LEAST-COST DISTRIBUTION NETWORK TARIFF DESIGN IN THEORY AND IMPLEMENTATION IN THE PALESTINIAN ELECTRICITY SYSTEM

MEDREG

REF.: MED20-30GA – 3.1.3

Electricity
Working group
(ELE WG)

ACKNOWLEDGMENTS
MEDREG wishes to express its gratitude to the following regulatory experts for their work in preparing this report: Qais Samara, Baraah Sharqia and Alessandro Rubino.

DISCLAIMER
This publication was produced with financial support from the European Union. The contents are the sole responsibility of MEDREG and do not necessarily reflect the views of the European Union

ABOUT MEDREG

MEDREG is the Association of Mediterranean Energy Regulators, which brings together 27 regulators from 22 countries, spanning the European Union, the Balkans and North Africa.

Mediterranean regulators work together to promote greater harmonisation of the regional energy markets and legislations, seeking progressive market integration in the Euro-Mediterranean basin.

Through constant cooperation and information exchange among members, MEDREG aims at fostering consumers' rights, energy efficiency, infrastructure investment and development, based on secure, safe, cost-effective and environmentally sustainable energy systems.

MEDREG serves as a platform for facilitating the exchange of information and providing assistance to its members as well as capacity development activities through webinars, training sessions and workshops.

The MEDREG Secretariat is located in Milan, Italy.

For more information, visit
http://www.medreg-regulators.org/

If you have any queries related to this paper, please contact: MEDREG Secretariat
E-mail: vlenzi@medreg-regulators.org

RELATED DOCUMENTS

Bloch, L., Holweger, J., Ballif, C. et al. Impact of advanced electricity tariff structures on the optimal design, operation and profitability of a grid-connected PV system with energy storage. Energy Inform 2, 16 (2019). https://doi.org/10.1186/s42162-019-0085-z

Entso E, 2020 Ten-year development plan, TYNDP2020, https://tyndp.entsoe.eu/documents/

Lu, L & Waddams Price, C 2018, Designing distribution network tariffs that are fair for different consumer groups. <http://competitionpolicy.ac.uk/documents/8158338/28406552/CCP+report+for+BEUC.pdf/8aeb45ae-3e8b-9b81-0441-65a940406ba3>.

MEDTSO, EC DEVCO - GRANT CONTRACT: ENPI/2014/347-006 "Mediterranean Project" Task 2 "Planning and development of the Euro-Mediterranean Electricity Reference Grid", https://www.med-tso.com/publications/Deliverable_2.1.1_Guidelines_for_Coordinated_Planning__a)_Grid_Planning_Methodology_v_1.pdf

Miguel Manuel de Villena, Axel Gautier, Damien Ernst, Mevludin Glavic, Raphael Fonteneau, Modelling and assessing the impact of the DSO remuneration strategy on its interaction with electricity users, International Journal of Electrical Power & Energy Systems, Volume 126, Part A, 2021, 106585, ISSN 0142-0615, https://doi.org/10.1016/j.ijepes.2020.106585.

Mohammad Ansarin, Yashar Ghiassi-Farrokhfal, Wolfgang Ketter, John Collins, The economic consequences of electricity tariff design in a renewable energy era, Applied Energy, Volume 275, 2020, 115317, ISSN 0306-2619, https://doi.org/10.1016/j.apenergy.2020.115317.

Schittekatte, T, Momber I, Meeus L (2018) Future-proof tariff design: Recovering sunk grid costs in a world where consumers are pushing back. Energy Econ 70:484–498. https://doi.org/10.1016/j.eneco.2018.01.028.

Simshauser, P (2016) Distribution network prices and solar PV: Resolving rate instability and wealth transfers through demand tariffs. Energy Economics 54:108–122. https://doi.org/10.1016/J.ENECO.2015.11.011.

Tomas Baležentis, Dalia Streimikiene, Multi-criteria ranking of energy generation scenarios with Monte Carlo simulation, Applied Energy, Volume 185, Part 1, 2017, Pages 862-871

World Bank Group. 2017. Securing Energy for Development in West Bank and Gaza. World Bank, Washington, DC. © World Bank. https://openknowledge.worldbank.org/handle/10986/28468 License: CC BY 3.0 IGO."
External documents

EXECUTIVE SUMMARY

Palestinian electricity systems are facing a number of significant challenges, related to existing energy security issues. In addition to these well-known aspects related to the management of the electricity sector in Palestine, PERC now has to face the challenges associated with the evolution in the electricity sector concerning the increased penetration of distributed energy resources. In recent years, an increasing number of electricity consumers have decided to become prosumers. Prosumers can introduce both environmental and social benefits as well as various utility and regulatory challenges. Utilities and regulators need to either update the current compensation systems and tariff structures or develop new ones to account for the impact of the high penetration rate of distributed generators on distribution system operators (DSOs), including costs related to connecting distributed generation prosumers to the grid. The goal of this report is to 1) define the guidelines and standard methodologies to evaluate infrastructure investment planning, 2) identify the main technical requirements for investment in infrastructure and 3) analyse the electricity system of the Palestinian territories and evaluate the possible structure of a novel multi-part tariff structure that accounts for these costs under the new dynamics in place in the Palestinian electricity system.

While a full cost–benefit analysis of new network infrastructure is out of the scope of this report, the main characteristics and requirements of such analysis have been provided to clearly identify the guidelines for evaluating investment in infrastructure. At the same time, the report builds on the scenario analysis performed by the World Bank (WB) report “Securing Energy for Development in West Bank and Gaza” (2017) and uses more recent data provided by the PERC to evaluate the impact of a possible capacity component in the tariff structure.

TABLE OF CONTENT

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

To better reflect local grid conditions to consumers, regulators are reforming their distribution network tariffs in order to account for the impact of RES and local development on the distribution grids. In this document, we discuss both the theoretical approach on "Cost Reflective tariffs", and we place this in the context of the projected evolution of the Palestinian electricity systems.

In the traditional charging approach, distribution network tariffs were simple rather than cost-reflective. At lower voltage levels, households and businesses were mainly charged based on their annual consumption (€/kWh), whereas industrial and large commercial users (connected at higher voltage levels) normally were charged using their capacity (€/kW) and time-of-use (TOU). Additionally, investments in distribution networks were limited, thus, the main job of tariffs was to recover sunk costs based on volumetric charges (consumption level) because wealthier households and businesses consumed more volume than the less privileged.

This situation has changed dramatically with the widespread introduction of rooftop PV connected at the distribution level, which might have two potential consequences:

1. Reversed welfare transfer: Wealthier households and businesses can more easily invest in rooftop PV. While the net impact of prosumers might be neutral, it might make them think that they should no longer pay for the network they continue to use at the expense of the other users who cannot afford PV panels.

2. Risk of overinvestment in the distribution network: Large-scale PV and wind generation in distribution grids can create new peaks that trigger network investments. In this case, the job of distribution tariffs is to signal the costs of network reinforcements in addition to recovering sunk costs

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

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

This situation poses significant challenges for the planning and development of the electricity infrastructure in Palestine. We will explore, in the remainder of this report, the main methodological approach and the practical application for the evaluation of infrastructure planning.

2

GUIDELINES FOR EVALUATING INFRASTRUCTURE INVESTMENT PLANNING

2

GUIDELINES FOR EVALUATING INFRASTRUCTURE INVESTMENT PLANNING

Bearing in mind the factors and dynamics discussed in the introduction, this section has the objective of illustrating the main guidelines and the standard methodology for developing a robust planning process that will be able to define credible, realistic and viable scenarios to meet the general scope of securing energy access. Investment in energy transport infrastructure is approved at the end of a cost–benefit analysis (CBA) that determines the characteristics of the investments in relation to suitable alternatives proposed by the TSO.

Infrastructure investment planning requires a sequence of complex evaluation and the availability of a great deal of data and assumptions. Such information is normally included in a national development plan providing a picture of the current status of the grid and its evolution (ideally in 5 to 10 years from now). This is a common practice in most liberalised markets[1] and reflects the forward-looking approach that transmission planning requires to accommodate the future needs of the electricity systems.

The Methodology has been split into two basic categories of assessments:

- Adequacy and CBA
- Technical analysis

2.1 Scope of adequacy of Cost-Benefits Analysis (CBA)

The objectives of security, supply and the sustainable development of the energy system with renewable energy source (RES) integration and affordable energy are common targets set at the national and regional levels in most Mediterranean countries.
The evaluation of the benefits associated with investment in transmission projects is made by conducting a CBA, which assessed through a consultation process. As stated, the main aim of the Methodology is to develop market scenarios suitable for the evaluation of network investments made to improve the system adequacy while coping with RES penetration targets.

The first target year is 2030, and the scenarios to be analysed should be contrasting scenarios and provide a framework for a credible/probable future. The methodology presented here illustrate the main steps required to calculate the indicators reflecting the performance of the investments planned in targets that normally include the following:

- Security of supply (SoS),
- Socio-economic welfare (SEW),
- Level of RES integration and
- Progress in decarbonisation.

The abovementioned indicators can be classified into benefit categories defined as follows:

1. SoS is the ability of a power system to provide an adequate and secure supply of electricity under ordinary conditions.
2. SEW or market integration is characterised as the ability of a power system to reduce congestion and thus provide an adequate level of transmission capacity so that electricity markets can trade power in an economically efficient manner.

1 See, for example, the Ten Years development plan for ENT-SO-E at https://tyndp.entsoe.eu/documents.

3. Support for RES integration is defined as the ability of the system to allow the connection of new RES plants and unlock the existing and future "green" generation while minimising curtailment.

4. Variation in CO2 emissions refers to the evolution of CO2 emissions in the power system.

Considering the specific situation of the Palestinian territory, which can be characterised as a small separate electricity island, the second benefit category (SEW), though currently with only limited relevance, is going to increase its impact significantly with the progressive integration of the internal market and of the Palestinian energy system with neighbouring countries.

2.2 Approach, methodology and assumptions

The activities performed for the CBA shall be organised according to a two-step approach:

- The first phase (Round A) will include the definition of the scenarios to be used, the data collection and the characterisation of the model to be used for the analyses.

- The second phase (Round B) shall be dedicated to the refinement of the hypotheses on the basis of the results obtained in Round A.

The following sections illustrate how the scenarios are built and defined; however, the numerical exercise will refine and impose some alternative hypotheses based on the Key Performance Indicators (KPI) provided by the PERC on the pre-existing scenario analysed in the report (and based on the WB deterministic scenario). Therefore, the practical application provided in this report is a basic financial evaluation of the economic output of the data derived from the WB deterministic scenario.

The scenario analysis aims to quantify the possible benefits related to investment projects, based on the following:

1. The assumptions that are adopted for future generation costs (CAPEX & OPEX, taking into consideration fuel and CO2 emission prices) and

2. The assumptions that are adopted with respect to the regulatory model governing the electricity interchanges. Normally, a perfectly competitive market is assumed (for simplicity).

The target shall be accomplished through the application of simulation models for carrying out an optimal coordinated hydrothermal scheduling of the electric system generation set over a period of one year. In order to ease the calculations, market zones can be reduced to one per country. An adequate tool to simulate competition in future market scenarios shall be adopted. Market simulation should be able to evaluate the profitability of investments in the grid through a dispatch assessment. For all generation units, the total production, cost, number of in-service hours and CO2 emissions shall be provided by the market simulation tool.

Finally, a Monte Carlo approach is applied to the availability of generating units and to the interconnection capacity, which is considered suitable for evaluating the SoS for the electric system under study and to provide information about limiting elements and the main SoS indicators (see Baležentis and Streimikiene, 2017)

The future electricity system in Palestine is likely to be characterised by many relatively small and dispersed renewable generators connected to the sunny parts of the network, which, historically, have not needed large amounts of transmission capacity. This rapid change in the type of technology deployed and where it is located means that generators (and storage) need to be provided with the correct locational signals for investment decisions that includes rapid changing technology and the tools to manage the growing risks, such as transmission congestion and losses.

Substantial and timely transmission infrastructure is likely to be required as this transition continues. These changes mean that a better way of coordinating generation and transmission investment decisions needs to be developed to better facilitate the transition that is occurring.

Four scenarios are normally selected to account for a two-by-two matrix of conditions normally related to macroeconomic cycle (GDP growth) and RES targets (RES percentage on total generation capacity) with 2030, as the target date, being the base of the first step of the activity. The scenarios need to be discussed and analysed to ensure that all the relevant aspects of the aims of the planning process are covered.

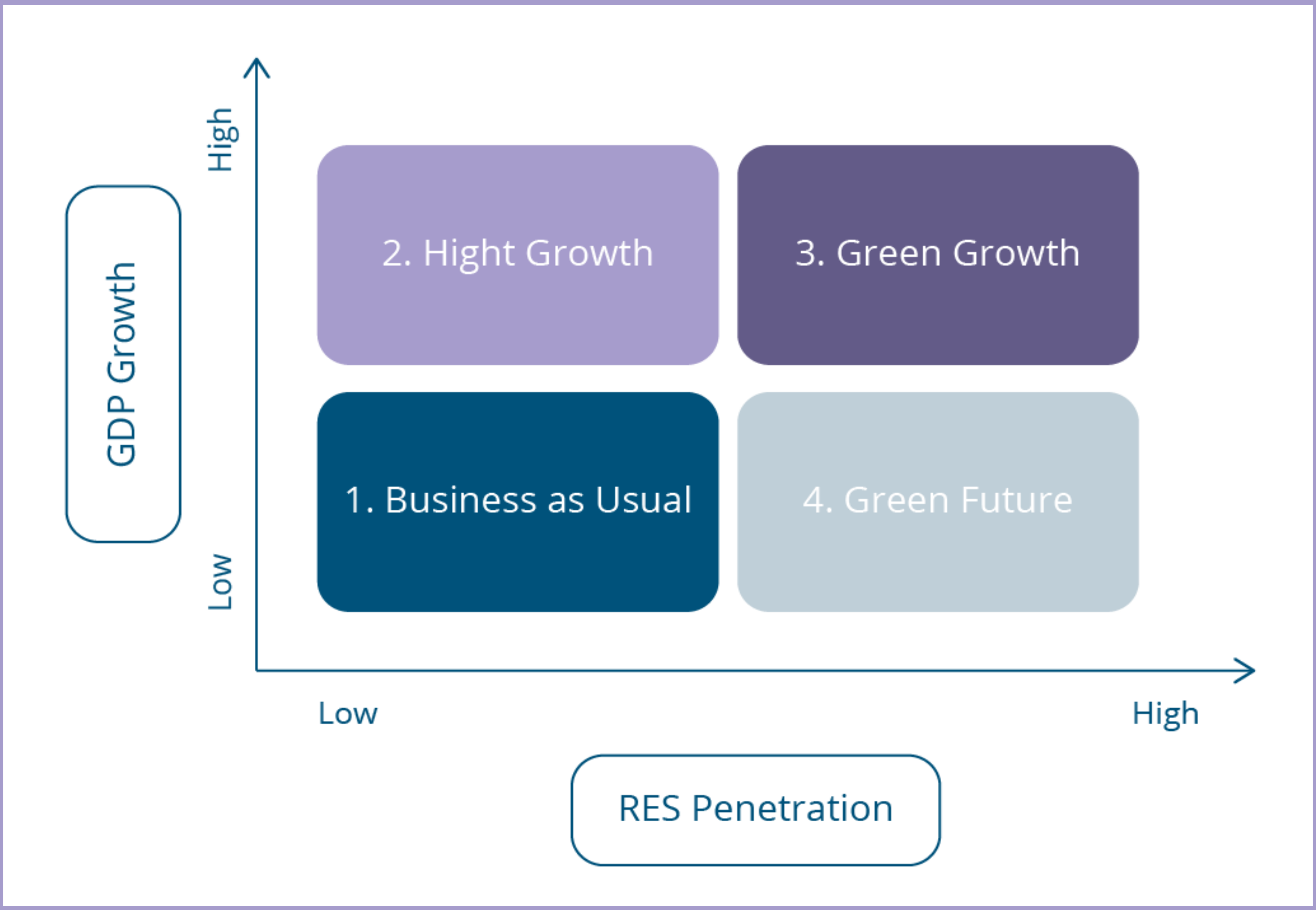
The uncertainties will preferably be the following:

- Load (demography, energy efficiency and end-user equipment)
- Generation evolution (technology, capacity)
- Interconnection capacity
- Economy (fuel prices, CO_2 price and GDP growth)
- Other (such as RES subsidies,)

Four scenarios, with 2030 as the target date, are considered as the base of the planning activity. The four scenarios are based on distinctively different assumptions; thus, the actual future evolution of parameters is expected to lie in-between the following:

1. Business as usual and improvement in SoS.
2. High growth based on gas utilisation and the local integration of renewable energies (and management of the complexities of this kind of grids).
3. Green growth that supports high economic growth and the high development of RES generation.
4. A green future and market integration at an international level.

Figure 1 . Scenario Building Exercise - Based on WB and MED TSO projections



Data Collection and Market Model (ROUND A)

The data collection procedure to generate and run the required market model comprises the following:

- Load curves.
- Thermal generation (size, primary fuel, efficiency, maintenance, minimum load factor, reliability, degree of flexibility, etc.)
- Power Generation and CO2 costs
- The value of loss load associated with unsupplied energy
- Wind and solar potential production profiles (producible energy)
- Other renewable or non-renewable profiles
- Power reserves (shared or strategic reserves)
- Number of nodes needed for market modelling
- Exchange capacities (interconnection capacity in both directions)
- Other (specific data such as exchange and contract in place with Israel Electricity Company)

Project assessment (ROUND A)

For the purposes of the planning methodology, a “project” is defined as a cluster of investment items that have to be fully realised to achieve the desired effect. It follows that a project consists of one or a set of various investments. An investment should be included only if the project without this investment does not achieve the desired effect. Clustering of a group of investments is recommended when any one of the following parameters are met:

- They are located in the same area or along the same transmission corridor.
- They achieve a common measurable goal.
- They belong to a general plan for that area or corridor. The results of the first runs of the market model will provide information about the risk of energy not supplied in the system. This can be due to the lack of interconnection, which is observed when power is available in a system area separate from the deficit one by saturated (or insufficient) interconnections.

The considered benefit categories at this stage shall be **SoS, SEW, RES integration and CO2 emission.**

In the following, some more details are given.

SoS – The aim of this task is to assess the reliability of the transmission/generation systems in the model to estimate the reduction of the expected energy not supplied (EENS) and the related monetisation. To attain the above target, probabilistic simulations shall be carried out taking into account all uncertainty factors (e.g., the forced outage rate of generating units, interconnections, intermittency of RES generation, etc.). Furthermore, the analyses will not address specific operating conditions (e.g., summer peak, winter peak, etc.) but shall cover all expected conditions over a whole year and other scenarios as much as possible. To this effect, a probabilistic approach is adopted based on the Monte Carlo technique.

Please note that the WB projections presented in Section 2.4 below are based on a deterministic approach; therefore, it assumes that there are no uncertainties regarding the main variable considered. The advantage of this approach is that the results are easy to understand and provide insight into the quantitative links between main assumptions and financial indicators.

SEW variation – A project that increases transmission capacity between interconnected market zones also allows generators in a lower-priced area to export power to a higher-priced area; therefore, a transmission project can increase SEW over the analysed perimeter. According to the Agency for the Cooperation of Energy Regulators (ACER) recommendation, the market model shall identify the variation in SEW benefits for each market area and inside each country for specific stakeholder groups: the variation of producer surplus (PS), variation in consumer surplus (CS) and variation in congestion revenues (CR). The demand will be considered to be inelastic, that is,

fixed and independent from electricity costs.
RES integration – The integration of existing and planned RES generation is considered. This indicator measures the reduction in renewable generation curtailment (avoided spillage) due to over-generation with respect to the load of the area. This indicator could be calculated in terms of energy curtailment or monetised considering the cost of substitution energy.

CO_2 variation – Network reinforcements may enable low-carbon and more economic electricity generation, replacing old power plants with higher costs and carbon emissions. The monetisation of eventually avoided CO_2 emission is already included in the SEW variation; thus, this benefit is expressed in terms of the avoided quantity of emission.

Second iteration of Project assessment (ROUND B)

Once the first round of the model is obtained and declined according to the various scenarios, a second iteration for the project could be performed. This second iteration will be based on improvement derived from the PERC KPI. One or more scenarios could be modified, and the updated results will highlight the differences. Evaluation of scenarios is the modern approach to system planning. It is the starting point for orienting the development of the grid in a market environment. The construction of multiple generation-demand scenarios for evaluating new transmission assets is an essential tool for dealing with uncertainties. The scenarios lay down technical and economic assumptions and identify possible solutions.

Methodology for Technical Analysis in Planning

Among the outcomes of the market studies are confirmation of projects or indications about the opportunity of opening new corridors (new initiatives). The technical analysis follows the adequacy and market analysis. At this stage of the process, the main characteristics of the investments are assumed as defined. On the basis of such a definition, further steps are needed for defining the following:

1. The main physical characteristics of the features of an investment,
2. The impact on the existing infrastructure and the steps for its integration and
3. Reinforcements to the existing grid.

All these evaluations contribute to the feasibility of an investment both from the physical and costs point of view. All these elements are part of the decision-making process

Common general criteria for planning

In order to identify future problems and determine the development required of the transmission network, some general technical criteria are defined to be used when TSOs assess the planning scenarios (technical studies).

The general procedure involves the following common technical criteria for planning:

- Network analysis
- Investigation of base case topology (all network elements available).
- Different types of events or contingencies (failures of network elements, loss of generation, loss of relevant loads, etc.) are considered depending on their probability of occurrence and/or depending on the region/ system or country.

As a main general rule and in the context of the main factors mentioned above, it is not acceptable if the technical limits set by TSOs or country legislations are exceeded. However, the precise definition of acceptable consequences may depend on the probability of the occurrence of the specific event.

2.3 The technical limits of infrastructure to be defined in the grid code

The permissible grid limits are the upper and lower limits of the voltages at the nodes of the system, the maximum currents that can flow through the the network components in a steady state or under temporary conditions and the maximum and minimum system frequencies.

Such limits include all quality, safety and security constraints and cannot be violated. A network analysis can be accepted if the resulting system variables are within such limits.

The permissible grid limits are as follows:

1. Standard values are needed for comparing results and for guaranteeing transparency.
2. In planning, the limits cannot be higher than those in operation.

Permissible Voltage Limits. In general, voltage limits are assumed to be +5% -10% of rated voltage in N condition and -15% +10% under contingency situations, unless national legislation\regulation prescribes stricter limits. The TSOs (or the company in charge of the Transmission network) will declare these limits.

Permissible Current Limits: These are assumed as the rated values declared by the TSOs (or the company in charge of the transmission network) corresponding to the max temperature compatible with the max sagging allowed by law. According to local laws on safety, they can vary according to the season. TSOs have to declare the values that can be sustained continuously for 20 min before reaching the max temperature and the initial values. In case of the absence of such values, they are assumed to be 120% of the rated value, starting from an initial value equal to 80% of the rated value. However, the current limits included in the national legislation of each TSO will be considered if they are different. The TSOs will declare these limits.

Permissible Frequency limits: They are taken to be ±0.2% in normal conditions and ±0.5% in upset conditions.

The next points describe the most relevant technical criteria for network planning and development in the region as declared by Med-TSO.

2.3.1 The load flow analysis to be performed

Evaluation of normal contingencies: The N-1 criterion is systematically assessed taking into account every single normal contingency of one of the elements mentioned below (loss of one of the following elements):

- Generation unit,
- Transmission circuit (overhead, underground or mixed),
- A single transmission transformer or two transformers connected to the same bay.
- Shunt device (i.e., capacitor banks, reactors, etc.),
- Single DC circuit,
- Network equipment for load flow control (phase shifter, FACTS, series reactors, etc.) and
- A line with two or more circuits on the same towers if the TSO considers that this is suitable for its normal system planning. Some countries/ TSOs consider this situation if the line with two circuits on the same towers has more than a specified number of km.

Evaluation of rare contingencies: Unusual contingencies are analysed in order to prevent serious interruptions of supply within a large area. This kind of assessment is done only in some specific cases based on the probability of occurrence and/ or based on the severity of the consequences.

A rare contingency is the loss of one of the following elements:

- A line with two or more circuits on the same towers if a TSO considers this appropriate and does not include this contingency in its normal system planning.
- A single busbar.
- A common mode failure with the loss of more than one generating unit or plant.
- A common mode failure with the loss of more than one DC link

Evaluation of some out-of-range contingencies: These types of contingencies are very rarely assessed. Their consequences are minimised through defence plans. The out-of-range contingencies include the very unusual loss of one of the following elements:

- Two lines that can independently and simultaneously (N-1-1) occur when contingencies occur simultaneously with maintenance.
- A total substation with more than one busbar.
- More than one independent generation unit.

In the planning network simulation, the N-1 security principle is satisfied if the network is within acceptable limits for expected transmission and supply situations as defined by the planning cases, following a temporary (or in some cases, permanent) outage of one of the elements of the normal contingency.

As mentioned above, different contingencies can be simulated. The loss of one or several elements of the power transmission system is possible, considering some specific approaches for each country. Therefore, the definitions of normal and rare contingencies can differ among countries and electricity systems.

Moreover, based on specific knowledge of the TSO, these common criteria should not restrict the application of some alternative contingencies that have not been described in this document. Therefore, other contingencies may be considered, taking into account their probability and impact within a specific network. The rare and out-of-range contingencies should be discussed when significantly affecting the benefits of an investment.

2.3.2 The grid code

The technical limits should be analysed in a system-specific manner and need to be defined together with the TSO (or the company in charge of the transmission network). This analysis will normally be included in the grid code.

The Grid code ensures that the transmission, dispatching, development and grid security protocols govern the procedures that the TSO must adopt in relationships with grid users.

The grid code must be prepared in compliance with the legal provisions on the management of the grid on the basis of the directives of the NRA. The grid code, approved by the NRA and the relevant Ministry, is subject to continuous updating according to the procedures defined within the document.

2.4 Project assessment (ROUND B) based on the KPI provided by PERC

In the next section of the report, we identify the implications of some specific project assessment, as defined by the KPI provided by PERC.

It is important to underline that the analysis performed in this report is an ex-post adaptation of the result defined in the deterministic scenario modelled by the WB. Given the limit and the scope of this study, it is not possible to model and perform complete adequacy and cost–benefit analyses. However, the numerical exercise proposed in this report might help identify the possible magnitude and evolution of the system and the likely tariff implications of the investment plan and whether the projected scenarios are affordable for the population and can ultimately be financially sustainable for the local utilities.

The costs of providing a secure electricity service include the costs of not only power generation but also the associated transmission and distribution infrastructure. Inefficient operations could inflate costs. Given fiscal constraints in the West Bank and Gaza, domestic power generation could be developed by the private sector under a power purchase agreement, leaving public investment for transmission and distribution, for which private investment would be difficult to harness. Ultimately, these costs must be paid either by the consumer, through retail tariffs, or by the government, through subsidies. Both sources of funding are constrained, given the relatively low income of the population and the limited budget of the government. An important reality check for any power-sector investment plan is to examine its impact on retail tariffs and determine whether these are affordable, and, if not, determine what the potential size of the associated subsidy bill would be.

In this report, we explore the potential impact on total revenues by using the input and output variables used in the financial model for each distribution company in the study “Securing

Energy for Development in the West Bank and Gaza." This is done under a deterministic scenario, integrated with demand data and customers' data provided by the PERC to perform some basic analysis of the changes impacting some of the main costs and revenues modelled in the financial model available in the Appendix. The main feature of the deterministic scenario is depicted in Figure 2 and Table 1 and 2. Most of the points of delivery are domestic customers, which accounts for 80% of total customers, followed by commercial customers, which accounts for 16% of total customers, while the presence of industrial customers is only marginal[2] . The points of delivery form the main basis of the analysis in this report, keeping in mind the significant implication that the evolution of the number of customers might have both in terms of estimated demand and stream of potential revenues for the revised tariff structure

The Palestinian market is showing a positive trend with a growing demand that is projected to increase for the period considered (2020–30), growing, on average, at 6.4% per year, which makes for a +48% over the entire period.

To serve this demand, important investments in generation and transmission infrastructure are required.

The WB model is able to accommodate the increased demand, but it doesn't take into account the additional transmission and distribution network requirements that can only be estimated by performing a CBA as described in Section 2.1. We will, therefore, perform some qualitative assessments to understand the likely implications of demand growth, as predicted using the KPI made available by the PERC.

2 The characteristic of the demand side might also be considered in terms of demand, and in this case, the weight of each category will be different. However, in the current analysis, we prefer to focus on the number of customers that might provide useful information (although stylised) on the aggregate demand and on the activated points of delivery.

Figure 2 . Energy mix and 2030 capacity share in the deterministic scenario - - WB Scenario

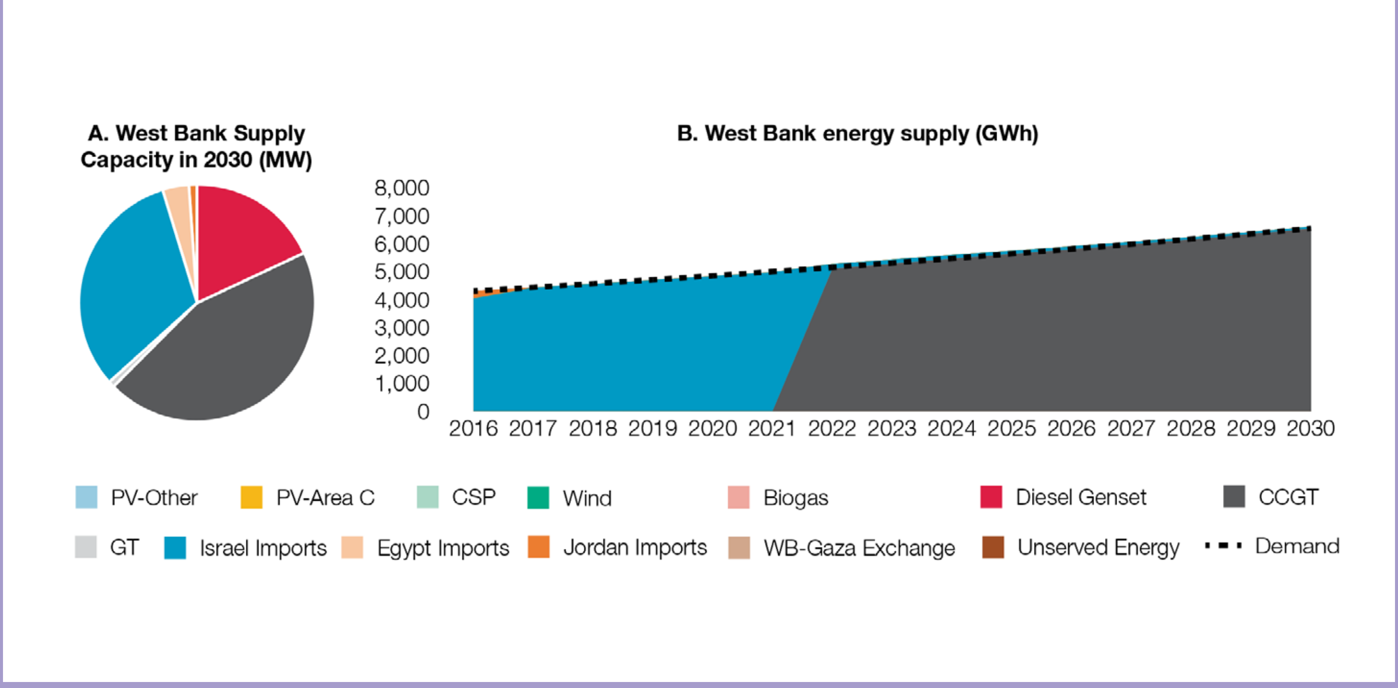


Table 1 . Structure of Retail Demand in Each DISCO

Consumer Classification	JDECO	NEDCO	HEPCO	TEDCO	SELCO	Total	%
Residential	247,923	89,612	39,993	17,216	29,628	424,372	79.54%
Commercial	45,237	23,070	13,064	1,928	3,838	87,137	16.33%
Industrial	1,528	902	1,576	87	145	4,238	0.79%
Other	9,693	3,981	2,241	671	1,216	17,802	3.34%
Number of Consumers 2019	304,381	117,565	56,874	19,902	34,827	533,549	100 %
Number of Consumers 2018	291,313	113,784	53,409	19,282	33,219	511,007	
Change YoY	4.3%	3.2%	6.1%	3.1%	4.6%	4.2%	

SOURCE: PERC KPI report 2019

Table 2 . Sales and Purchase

Statement	Year	JDECO	NEDCO	HEPCO	TEDCO	SELCO	Total (GWh)
	2019	1,950	569	394	129	164	3,206
	2018	1,776	532	369	113	148	2,938
Total sales	**Annual growth 2018–2019**	**10%**	**7%**	**7%**	**14%**	**11%**	
	2019	2,545	703	492	158	208	4,106
	2018	2,334	650	466	137	188	3,775
Total purchases	**Annual growth 2018-2019**	**9%**	**8%**	**6%**	**15%**	**11%**	

SOURCE: PERC KPI report 2019

3

THEORETICAL STARTING POINT AND IMPLEMENTATION LIMITS

3

THEORETICAL STARTING POINT AND IMPLEMENTATION LIMITS

Marginal pricing is the first-best solution, but there are many challenges with marginal pricing in distribution grids.

- The first challenge is that marginal pricing in distribution grids would require that a big change be made in electricity markets. They currently do not take into account distribution or transmission constraints. Electricity markets with integrated transmission and distribution constraints would produce market prices for each transmission and distribution location or node in each market period. This is very complex to implement and monitor over time.

- The second challenge is cost recovery. The revenues collected with locational marginal pricing recover only a fraction of the total costs in transmission grids. Pérez-Arriaga et al. (1995) showed that revenues from efficient nodal prices recover only up to approximately 30% of the total costs of an actual transmission grid. The reason is that grids are typically overdesigned to keep a reliability margin, and when the limits of the grid are reached, additional investments are activated. As investments are lumpy and characterised by strong economies of scale, the transmission grid owner has to invest more than what is needed. Distribution tariffs that are set following a long-run marginal pricing approach typically cover more of the total investment costs. Under such an approach, a cost model is used to simulate the required grid investments to handle future demand and generation and allocate these costs to grid users. These simulated costs do not consider the historical or sunk costs that still need to be recovered.

- To achieve cost recovery, distribution charges require an additional charge. Following the principles of Ramsey-Boiteux pricing, this charge should achieve cost recovery with minimal distortions. This can be done by applying simple fixed charges. The only way to avoid fixed charges is to disconnect consumers from the grid; thus, the only possible distortion is consumers going off-grid, which is currently not sustainable in most places.

The simplest version of fixed charges is that all grid users pay the same annual fee to remain connected to the grid. This can be considered unfair for smaller users as opposed to larger users, and it is not always easy to find a good metric to differentiate small from larger users. Possible approaches might include looking at historical data, historical consumption and/or voltage levels or even income levels or property value.

In conclusion, cost-reflective distribution tariffs are two-part tariffs: They combine a forward-looking charge based on a forward-looking cost model with a fixed charge to recover the residual costs. In the next section, we discuss the detailed design choices related to forward-looking costs models and charges

3.1 Cost models need to incorporate the increasing demand and, therefore, must look at the future state of the grid

Three types of forward-looking costs are considered, and they can be classified on the basis of different types of costs, time horizons, cost drivers, grid modelling and calculation of charges. In general, different cost models are identified, and typically, different time horizons are considered. They are briefly described as follows:

- 40 years into the future: Long-Run Incremental Cost (LRIC)

- 10 years into the future: Forward Cost Pricing (FCP)

- 1 year into the future: Investment Cost-Related Pricing (ICRP)

- Fixed demand growth: Distribution Reinforcement Model (DRM), which does not specify a time span, instead, only a fixed demand expansion (500MW at each voltage level)

The models identified under the least-cost scenario by the World Bank report and that form the basis of the present analysis rely on the following assumptions:

Investments plans are based on the planners' best estimate of the future (the period considered, that is 2020–2030). The power generation switches from IEC imports to gas and meets the entire demand.

CCGT is the least cost option when gas is available, followed by utility-scale PV at approximately US$ 1,041 per kW and 7 US cents per kW. The scenario considered predicts that 428MW of distributed diesel capacity is installed largely to satisfy reserve margin requirements, and this is maintained till 2030. The main assumptions for the scenario considered are illustrated in Table 3.

The total capacity is 3,484 MW for an average expected peak capacity of 1,300 MW. The total capacity is high, but it is required to meet the planning requirements. The system reserve requirement is set at 15% above peak demand and must be satisfied internally. The import capacity, therefore, does not contribute to reserve requirements. Additionally, PV does not provide firm capacity and, so, does not contribute to the reserve margin limits. While the low CAPEX requirements for distributed diesel plants make them an attractive option to meet reserve margins, the energy output shows that they are low on the merit order of dispatch because of the relatively higher costs of fuel and utilisation, which is approximately 1%. The PV capacity helps reduce fuel and repair costs.

Table 3 . The Underlying Assumptions for the Deterministic Plan

Parameter	Assumption
Demand	Central case
Diesel prices	Base case
Gas prices	5.75 $/MMBTU
Increase in Israel - WB	2021
Increase in Jordan - WB	2024
Egypt - WB	2024
Increase in Israel - Gaza	2024
Increase in Egypt - Gaza	2023
Israel Import price	90 $/MWh + 1% p.a.
Jordan Import price	Based on diesel price
Egypt Import price	81 $/MWh + 1% p.a.
Timing of gas (WB)	2022
Timing of gas (Gaza)	2023
Volume of gas (WB)	1.1 BCM
Volume of gas (Gaza)	1.1 BCM
Reserve margin requirements	15%
Access to area C	2020
Financial constraints	No
Unplanned outages	No
RE Capex	Base Case

Source: Securing Energy for Development in West Bank and Gaza – World Bank 2017

4

DISTRIBUTION NETWORK TARIFF STRUCTURES

4

DISTRIBUTION NETWORK TARIFF STRUCTURES

Network tariffs are composed of different elements. Although consumers may typically observe a standing charge and some unit prices in their bills, these prices are themselves dependent on various factors at multiple levels, including tariff classes, tariff components and charging bases.

A tariff class refers to a customer segment or category. Tariff classes can be defined by voltage level (kV) as a measure of capacity (e.g., high, medium or low), customer types (e.g., household or industrial), metering (e.g. whether metered or unmetered and the type of meter), geographic zone, etc. As a result, depending on the definition of tariff classes, consumers belonging to different classes may face different tariff constituents and levels. In the EU, tariff classes are mostly defined by voltage level. This review will briefly explore the tariff components and charging bases.

Network tariffs can have three main components, used either alone or in combination:

1. Fixed (€/point of delivery),
2. Capacity (€/kW), and
3. Volume (€/kWh).

Common charging bases include the flat rate and non-linear rates, varying with volume or time of use. The advantages and disadvantages of each tariff component and each charging basis are summarised in Tables 1 and 2.

Distribution networks have traditionally been dominated by users relying exclusively on the network for electricity supply, and the costs have been mainly recovered to reflect network usage through a volume-based charge. With the changing supply and demand patterns emerging in Palestine, the increased presence of prosumer network costs are being increasingly driven by the growth of embedded generation; consequently, DSOs, in most geographies, are experiencing volume and revenue risk, and this is likely to be the case in Palestine as well. Capacity-based and ToU tariffs, which better reflect the main driver of network costs, are important instruments for optimising the use of networks and enhancing flexibility. They may also help neutralise the impact of variations in volumetric consumption on DSOs' revenues. They can also mitigate or avoid cross-subsidisation between consumer groups, and there is broad support in most jurisdictions, and particularly in the EU, for a move towards capacity-based tariffs.

The structure of the existing distribution network tariffs varies considerably across countries, and the optimal tariff design depends on the objectives of each system. In particular, tariff reforms triggered by the development of new technologies and changes in electricity systems are at different stages in different jurisdictions. At the core of practical tariff design and reform is the achievement of a balance in different tariff components and/or combinations of the charging bases, and thus, it is useful to review the existing tariff structures in different jurisdictions, especially those attempting to accommodate new structures. The following four case studies have been chosen for this report:

1. Italy, where Incremental Block Tariffs (IBTs) have been a key feature but are set to be discontinued.
2. Portugal, where static ToU tariffs have been in place for a long time and dynamic ToU tariffs are to be introduced.
3. Romania, where distribution tariffs are based only on volume.
4. The Netherlands, where tariffs for household consumers are capacity-based and have no volume component.

Table 4 . Tariff Components

Tariff Component	Fixed	Capacity		Volume
		ex ante	ex post	
Advantages	• Simple • Stable • Predictable	Signals that capacity has a price	• Signals that capacity has a price • Cost reflective	• Acceptable to consumers
Disadvantages	• Does not signal long-term costs and, so, does little to encourage energy efficiency and system flexibility	• Reflects the capacity costs to a limited extent	• Requires smart metering • Complex • Less predictable • Less acceptable to consumers	• Does not reflect capacity costs • Can raise revenue uncertainty for DSOs

Table 5 . Tariff Charging Bases for Capacity and Volume Components

Tariff charging basis for capacity and volume components	Flat Rate	Time of Use		Non-Linear
		Static	Dynamic	
Advantages	• Simple • Acceptable to consumers	• Mitigates congestion • Reflects capacity costs • Signals the value of flexibility • Benefits engaged consumers financially	• Mitigates congestion • Reflects capacity costs • Signals the value of flexibility • Benefits helped consumers financially • Can target specific system events on short notice	• Can be designed to balance multiple objectives of affordability, conservation, efficiency and cost recovery
Disadvantages	• Less cost-reflective • Can over-incentivise self-generation, which does not always synchronise with system peaks	• Predicted peak times may not coincide with actual system peak • Does not allow for variability when peak conditions occur	• Requires advanced metering • The risk of all consumers responding simultaneously to a single price signal • Traditional consumers who cannot change consumption pattern may face higher prices	• Complex • Has potentially adverse consequences due to poor design or consumer understanding

4.1 Italy

4.1.1 Overview

Italy has 144 DSOs, which provide cost and quality data to the regulator, who, in turn, determines the distribution tariff structure. Tariff classes are first defined by customer types, namely household and business, and within each type, further by voltage levels (low, medium, high and extra high). Tariffs for all classes contain fixed, capacity and volume components, but volume has a much higher weight in the design of residential tariff (66%) than in industrial tariffs (17%). Distribution and transmission tariffs are not separate for residential customers, and tariffs are not geographically differentiated. A social tariff scheme is implemented in the form of a discount for households with income lower than a fixed threshold. The cost of the scheme is not borne by DSOs.

4.1.2 Key features of tariff components and charging bases

In Italy, the capacity component is ex ante through the contractual capacity, and households can choose the size of the power limit – ≤ 3 kW or > 3 kW – to differentiate between low and intensive use. Most Italian households belong to the low-use group, and second homes that are not owner-occupied are charged as intensive-use households. One function of the smart meters installed in Italian homes is to ensure that the power delivered does not exceed the contractual limit and to adjust the limit remotely upon any household's request to change the limit. ToU is not used for any of the tariff classes, but Italian households have faced IBTs for their electricity bills since the early 1970s. The volume component of distribution tariffs has a progressive structure. The initial design included three blocks, which has grown to six over the years.
IBTs for energy distribution were initiated in Italy for conservation purposes, as they provide incentives to save energy through higher marginal prices at larger consumption levels. Although block prices are not directly linked to income, as the initial consumption is priced low, IBTs also address the issue of affordability. However, the fact that the sizes of the first few blocks have not changed for the past 40 years suggests that such a framework of IBTs has not taken account of the radical changes in households' socio-demographics and consumption patterns and the development of technologies and the electricity sector in general.

4.1.3 Self-generation and net metering

In Italy, consumers who can generate renewable energy on a small-scale are entitled to be connected to the national electricity grid upon request. All consumers generating up to 500 kW are eligible to apply. Plants commissioned before 31 December 2007 were only eligible if their generation capacity did not exceed 20 kW, and plants commissioned before 31 December 2014 were eligible if their generation capacity did not exceed 200 kW. Net consumption is calculated once a year. If more energy is fed into the network than is taken from it, plant operators are entitled to receive economic compensation, which is calculated on a ToU basis.

Table 6 . Key Features of Household Tariffs in Selected Cases

Case	Tariff Component			Tariff Charging Basis		Net Metering	Main Agency Responsible for Setting Tariffs
	Fixed	Capacity	Volume (Weight)	Non-Linear	Time of Use		
Italy	YES	YES	YES (66%)	YES	NO	YES	NRA
Portugal	NO	YES	Yes (62%)	NO	YES	NO	NRA
Romania	NO	NO	YES (100%)	NO	NO	NO	NRA
The Netherlands	YES	YES	NO (0%)	NO	NO	NO	DSOs

4.2 Portugal

4.2.1 Overview

The national energy regulator determines and publishes distribution tariffs for the one national and ten local DSOs in Portugal. Tariff classes are defined by voltage levels:

- Standard low: typically households.
- Special low : typically small business customers.
- Medium: typically small industrial customers.
- High: typically large industrial customers.

Tariffs for all classes contain the same components – capacity and volume – but volume has a much higher weight in tariffs for households (62%) than tariffs for large industrial firms (17%). Tariffs are not geographically differentiated. A social tariff scheme is applied to the network access tariff to enable the provision of an equal discount to all consumers, regardless of the contracted final tariff.

4.2.2 Key features of tariff components and charging bases

In Portugal, the capacity component is charged through contracted power for households. While both capacity and volume components are linear, the latter can be differentiated by static ToU. The options for households are no ToU, two-period ToU (peak and off-peak), and three-period ToU (peak, off-peak and super off-peak). Industrial customers are charged on a minimum four-period ToU for their energy consumption (peak, half-peak, off-peak and super off-peak) or more periods if they request it, together with variations between two seasonal periods.

Static ToU tariffs have been used in Portugal for a long time, representing 80% of the total demand. To further benefit from demand-side flexibility and promote more efficient use of the network, the Portuguese energy regulator has created a regulatory framework to introduce dynamic ToU. As part of the CBA, a pilot project has been recently started with volunteer industrial users. Such a gradual, phased approach avoids the potential adverse impact on some consumer groups who are unable to react to price signals.

4.3 Romania

4.3.1 Overview

Romania has eight DSOs. The Romanian Energy Regulatory Authority takes the main responsibility for setting distribution tariffs. DSOs may propose a change in tariff for the regulator. Tariff classes are defined by voltage level (low, medium and high), which typically correspond to household, small industrial and large industrial consumption levels, though no formal distinction is made between customer types. Households whose members earn an average income equal to or below the minimum wage may be eligible for social tariffs.

4.3.2 Key features of tariff components and charging bases

Romania is a special case where customers in all classes are charged only by the volume component. The pricing of the volume component is linear, though tariff levels differ across the eight DSO regions. Tariffs are not time-differentiated.

4.4 The Netherlands

4.4.1 Overview

Eight DSOs distribute electricity in The Netherlands and propose tariff structures to the regulator, who makes the final decision. Tariff classes are defined mostly by customer types, namely residential, small industrial and large industrial. Residential and small industrial customers are also defined as small users (connection size ≤ 3× 80 A). Tariffs for different classes contain different components:

- Residential: fixed and capacity.
- Small industrial: capacity.
- Large industrial: capacity and volume.

Tariffs are similar for customers belonging to the same class. A separate, nationally uniform metering tariff is available for residential and small industrial customers; for large industrial customers, the market for metering has been liberalised. There is no social tariff in The Netherlands.

4.4.2 Key features of tariff components and charging bases

In the Netherlands, all tariff components used are linear within each tariff class. ToU is used to a limited extent for large industrial customers. One distinctive feature is that the combination of tariff components differs across tariff classes, and, in particular, there is no volume component for residential and small industrial classes. Such capacity-based tariffs were introduced in 2009 for greater cost-reflectivity and efficiency, as well as to considerably reduce administrative costs through simplified billing. Small users are further divided into six capacity categories. As shown in Table 5, each category is assigned an 'accountable capacity' factor, which is the lowest (0.05) in Category 1 and increases to 50 in Category 6. The tariff level charged for each category is determined by the product of a general tariff (€/kW) set by the Authority for Consumers and Markets (ACM) the competition authority, and the respective category factor.

However, the distributional impact of this tariff reform needs to be considered. Ceteris paribus, compared to volume-based tariffs, capacity-based tariffs would benefit households whose volumetric consumption is relatively high, but connection capacity is relatively low and would recover more costs from households whose volumetric consumption is relatively low, but their connection capacity is high. To mitigate the distributional impacts, such as sudden and large bill increases for some, households in The Netherlands were encouraged, through the promise of a reduction in connection fees, to lower their connection capacity. Those who could not reduce their connection capacity were offered compensation, as their new bills would be significantly higher. However, because of the favourable conditions offered to consumers, the incomes of DSOs did not increase with the expected cost reduction.

4.4.3 Self-generation and net metering

The market for solar PV is relatively mature in The Netherlands, with prosumers being defined and regulated according to the general Energy or Electricity law. The Electricity Act defines residential prosumers' right to feed self-generated electricity into the grid, for which grid operators must provide a contract to prosumers. Compensation to prosumers is determined by the net metering scheme. Under the net metering scheme, the electricity bill summarises how much electricity the prosumer has produced and the supplier has delivered, respectively, and the prosumer is only invoiced for the difference, i.e., net consumption. In order to participate in the scheme, the prosumer has to be a small user (connection size ≤ 3× 80 A), with electricity supplied to and extracted from the same connection.

Forward-looking cost models will typically allocate the investment costs to the critical peaks that drive the grid expansion. Sophisticated models can also identify different peaks for different locations, but there are many good reasons why regulators might prefer simpler tariffs for some or all grid users. First, sophisticated cost models are complex to administer. Second, some grid users might not be able to handle the complexity. Third, sophisticated tariffs require the use of smart meters (to precisely measure grid usage) and smart grids (to measure which peaks are critical at different locations).

Table 7 . Capacity Tariffs for Small users in The Netherlands

The tariff level for each category is produced by general tariff €/kW × factor

Customer Category	Capacity	Accountable Capacity Factor
1	≤ 1×6 A on the switched network	0.05
2	≤ 3×25 A + all 1-phase connection	4
3	3×25 A – 3×35 A	20
4	3×35 A – 3×50 A	30
5	3×50 A – 3×63 A	40
6	3×63 A – 3×80 A	50

5

NUMERICAL EXAMPLE DATA AND SET-UP

5

NUMERICAL EXAMPLE DATA AND SET-UP

In this section, the setup and data of a numerical example based on Palestinian DISCO's input-output and costs are described. The numerical example is used to gain insights from the model when introducing financial sustainability constraints.

The financial model of the Palestinian Authority power sector is considered at the simplest level by analysing the cash flow models of six Palestinian power distribution utilities' DISCOs (JDECO, GEDCO, HEPCO, NEDCO, SELCO & TEDCO)[3] . The objective of the financial modelling is to identify the variation in the allowed revenues of the DISCOs and the most efficient way to cover the additional costs that generation and network expansions are likely to require. The electricity average equilibrium cost and retail tariff for each distribution utility as well as at aggregate level are considered. Based on data projections and the input parameters, the model will help qualitatively define the impact on tariff components that might assure the financial equilibrium of the 5+1 DISCO.

- Input variables: These are distribution losses and revenue collection ratio. The model allows the selection of target values for distribution losses and revenue collection ratios for 2020 to 2030. These two parameters reflect the overall operational and financial performance of the utility and can be improved over time through management efforts but will have an impact on O&M costs. Given that measures to improve the poor current performance in these areas are still underway, the model assumes that the full benefit of these measures will be achieved by 2030. It is possible to input different targets and parameters to see what impact this has on the equilibrium tariff.
- Data projections: The revenues and expenditures are characterised. Basic data on the revenues and expenditures of the utilities is provided to determine the revenue requirements for the tariff-setting process.
- Expenditure: The model uses data from the DISCOs' annual financial reports on O&M, taxes, debt service, planned investments and power purchase costs. O&M are projected based on demand projections and the efficiency factor set by the regulator. Debt service and planned investments are projected based on information about the repayment profile of currently held debts, interest rate on debt and investment plans for the period. The distribution utilities' most significant expenditure is power purchase. It is not possible to make any additional assumptions on the capital expenditure required to meet the projected growing demand.
- Revenues: The revenue numbers have been revised (upward) to include the most recent data available from the PERC on the number of customers, purchase, and sale of electricity (see Appendix for a detailed analysis of the revenues stream). The total revenue accruing to the DISCOs is significantly boosted due to a significant increase in the amount of power purchased by final customers and the number of total customers served. However, an assessment of the total cost of the increased demand and consequent supply, particularly of the additional distribution and transmission capacity is impossible to calculate at this stage, and therefore, our analysis can only be partial, considering the data available.

As discussed in the previous sessions, the optimal tariff structure depends on the different cost drivers that affect the considered energy system,

3 GEDCO is also considered in this analysis, notwithstanding the fact that the KPI are not available for this DISCO.

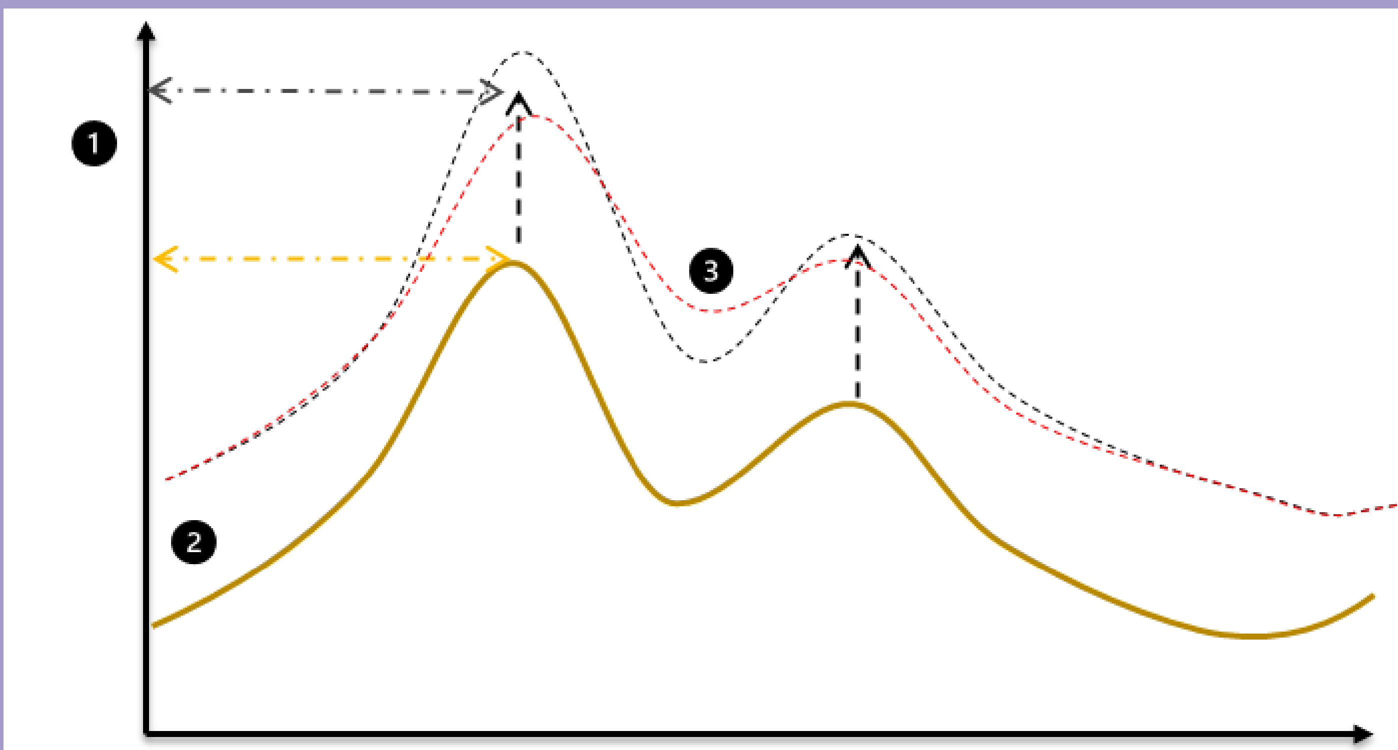
and therefore, we need to identify the main cost element that will impact the Palestinian electricity system to define its likely implications on the tariff structure.

Three main effects are likely to materialise (see Figure 3) with the projected increase in the number of customers, consequent increase in power sales and the increased penetration of distributed energy resources:

1. An increase in the peak demand and system peaks,
2. Increase in the average demand at most time intervals as well as an increase in the average consumption and
3. Increase of RES generation, or otherwise decrease of the net demand, at peak hours for the distributed prosumers in the systems.

1. Increase in the peak demand and system peak – An increase in the number of customers (and connection points in general) is typically associated with upward pressure on peak demand. Electricity consumption depends on social habits (such as cooking and dinner time) and is relatively stable with time. Therefore, with the addition of new households and commercial points of delivery, the overall demand will increase, and, provided that the electricity network is able to accommodate it, at least in part, such an increase will also determine a system peak.
2. Increase in the average demand at most time intervals – More customers and additional points of delivery will impact the overall demand/consumption at each time interval, as new customers will have non-zero demand also at off-peak times. Additionally, the progressive electrification of energy demand needs to be taken into consideration for such an assessment. The ability of the system to handle such an increase in network usage must be considered at all time frames.
3. Increase of RES generation – RES generation and Distributed RES generation (DER) must also be taken into consideration to assess their overall impact on network usage. The availability of net metering schemes can provide powerful incentives for increased

Figure 3 . Possible Changes in the Palestinian Electricity system – Daily Demand Profile



installation rates of domestic solar PV kits. Depending on the relative penetration of PV compared to the total increase in household demand, the net effect might be zero (or negative) at peak times, decreasing the residual demand in the central hours of the day while releasing electricity into the system before and after the peak times (this is often referred as the duck curve[4]). This effect will likely materialise when penetration rate of solar PV is reached.

The three aspects are evaluated in greater detail in the remainder of the report.

Impact on tariffs: how power bills will change following the implementation of the deterministic scenario.

The baseline scenario results provide an overview of the situation in different DISCOs for 2020–2030. As the model returns the "electricity average equilibrium cost" for each distribution company, we can evaluate the loss that the average retail tariff imposes on each DISCO. In Figure 4, the reader can find the total revenues/debts of the five DISCOs and GEDCO. The revised demand curve is also mirrored by a significant increase in the total power sales, which is increasing by 5% each year. The DISCOs will, therefore, benefit from a significant increase in revenues, derived from the expansion of the demand base. However, according to the WB deterministic scenario, the electricity average equilibrium cost is higher than the average retail tariff in each of the DISCOs, except for NEDCO. According to this scenario, the significant increase in the revenues deriving from the greater number of customers and level of demand will not offset the increased costs required to efficiently supply the growing market. Thus, a gradual increase in the tariff level is required along with an appropriate re-definition of the tariff structure.

As we know, electricity is an instantaneous commodity and is very expensive to store. Therefore, currently, electricity generation must match the demand at each instant, responding to seasonal patterns and instantaneous fluctuations. Thus, one of the biggest drivers of costs and capacity requirements is the electricity demand that occurs during peak periods, particularly during the hours between 5 p.m. and 7 p.m. – when residents return home and prepare meals – and during excessively hot and cold days. These peak periods require utility companies to maintain an operational capacity to meet such high demand. This requisite peak capacity is often outdated, expensive and underutilised. Yet, peak costs must be recovered through the capacity component of the tariff because peak demand is negligible in terms of overall volume (considered on an annual basis) and is, thus, spread across the entire spectrum of the network users but occurs at times of system stress.

On the other hand, the generalised increase in electricity demand will increase the overall volume of the system demand, and this will be reflected in the variable costs of electricity supply (that will increase), and therefore, a similar variable component of the tariff needs to increase. In this case, the volume component of the tariff needs to be reconsidered.

Finally, the fixed component of the tariff covers the fixed costs, and these costs typically depend on economies of scale and density.

4 There are several research and dissemination articles dealing with this specific aspect. For reference, please visit https://www.energy.gov/eere/articles/confronting-duck-curve-how-address-over-generation-solar-energy

Figure 4. Total Cumulated revenues/debts and power sales for 5 DISCOs and GEDCO.

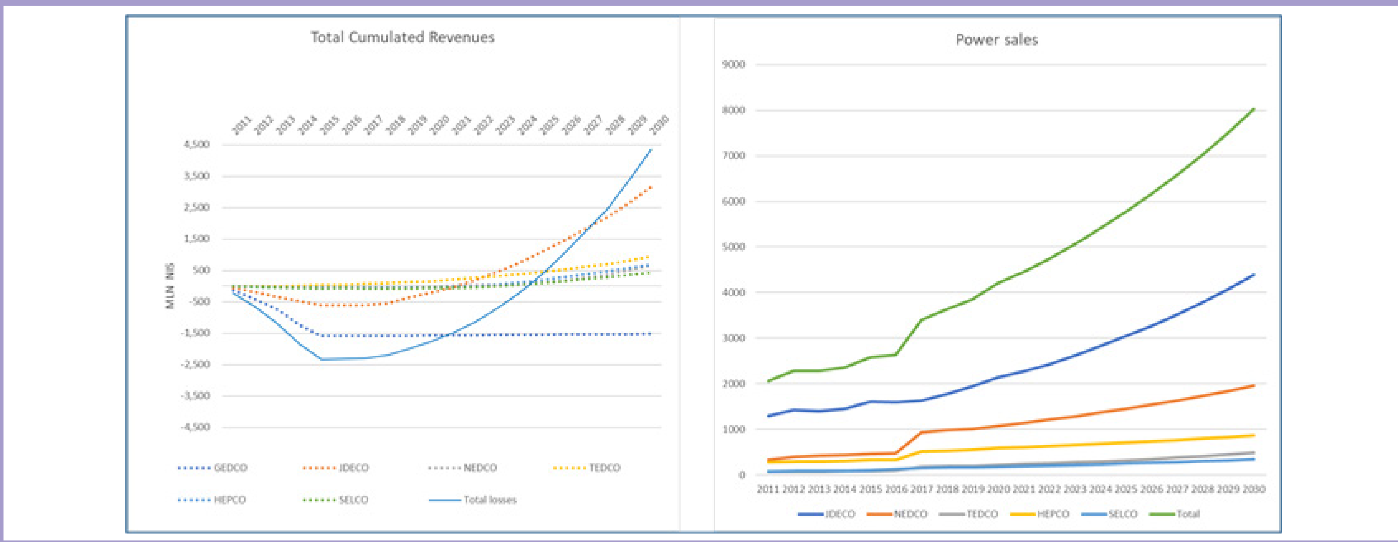


Table 8 . Impact of the Evolution of the Electricity Systems on the Tariff Components

	Tariff Component	Unit of Measure	Function	Situation in Palestine	Impact on the Component
1	Capacity	€/kW	Recovering generation and network capacity costs. Should be based on demand (kW) at times of system peaks, as this drives investment needs.	The system peak is likely to increase in Palestine, as more consumers will be online and due to the increased generation transmission capacity.	
2	Volume	€/kWh	Used to recover the variable costs of additional electricity supply in each interval.	Electricity supply is likely to increase at each time interval. Better interconnection and greater availability of more reliable generation capacities will boost supply and demand at each time of the day.	
	Fixed	€/point of delivery	Used to recover the costs of customer-related activities, such as metering, billing and collections that do not vary with customer demand or consumption.	The increase in the number of customers will introduce some economies of density and concentration. The likely impact is declining.curve	
3	Capacity	€/kW	Recovering generation and network capacity costs. Should be based on demand (kW) at times of system peaks, as this is the driver of investment needs.	The increase in the distributed generation is likely to flatten the peaks and shave the demand in the central hours of the day, shifting it to off-peak hours. It will also contribute to reducing the capacity component of the tariff.	

6

TARIFF STRUCTURE AND STATIC ANALYSIS

6

TARIFF STRUCTURE AND STATIC ANALYSIS

We now provide a brief overview of the characteristics of a proposed tariff re-design that shall include a fixed capacity component, to be levied on each consumer to write off the cumulated debt accruing for investments and operation under the implementation of the selected scenarios.

The calculation is performed with the following assumptions:

1. The cumulated debt will be covered by each connection point, assuming that the number of customers will grow proportionally with the projections of the demand.

2. The outstanding debt will be spread proportionally along the remaining time of the period considered starting from the current year (2020)

3. No affordability constraints are considered at this stage; only pure financial sustainability has been considered. Other different scenarios can be developed if required.

4.

The results emerging from this analysis provide a scattered picture. In five out of six DISCOs, according to the selected scenario, starting from 2020, an additional capacity element needs to be introduced in the retail tariff to cover the capacity charge of the network in the form of a flat-rate ex-ante component. This component is not sustainable and affordable for GEDCO, JDECO and SELCO and will lead to a substantial increase in the yearly electricity bill. This will be less expensive in the case of NEDCO and HEPCO, and TEDPCO can be exempted from the introduction of this additional tariff component.

While revisions of the tariff structure of this magnitude are certainly not viable in the current circumstances, the numerical example highlights the necessity of radical interventions to guarantee, in the medium and long run, the SoS in Palestinian territories. A careful programme of targeted subsidies (and perhaps cross-subsidies among the various DISCOs customers) should be designed and implemented.

Table 9 . Financial Data – Additional Capacity Component

			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GEDCO	**New Capacity Tariff**	**NIS Year/ Consumer**	**467**	**443**	**428**	**414**	**400**	**387**	**378**	**370**	**361**	**353**	**345**
	Total ajusted Cumulated Revenues	NIS MLN	-1160	-1016	-873	-731	-589	-448	-307	-169	-29	110	248
JDECO	**New Capacity Tariff**	**NIS Year/ Consumer**	**179**	**162**	**154**	**157**	**149**	**150**	**146**	**138**	**131**	**125**	**124**
	Total ajusted Cumulated Revenues	NIS MLN	-448	-392	-335	-280	-224	-167	-111	-56	-1	53	107
NEDCO	**New Capacity Tariff**	**NIS Year/ Consumer**	**26**	**24**	**23**	**20**	**19**	**17**	**15**	**15**	**14**	**13**	**12**
	Total ajusted Cumulated Revenues	NIS MLN	29	26	23	21	18	15	13	11	8	6	4
HEPCO	**New Capacity Tariff**	**NIS Year/ Consumer**	**88**	**85**	**80**	**81**	**81**	**78**	**78**	**77**	**70**	**67**	**64**
	Total ajusted Cumulated Revenues	NIS MLN	-42	-36	-30	-25	-19	-14	-8	-3	2	7	12
SELCO	**New Capacity Tariff**	**NIS Year/ Consumer**	**168**	**161**	**155**	**156**	**159**	**154**	**154**	**154**	**141**	**138**	**130**
	Total ajusted Cumulated Revenues	NIS MLN	-51	-45	-39	-32	-26	-20	-14	-9	-2	4	10

7

CONCLUSION

7 CONCLUSION

The analysis carried out in this report aims at providing practical guidance for the definition of a cost-reflective distribution tariff in Palestinian territories. The huge import dependency and the weakness of the existing networks require a rapid intervention in terms of additional installed generation and interconnection capacity.

Additionally, the projections in terms of new customers and additional power sales suggest that the distribution tariff needs to be revised both in terms of level and structure. While social viability, affordability and social acceptability are key, these aspects remain in the background of the present study. Keeping in mind the complex social consideration that needs to be at the basis of the tariff restructuring, financial sustainability seems to be an important priority for the long-term efficiency of the energy system in Palestine. Nevertheless, a significant reform in the tariff structure currently in place should be considered to reduce the debt burden and avoid an even further delay in the implementation of urgent investment plans.

Co-funded by
the European Union

MEDREG – Association of Mediterranean Energy Regulators
Via Fieno 3, 20123 Milan, Italy –Tel: +39 3402938023
info@medreg-regulators.org www.medreg-regulators.org

Empowering Mediterranean regulators for a common energy future