFO	-	-	-	-	-	-	-	-	-	-
Zouk New CCPP (CC) - HFO	-	-	-	-	-	-	-	-	-	-
Hrayche New Thermal Plant - HFO	-	-	-	-	-	-	-	-	-	-
New wind 1 (rate 1) - Wind	-	-	-	-	200	200	200	-	-	-
New wind 1 (rate 2) - Wind	-	-	-	-	-	-	-	200	200	200
New wind 2 - Wind	-	-	-	-	-	-	-	400	400	400
New PV 1 - Solar	-	-	-	180	180	180	180	180	180	180
New PV 2 - Solar	-	-	-	-	-	-	300	300	300	300
New PV 3 - Solar	-	-	-	-	-	-	-	360	360	360
Janneh Hydro - Hydro	-	-	-	-	-	54	54	54	54	54
New Hydro (Daraya, Chamra, Yamouneh, Blat derated for CF) - Hydro	-	-	-	-	33	33	33	33	33	33
Existing - EDL on LNG										
Zouk Recip - LNG	-	-	-	-	-	-	194	194	194	194
Jieh Recip - LNG	-	-	-	-	-	-	78	78	78	78
Zahrani - LNG	-	-	-	-	-	435	435	435	435	435
Deir Amar - LNG	-	-	-	-	-	435	435	435	435	435
Baalbak - LNG	-	-	-	-	-	60	60	60	60	60
Sour (Tyr) - LNG	-	-	-	-	-	60	60	60	60	60
Existing - Temporary Generation on LNG										
KPS Zouk - LNG	-	-	-	-	-	-	-	-	-	-
KPS Jieh - LNG	-	-	-	-	-	-	-	-	-	-
New - Fast Track Generation on LNG										

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fast Track Deir Amar - LNG	-	-	-	-	-	450	450	450	-	-
Fast Track Zouk - LNG	-	-	-	-	-	-	-	-	-	-
Fast Track Jieh - LNG	-	-	-	-	-	-	100	100	-	-
Fast Track Zahrani - LNG	-	-	-	-	-	400	400	400	-	-
Fast Track Bint Jbeil - LNG	-	-	-	-	-	50	50	50	-	-
Fast Track Jib Jannine - LNG	-	-	-	-	-	50	50	50	-	-
New - IPPs on LNG										
DAPPII PPA (OC) - LNG	-	-	-	-	-	360	-	-	-	-
DAPPII PPA (CC) - LNG	-	-	-	-	-	-	550	550	550	550
Zahrani II CCPP (OC) - LNG	-	-	-	-	-	430	-	-	-	-
Zahrani II CCPP (CC) - LNG	-	-	-	-	-	-	650	650	650	650
Selaata I CCPP (OC) - LNG	-	-	-	-	-	500	-	-	-	-
Selaata I CCPP (CC) - LNG	-	-	-	-	-	-	740	740	740	740
Jieh New CCPP (OC) - LNG	-	-	-	-	-	-	-	-	360	360
Jieh New CCPP (CC) - LNG	-	-	-	-	-	-	-	-	-	-
Zouk New CCPP (OC) - LNG	-	-	-	-	-	-	-	360	360	360
Zouk New CCPP (CC) - LNG	-	-	-	-	-	-	-	-	-	-
Hrayche New Thermal Plant - LNG	-	-	-	-	-	-	-	-	-	-
Total	**2,370**	**2,370**	**2,370**	**3,600**	**3,393**	**4,340**	**5,290**	**6,410**	**5,720**	**5,720**

A4.1.3 Plant efficiencies

Name	Current Fuel Type	Technology	Year switch to LNG	Fuel efficiency with current fuel (GJ/MWh)	Fuel efficiency with current fuel (Metric Ton/MWh)	Fuel efficiency with LNG (GJ/MWh)
Existing - EDL						
Zouk	Fuel Oil (Grade A)	Steam Turbine		11.6	0.26	
Jieh	Fuel Oil (Grade A)	Steam Turbine		15.0	0.34	
Zouk Recip	Fuel Oil (Grade B)	Recip	2023	7.8	0.18	7.6
Jieh Recip	Fuel Oil (Grade B)	Recip	2023	8.1	0.18	7.8
Zahrani	Gas Oil	CCGT	2022	7.3	0.16	6.4
Deir Amar	Gas Oil	CCGT	2022	8.4	0.19	7.4
Baalbak	Gas Oil	OCGT	2022	11.6	0.26	11.1
Sour (Tyr)	Gas Oil	OCGT	2022	12.5	0.28	11.9
Existing - Temporary generation						
KPS Zouk	Fuel Oil (Floating)	Recip	n/a	8.6	0.19	8.9
KPS Jieh	Fuel Oil (Floating)	Recip	n/a	8.6	0.20	8.9
Existing - IPPs						
Hrayche	Fuel Oil (Grade A)	Steam Turbine		13.0	0.30	
New - Fast Track Generation						
Fast Track Deir Amar	Fuel Oil (Grade B)	Recip	2022	8.6		8.3
Fast Track Jieh	Fuel Oil (Grade B)	Recip	2023	8.6		8.3
Fast Track Zahrani	Fuel Oil (Grade B)	Recip	2022	8.6		7.2
Fast Track Bint Jbeil	Fuel Oil (Grade B)	Recip	2022	10.3		9.9
Fast Track Jib Jannine	Fuel Oil (Grade B)	Recip	2022	10.3		9.9
New - IPPs						
DAPPII PPA (OC)	Fuel Oil (Grade B)	OCGT	2022	10.8		10.8
DAPPII PPA (CC)	Fuel Oil (Grade B)	CCGT	2022	7.2		7.1
Zahrani II CCPP (OC)	Fuel Oil (Grade B)	OCGT	2022	10.8		10.8
Zahrani II CCPP (CC)	Fuel Oil (Grade B)	CCGT	2022	7.2		7.1
Selaata I CCPP (OC)	Fuel Oil (Grade B)	OCGT	2022	10.8		10.8
Selaata I CCPP (CC)	Fuel Oil (Grade B)	CCGT	2022	7.2		7.1
Jieh New CCPP (OC)	Fuel Oil (Grade B)	OCGT	2023	10.8		10.8
Jieh New CCPP (CC)	Fuel Oil (Grade B)	CCGT	2023	7.2		7.1
Zouk New CCPP (OC)	Fuel Oil (Grade B)	OCGT	2023	10.8		10.8

A4.1.4 IPP charges

Name	Technology	IPP energy charge ($/MWh)	IPP capacity charge ($/MW/year)	IPP take or pay %
Existing - Temporary generation				
KPS Zouk	Recip	49		
KPS Jieh	Recip	49		
Existing - IPPs				
Litani	Hydro	40		
Nahr Ibrahim	Hydro	26		
Bared	Hydro	26		
Kadisha hydro	Hydro	26		
Hrayche	Steam Turbine	54		
New - Fast Track Generation				
Fast Track Deir Amar	Recip		324,996	70%
Fast Track Zouk	Recip		324,996	70%
Fast Track Jieh	Recip		324,996	70%
Fast Track Zahrani	Recip		226,884	70%
Fast Track Bint Jbeil	Recip		251,412	70%
Fast Track Jib Jannine	Recip		251,412	70%
New - IPPs				
DAPPII PPA (OC)	OCGT		180,894	70%
DAPPII PPA (CC)	CCGT		180,894	70%
Zahrani II CCPP (OC)	OCGT		156,979	70%
Zahrani II CCPP (CC)	CCGT		156,979	70%
Selaata I CCPP (OC)	OCGT		156,979	70%
Selaata I CCPP (CC)	CCGT		156,979	70%
Jieh New CCPP (OC)	OCGT		156,979	70%
Jieh New CCPP (CC)	CCGT		156,979	70%
Zouk New CCPP (OC)	OCGT		156,979	70%
New wind 1 (rate 1)	Wind	105		
New wind 1 (rate 2)	Wind	96		
New wind 2	Wind	96		
New PV 1	Solar	70		
New PV 2	Solar	70		
New PV 3	Solar	70		
Janneh Hydro	Hydro	70		
New Hydro (Daraya, Chamra, Yamouneh, Blat)	Hydro	70		

A4.2 Network financing costs

A4.2.1 Summary of network capex

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Transmission	$m	67	65	61	83	38	82	125	86	84	83	83	83
Distribution	$m	111	124	114	58	58	58	58	58	58	33	33	33
Total	$m	178	190	175	141	96	140	183	144	142	116	116	116

A4.2.2 Network financing costs

		2018	2019	2020	2021	2022	2023	2024	2025	2026
Transmission	$m	12	20	32	47	59	71	81	90	100
Distribution	$m	25	19	17	17	16	16	15	15	14
Total	$m	36	39	49	64	75	87	96	105	114

A4.3 Other operating costs

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Non-generation O&M costs	$m	462	471	481	490	500	510	520	531	542	552
Generation O&M expenses	$m	210	210	210	210	210	210	210	210	210	210
Total	$m	672	681	691	700	710	720	730	741	752	762

A4.4 Total cost of supply

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total costs ($m)											
Fuel costs	$m	1,317	1,667	1,533	2,014	1,760	1,560	1,334	1,247	1,311	1,368
IPP costs	$m	320	216	257	488	575	636	776	1,001	763	763
Other operating costs	$m	672	681	691	700	710	720	730	741	752	762
Network financing costs	$m	30	36	39	49	64	75	87	96	105	114
Total	$m	2,339	2,602	2,519	3,251	3,109	2,992	2,928	3,086	2,931	3,008
Total costs ($/kWh billed)											
Fuel costs	$/kWh	0.13	0.17	0.13	0.11	0.10	0.08	0.07	0.06	0.06	0.06
IPP costs	$/kWh	0.03	0.02	0.02	0.03	0.03	0.03	0.04	0.05	0.04	0.03
Other operating costs	$/kWh	0.07	0.07	0.06	0.04	0.04	0.04	0.04	0.04	0.03	0.03
Network financing costs	$/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Total	$/kWh	0.24	0.26	0.22	0.18	0.17	0.15	0.14	0.15	0.14	0.14
Total costs ($/kWh collected) i.e. cost-recovery tariffs											
Fuel costs	$/kWh	0.20	0.18	0.14	0.12	0.10	0.08	0.07	0.06	0.06	0.06
IPP costs	$/kWh	0.05	0.02	0.02	0.03	0.03	0.03	0.04	0.05	0.04	0.04
Other operating costs	$/kWh	0.10	0.07	0.06	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Network financing costs	$/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Total	$/kWh	0.36	0.27	0.23	0.19	0.18	0.16	0.15	0.16	0.14	0.14

A4.5 Forecast subsidies

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Assumed tariffs ($/kWh billed)											
Cost-reflective tariff (after deducting arrears)	$/kWh	0.36	0.27	0.21	0.16	0.16	0.14	0.14	0.14	0.14	0.14
Assumed tariff increase	%	-	-	-	74%	2%	-13%	-5%	3%	2%	-0%
Assumed EDL tariff	$/kWh	0.09	0.09	0.09	0.16	0.16	0.14	0.14	0.14	0.14	0.14
Required subsidy ($m)											
Total cost of EDL supply	$b	2.34	2.60	2.52	3.25	3.11	2.99	2.93	3.09	2.93	3.01
Arrears collected	$b	-	-	0.19	0.52	0.33	0.33	0.33	0.33	0.03	0.03
Tariff revenue collected	$b	0.61	0.87	1.01	2.76	2.80	2.68	2.62	2.77	2.90	2.98
Total revenue collected	$b	0.61	0.87	1.19	3.28	3.12	3.01	2.94	3.10	2.93	3.01
Required subsidy at assumed EDL tariff	$b	1.73	1.73	1.33	-	-	-	-	-	-	-

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