ABOUT MEDREG

MEDREG stands for the Association of Mediterranean Energy Regulators which gathers 27 energy regulators from 22 countries, spanning the European Union (EU), the Balkans and the MENA region.

Mediterranean regulators work together to promote greater harmonization 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 to foster consumers’ rights, energy efficiency and infrastructure investment and development based on secure, safe, cost-effective and environmentally sustainable energy systems. MEDREG serves as a platform allowing information exchange and providing assistance to its members as well as offering capacity development activities through webinars, training sessions and workshops. The MEDREG Secretariat is located in Milan, Italy.

ACKNOWLEDGMENTS

This report is the result of the work carried out by the Consumers Working Group (ELE WG) and the MEDREG Secretariat in the March–December 2018 period.

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<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>AFIK</td>
<td>Frequency of Unscheduled Interruptions Index</td>
</tr>
<tr>
<td>AFIKe</td>
<td>Avg. Frequency of External Interruptions per nominal installed kVA of the MV network</td>
</tr>
<tr>
<td>AFIKs</td>
<td>Avg. Frequency of Scheduled Interruptions per nominal installed kVA of the MV network</td>
</tr>
<tr>
<td>AFIKtp</td>
<td>Avg. Frequency of Third-Party Interruptions per nominal installed kVA of the MV network</td>
</tr>
<tr>
<td>AFIKu</td>
<td>Avg. Frequency of Unscheduled Interruptions per nominal installed kVA of the MV network</td>
</tr>
<tr>
<td>ARERA</td>
<td>Autorita di Regolazione per Energia Reti e Ambiente (The Italian Regulatory Authority for Energy, Networks and Environment)</td>
</tr>
<tr>
<td>ASAI</td>
<td>Average subscriber electrical feeding</td>
</tr>
<tr>
<td>Avg.</td>
<td>Average</td>
</tr>
<tr>
<td>CAIDI</td>
<td>Duration of customer interruptions (Customer Average Interruption Index)</td>
</tr>
<tr>
<td>CARD</td>
<td>Contract for Access to the Public Distribution Network</td>
</tr>
<tr>
<td>CART</td>
<td>Contracts for Access to the Public Transmission Networks</td>
</tr>
<tr>
<td>CEO</td>
<td>Chief Executive Officer</td>
</tr>
<tr>
<td>CoRDIS</td>
<td>Committee for the Settlement of Disputes and Sanctions</td>
</tr>
<tr>
<td>CRE</td>
<td>Commission de Régulation de l’Energie (French Energy Regulatory Authority)</td>
</tr>
<tr>
<td>DSO</td>
<td>Distribution System Operator</td>
</tr>
<tr>
<td>EDCO</td>
<td>Electricity Distribution Company</td>
</tr>
<tr>
<td>EED</td>
<td>Energy Efficiency Directive</td>
</tr>
<tr>
<td>EENS</td>
<td>Expected Energy Not Supplied</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
</tr>
<tr>
<td>GASREG</td>
<td>Gas Regulatory Authority</td>
</tr>
<tr>
<td>GDF</td>
<td>Gaz de France</td>
</tr>
<tr>
<td>GIS</td>
<td>Geographic Information System</td>
</tr>
<tr>
<td>Hi</td>
<td>Duration of Momentary Interruption</td>
</tr>
<tr>
<td>HVB</td>
<td>Extra high-voltage (in French)</td>
</tr>
<tr>
<td>JEPCO</td>
<td>Jordanian Electric Power Company</td>
</tr>
<tr>
<td>JOD</td>
<td>Jordanian Dinar</td>
</tr>
<tr>
<td>IDECO</td>
<td>Irbid District Electricity Distribution Company</td>
</tr>
<tr>
<td>Kto</td>
<td>Total number of Momentary Interruptions during calendar year</td>
</tr>
<tr>
<td>kVA</td>
<td>Kilo-volt-ampere</td>
</tr>
<tr>
<td>LV</td>
<td>Low Voltage</td>
</tr>
<tr>
<td>MAIFI</td>
<td>Momentary Average Interruption Frequency Index</td>
</tr>
<tr>
<td>MAIFItoto</td>
<td>Momentary Average Interruption frequency</td>
</tr>
<tr>
<td>MEDREG</td>
<td>Association of Mediterranean Energy Regulators</td>
</tr>
<tr>
<td>MV</td>
<td>Medium Voltage</td>
</tr>
<tr>
<td>Nci</td>
<td>Number of Consumers affected by Momentary Interruption</td>
</tr>
<tr>
<td>NRA</td>
<td>National Regulatory Authority</td>
</tr>
<tr>
<td>RCBCI</td>
<td>Report on the respect of codes of good conduct and independence of network operators</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable Energy Sources</td>
</tr>
<tr>
<td>REWS</td>
<td>Regulator for Energy and Water Services</td>
</tr>
<tr>
<td>SAIDI</td>
<td>System Average Incidence Duration Index</td>
</tr>
<tr>
<td>SAIDite</td>
<td>Average time of External Interruption</td>
</tr>
<tr>
<td>SAIDIs</td>
<td>Average time of Scheduled Interruption</td>
</tr>
</tbody>
</table>
### Regional integration: sub-regional regulatory convergence

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIDItp</td>
<td>Average time of Third Party Interruption</td>
</tr>
<tr>
<td>SAIDIu</td>
<td>Average time of Unscheduled Interruption</td>
</tr>
<tr>
<td>SAIFI</td>
<td>System Average Incidence Frequency Index</td>
</tr>
<tr>
<td>SAIFle</td>
<td>Average External Interruption frequency</td>
</tr>
<tr>
<td>SAIFIs</td>
<td>Average Scheduled Interruption frequency</td>
</tr>
<tr>
<td>SAIFItp</td>
<td>Average Third-Party Interruption frequency</td>
</tr>
<tr>
<td>SAIFIu</td>
<td>Average Unscheduled Interruption frequency</td>
</tr>
<tr>
<td>SCADA</td>
<td>Supervisory control and data acquisition</td>
</tr>
<tr>
<td>SEI</td>
<td>EDF la Direction des Systèmes Energétiques Insulaires (the Directorate of Insulated Energy Systems)</td>
</tr>
<tr>
<td>SMEs</td>
<td>Small and medium-sized enterprises</td>
</tr>
<tr>
<td>SoLLEn</td>
<td>Solution en Ligne Aux Litiges d’Energie (French online dispute resolution system)</td>
</tr>
<tr>
<td>TIEPI</td>
<td>Hours lost per year, weighted by the installed transformer capacity</td>
</tr>
<tr>
<td>TIF</td>
<td>Testo integrato fatturazione (Billing for the Retail Service for Electricity and Natural Gas Customers)</td>
</tr>
<tr>
<td>TIME</td>
<td>Disposizioni per l’erogazione del servizio di misura (Provisions for the provision of the measurement service)</td>
</tr>
<tr>
<td>TIQE</td>
<td>Regolazione output-based dei servizi di distribuzione e misura (Output-based regulation of distribution and measurement services)</td>
</tr>
<tr>
<td>TIQV</td>
<td>Qualità dei servizi di vendita (Quality of sales services)</td>
</tr>
<tr>
<td>TNC</td>
<td>Total number of Licensee’s Consumers</td>
</tr>
<tr>
<td>TPA</td>
<td>Third-party access</td>
</tr>
<tr>
<td>TSO</td>
<td>Trasmission System Operator</td>
</tr>
<tr>
<td>TTIK</td>
<td>Total Time of Unscheduled Interruptions Index</td>
</tr>
<tr>
<td>TTIKe</td>
<td>Avg. time of External Interruptions per nominal kVA in the MV network</td>
</tr>
<tr>
<td>TTIKs</td>
<td>Avg. frequency of Scheduled Interruptions per nominal installed kVA of the MV network</td>
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<tr>
<td>TTIKtp</td>
<td>Avg. frequency of Third-Party Interruptions per nominal installed kVA of the MV network</td>
</tr>
<tr>
<td>TTIKu</td>
<td>Avg. time of Unscheduled Interruptions per nominal kVA in the MV network</td>
</tr>
<tr>
<td>TURPE</td>
<td>Tariff for the use of public electricity</td>
</tr>
<tr>
<td>VAT</td>
<td>Value added tax</td>
</tr>
</tbody>
</table>

This report was developed with the support of a Drafting Team including Mr. Dario Franchi (ARERA, Italy), Ms. Rébecca Radereau (CRE, France), Mr. Hatem Mahmoud (GASREG, Egypt) and Mr. Andre Buttigieg (REWS, Malta).
INTRODUCTION
TMEDREG supports the development of higher regulatory awareness in Southern and Eastern Mediterranean countries, with a view to contribute to a more recognisable and effective role of regulators in the regional energy markets. Consequently, in the latest years, MEDREG developed a framework to support regulatory reforms in its countries of operation and assist its members towards attaining the required level of development in their energy regulatory frameworks.

In this context, the Action Plan for the Consumer Working Group foresaw an opportunity to carry out a peer review assessment for the Jordanian energy regulator EMRC, focusing on the current status of the consumers’ quality of services and the regulatory and legislative acts in place in Jordan.

As a first step, the MEDREG Secretariat in coordination with EMRC has defined the expected content and outcomes of the peer review exercise. The structure and content are reported below. This outline also mentions the documents to be shared by the Jordanian regulator to properly carry out the peer review exercise.

This report considers the applicability to not only Jordan – which is the principal focus of this study – but also the wider MEDREG region countries. The MEDREG region comprises countries that are not only direct members of the EU and hence subject to further transition of their energy industries to comply with the new EU targets relating to the Green Digital Strategy for the EU announced in March 2020. It also includes member states that rely on European policy and financial institutions for regulatory and market development.

Moreover, following MEDREG support, all member countries – with varying speeds – are moving towards unbundling of their hitherto vertically integrated energy industry structures, introducing non-discriminatory third-party access, endeavouring to reduce their dependence on fuel imports, especially fossil fuel imports to introduce new investments in the form of natural gas/LNG and/or renewable energy. As a result, the inter-fuel competition already experienced in the EU between natural gas and renewable energies is now likely to also play out on the southern shore MEDREG region countries.

The other areas of similarity with Jordan that this group of MEDREG region countries experiences is the rising per capita energy consumption, growing urbanisation – in some cases leading to a clear urban/rural divide when it comes to electricity networks – and its related challenges. These include the growing need to be able to serve this demand with products and services that reflect the sophistication that these consumers are demanding and finally the tariff pressure from end users. In some cases, like in Jordan, the tariffs are quite similar to tariff levels seen in Western Europe and yet the level of product or service sophistication that European consumers enjoy is often found lacking. The clearest evidence of this in Jordan was in the period August 2019–February 2020 when the country witnessed a high level of consumer protests over rising electricity costs.

The substitution of centralised generation plants, often connected to the HV transmission networks, has so far resulted in distribution companies having to focus primarily on connecting and managing demand related issues. The substitution of centralised HV connected fossil fuel plants distributed was lower in capacity and larger in number and the renewable plants often at MV/LV interface levels pose a new dimension to distribution companies. This aspect was usually
covered under the allowed embedded generation for EU networks and the learnings associated with this aspect will remain applicable for most MEDREG countries. Traditionally, EU regulation has treated this event-specific new connection business as outside of the regulatory ringfence but with substantial disclosure norms to ensure transparency/ non-discriminatory access. In the light of growing RE capacity being required to connect at the MV/LV interface, this aspect may have to be reviewed on a case-by-case basis. Even in developed EU member states, this issue may require a review as the EU/ENTSOG promoted TSO/DSO model begins to develop. This is a “wait and observe” issue. Nevertheless, it will be an important consideration for electricity networks, especially as they have to cope with rising levels of end-use demand, greater imbalances across urban/rural areas and the challenges of connecting a larger number of distributed generation units.

The significance of this aspect for the MEDREG region countries can be understood from the graphic published by the EDSO secretariat in its recent case study-based report on the future of DSOs and the role of smart grids. Of the four themes covered in this report, the following is the significance of the DSO formation as many of the SO functions move to lower MV/LV levels:

- **New Connections**: As a greater number of smaller size renewable projects seek to connect to the grid, the newly formed DSOs will be expected to offer a higher/sophisticated level of connection services thus advancing the best practice.
- **The customer management related services and billing and metering processes will be required to step up as DSOs start to offer multiple channels of access including mobile apps and customer-led meter reading and reporting services including automatic meter reading interfaces.

---

**Industry figures**

- **41** DSOs, **2** Associations
- **24** Countries
- Serving > **350 million** citizens
- Participation in **12** EU-funded research projects
- Founded in **2010**
- **11 full-time staff** in E.DSO Secretariat
- Participation in **all** EU expert groups in Smart Grids (SGTF, ETIP SNET, TSO/DSO Platform)
- **€ 27 billion** annually for grid investment
- **+330,000** DSO grid jobs in the EU
- **7 million km** of distribution lines (9 times from Brussels to the moon and back)
- **35%** of all value chain of electricity sector

*Source: EDSO for Smart Grids Case Study Report August 2020*
2

THE JORDANIAN ELECTRICITY DISTRIBUTION CONTEXT
2 THE JORDANIAN ELECTRICITY DISTRIBUTION CONTEXT

In this chapter, MEDREG considers the developments specific to Jordan that highlights the importance of the four themes considered in this report. The points made in the previous chapter of the relevance of this assessment to the wider MEDREG region will become self-evident.

Several proposed/expected changes in the Jordanian electricity sector including a greater degree of system operating functions transferring from the transmission company NEPCO to the three licenced DSOs and the expected continuing growth in demand bring into sharp focus the importance of the role of electricity distribution in the country today and the relevance of the four themes:
- Two relating to distribution system performance management.
- Two relating to the consumer-facing role that Jordanian distributors currently perform as part of the bundled distribution and supply role they perform.

The table below reproduced from NEPCO’s latest annual report provides an insight into the growth challenge facing the Jordanian electricity system. Aside from the ever-rising peak demand till 2040, the real challenge is to manage a CAGR of 3% or more for the next 20 years.

<table>
<thead>
<tr>
<th>YEAR</th>
<th>Max. Demand* MW</th>
<th>Growth(%)</th>
<th>**Electrical Energy Generated GWh</th>
<th>Growth(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>3,057</td>
<td>1.9</td>
<td>20,143</td>
<td>2.6</td>
</tr>
<tr>
<td>2020</td>
<td>3,146</td>
<td>2.9</td>
<td>20,744</td>
<td>3.0</td>
</tr>
<tr>
<td>2022</td>
<td>3,341</td>
<td>3.1</td>
<td>22,063</td>
<td>3.2</td>
</tr>
<tr>
<td>2025</td>
<td>3,645</td>
<td>2.9</td>
<td>24,250</td>
<td>3.2</td>
</tr>
<tr>
<td>2030</td>
<td>4,186</td>
<td>2.8</td>
<td>28,230</td>
<td>3.1</td>
</tr>
<tr>
<td>2040</td>
<td>5,528</td>
<td>2.8</td>
<td>38,261</td>
<td>3.1</td>
</tr>
</tbody>
</table>

This projected growth is expected to be met not only by a rising share of natural gas so far that has managed to displace oil imports in the electricity mix but also noteworthy is the rising role of renewable energy. A large number of distributed solar and wind plants may have to be connected to the distribution system to propel the current distribution licensees into performing the role of a Distribution System Operator (DSO). The graphic, sourced from the NEPCO annual report provides an insight into the changing fuel mix coincident with the rise of renewables in the system.

The remainder of this chapter discusses the challenges to the Jordanian electricity distribution system in the context of the four themes that form the basis of the case studies discussed in this report. This should help explain the rationale for the identification/selection of these themes. Within the context of “New Connections”, it’s important to note that Jordan has many planned RE projects that will connect at the MV/LV levels.
at the DSO interface. Thus, the new connections activity is expected to significantly rise within the DSO operations. In addition, a number of welling connections are also increasing where electrical pumping is added to existing networks.

As far as “Network Performance Indicators” are concerned, in the Jordanian context the principal driver is again the development of consistency of metrics as applied in the EU or MEDREG context. The need for standardised well-understood parameters of network performance is important in the context of the price/value ratio that has been argued in the Jordanian context. The issue at hand is that there has been considerable unrest over the issue of electricity end user prices in Jordan with the finding that prices for end users in the EU and Jordan are almost on par. This has made EU standard/compatible network performance standards a necessary requirement.

On the subject of “Billing and Metering”, again the context is that as a greater number of commercial customers have installed their own generation (including renewables), there has also been a commensurate growth in net metering. This is a positive development as greater demand-side participation is likely to become possible in the future provided the required sophistication in billing is made. Importantly the processes associated with billing and metering are integrated/harmonised to reduce billing errors and provide efficient and possibly automatic billing.

Finally, on the issue of “Customer Complaint Handling”, the primary concern in Jordan is of accurate billing in the first place which is likely to have a considerable impact on the level of consumer satisfaction. Jordan has in place several initiatives relating to developing billing channels though all of these activities are still carried out as part of the integrated distribution company license conditions.

As seen later in this report, each of the four countries from where the case studies have been prepared offers considerable similarities to the Jordanian context. Hence, EMRC has a menu of options to choose from a selection of identified best practices. This is discussed in the final chapter on the summary of lessons learnt from the best practices, which forms the following chapters.
3

REGULATION OF NEW CONSUMERS’ CONNECTION TO THE GRID
3.1 Principles regulating new consumers’ connections to the grid

The regulation of new connections to the grid is generally based on the principle of non-discriminatory access to electricity transmission and distribution networks which is a prerequisite for the development of functioning electricity markets. Third-party access policies, involving the identification and isolation of the natural monopoly function and then subjecting the non-monopoly elements to comparative/benchmark driven competition including ensuring transparency in their operations to protect consumer interests require owners of natural monopoly infrastructure facilities to grant access to those facilities to parties other than their own customers. They are usually competitors in the provision of the relevant services, on commercial terms comparable to those that would apply in a competitive market. The third-party access right (TPA) in the energy market context is the idea that in certain circumstances economically independent undertakings operating in the energy sector should have a legally enforceable right to access and use various energy network facilities owned by other companies. This third-party access can be applied on a regulated (rTPA) or a negotiated (nTPA) basis and this determination is generally made by the regulators.

Indeed, competitive power markets cannot exist if generators and suppliers are not able to supply electricity and household and industrial customers are not able to connect to the grid and consume it using the services provided by transmission and distribution grids. The connection to electricity networks is therefore a component of the regulated access to the network and refers to both the connection of generation facilities and consumption centers to the grid. Often regulators, in the interests of ensuring competition, made the business of providing “new connections” outside of the regulatory ringfence with the caveat that these new connections eventually come within the ambit of the regulatory asset base at subsequent price control or tariff reviews. This has been applied in the case of the UK, Netherlands and other Western European countries though not yet in France and Italy – the two countries considered in this report.

To participate in the electricity market as generators, consumers, distributors or suppliers, the new users of the electricity transmission and distribution networks must be connected to the network in the first place. The necessity to regulate the connection process is fundamental to ensure non-restrictive access to the network and that all market participants enjoy equal and non-discriminatory conditions. In this context, it is generally accepted that all network connection requests must be completed if they are compliant with the law and connection costs of a user are to be paid by that particular user and are not socialised. On top of it, regulatory frameworks usually address the challenges of connections to the grid with two sets of regulation: the transmission and distribution grid codes. Technical requirements to be met by users requesting connection to the electricity network are detailed, and the network connection regulation which addresses the economic and legal procedures are applied for the connection, starting with the issuance of the connection notification request until the finalisation of the connection works through the payment of the connection tariff.

When talking of connection tariff, there is a clear distinction to be made between connection charges and connection costs. The term “connection charge” refers to the fee charged to a consumer to connect to an established distribution network. In this context, the cost
related to connection charge usually covers the estimated costs of materials, labor, and transport needed to make the connection from the nearest pole of the distribution system. It includes the costs of inspection of the consumer’s premises, and, in some instances, the downstream cost of the internal wiring of the consumer’s house and a relatively small one-time application fee. By contrast, “connection cost” usually considers the total expenses of both the operator and the consumer for providing the new electricity supply. Therefore, connection costs consist of the connection charge, plus the cost of upstream development of the power grid to serve an area, mainly meaning the distribution system (medium voltage) expansion. It can also include, depending on the type of connection, further upstream development costs needed in the transmission and generation systems.

However, the general distinction outlined above is not always respected and three different approaches may be considered when charging new users for the connection to the grid. The principal drivers in this regulatory treatment are really the extent of the network development that has already occurred vis-à-vis the required expansion of the network:

1. Where extensive developments in the network have occurred or in mature networks, Super-shallow connection charges apply i.e., no costs are charged to the new user due to low marginal costs associated with new connection developments and usually included in the tariff formula.

2. Shallow connection charges: Connection costs are limited only to the user installations and its direct connection works are carried out between the delimitation point and the closest network point. In this case, network strengthening is socialised through the network utilisation tariff. E.g., this would apply to the semi-urban areas in Jordan whereas,

3. Deep connection charges: All the costs are incurred for the connection. Therefore, both the costs for installations and its direct connection works carried out between the delimitation point and the closest network point and network strengthening costs are allocated to the new user. E.g., this would apply in the case of areas in Jordan where new network development is required or customer density is low. The Jordanian government implemented a fee channelled into installing solar panels for underprivileged families. It is called “Fils Al Reef” and targets specifically the installation of power cells in rural areas.

Looking specifically at the regulation of new household consumers to the grid, several issues need to be regulated by national regulatory authorities to guarantee minimum standards of customer friendliness and the following are the most relevant:

1. Definition of tolerance limit times in which DSOs are obliged to finalise the realisation of the different steps of the new connection procedure, including the detailed timing for the practical set up of the connection to the grid.

2. Monitoring of operators’ activities and the imposition of sanctions and fines against the operators in case of breach of tolerance limit times or other existing regulations.

3. Definition of the methodology for calculating the customer’s contribution to connection costs and the calculation of concrete fees based on the defined methodology. To some extent, the fee methodology might be also defined by distribution system operators but, in this case, regulators must be in charge of its approval.

4. Definition of the cases for refusing connection requests and obligation to provide justifications in case of refusal.

5. Implementation of dispute settlement procedures to solve any possible connection-related disputes that might arise in the connection process between operators and new subscribers.

In general, the terms, conditions and tariffs are defined at the national level by National Regulatory Authorities (NRAs) which have to monitor that obligations of licensees towards consumers are respected and that the local infrastructures function properly. Therefore, rules for new connection procedures vary among countries and this also applies to the European Union where there is no harmonisation at the
European level.
In the subsequent section, it is provided more specific information on the regulation of new users’ connection to the grid in Jordan with a view of understanding practically how the Jordanian system works and what space of improvement can be proposed comparing it to the procedures applied in other relevant countries.

3.2. Overview of new consumers connections in Jordan

3.2.1. Procedures regulating new consumers connections

In Jordan, the connection of new consumers to the grid is regulated by art. 18 of the Performance Standards Code for Retail Distribution and Supply Licensees. Therein, the procedures regulating the relationship between licensees and consumers and their respective obligations are clearly specified. The steps taken for finalising a new connection and the time frame to be respected by consumers and licensee are detailed below:

1. The consumer submits a complete application to be connected to the power service.

2. The licensee must complete technical inspections with different time limits depending on the requested load unless the subscriber demands are otherwise in agreement with the licensee. For JEPCO, regardless of the type of consumer, the inspection must be completed within 10 business days and, in case adjustments are needed, they must be performed within 10 additional business days. For IDECO and JEPCO, time limits for inspection procedures can be extended in case of any changes on the current network to complete inspection and connection procedures for the applicant with the mandatory clause that the licensee makes such changes at its own expense and not at the expense of the applicant. Such time limits are detailed in the table below:

3 - Once the licensee has finalised the inspection procedure, it informs and negotiates with the new subscriber the connection fee to be paid and, upon agreement, the new customer should submit the payment within different time limits depending on the type of connection.

4 - Once consumer connections procedures are completed, and due payments are made, the licensee shall complete the connection to the consumer according to different time limits which depend on the type of connection to be done. All the expected time limits are detailed above.
### Table 3a: Tolerance limits for completion of connection after payment for IDECO and EDCO

<table>
<thead>
<tr>
<th>Type of connection</th>
<th>Tolerance limits for fee payment</th>
<th>Tolerance limits for connection time after fee payment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple connections (overhead line service)</td>
<td>3 business days</td>
<td>15 Business days</td>
</tr>
<tr>
<td>Simple connections (land cable line service)</td>
<td>3 business days</td>
<td>30 Business days</td>
</tr>
<tr>
<td>Simple connections (Low Voltage up to 15 poles – land or overhead cable up to 350 meters)</td>
<td>15 business days</td>
<td>45 Business days</td>
</tr>
<tr>
<td>Other subscriptions</td>
<td>-</td>
<td>For all these connections, implementation time to be agreed between the licensee and Consumers provided it does not exceed 120 business days unless otherwise agreed</td>
</tr>
<tr>
<td>Includes Low Voltage works</td>
<td>20 business days</td>
<td></td>
</tr>
<tr>
<td>Includes Medium Voltage works</td>
<td>45 business days</td>
<td></td>
</tr>
<tr>
<td>Includes transmission works</td>
<td>60 business days, unless otherwise agreed</td>
<td></td>
</tr>
</tbody>
</table>

### Table 3b: Tolerance limits for completion of connection after payment for JEPCO

<table>
<thead>
<tr>
<th>Type of connection</th>
<th>Tolerance limits for fee payment</th>
<th>Tolerance limits for connection time after fee payment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple connections (overhead line service)</td>
<td>3 business days</td>
<td>10 Business days</td>
</tr>
<tr>
<td>Simple connections (land cable line service)</td>
<td>3 business days</td>
<td>20 Business days</td>
</tr>
<tr>
<td>Simple connections (Low Voltage up to 15 poles – land or overhead cable up to 350 meters)</td>
<td>10 business days</td>
<td>45 Business days</td>
</tr>
<tr>
<td>Includes Low Voltage works</td>
<td>15 business days</td>
<td></td>
</tr>
<tr>
<td>Includes Medium Voltage works</td>
<td>30 business days</td>
<td>Agreed for a maximum of 90 business day</td>
</tr>
<tr>
<td>Includes transmission works</td>
<td>45 business days, unless otherwise agreed</td>
<td></td>
</tr>
</tbody>
</table>
3.2.2. EMRC reporting procedure for new connections

In the context of the new consumer connections, EMRC has the power to monitor licensees to guarantee the respect of obligations set in the Standards Code for Retail Distribution and Supply licensees, thus ensuring the rights of new consumers connections to the grid. The monitoring powers are applied through the monthly reporting procedure in which licensees submit a monthly report to the Commission in an organised manner within the thirtieth day after the end of the report’s month, to enable the Commission to control and monitor the licensee’s compliance. In the case of new consumers connections, EMRC may be asked to intervene in three main cases:

1 – Following the payment of the connection fee by the consumer to the licensee, both the parties have 15 days to finalise the new connection procedure. In case they fail to reach an agreement on the required connection and there is a breach of the tolerance time limit set by the EMRC, the consumer may present their case to the Commission which shall take a final decision based on the available technical information and in discussion with the two parties. In this case, the 15 days’ time limit is not considered as the licensees have to include the cases exceeding the set tolerance limits for connection with the necessary justifications in the monthly reporting and EMRC starts the dispute settlement procedure to solve the complaint.

2 – In case no agreement is reached between the Licensee and Consumer regarding the proposed estimated fees before its payment, the consumer may present the issue to the Commission which shall take the appropriate decision based on:
   - Connection fees instructions or any other regulations or instructions issued by the Commission regarding connection fees.
   - Available technical and economic information in the cases in which the connection process requires other equipment, devices and/or works not included in the connection fees or any fees regulating instructions issued by the Commission.
   - Consultations with the two parties: EMRC may hire an expert to give their opinion on the subject, and the Commission’s final decision shall be binding upon the Licensee and the Consumer.

3 – If the new consumer submitting the connection request to the licensee provide incorrect or false documents within its application, the Licensee can cancel its request of subscription, informing EMRC through the monthly reporting procedure.

3.2.3. Penalties for non-compliance with new consumers connections

Licensees are obliged to comply with the tolerance limits for new consumer connections set in the Performance Standards Code for Retail Distribution and Supply Licensees. Otherwise, their non-compliant behavior may result in penalties for exceeded tolerance limits. The EMRC calculates the total amount of fines resulting from non-compliance yearly, deducting the overall financial value from the licensee’s revenue requirements through the tariff in the subsequent tariff period according to the tariff methodology which applies to them. Fines imposed by EMRC vary based on the type of infraction committed by the Licensee in the procedure regulating new consumers connections, as detailed below.

1. If the Licensee exceeds the standard for completing the technical inspection for the set time limits which depend on the requested load according to the Performance Standards, the Licensee shall be liable to pay the following fines for each business day exceeding the maximum limit as follows:
2. Once consumer connections procedures are completed, and due payments are made, the licensee has the obligation to complete the consumers' connection based on different time limits which changes according to the type of connection. If the licensee is unable to meet the stated standards, they are liable to pay the following fines for each business day exceeding the maximum limit as follows:

**Table 4: Fines to be incurred for delayed technical inspection**

<table>
<thead>
<tr>
<th>Requested Load</th>
<th>Fine</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Phase 1–10 subscriptions (new or existing on the same land lot)</td>
<td>JOD 10/per business day</td>
</tr>
<tr>
<td>More than 10 subscriptions</td>
<td>JOD 10/per business day</td>
</tr>
<tr>
<td>3 Phases Up to 32 Amperes</td>
<td>JOD 10/per business day</td>
</tr>
<tr>
<td>From 33–64 Amperes</td>
<td>JOD 15/per business day</td>
</tr>
<tr>
<td>From 65–80 Amperes</td>
<td>JOD 15/per business day</td>
</tr>
<tr>
<td>More than 80 Amperes</td>
<td>JOD 20/per business day for IDECO and EDCO; JOD 30/per business day for JEPCO</td>
</tr>
</tbody>
</table>

**Table 5: Fines to be incurred for delayed completions**

<table>
<thead>
<tr>
<th>Type of Subscription</th>
<th>Fine</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regular subscription (overhead line)</td>
<td>JOD 10/business day</td>
</tr>
<tr>
<td>Regular subscription (land line)</td>
<td>JOD 10/business day</td>
</tr>
<tr>
<td>Regular subscription with the connection of 15 poles or 350 meters of land or overhead cable</td>
<td>JOD 10/business day</td>
</tr>
<tr>
<td>Other subscriptions</td>
<td>JOD 30/business day</td>
</tr>
</tbody>
</table>
3. In case of consumer connections that require special extensions or updating the Distribution System, there are specific penalties if the licensee delays connection costs to the Consumer and is liable to pay the following fine for each business day after the deadline:

<table>
<thead>
<tr>
<th>Type of Subscription</th>
<th>Fine</th>
</tr>
</thead>
<tbody>
<tr>
<td>Subscriptions requiring works on the LV Network</td>
<td>JOD 20/business day</td>
</tr>
<tr>
<td>Subscriptions requiring works on the MV Network</td>
<td>JOD 45/business day</td>
</tr>
<tr>
<td>Subscriptions requiring works on the Transmission Network</td>
<td>JOD 60/business day</td>
</tr>
</tbody>
</table>

The penalties are not applied on licensees if the exceeding of tolerance limits for new consumers connections is caused by a third party and not by the licensee itself. Such a clause is defined as “Third-party dependent time” which is the number of business days in which the Licensee depends on one or more third parties to provide an official license for the connection or to prepare fee estimations. If the Licensee faces any opposition by a third party that prevents them from implementing inspection or connection processes for the subscriber, the distributor shall be required to prove the start and end of such opposition in writing supported with all necessary evidence and official reports if required. Upon reviewing the transactions, if the Commission finds out that the distributor has an unproven case or the Commission is not convinced of the provided evidence, the case shall be deemed as non-compliance. In this case the time limiting penalties would apply.

3.3. Recommendations

The regulation of new consumer connections to the grid in Jordan is very comprehensive concerning the timeframe to be respected by market operators, the reporting procedure to EMRC and the penalties imposed to DSOs for non-compliance with the regulation in place. Looking at the international case studies described above, the following aspects may be considered to reinforce the regulation of power supply to new customers in Jordan:

- **Incentive regulation**: Setting up incentive mechanisms for DSOs in the new connection’s procedures would support better treatment of customers requiring a new connection to the grid. Among others, quality indicators to be considered for granting a financial incentive to operators that act in line with the regulation may be the number of penalties paid for the late submission of proposals for connection, the number of penalties paid for late commissioning of the facilities, customer satisfaction with network connections or analysis of the operators’ compliance with the timeframe required for providing the new consumers’ connection.

- **Timeframe**: Revision of costs and rules for new consumers connections and supply according to a determined timeframe to guarantee rules and costs which evolve depending on the real economic situation of the country.

- **Vulnerable consumers**: A review of the connection charges for vulnerable consumers to guarantee electricity supply to the most vulnerable part of the population in case they are not able to settle the connection charges.

- **Connection charges**: Shall be cost reflective and spread over time to make them affordable

  - If users are not able to afford a lump-sum connection charge, there are several options:
    - A - Incorporate most of the connection cost in the electricity tariff or to allow the customer to pay the charge over a period of years through
credit schemes. In the first case, in particular, instead of passing on the full cost of the materials and labor necessary to connect to the grid to the new customer, the customer is required to pay only a low processing fee which is collected with the application for new service. In the second case, consumers may be allowed to pay their connection charge over a period of time (say, three to five years) through credit schemes provided by the distribution company or an agent or partner.

B - Partially reimburse companies via a subsidy mechanism or grant fund route for the costs of connection based on demonstrated outputs (functional connections, billing cycles and so forth). Under such a “results-based” system, connection charges to new residential customers are steeply discounted. Once the household has been connected, the electricity company receives a subsidy per connection from a capital fund established by the government or by a donor. A variation of this theme is for the electricity company to apply for grant funds from a government program that covers the cost of supplying electricity to communities that promise to yield a positive financial and economic rate of return.

C - Finance the connection charge over years through loans which may be at commercial banking rates or subsidised interest rates. Paying connection charges over time is a fairer system for customers since the equipment required for new electricity connections generally lasts for 20 or more years.

D - Minimise connection charges through the sharing of the costs between a community or a group in which all the parties are interested in obtaining the service. Under this method, the DSO estimates the cost of extending electricity to the community, after which the community raises funds to pay a proportion or all of the costs. The success of this arrangement depends on the ability of the company to provide reliable service because no one will agree to pay for unreliable service. Community payment schemes indeed involve system development costs, which are broader than connection charges, but they enable a small group of consumers located fairly close to an existing network to obtain electricity supply.

3.4. International practices in the regulation of new consumers connections

3.4.1. Egypt

EgyptERA’s procedures regarding the connection of low-voltage new consumers to the grid include the revision of costs every two years and revision of rules for conducting electrical supply every five years. In this context, procedures for connecting low voltage power supply include the following steps:

1. The customer requests the licensed electricity distribution company to deliver electricity to the facility, the company examines the facility, studies different alternatives to its access to electricity and prepares a statement of the costs and technical specifications required (the request is cancelled if the applicant couldn’t allow the company to make site inspection within two months of the requested date).

2. Egypt ERA operates a differentiated approach for governmental and non-governmental customer connections when it comes to dealing with non-payment. If the power is supplied to residential divisions or projects, the calculation shall be made at “actual costs”, meaning the total value of power supply including VAT. In case of non-payment within three months from the date of the claim for government institutions and two months for the non-government institutions, the company has the right to re-calculate the cost of connecting power at the then-prevailing prices (current prices). Moreover, in case of non-payment within four months of the date of the claim for government institutions and three months for non-government institutions, the company has the right to re-examine and evaluate the project financially and technically after paying for a new study.

3. In case the power is supplied to a single facility, the calculation is at the “standard costs”, (The standard cost means the Kilovolt share of the connection in addition to installation fees and VAT). In case of non-payment within two months from the date of the claim, the company has the right to re-calculate the cost of connecting power
at the current prices. Additionally, in case of not-paying within three months of the date of the claim for government institutions, the company has the right to re-examine and evaluate the project financially and technically after paying for a new study.

The time schedule for implementing electric supply and releasing it to the facilities is as follows:

**Table 7: Time schedule for implementing electric supply and releasing it to the facilities**

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Party Involved</th>
<th>Time limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Submitting the connection request application for the facility, including the required data</td>
<td>customer</td>
<td></td>
</tr>
<tr>
<td>2. Site inspection and determining the required permits</td>
<td>the company, customer</td>
<td>One day from the site being available for inspection</td>
</tr>
<tr>
<td>3. Re-claiming power connection costs, with explanation of the total cost required, method of payment and the obligations of the company and the customer, as well as a detailed statement for the cost of connecting the electricity calculations and the documents required for implementation</td>
<td>The company</td>
<td>1 week after availability of data and inspection</td>
</tr>
<tr>
<td>4. Giving the customer sketch with drilling permits (for non-residential customers)</td>
<td>The company</td>
<td>1 day</td>
</tr>
<tr>
<td>5. Executing electrical supply, releasing current and installing the meter (for residential customers)</td>
<td>The company</td>
<td>8 working days after paying the cost and providing the permits</td>
</tr>
<tr>
<td>6. Implementing power supply (for non-residential)</td>
<td>The company</td>
<td>1 week after paying the cost and providing the permits</td>
</tr>
<tr>
<td>7. Signing supply contract, releasing current and installing the meter (for non-residential customers)</td>
<td>The company &amp; customer</td>
<td>One day after paying all the company's dues according to the agreement and completing the works</td>
</tr>
</tbody>
</table>

For the power access of residential and non-residential sectors, the maximum expected time for implementation is 16 days and 17 days respectively. The following documents or a true copy and are to be completed:

1. Payment receipt for the utility network information center.
2. Road and street drilling permits to lay cables and return the object to its origin.
3. Receipt of payment for the cost of the electrical supply connection.
4. Railway Authority permit in case of crossing the railways.
5. Approval of the Ministry of Water Resources and Irrigation for transgressing waterways as well as groundwater wells for agricultural purposes permits
6. Minutes of receiving the transformer room from the company's committee in case the room is not available.
3.4.2. France

The procedures for processing connection requests must guarantee transparent and non-discriminatory access to public electricity networks while ensuring their development and security. CRE monitors the development of these procedures and their implementation. In this context, the Distribution System Operators (DSO) are responsible for ensuring, under non-discriminatory conditions, the connection and access to the public electricity distribution network. Relationships between the system operator and the connection applicant are governed by technical reference documentation with which the system operator has to comply.

More specifically, as technical regulation cannot cover all possible technical fields and practical situations, CRE decided that network operators had to publish, in a coordinated way, a set of technical reference texts. This technical reference documentation compiles provisions of the existing regulatory texts and additional technical rules that the network operator has to observe in its relations with the network users. It also sets out good practices for network operators and users. In addition to this decision, CRE provided a list of topics that have to be dealt with in the technical texts. This is applied where the connection services involve activities not previously covered by the CRE reference documentation. Once this documentation is accepted, the CRE endeavours to include its technical reference documentation.

The technical reference documentation includes:

- The **connection procedure** developed by the system operator within the framework of the requirements defined by CRE's decision of 25 April 2013 adopted in application of Article L. 134-1 of the Energy Code. It describes all connection stages: preliminary information to applicants, contractual process; deadlines at each stage of the connection; conditions for entering, maintaining and exiting connection queues, etc. These procedures must be notified to CRE before they come into force. Then they become binding on network operators.

- The **technical requirements**, mentioned in the regulatory texts, are detailed in the technical reference documentation. All installations shall meet the technical requirements (capacity and operating methods). Knowing and complying with these requirements is essential from the very beginning of the connection analysis. Any new connection or modification to an existing connection must be formalised in a connection request. In response to the request, the DSO shall send the applicant a technical and financial proposal, which describes the technical solution envisaged, the time limit for making the connection available, and the amount of the contribution to be paid by the applicant. If the applicant accepts the proposal, the DSO sends him a connection agreement for approval. Works can then begin.

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1. [https://www.cre.fr/Electricite/Reseaux-d-electricite-Raccordement](https://www.cre.fr/Electricite/Reseaux-d-electricite-Raccordement)
2. Pursuant to article L322-8 of the Energy Code
3. [https://www.cre.fr/Documents/Deliberations/Decision/demandes-de-raccordement](https://www.cre.fr/Documents/Deliberations/Decision/demandes-de-raccordement)

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![Diagram 1: Processes associated with the stages of the procedures for processing connection requests of public DSOs](https://www.cre.fr/media/Fichiers/reseaux/Bilan-des-delais-associes-aux-differentes-etapes-des-procedures-de-traitemement-des-demandes-de-raccordement-des-gestionnaires-de-reseaux-publics-de)
As the DSO is the sole licensee providing the connection agreement in the particular area, the available alternatives and provisions for the applicant to challenge the contribution amount are relatively limited and disputes of this nature are rare. According to the type of installations, deadlines differ:

**Table 8: New connections timeframe for Installations > 36 kVA**

<table>
<thead>
<tr>
<th>Installations &gt; 36 kVA</th>
<th>Generation installations</th>
<th>Consumption installations</th>
</tr>
</thead>
<tbody>
<tr>
<td>LV</td>
<td>HV</td>
<td>LV</td>
</tr>
<tr>
<td>Transmission of the technical and financial proposal by the DSO, upon receipt of the complete connection request</td>
<td>3 months and up to 6 months when there is an exceptional number of requests</td>
<td>3 months, if anticipation measures 6 weeks otherwise 6 months when exceptional number of requests</td>
</tr>
<tr>
<td>Acceptance of the proposal by the connection applicant</td>
<td>3 months, with a possibility of extension</td>
<td></td>
</tr>
<tr>
<td>Transmission of the connection agreement</td>
<td>5 months</td>
<td>9 months, or 12 months when extension works are related to the TSO</td>
</tr>
<tr>
<td>Acceptance of the connection agreement by the connection applicant</td>
<td>Between 6 weeks and 6 months</td>
<td>Between 3 months and 6 months</td>
</tr>
<tr>
<td>Connection works by DSO</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 9: New connections timeframe for Installations < 36 kVA**

<table>
<thead>
<tr>
<th>Installations &gt; 36 kVA</th>
<th>Generation installations</th>
<th>Consumption installations</th>
</tr>
</thead>
<tbody>
<tr>
<td>RES installations &lt; 3 kVA without extension</td>
<td>Other installations</td>
<td>Without extension</td>
</tr>
<tr>
<td>Transmission of the technical and financial proposal by the DSO, upon receipt of the complete connection request</td>
<td>The proposal includes a connection agreement</td>
<td>3 months for connections with extension 6 weeks for connections without extension</td>
</tr>
<tr>
<td>Acceptance of the proposal by the connection applicant</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission of the connection agreement</td>
<td>1 month upon receipt of the complete connection request</td>
<td></td>
</tr>
<tr>
<td>Acceptance of the connection agreement by the connection applicant</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Connection works by DSO</td>
<td>2 months upon receipt of the acceptance of the convention agreement by the applicant</td>
<td></td>
</tr>
</tbody>
</table>
If a network operator exceeds the maximum time limit for the transmission of the technical and financial proposal to the applicant, a penalty may be due by the network operator to the connection applicant (Article L. 341-3 of the Energy Code). Any refusal to examine a connection request or to produce a connection agreement must be justified and notified to the applicant, the private network operator and CRE. The refusal criteria must be objective, non-discriminatory and published.

In this regard, CRE has set up incentive mechanisms for distribution system operators (Enedis, local distribution companies, EDF SEI in non-interconnected areas) as part of the tariff for the use of public electricity networks (TURPE). Registered for the first time in TURPE 3 (2009), these mechanisms encourage Enedis to control its costs while improving the quality of electricity.

CRE publishes electricity quality indicators in its report on incentive regulation of service quality. More specifically, CRE is looking at: the number of missed appointments by Enedis, the number of penalties paid for the late submission of proposals for connection and the number of penalties paid for late commissioning of the facilities. Each indicator generates a financial incentive. In the last edition, CRE noted that Enedis had taken specific measures to improve customer satisfaction with a network connection: dematerialisation of exchanges, simplification of connection processes and strengthening of the role of the single point of contact for connection.

3.4.3. Italy

In Italy, connection charges are currently regulated by the “Economic conditions for the delivery of connection service”, Annex C to Resolution 568/2019/R/eel of 27 December 2019. For standard permanent connections, a lump sum charge is due to the DSO, consisting of

- a distance charge, depending on the distance between the supply to be connected and the nearest MV/LV transformation substation in service for at least 5 years;
- a power charge depending on available power requested by the customer;
- a fixed administrative charge.

Procedures and quality standards regarding new connections to the electricity distribution network (maximum time for issuing an estimate, the maximum time for the completion of connection works) are currently regulated by the Quality Code “Output-based regulation of the distribution and metering service”, Annex A (Part II) to ARERA Resolution 566/2019/R/eel of 23 December 2019.

The DSO is responsible for the connection of customers’ facility to the distribution network and, if the customer entered a supply contract with a supply company, for the activation of the supply (energisation).

Connection works are classified into two different categories: “simple works”, if the connection requests the realisation or modification of the derivation cable and installation of the meter; “complex works”, in other cases (e.g., works involving the distribution network).

Customers willing to obtain a new connection and the activation of energy supply must contact a supply company to enter a supply contract. In this case, the supplier must submit a connection and activation request to the local DSO. Customers willing to obtain only the connection (without activation) must submit a connection request directly to the local DSO.

When receiving a request for a new connection (directly from the customer or from a supplier on behalf of the customer), the DSO must issue within 15 working days an estimate, including information on the number of charges, technical specifications, any works or activities to be carried out by the customer, maximum time (standard) for the completion of the connection works and automatic compensation to be paid to the customer in case the maximum time for completing the connection is not respected.

When receiving acceptance of the estimate (directly from the customer or from a supplier on...
The Regulator can check the quality performance of DSOs using a sample methodology aimed at assessing the correct application of the regulation regarding quality standards, payment of compensations and record keeping. Penalties are due from the DSO in proportion to the number of requests for services that have not been processed and executed following the regulation.

3.4.4. Malta

In Malta, the charges for connecting to the network and determination of charges are established by the Electricity Supply Regulations (S.L.545.01). These regulations are determined by the regulator REWS and included in a performance contract which is implemented by a jointly-owned utility service provider ARMS Ltd which carries these activities on behalf of the DSO. In general, the connection charges are the following:

- A simple single-phase service of 40 Amps within 150m from an existing overhead line: standard application fee of €300.
- A simple three-phase service of 60 Amps per phase within 150m from an existing overhead line: standard application fee of €900.
- A service from extended from an existing substation (within 300m of the substation) is charged at the full cost of the low voltage works and a charge of €81.52 per kVA as a high voltage contribution.
- Services that cannot be extended from an extended from the existing overhead line or substation are financed by the consumer and charged at full costs of the works unless the DSO needs to utilise the substation to supply other customers in which case there would be a cost-sharing agreement between the customer financing the substation and the DSO.

The regulators’ report notes that most connections originate within the 300 m distance of a substation and where cost-sharing/co-financing agreements are required. The regulator has adjudication authority under which any disputes arising can be addressed.

Some additional conditions apply particularly
in the case of multi-consumer premises where the type of services and charges depend on the number of units to be supplied and loaded.

There is no definition established by law for the ‘time to connect’ customers and producers to the network. The REWS guideline for new connections is 21 days and the regulator notes in its recent reports state that typically these requests are completed within 9 days. However, in general, in the case of non-complex services, the time to connect customers and producers is taken to be the time that elapses between the submission of an application to the distribution system operator for connecting to the network and the date of the provision of the service connection and electricity meter. Normally, the activation of the service occurs on the same day on which the electricity meter is installed. Activation of the service is understood to be the possibility to either import and/or export through the metering equipment provided by the distribution system operator.

The application to connect to the network serves also to enter into a supply contract since the DSO is also the sole supplier of electricity to final customers. All the TSO-related and network balancing services within Malta are offered via a transmission services contract between EneMalta and Terna of Italy. Terna provides these additional services. Hence though EneMalta covers the entire country, it technically operates as a DSO.

There are no mandatory targets regarding the time in which the DSO must provide the service connection. However, the customer charter provides the following indicative targets:

The indicative target for a new service connection provided from an existing overhead line that does not require any development or extension of existing infrastructure (in general service of single-phase 40 Amps and three Phase 60 Amps are provided from existing over headlines) is 21 calendar days. In practice, the time to provide such service is normally around 9 calendar days. For services not covered by a standard application fee and requiring a quotation, the indicative target for the provision of a quotation is 30 business days from the date of application.

The Regulator can check the quality performance from the data related to the services requests, received date of application and date of installation of service/meter, which is provided by the DSO annually as part of the Licence Monitoring Reports. The targets are indicative and there is no compensation scheme.
4
CATEGORIES AND MANAGEMENT OF COMPLAINT HANDLING PROCEDURES
When talking about complaint handling procedures, there are different steps household consumers can take in the EU. If a consumer thinks that the electricity or gas supplier has breached his rights (contract conditions, quality of service, etc.), a first step to get redress is the proper handling of consumer complaints by the supplier, toward which the customer may file a complaint. The energy supplier has to provide the consumers with information on how to do it, enabling them to settle the dispute promptly and get reimbursed and/or compensated if relevant. However, if suppliers do not provide satisfactory solutions, consumers settle their supplier settled by an independent out-of-court mechanism before going to court. To this end, EU member states are obliged by the Third Energy Package to set up an independent out-of-court resolution scheme for energy complaints to deal efficiently with complaints and facilitate out-of-court dispute settlements. This independent body is a “third party” to a complaint between a customer and a service provider. It is independent of the industry and it proposes a solution to a dispute between the two parts providing recommendations that may be legally binding or not depending on the state of application.

Out-of-court consumer redress in the energy sector can be provided by the regulator, a Public (Energy) Ombudsman, a complaint board or a consumer protection authority. In addition to public schemes, several member states have private out-of-court dispute settlement schemes that enable consumers to get redress.

Indeed, customer complaints are an expression of dissatisfaction when measuring the performance of market operators and they represent one of the clearest indicators to evaluate the quality of service provided. In general, household consumers are likely to be disadvantaged towards the market operators they are served by, as they are less experienced in legal matters, financially weaker and usually, the value at stake does not economically justify the costs of a complaint process. Therefore, the role of public institutions and specifically NRAs to ensure the safe and fair position of the customers in front of market operators is of vital importance as formal reporting systems provide records of customers’ concerns and operators' behaviors.

When complaints handling procedures are within the responsibility of the NRAs, their design should be as transparent as possible to guarantee the

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maximum spreading of consumers' awareness, giving households fair access to justice and encouraging them to duly exercise their rights. In case the responsibility of complaint handling procedures is managed by other entities independent from the regulator, such bodies should guarantee the impartiality and objectivity of the complaint handling process according to the means of their granted legal mandate and their functioning in practice.

If a solution to the complaint is not reached through an independent out-of-court mechanism, the last resort of the consumers before the judicial court is referring to the dispute settlement authority, a public entity that settles unresolved disputes between customers and service providers with binding recommendations. This intervention is not a preliminary condition for an appeal to the court but it is an alternative to this without prejudice to the right to judicial protection even after it.

The regulator may act as a dispute settlement authority and this is clearly foreseen within the Third Energy Package in which “Any party having a complaint against a transmission or distribution system operator in relation to that operator’s obligations... may refer the complaint to the regulatory authority which, acting as dispute settlement authority, shall issue a decision within a period of two months after receipt of the complaint. That period may be extended by two months where additional information is sought by the regulatory authority. That extended period may be further extended with the agreement of the complainant. The regulatory authority's decision shall have binding effect unless and until overruled on appeal" 2.

Complaint handling procedures are a fundamental tool of the market monitoring powers NRAs have to enforce in the EU legislation to ensure the development of retail market competition and enhanced customer protection. In this context, the following tasks are carried out by regulators on complaint handling procedures to monitor the market and the compliance to national and EU regulations:

1. **Data collection by NRA:** When a regulator deems it appropriate to receive data on complaints, with the aim of monitoring retail markets, it should have the possibility to receive the relevant information from third parties as well as from service providers. Data on complaints can be used by NRAs who decides to publish reports on complaints to analyse data at a national level and identify any market malfunctioning in relation to them contributing to the monitoring and effectiveness of market opening and competition at the retail level.

2. **Complaint data publication:** The possibility of complaint data publication by the NRAs is fundamental to pressure indirectly the industry to cooperate and act fairly and promptly regarding customer complaints. Indeed, the transparency of information which might include the categories of complaints that most frequently appear, the identification of areas of improvement on the retail market and a list of recommendations to be followed by service providers including the names of non-compliant operators are one of the means to empower customers in their rights when it comes to complain handling, counterbalancing the asymmetry between a large company and small customer, taking into account the fact that electricity and gas are vital services.

3. **Complaints monitoring & indicators:** In the context of the market monitoring role by the NRAs, customer complaints are an indicator of the quality of service provided by operators or infringing rules. The publication of such indicators reinforces customers’ position in the market and contribute to an increase in commercial quality of service. Monitoring a selection of indicators on customer complaints permit to identify problems in market design or processes so that action can be taken to change faulty processes or carry out procedures against malpractice and single companies.

4. **Complaint classification:** data collection by the NRAs has to be standardised according to a precise classification as consistency in the definitions of consumer dissatisfaction is a key-element to guaranteeing the accuracy of statistical data on complaints.

After having identified the principles behind the

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complaint handling procedures in general and in the EU, the subsequent section analyses in detail the state of play of complaint handling procedures in Jordan, with the aim of understanding practically how the Jordanian system works and what space of improvement can be proposed comparing it to the experience of other relevant countries.

4.2. Overview of complaint handling procedures in Jordan

In Jordan, consumer complaints are regulated by art. 21 of the Performance Standards Code for Retail Distribution and Supply Licensees, where the procedures on how EMRC manages the complaints of consumers in front of the licensee are specified.

In this context, to record consumer complaints, licensees have to provide and maintain commercial offices at each of their supply areas, and their location may be decided in coordination with EMRC. In addition, licensees are obliged to provide a free and permanent phone line devoted to consumer complaints and the related special unit within the corporate structure. The latter is dedicated to receiving and responding to complaints, inspecting issues and resolving them, maintaining and processing relevant data and related reports. In this context, licensees have to also guarantee the existence of an information system where all complaints submitted both in writing and by phone are recorded as well as kept up to date.

Once a complaint is received, licensees shall provide a reply to consumers with the same contact method and including the following information:

- A clear indication of whether the complaint was accepted or rejected.
- A clear explanation of the actions which were taken to remedy the situation in case the complaint was accepted or the planned actions in case of complaints regarding Power Quality.
- In case the complaint is rejected, a justification of the reasons.
- All other relevant information enables the Consumer to assess the current situation.

Within a maximum of thirty days from the end of each month, licensees have to provide a report to the EMRC including the following set of information:

- A complete evaluation of Consumer complaints.
- A table with the complaints which were received from consumers during the relevant month including the reason for the complaint and the time at which the complaint was replied to or the issue was resolved.
- A list of rejected consumer complaints, rejection reasons and a technical report, if required.
- Detailed records of the cases in which the time limits for replying to complaints were exceeded.
- A list of consumer complaints that were already accepted and processed during that month.

If licensees exceed time limits for responding to complaints or resolving issues, they are considered non-compliant with the regulation in place and therefore are subject to fines imposed by EMRC equal to JOD 15 for every business day of delay in resolving the complaint. In case the non-compliance refers to the failure in providing the required reports and information in the time limits for reporting procedure to EMRC, the behaviour is considered as a lack of competence on the part of the licensee, and in this case, a financial fine equal to JOD 200 per business day of delay is applied.

In this case, the financial value of the fines is calculated yearly and deducted from the Licensee’s revenue requirements through the tariff in the subsequent tariff period according to the tariff methodology which applies to them.

Once the EMRC receives monthly and quarterly reports from the distribution companies, its staff reviews the complaints and split them into four categories, namely technical, financial, interruptions and voltage variations. The first three categories refer to the “other complaints” identified by the Performance Standards Code for which the licensees shall provide a reply within 15 business days. The last one refers to power quality complaints, for which the licensees shall provide a reply within 20 business days. The four categories are explained below:
1. **Technical complaints** are considered those issues that occur to the consumer like a wrong connection between the grid and the meter, delay in new connections, errors in the accuracy of the meter, registration by mistake, electric theft state and other similar cases.

2. **Financial complaints** refer to financial problems faced by household consumers which may include the wrong application of the tariff set on the customer, mistakes in calculating the costs of new connections and mistakes in bills, for which the licensee shall resolve all complaints submitted by consumers, including those related to the estimated consumption, before issuing the next bill, to avoid the repetition of the mistake.

3. ** Interruptions complaints** include problems customers may face when they are wrongly disconnected, there is a delay in reconnection after fee payment, non-scheduled interruptions occur leaving the customer without electricity supply, which may also result in the burning of households’ devices. For unscheduled interruptions, the start time to calculate the 15 business days to reply to the complaint depends on whichever occurs first between the moment in which the SCADA system detects the interruption and reports equipment disconnection or the moment in which the first consumer complaint regarding the interruption is received by the licensee.

4. **Power quality complaints** derive from issues consumers face in case of voltage variations or perturbation standards. In the first case, voltage variations complaints are a criterion that licensees have to take into account when selecting consumers subject to measurement campaigns. Indeed, in January of each year, the licensee shall submit to the EMRC a complete list of the names of consumers to be used for selecting the consumers who will undergo measurement. The same applies in the monthly reporting, in which the licensee shall submit to the Commission a list of consumers selected for measurement in the following month. When monitoring lists of consumers, the EMRC has the power to propose other measurement locations according to consumers’ complaints or previous Performance Indicators. In addition, it may also ask DSOs and/or third parties to take measurements at the locations of specific consumers’ area during a specific week based on consumers’ complaints and/or internal analysis.

In the case of perturbations, control of flicker adequacy and harmonic distortion is done through measurements taken at Consumers’ connection points. In addition to the usual checks, licensees shall also take measurements for every consumer’s complaint received on this matter, sending copies of the complaint to the EMRC stating the time at which verification measurements will be taken. The EMRC may carry out controls on the licensee’s compliance to taking flicker and harmonics measurements at specific connection points, even without any consumer complaints.

4.3. **Recommendations**

The Performance Standards Code for Retail Distribution and Supply Licensees regulates complaint handling procedures in Jordan. If the procedure for managing complaints, data collection and the sanctioning powers of EMRC in front of non-compliant operators are clear and detailed, the same does not effectively apply to the classification of categories of complaints that must be addressed by the market operator and which may be referred for dispute resolution by the Regulator. As a consequence, the complaint data publication may also be negatively influenced. In this regard, categories of complaints are not clearly defined in the Performance Standards Code, but follow an EMRC internal procedure, leaving space for interpretation to operators when receiving complaints from customers. In this regard, better identification of the categories of complaints in the Performance Standard Code would support more clarity in the case of consumers filing complaints against market operators. Categories are indeed well defined in the analysed national case studies and such a level of precision would support a more effective regulation on consumer protection.

Moreover, the publication of clear complaint data is relevant to indirectly pressure the industry to cooperate and act fairly and promptly regarding customer complaints. Indeed, the transparency of information, which might include the categories of most frequently appearing complaints and a
list of recommendations to be followed by service providers including the names of non-compliant operators, is one of the means to empower customers in their rights, counterbalancing the asymmetry between a large company and small customer.

6. In the case of non-enforcement of the solution given to the complaint by the regulator, the case is reported to the Board of Director for a final decision.

In Egypt, the complaints are treated according to the following categories (not an exhaustive list):
• Billing issues: about: Payment, e.g., fixed charges, debts, customer activity charges without utility notification, request for reimbursement, etc.
• Metering issues: about meters replacement, meter readings, etc.
• Connection & contracting issues: Disconnections, delays in connections, installation required for connections, contract amendments, etc.
• Power quality issues: Voltage unbalance, voltage level, etc.
• Electrical installation issues: Request for removal of electrical equipment for environmental reasons, etc.

Egypt has introduced the concept of “one window” based system for all customer complaints except bill payment and pe-payment meter charging, for which other electronic payment methods already exist. Pre-payment meters customers have several retail channels through which customers can make payments and the principle applied in Egypt in the “one window” concept is for all customer related issues except metering and billing which is treated differently in the regulation (and described separately in the chapter related to Billing and Metering.

Egypt is also piloting a Unified Number Service (121) that will be applicable for all the nine DSO areas. Three DSOs are currently participating in the pilot. This is expected to bring convenience and ease of access to all customers across the country.

4.4.2. France

The explicit commitments of public network operators are relatively limited. Article L121-1 of the Energy Code specifies that: “the public...
electricity service is managed in accordance with the principles of equality, continuity and adaptability, and under the best conditions of security, quality, costs, prices and economic, social and energy efficiency”. If the public network operators fail to meet one of their commitments, or more generally to comply with the Energy Code, network users may contact:

- The operator of their network, which can take corrective measures to address the problem and/or offer compensation (Enedis for most users: 95% of complaints are answered within 15 calendar days);
- The National Energy Ombudsman (Médiateur National de l’Energie), for small consumers only;
- CRE’s Committee for the Settlement of Disputes and Sanctions (CoRDiS);
- Competent courts.

**Focus on small consumers**

All individual consumers may refer to the Ombudsman, as well as artisans, shopkeepers and liberal professions, non-profit organisations, small city councils, small businesses (SMEs of less than 10 employees and less than €2M in turnover) and condominiums. The French Energy Ombudsman may intervene in all disputes arising from contracts signed with energy companies.

The law regarding energy transition of August 2015 made it possible for the Ombudsman to settle disputes dealing with all domestic energies, in addition to electricity and natural gas: fuel oil, liquid petroleum gas (LPG), wood-fired heating and district heating.

However, the Ombudsman has no authority for complaints that deal with the formation of the contract, such as abusive sales practices (doorstep selling for instance), professional consumers with more than 10 employees or more than €2M in turnover; renewable energy production (solar panels, wind turbines).

Accessing the Ombudsman services is simple and user-friendly:

- First contact possible by phone through a toll-free number;
- Cases can be brought by a third party;
- Online dispute resolution with SoLLEn (online platform to declare a dispute);
- Consumers can still use regular mail if they wish (no stamp is required).

The Ombudsman offers solutions to disputes with energy companies. They make several personalised contacts with the consumer to explain their analyses. Consumers are informed at the end that they can take the case to court if they are not satisfied or if the company chooses not to follow the Ombudsman’s recommendation. The average time to solve eligible disputes with the help of the Ombudsman is 63 days. Operators follow decisions of the Ombudsman in 86% of cases.

For non-domestic but non industrial consumers – i.e., customer categories not covered by the CRE-CORDIS scheme – there are similar recourse options available though the primary point of contact which is expected to be the regional DSO for the area. CRE regulations specify that in the case of non-resolution of complaints, it retains the reserve judgement to determine matters including the issuance of penalties. In this area, however, the CRE regulations include sufficient incentive mechanisms incorporated in the tariff formulae that incentivise DSOs to secure an early resolution to the complaints. Matters being referred to CRE for dispute resolution in this category are rare. This has been noted in the CRE publications.

For I&C customers, the CRE has a CRE-CORDIS dispute resolution mechanism which grants the CRE adjudicatory rights to make determinations and issue penalties. This process is well understood by industrial clients in France.

**4.4.3. Italy**

In general terms, customers must address their written complaints or written requests for information to their supply company. Written complaints or requests for information exclusively relating to distribution and metering services may be addressed, as an alternative, directly to the DSO. Procedures and quality standards regarding
complaints handling are currently regulated:

- for supply companies, by the Code “Quality of electricity and natural gas retail services” (TIQV), Annex A to ARERA Resolution 413/2016/R/com of 21 July 2016;
- for distribution companies (DSOs), by the Code “Output-based regulation of the distribution and metering service” (TIQE), Annex A (Part II) to ARERA Resolution 566/2019/R/eel of 23 December 2019.

Complaints must include a minimum set of information: customer name, supply address, postal or e-mail address for sending the reply (if different from the supply address), service involved (electricity, gas, both), customer code and a brief description of the disputed facts. Supply companies must publish on their website a standard complaint form that can be used by their customers.

Complaint answers must be explanatory and include, inter alia, the documented assessment of the complaint; the relevant regulatory or contractual references, applicable and applied due to the type of supply and the service concerned; the description and timing of any corrective actions taken and information on how to resolve the dispute, if it is not possible to settle the complaint.

The following quality standards, subject to automatic compensation to the customer if the standard is not respected, are set for supply companies:

- the maximum time for explanatory written answer to a written complaint (30 calendar days): the time between the receipt of the written complaint and the sending of the written response (includes the time for the acquisition of technical data from the DSO, where necessary);
- the maximum time for billing adjustment (60 calendar days): the time between the receipt of a written complaint which entails the adjustment of an invoice already paid, or between payment by instalments requested and the date of crediting of the undue amount (includes the time for the acquisition of technical data from the DSO, where necessary);
- the maximum time for a double-billing adjustment (20 calendar days): the time between the receipt of a written complaint which entails a billing adjustment for consumption related to a point of delivery not included in the supplier dispatching and/or transport contract and the date of crediting of the undue amount (includes the time for the acquisition of technical data from the DSO, where necessary).

The 25€ basic amount of automatic compensation (no request from the customer is needed) is doubled if the delay is more than double the standard time and is tripled if the delay exceeds triple the standard time. It is excluded when the delay is due to force majeure (natural disaster, an act of a public authority, strikes, etc.) or due to the responsibility of the customer. The basic amount is subject to periodic reviews and the regulator has the right to amend these with a simple notification though the review has mostly been considered only during the regular periodic tariff reviews that the regulator carries out.

An additional quality standard, not subject to automatic compensation, is set about written requests for information:

- percentage of a timely written answer to written requests for information (at least 95% answers within 30 calendar days) related to the time between the receipt of a written request for information and the sending of the reply to the applicant (includes the time for the acquisition of technical data from the DSO, where necessary).

The supplier must classify written complaints and written requests for information according to the following categories, which include a second-level group of sub-categories:

- Contracts: issues relating to contract events, such as withdrawal, change of owner (completion and transfer costs), unilateral changes where allowed;
- Payment delay and supply suspension: issues relating to arrears procedures, power reduction, suspension of supply, reactivation, administrative termination;
- Market: issues on procedures and information to enter new contracts, the timing for switching, economic conditions;
- Billing: issues related to the correctness of consumption and invoiced fees, customers’ meter self-reading, billing frequency, payments and refunds;
• Metering: issues relating to the operation, malfunctioning and replacement of the meter, timing and procedure for meter checking, reconstruction of consumption due to meter malfunctioning;
• Connection, works and technical quality: issues relating to the timing of works, on the costs indicated in the estimates, on continuity or voltage quality;
• Social bonus: issues relating to the support scheme for vulnerable consumers, such as missed or delayed validation of applications, delivery times, improper terminations;
• Commercial quality: issues regarding the functioning of customer service, or payment of automatic compensation;
• Other: issues not falling under the previous categories / non-competence.

All suppliers must keep a register where all relevant data and information related to written complaints and requests for information and the consequent steps including the answer and automatic compensation when due is noted and updated. Suppliers must ensure that the recorded information and data are verifiable through commercial and technical archives or any other documentation deemed necessary and must keep in an orderly and accessible way, for at least three years, all the relevant documentation.

Suppliers must communicate yearly to ARERA a set of data regarding written complaints and requests for information received, time of response, number of answers exceeding the standard maximum time, number of compensations paid. ARERA can verify the correctness and accuracy of the data.

For suppliers with more than 50.000 customers, ARERA carries out a yearly satisfaction survey of customers who have received a response to a complaint.

DSOs have similar obligations to those imposed on suppliers with regards to written complaints or requests for information exclusively relating to distribution and measurement services directly submitted by customers, but the quality standard related to the timing of response (percentage of timely written responses to written complaints or request for information: at least 95% answers within 30 calendar days) is not subject to automatic compensation.

A specific quality standard, subject to automatic compensation, is defined to allow suppliers who need technical data owned by the DSO to give a timely response to a customers' complaint:
• time for making the technical data requested by the supplier available (6 working days for simple data, 12 working days for complex data indicated by the regulation): the time between the receipt of the request for technical data from the supplier and making the requested data available.

The basic value of automatic compensation is 30€. In case the DSO exceeds the standard time, the payment of the compensation is due to the applicant supplier. If the supplier exceeds his own standard time for answering the complaint, it pays to the customer both his own and the DSO compensation. If the supplier still manages to meet his own standard time for answering the complaint, it retains the DSO compensation.

ARERA publishes a yearly report (on the processing of complaints and disputes resolution of electricity and natural gas customers), which includes overall and (from 2020) comparative elaborations of the data on complaints handling provided by suppliers and DSOs and the results of customer satisfaction surveys.

4.4.4. Malta

In general terms, customers must address their complaints related to technical issues to the DSO by phone, email, or through a contact form on the website of the DSO (Enemalta plc). Complaints related to billing are addressed to the sub-contractor of the DSO (ARMS Ltd) by phone, email or through a contact form on the ARMS Ltd website.

There are no quality standards subject to compensation however in terms of the customer charter the DSO should reply to emails from customers-within 7 calendar days.

Malta has established a jointly owned corporation
(by Enemalta and Water Services Corporation) as a single utility service provider (under a performance contract with its respective counterparties) that is overseen by REWS – the Maltese regulator all services related to utilities including consumer complaint handling. Malta electricity system is vertically integrated, exempt from obligatory unbundling and is fully DSO operated. The traditional TSO functions are provided to it by Terna of Italy with which Malta has a major undersea interconnector that provides a bulk of the power requirement.

The oversight of Enemalta is with REWS, the regulator, which in the case of complaint handling, provides the general guidelines which govern the contractual relationship for providing customer services between Enemalta and ARMS Ltd – the utility service provider. The terms including minimum turnaround times for responses to complaints and escalation to Enemalta for resolution by nature of the complaint (whether technical or commercial) are included in the contract.

Dispute Resolution between a customer and an electricity provider

In terms of the Regulator for Energy and Water Services Act (‘Act’), the Regulator is vested with the determination of disputes in relation to matters regulated by or under the Act (Article 5(1) of the Act). REWS indeed receives and considers disputes that may arise between a consumer and an authorised provider – in this case, Enemalta. To submit a complaint regarding a dispute with a REWS authorised provider under the Dispute Resolution (Procedures) Regulations (S.L.545.30), the consumer should first file his complaint with such authorised provider – in this case ARMS Ltd – and seek resolution. All unresolved cases are escalated upwards to Enemalta and subsequently to the regulator REWS. If it is unresolved by Enemalta, the regulator REWS has adjudication and penalty levying powers.

To file a complaint with the Regulator, the consumer has to provide all necessary information indicated on the complaint forms available electronically.

The following details all categories of complaints (non-exhaustive) which must be addressed by the service provider and which may be referred for dispute resolution by the Regulator:

- Service connections: delay to receive an estimate for a non-standard connection, delay to receive an appointment for a standard service, obstacles to connection, time to provide a non-standard service, delay in the connection of RES generators;
- Quality and continuity of supply: frequency level, voltage flickering, low voltage, high voltage, harmonics, continuity of supply (outages);
- Metering: meter reading, meter functioning, incorrect meter readings, meter switching, unfair commercial practices, pre-contractual information, contractual terms, unfair terms and conditions, changes in contractual terms;
- Activation: moving in, reconnection after disconnection, disconnection after no or late payment;
- Invoicing issues: unclear invoice, incorrect invoice, double invoice, non-issue of invoice or difficult access to the invoice of a monthly statement, high consumption estimation, irregular frequency of billing on actual readings;
- Other: information on price of tariff, price tariff change, social tariff, poor or deficient customer service.

This escalation-based complaint handling and related dispute resolution imply that the majority of consumer complaints are resolved at the ARMS Ltd level with few escalations to Enemalta. Furthermore, the escalation from Enemalta to REWS is rare and usually does not involve commercial or domestic consumers. The cases usually refer to industrial or high-value consumers typically involving complex disputes. Where such cases are reviewed and adjudicated by REWS, the general procedure is as follows:

Before the case is heard by REWS, the customer must indicate whether any court / tribunal / arbitration proceedings relating to the complaint have been initiated and whether any other authority has been contacted about the complaint. The decision of the Regulator is binding and, saving any suspension of the decision pending the final determination of an appeal, has to be complied to forthwith. If the party concerned fails to comply, it shall be deemed to have committed
an infringement of the law and the Regulator may impose an administrative fine of not more than six hundred euro (€600) for each day of non-compliance under the provisions of the Regulator’s Act. The period of non-compliance shall be deemed to have commenced from the date of notification of the decision of the Regulator or any such other date as may be communicated in the decision which date shall, in any case, be on or after the date of notification.

The Regulator is obliged to conclude dispute resolution proceedings expeditiously by law within a time-frame of ninety calendar days starting on the date on which the Regulator has received the complete complaint file including all relevant documentation on that complaint and ending on the date on which the outcome of the dispute resolution proceeding is made available. The Regulator is obliged to notify the parties after receiving all the documents necessary to carry out the dispute resolution proceeding. In certain exceptional cases of a highly complex nature, including where one of the parties is justifiably unable to take part in the dispute resolution proceeding, the Regulator may extend the timeframe to undertake an examination of the case in question. The Regulator is obliged to inform the parties of any such extension and of the expected approximate length of time that will be needed for the conclusion of the dispute.
5

PERFORMANCE STANDARDS AND BEST INTERNATIONAL PRACTICES FOR BILLING AND METERING
PERFORMANCE STANDARDS AND BEST INTERNATIONAL PRACTICES FOR BILLING AND METERING

5.1. Principles of performance standards for billing and metering

Standards applied for billing are a key aspect of the energy market development, as they directly insist on the relationship between consumers and suppliers. The provision of clear rules should be provided on the information included in energy bills. They should be made aware of the frequency and methodology of meter readings and the tools available to consumers if they need to acquire additional information on their energy expenses so that consumers are empowered and better protected. Thus, a functioning billing system improves consumers’ participation within the energy market. They are better protected and can enjoy a stronger position in the energy supply chain.

Consumers must receive frequent and regular information about their energy consumption to allow them to regulate how much energy they use. Any additional data on these consumptions should be made available to consumers at no additional cost. They should have the right to easily access their historical information on their energy consumption for free at least of the previous 2-3 years according to general international practice and, more specifically, for EU Energy Directives. In the same way, when new individual meters (including smart meters) are installed, they should respect some basic standards in terms of accuracy and functionality and their price should be defined competitively.

Energy bills are relevant pieces of information particularly in systems that use annual settlement bills. They represent a formal document to check that consumers are indeed receiving their electricity according to the conditions advertised by the supplier in its pre-contractual information and subsequently indicated in the contract. To ensure this, the content of the energy bill should directly follow the offer selected by the consumer and include information about price changes. Through the bill, the consumers should be able to autonomously check whether the supplier delivered what was agreed in the contract. Another important aspect of a correct billing system concerns ensuring a coherent information flow by using the same definitions, wordings, units and level of detail in all documents so that they compose a seamless information flow.

On energy bills, consumers should be able to see all the tariffs and costs related to their energy supply and be promptly informed on any change, both concerning prices and other bureaucratic and contractual agreements. For price changes, different prices should be linked to the correct price period in time and report the correct energy usage of that period. Therefore, regular reading of the meter is key to provide correct and timely information to consumers. When smart meters are deployed, bills can become more accurate as they can provide information on actual consumption for every price period.

The novelties which characterise the energy market, such as innovative price concepts including contracts directly linked to spot markets or hourly billing based on smart meter readings, represent a new challenge for the billing system. In fact, these concepts are not compatible with the classic yearly settlement bill made up of a few pages. They require moving to a digital billing and personal pages on the website of the energy supplier so that consumers can easily check their situation at any given time.

Looking at the specific provisions of the European Union, the internal energy market legislation and the 2012 Energy Efficiency Directive (amended
in 2018 in the “Clean Energy for All Europeans” package) have established that consumers have the right to accurate metering and consumption information. It is recognised that consumers’ trust and engagement in the energy market increases with more transparent and updated billing information. Despite the clear normative indications present in the EU, the majority of European citizens receive billing information once or twice per year and disputes over metering readings are frequent. To tackle this issue, the European Commission, together with national energy regulators, has committed to working on making proposals to increase the clarity and comparability of energy bills. The goal is to ensure that consumer awareness of the various components of energy bills increases with a better understanding of network charges, taxes and other levies. This understanding, coupled with easy access to real-or near-time consumption data would also have the positive consequence of enabling consumers to adapt their consumption patterns and save energy.

The revised Energy Efficiency Directive (EED) contains the requirement that final consumers are provided with meters that accurately measure their effective energy consumption. Where thermal energy is supplied to a building from a central source that services multiple buildings or from a district heating/cooling system, it is necessary to install a meter at the heat exchange or point of delivery.

The EED also demands that “in order to enable final users to regulate their own energy consumption, billing shall take place on the basis of actual consumption or heat cost allocator readings at least once per year”. What is particularly relevant here is the mention of final users, which makes this provision valid also for sub-metered consumers. However, it should be noted that in the case of sub-metering, the requirement for billing and consumption information to be based on actual consumption or heat cost allocator readings does not imply that costs for heating and cooling are determined solely based on readings from individual meters. The goal of this provision is to make sure that final users are informed about their actual consumption at least once a year and that their fees based on consumption are calculated or adjusted accordingly, for example by settling differences between the flat rate payments regularly made by the final user and the actual amount due.

According to the Directive, wherever remotely readable meters or heat cost allocators have been installed, it is required that sub-annual information on the consumption read by meters is provided to consumers. Each member state has its own definition of what devices are considered remotely readable. In some cases, it is even possible that some buildings contain both remotely readable and non-remotely readable devices. In these hybrid cases, it is necessary to reconcile the requirement that billing and consumption information is reliable, accurate and based on actual readings with the fact that without sub-annual values for aggregate consumption, allocation calculation costs are approximated. In this case, the legal approach of the European Commission is that, even in the absence of sub-annual readings, the supplier should still provide sub-annual consumption information to sub-metered users as long as possible or, when it is not possible, it should provide reasonably fair estimates of the costs.

A final remark on billing and metering procedures concerns the difference between making information available to consumers and providing this information. In the EU, the core requirement is to provide information to consumers. This can be done either on paper or by electronic means, such as via e-mail. If the information is made available on the internet (for example on the website of the supplier), the consumer should be actively notified somehow to comply with the Directive, to be in line with the objective to use billing and metering as tools to increase final users’ awareness of their energy consumption.

After this overview of the most relevant procedural aspects pertaining to billing and metering, which are in various ways translated into practice by European regulators, the report will now deepen the procedure currently used by EMRC to identify which of these principles are implemented by the Jordanian regulator. Subsequently, this chapter will detail the best practices from Egypt, France,
Italy and Malta to draw some recommendations to refine billing and metering procedures in Jordan.

### 5.2. Overview of performance standards for billing and metering in Jordan

In Jordan metering asset ownership, operations are not unbundled in Jordan. However, the activities are segregated by departments and standards relating to meters and their test certification is maintained. Performance standards for billing are regulated by art. 22 of the Performance Standards Code for Retail Distribution and Supply Licensees where the procedures on how EMRC regulates the billing and metering process is described. In this context, licensees have to ensure and provide the following tasks concerning billing:

- Ensure that meters are suitable for the tariff applied to the consumer and that they meet the conditions set out in the Distribution Code.
- Install, maintain, fix, replace and verify the accuracy of electricity meters and measurement systems.
- Abide by all the conditions stated in the license and Distribution Code with regards to bills and meters.

Bills are issued by licensees based on actual meter readings. When it is not possible to read the real consumptions measured by meters, bills can be issued by estimating consumption (for one month) while considering the following points:

- If actual readings for previous periods are available, the estimated reading shall be equal to the actual reading of the previous period, taking into consideration the Time Correction Factor which is applied retrospectively by the DSO and the system load is the overall (system level) load on the specific DSO system and does not relate to the customer load.
- If no actual previous readings are available, the estimated reading shall be equal to the previously estimated reading in kilowatt-hours, taking into consideration the Time Correction Factor.
- In the previous cases, the “Time Correction Factor” is defined as the system’s maximum load for the current period divided by the maximum system load for the previous period.

• Once the licensee can read the meter, they shall amend and reissue the estimated bills based on the actual readings.
• The consumer may ask the licensee to read the meter at a previously agreed time.

When a special situation occurs in one of the parts of the distribution network which are out of the licensee's control, the latter does not have the possibility to read the actual consumption measured by the meter and, as a result, it is obligated to raise the issue to the EMRC with all the required supporting documents.

The licensee shall resolve all complaints submitted by consumers regarding mistakes in bills, including complaints regarding estimated consumption before issuing the next bill, if possible. If there was a mistake, it should not be repeated in the next bill. The licensee shall notify the consumer of the results of their complaint within a maximum of 15 business days. In this framework, a “Complaint” is defined as any request submitted in writing by the consumer.

The licensee shall recalculate the consumed amount in case of any malfunction in any measurement devices or electricity meters according to the previous average consumption during the period in which the malfunction occurred. Within a maximum of 30 days from the date of the EMRC request, the Licensee shall send to the Commission a report containing the following:

- A list of consumers’ names, telephone numbers (if available), type, area, reasons for consumption estimation and the estimated consumption in kilowatt-hours and JOD.
- A detailed record of the consumers whose consumption was estimated by the licensee for more than two times during the year.

In case of non-payment of bills, licensees can apply temporary disconnection of service for insolvent consumers. If this happens, licensees have to follow a standard procedure composed of the following steps:

1. The licensee shall issue a written notice before
disconnecting the service to any consumer due to non-payment of bills according to the deadlines and the procedures set out in the Distribution Code and Retail Distribution and Supply License.

2. If the consumer pays the owed amount with interest, fines and any additional fees, the licensee shall reconnect the service to the consumer within 24 hours from the time of payment.

3. The licensee shall prepare, update and maintain a record of the consumers who are disconnected from service due to non-payment.

4. Within 30 days after the end of the report’s month, the licensee shall send a report to the Commission containing the following:
   - A list of the consumers who were disconnected from service during the previous month (report month) with the time of service disconnection and reconnection for each consumer.
   - Separate records of the cases which have exceeded the tolerance limits of 24 hours during the previous month when service was restored.

If the licensee does not restore the service to the consumer within the set tolerance period, such a case shall be considered as exceeded tolerance limits (or non-compliance) and result in fines equal to 20% of the monthly average value of energy consumed by the customer in the last 12 months (max.), if available, for every day in which the licensee exceeds the reconnection deadline. Such fines are deducted from the licensee’s revenue requirement through the tariff in the subsequent tariff period according to the tariff methodology which applies to the non-compliant licensee.

Another typology of sanction is inflicted to licensees if they fail to provide the required reports and information to EMRC within the deadlines. This is deemed as lack of competence on the part of the licensee, with a consequent financial fine of JOD 200/per business day of delay which is deducted from the licensee’s revenue.

5.3. Recommendations

EMRC seems to have a solid legal background at its disposal to monitor the regular issuing of electricity bills and reading of meters. In this regard, the procedures and their related timelines seem consistent with the correct management of consumers according to the international practice and the best cases of MEDREG members.

On the other hand, EMRC’s activities could benefit from a more detailed definition of the content of bills. As highlighted in the case studies, the specific regulation for energy bills are important to complement national general laws and rules on billing, since the energy bill is the only periodic communication to energy consumers who need to be informed on consumed energy, prices, payment instruments, the regularity of payment, risk of disconnection, among other aspects. EMRC should therefore bring its action forward to reconsider the information included in the bill so that this document is fully accurate and easily understandable for all categories of consumers. The right to understand prices and quantities paid is a basic right, even for consumers with low educational levels because energy can be a relevant share of their monthly budget.

In this regard, EMRC could revise the bill form to ensure that it includes all information on the final price that consumers pay for their energy. This entails indicating not only the price of energy itself but all the different components (both those that are regulated by national NRAs and those determined by the energy providers). The bill should therefore include the energy component (price or tariff for energy itself), transmission and distribution tariffs, taxes and other types of charges. All this information should be reported synthetically, to avoid an information overload that would make the bill confused, and in a plain language that is easy to understand.

The fuel cost component earlier borne by NEPCO is to be phased out to the distribution companies in a gradual manner. This poses a new procurement-related risk and how and who takes this up gradually is yet to be determined. This may therefore be the reason that this issue cannot be fully clarified in the short term. This transfer of fuel procurement-related risk from the traditional NEPCO is likely to affect end-user tariffs and how the procurement efficiencies are to be handled is still a matter of consultation.
As for metering, EMRC could take stock of the substantial changes which are underway in the technology of utility meters and use them to get more data on the consumption pattern of Jordanian electricity consumers, as well as increase its control over the relations between consumers and the utility. In this sense, it is the most important step lies in advocating for the extensive deployment of smart meters in the country. Indeed, smart meters can accurately reflect consumers’ energy consumption, providing EMRC information on the time of use as well as allowing remote meter reading.

To this aim, EMRC could consider elaborating measures to incentivise stakeholders to speed up the development and uptake smart metering products and services by studying and implement timely regulations or take measures to increase confidence in utilities and operators to invest in smart metering technology and develop related service. This could start through small-scale roll-outs or pilot projects that can provide useful lessons on the methodology used before moving to large-scale roll-out, particularly concerning techno-economic issues, consumer involvement and the market development of smart metering services.

5.4. International best practices in billing and metering procedures

5.4.1. Egypt

As regards to electricity distribution, EgyptERA is pursuing a strategy of harmonisation of standard processes to initiate further unbundling (distribution-supply) and possible out of area supply competition. This is aided by the fact that Egypt DSO areas are relatively uniform and the existence of 9 DSOs makes a compelling case for benchmark-driven comparative competition as has been applied in some western European countries. In the pursuit of these objectives, there are areas of DSO operations that have the commonality of functions e.g., Billing and Metering services and customer services where consolidation and cost efficiencies can be explored to control the rising end-user tariffs and balance the interests of the customers and the industry.

In Egypt, the regulator has already allowed the use of mobile apps for customer services that do not involve non-payment of dues (as there are separate due regulatory processes that need to be followed which prevents the use of app-based communications) and trials in 3 distribution areas with mobile apps have proved to be successful and a nationwide rollout of mobile apps based usage reporting and other consumer activities is contemplated.

Following this experience and in the interests of driving scale efficiencies, the Egypt ERA is trialling the usage of Unified Meter Reading (UMR). The driver behind this initiative is the progress already achieved in the early years of harmonisation of the distribution codes across the 9 DSO areas. The addition of metering code harmonisation will enable the use of a single, well-understood meter point identification and reading system that is expected to significantly reduce the across network originated errors in meter reading and consequently inaccurate billing. The regulator is seeking to reduce the un-metered energy that is a significant component in Egypt’s electricity transmission and distribution.

At present, the common metering and billing functions across the nine DSOs are carried out independently albeit now under a common grid code. This still leaves considerable error margins within the distribution sector unmetered hence unbilled energy.

While UMR is expected to reduce the lost/unbilled energy, the access to a single shared consumer call centre that was discussed in the chapter on customer services is also expected to offer individually contracted services to the DSOs using the same Unified Number Call Service facility.

Furthermore, Egypt has already started a smart meter roll-out programme in 6 of the 9 DSO areas with an initial target of 250,000 meters to be rolled out by June 2020. As per the latest information, 150,000 smart meters have been successfully implemented from June 2020 delayed till March 2021 due to the ongoing global pandemic.

It is expected that this approach of functional harmonisation to drive through cost synergies
and to accelerate the comparative competition approach that the Egypt ERA has initiated will help drive cost efficiencies that might then be possible to pass on to end-users through a capping/reduction of end-user tariffs.

5.4.2. France

The most significant metering and billing-related challenges in France are still the issue of estimated versus actual bills and improving the efficiency of metering and billing systems. Much has been achieved in the latter through innovative use of IT systems that do not compromise on the inherent EU data protection and privacy-related directives and guidelines that France has to adhere to.

Estimated vs. actual consumption

Types of contracts

In France, individual customers subscribe to a single contract with the electricity supplier, both for supply and distribution of electricity. As Enedis still manages the distribution stage, the supplier must sign a contract with Enedis called a DSO-Supplier.

After signing a single contract with a customer, the supplier is responsible for drawing up a single bill for the supply of electricity and the use of the network. In case of a request from the customer related to the distribution stage (commissioning, power changes, etc.), metering and billing are still addressed to the supplier who will pass it on to Enedis if necessary.

Local authorities or companies may also opt for a Contract for Access to the Public Distribution Network (CARD), which implies that they have to, on the one hand, sign a network access contract with Enedis for the distribution of electricity on the one hand and on the other hand, negotiate supply contract(s) with one or more suppliers and appoint a balance responsible entity.

Billing process

Following the opening of the energy market in 2007, new electricity and gas suppliers appeared alongside the two former historical monopolies EDF and GDF. To set up a harmonised system among suppliers, a “Bill decree” was published on 18 April 2012 to determine the structure of all bills and the mandatory information they must display. The consumer code now includes these provisions.

Article L224-11 of the consumer code provides that the supplier must issue a bill at least once a year, based on the energy actually consumed by the customer and not only based on estimated indexes. After amendment by the Energy Transition for Green Growth Act in 2015, the Energy Code provides that no consumption of electricity or natural gas that happened more than 14 months before the last meter reading may be billed, or exceptionally in the event of failure to access the meter, failure by the consumer to transmit an index relating to his actual consumption after a request from the system operator, or fraud.

Billing Standardisation:

Over the last few years, CRE has brought about a billing standardisation approach that all suppliers now agree and comply with. These standards include not only the standardisation of format and appearance for ease of reading but also include standardised data elements that have to be included which form the “Bill Decree” in France applicable since April 2002 and include:

- The amount to be paid or reimbursed;
- The deadline for payment or reimbursement;
- The customer reference number;
- The address of the consumption site;
- The offer subscribed to;
- The references of the metering equipment;
- The bill reference number, the date of issue and the deadline for payment;
- The estimated date of the next bill and, if possible, the next meter reading.

6 https://www.mEDIATEUR-engie.com/faq/elements-qui-la-compo- sent/comment-lire-une-facture-denergie/
• The payment terms;
• Consumption history (for optimisation and detection of inconsistencies).

More precisely, in France, the energy bill is divided into 3 parts: subscription (fixed amount covering the cost of bringing the energy to the dwelling and the supplier’s commercial fixed costs); consumption; and taxes. The contract may be terminated in two cases:

• In case of a change of supplier: termination is possible at any time. This operation is carried out free of charge, except for the network operator’s costs if mentioned in the offer.
• Following a change in the contractual conditions: the supplier shall inform the consumer, at least one month before the date of application of the intended change, that he may terminate the contract without penalty, within a maximum period of three months from the communication of that information.

The consumer shall receive the closing bill within four weeks of termination of the contract and repayment of any overpayment within a maximum of two weeks after the issue of the closing invoice. Regardless of the type of contract (at market price or regulated tariffs), the consumer may change his offer or supplier at any time, free of charge (except for network costs if mentioned in the offer)⁹.

Impact of the “Linky” smart meters deployment

Smart metering is intended to allow access to consumers, at a minimum of every month, of accurate information on their consumption of electricity to improve the quality of billing and better management of energy consumption. A smart metering system stores data (index, load curves), records information (interruption of supply, power overload), can be optionally configured, interrogated and operated remotely (bi-directional operation). Smart metering involves the introduction of smart meters capable of storing the measurement information and the establishment of data transmission systems enabling the rapid and reliable flow of information contained in the meters between the users, system operators and suppliers.

In December 2015, Enedis, the French DSO started the deployment of Linky smart meters, to install 35 million meters. More than 26 million meters have already been deployed in July 2020. Linky meter allows the distributor to have much more regular access (at least once a month) to consumption data. In addition, the Linky meter will greatly reduce the number of bills based on an estimation of the consumption because the distributor will no longer need to realise an actual reading.

Evaluation by CRE

Every year, CRE publishes a report on the respect of codes of good conduct and independence of network operators (RCBCI). In this regard, CRE carries out audits to assess the respect of system operators’ obligations of non-discrimination and transparency in their billing processes. For a deviation beyond accepted tolerance levels and/or subject to the regulators’ determination, a penalty can be issued by the CRE. The various CRE reports suggest that the transfer of an incentive mechanism for DSOs through the tariff review consultations has significantly reduced the requirement for granular inspection and the regulator now uses several statistical tools and techniques as a measure of assurance it is obligated to provide to customers.

5.4.3. Italy

Billing procedures are regulated by the Code “Billing of the supply service for electricity and natural gas customers” (TIF), Annex A to ARERA Resolution 463/2016/R/com of 4 August 2016. Issuance of periodic billing for electricity must respect the following frequency:

• domestic customers: every two months;
• non-domestic customers with up to 16.5 kW installed: every two months;
• non-domestic customers with more than 16.5 kW installed: every month.

Each invoice must be issued within 45 calendar days from the last day of consumption charged on the same invoice. If the invoice is issued beyond the 45 calendar days term, the supplier must pay an automatic compensation to the customer. The basic amount of the compensation is €6, increased for delays higher than 10 calendar days. It is forbidden to charge consumption for periods falling after the invoice issue date.

To calculate the consumption accounted for in the invoice, the supplier must use the metering data in the following order:

a) data made available by the DSO;

b) self-readings communicated by the customer and validated by the DSO;

c) data estimated by the supplier.

Free market contracts may establish a different order of priority provided. At least once every 12 months, an invoice is issued that accounts for actual consumption.

In the case of metering procedures, they are regulated by the Code “Regulation of the electricity metering activity” (TIME), Annex B to ARERA Resolution 568/2019/R/eel of 27 December 2019. The installation and commissioning of the first generation of smart metering systems (1G) were substantially completed in 2006 as regards the main DSO (approx. 85% of electricity customers) and was completed (with few and limited exceptions) in 2011 for the remaining DSOs. The installation and commissioning of the second generation of smart metering systems (2G) are currently in place.

With regard to meter reading, if an electronic meter is installed, a monthly reading is required. In case of unavailability of actual reading data, the monthly data made available to the supplier must be estimated by the DSO. If this happens for two consecutive months, the DSO must pay a €10 automatic compensation to the customer through the supplier.

If a traditional non-electronic meter is installed, a reading attempt must be carried out at least every four months for customers with up to 16.5 kW power installed and at least once a month for customers with more than 16.5 kW. In case of two consecutive failed reading attempts and in the absence of validated self-readings, a further reading attempt must be carried out in the month following the one in which the second attempt failed. Suppliers must make a method for collecting the customer self-reading with a traditional non-electronic meter available to customers to be communicated within a time period indicated on the invoice. The supplier will take over the self-reading data unless it is clearly incorrect (as of at least one order of magnitude different from the last available actual data) and send it to the DSO for validation within 4 working days.

If the supplier uses its own estimates, they must be based on the customers’ actual historic consumption as provided by the DSO and possibly supplemented with other information deemed useful for the determination of customer consumption. These methods must, in any case, minimise the gap between actual and estimated consumption.

5.4.4. Malta

Billing and meters are regulated by the Electricity Supply Regulations and the Customer Charter. According to the Customer Charter, customers should receive an invoice based on actual readings every two months. This is normal practice in the case of domestic customers with a smart meter installed. Customers who do not have a smart meter should receive a bill based on actual readings twice a year.

Malta has a vertically integrated and a relatively smaller electricity system with high levels of sophistication (e.g., more than 90% of domestic consumers have remotely/automatically read smart meters which is an activity the utility service provider ARMS Ltd carries out on behalf of the DSO, EneMalta. The activities of ARMS Ltd are governed by a performance contract between the DSO and itself. This contract specifies in some cases the performance parameters that have to be implemented. The regulator has an oversight function in the adherence to the performance contract and the primary point of contact for the consumers for billing and metering (like in the case of complaint handling) lies with ARMS Ltd.
ARMS Ltd carries out all meter reading and related activities including the issuing of bills on behalf of EneMalta and like in the case of complaint handling, has statutory obligations to respond to queries from customers as well as the collection of bill payments. Consumers have the option of self reporting meter readings though, given the high proportion of remote/electronic meter reading in Malta, this remains a small proportion for self reporting.

Customers have 45 days to settle an invoice. Otherwise, they would incur interest on the amount due as from the 15th day from the date of the invoice.

The consumption accounted for in the invoice may be based on

• Remote readings from the smart meters
• Manual reading by the DSO
• Customer self-readings
• Estimated readings by the DSO if none of the above is possible

Smart meters reachable remotely reached the figure of 88.5% of all installed active meters and 90.85% of households were equipped with a remotely reachable smart meter by the end of 2019.

Unlike other systems, there is limited complexity in the TSO/DSO interface which results in minimal distortions in unmetered energy or unbilled supply as the TSO functions in Malta are carried out by Terna of Italy under a government-to-government agreement. Hence the Maltese electricity system is a DSO only system with a vertical integrated structure and no provision/obligation for distribution and supply unbundling or out of area supply competition.

As in the case of customer complaint handling, an identical escalation process applies for billing and metering with 90% or more cases resolved at the ARMS Ltd interface stage itself. It is unclear if any incentive mechanisms are in place in the performance contract for timely/accurate billing though ARMS is obligated to collect payments relating to its billing with a maximum settlement period of 45 days.
6

EVALUATION OF PERFORMANCE INDICATORS AND THEIR CALCULATION FOR POWER INTERRUPTIONS
EVALUATION OF PERFORMANCE INDICATORS AND THEIR CALCULATION FOR POWER INTERRUPTIONS

6.1 Options for the calculation of power interruptions and related performance indicators

Considering continuity of supply, one can notice that it concerns a single service, the supply of electricity to consumers. The main quality dimension of this service is the absence of interruptions. In fact, interruptions in the supply to final consumers depend on the reliability of the entire power system, made up of a generation system, a transmission grid and a distribution network.

However, this chapter focuses mainly on the reliability of the distribution network. From the point of view of a network user, the problems caused by interruptions in electricity supply coincide with the number of events in a period of time and the duration of service interruptions. For this reason, continuity of supply regulation focuses on quality indicators that capture the frequency and duration of supply interruptions. Failure rates of system components and similar indicators are what concern the distribution company, but they can be considered as only intermediate measures of the quality dimensions that consumers value directly.

Therefore, regulatory instructions and guidance on data collection should aim at gathering valid information that describes the performance of the distribution network with respect to the number and duration of supply interruptions. Some relevant features of regulatory instructions for data collection include the following:

- The information must be collected uniformly for all consumer categories to ensure fairness;
- The procedures for measuring quality indicators must be clearly defined to revise and audit the collected data;
- The information recorded must be consistent with the objective of the regulatory instruments to be introduced, as some indicators fall under regulation;
- Any information recorded must be relevant with respect to the technical equipment available.

When building an information database, it is advisable to first collect information on the average performance of the utility (over the distribution territory or a part of it), starting with system level measurement. Then, it is possible to get information on individual delivery points. In the same way, the number and duration of long interruptions (over three minutes) are easier to account for than to measure the number of short interruptions (up to three minutes).

Consequently, regulatory policies should therefore focus on data on long interruptions at the system level for the first years of implementation. Indeed, long interruptions are the main concern of domestic customers. The process of data collection on continuity of supply can be broken down into four main steps:

1. recording all interruptions and their characteristics;
2. computing the relevant quality indicators from the register;
3. reporting these indicators to the regulatory authority (and to consumers, where relevant);
4. and verifying the reliability of the figures reported by the relevant utilities.
On the side of companies, interruptions events can serve the scope to learn how to apply the regulatory instruments correctly. Generally, utilities should register five basic characteristics of the interruption event:

- point of origin of the interruption: e.g., the transmission network or distribution network. In the latter case, it may be useful to also register the name of the faulted component and the voltage level (high, medium or low voltage);

- type of interruption (planned or unplanned);

- cause of interruption in terms of regulation (i.e., if any exemption applies);

- classification of interruption for its duration (long or short);

- the number of consumers involved by the interruption.

Statistical indicators of performance are communicated to the regulator regularly, generally once per year. It is the regulator that decides on the content, timing and form of these communications. The annual statistical indicators can be computed from the register and it may be useful to break down the data in a specific manner for regulatory purposes. For example, the regulator may need to separate statistical indicators of performance for different areas of the distribution territory (urban, sub-urban and rural). This is important in cases where various performance standards are employed for different geographic areas. On top of this, the regulator must be able to identify the statistical figures regarding the events to which exemptions apply.

Based on the data collected, the regulator can then evaluate reward and penalty schemes that can induce the regulated utility to an optimal level of service for the quality dimensions registered. Of course, this will happen when the increased quality, which for the utility translates into financial rewards, outweighs the associated costs and, conversely, when a lower level of quality than specified in the performance standards set by the regulator, outweighs the associated losses incurred by consumers, resulting into financial penalties for the utility. Therefore, when developing a reward and penalty scheme, a regulator must consider that, in practice, the regulatory instrument will influence a reduced set of quality dimensions and that the utility will deliver a level of quality that depends on the approach adopted by the regulator about the level of performance standards and financial incentive. Thus, the choice of quality indicators to be regulated, the respective performance standards and the number of financial penalties and rewards will be key elements in the overall design of these mechanisms.

Regulators should pay particular attention to the quality indicators that are subject to financial incentives. Objective and verifiable measures must be collected and assessed for the selected indicators, taking into account that offering financial incentives for some indicators of quality and not others may involuntarily introduce an incentive to neglect those not covered. Continuity of supply is noted through both duration and frequency of interruptions and interruptions falls under different durations and types. Several quality indicators can therefore be derived from the collected data. However, workable incentive schemes focus can only focus on a selected number of them. It is therefore safer to start by regulating two-three indicators. Further rewards and penalties can be introduced for other indicators later in time.

6.2 Calculation of power interruptions and related performance standards in Jordan

6.2.1. Definitions and categories of power interruptions in Jordan

Supply quality is expressed as the effect of interruptions on consumers and it is evaluated using the indices which measure the number and duration of interruptions. In Jordan, power interruptions are classified as follows into 4 categories:

- Scheduled interruptions: power interruption to consumers by a decision from the licensee. Interruptions are considered as scheduled
interruptions if the affected consumers are notified at least 72 hours in advance. The licensee may submit a request to the EMRC, supported by relevant documentation, to reduce the notification period to 48 hours if the licensee considers that committing to such a period would cause major problems and/or a significant increase in costs.

- Unscheduled interruptions: any interruption which cannot be classified as a temporary, external, third party or scheduled interruption, regardless of the cause and duration.

- External interruptions: any scheduled or unscheduled interruption due to generation shortage, transmission lines overloading, an interruption due to facilities owned and operated by other operators, upon request of one of the other licensees or due to a generation facility not owned by the licensee.

- Third Party interruptions: any unscheduled interruption resulting from an action by an unlicensed party that causes one or more facilities in the Licensee's Distribution System to go out of service.

In addition, three other subcategories are considered and defined by the Performance Standards Code for Retail Distribution and Supply Licences:

- Emergency maintenance interruption: power interruption to consumers decided by the licensee to perform maintenance or other operational works. Such interruption is not subject to the procedures established in this Performance Standards Code as it is considered a scheduled interruption.

- Force majeure interruption: any interruption caused by exceptional and unpredictable conditions that are not within the licensee's control, provided that they have taken all possible actions to prevent such condition or to mitigate its effects. Interruptions shall not be considered as force majeure interruptions unless the licensee asks the EMRC to consider them as such, and the regulator explicitly classifies them as such.

- Temporary Interruption: power interruption to consumers for a period of up to 5 minutes.

Licensees are required to keep track of all interruptions which affect their consumers, clearly indicating the dates and start and end times of such interruptions. Such records are kept by licensees for at least five calendar years. Licensees have to provide a sufficient number of phone lines to receive consumers' complaints to ensure appropriate documentation of the time in which the distributor is notified of the interruption by consumers. In addition, licensees shall set in place procedures and a system to ensure time consistency and synchronisation among the offices and sites assigned to determine interruption times. In this regard, the start time is calculated as follow:

- For scheduled interruptions, the moment when maneuvers start.

- For unscheduled interruptions, the moment in which the SCADA system detects the interruption and reports equipment disconnection, or the moment in which the first customer complaint regarding the interruption is received by the licensee, or the moment in which the licensee learns about the interruption via any other means, whichever occurs first.

The interruption end date and time is calculated in the record from the moment in which the consumers affected by the interruptions are reconnected to the distribution system.

Beyond the 4 general categories identified above, the following additional special categories of power interruptions are considered for the calculation of supply quality performance indicators:

- Interruptions due to emergency maintenance are considered unscheduled interruptions.

- If a fault occurs in a facility owned by the licensee, and it could not be correctly solved using the equipment under the licensee's control and was due to a fault in the protection systems of the transmission licensee or other retail distribution and supply licensees, the interruptions resulting from such fault shall be considered as external interruptions.
Performance Standards, licensees are requested to prepare and submit a report to the EMRC for their approval containing adequate documentation of internal procedures, databases and information systems which should be implemented including, among others, the following items:

- Procedures and systems to identify and record all consumer interruptions in the distribution area under their control.
- Procedures and systems to classify consumer interruptions according to performance indicators.
- In the cases where the interruption affects more than one consumer, the licensee shall determine the interruption period for each consumer or group of consumers.

Moreover, licensees are required to use an information system capable of both connecting the above-mentioned databases to accurately

6.2.2. Performance indicators for power interruptions in Jordan

In Jordan performance indicators, licensees are evaluated according to two categories of supply quality performance indicators, namely individual performance indicators and overall performance indicators. For the measurement of supply quality for each consumer, the following individual performance indicators are used:

- The total number of scheduled interruptions per calendar year (Ns).
- The total number of unscheduled interruptions per calendar year (Nu).
- The total number of external interruptions per calendar year (Ne).
- The total duration of scheduled interruptions per calendar year (Ds).
- The total duration of unscheduled interruptions per calendar year (Du).
- The total duration of external interruptions per calendar year (De).

Details on the formula related to those indicators are provided in Annex 1 to this report.

6.2.3. Procedures for monitoring interruptions and performance indicators

To control supply quality and calculate performance indicators according to the

• The interruptions affecting consumers due to issues in their facilities shall not be taken into consideration when calculating supply quality for such consumers. If such interruptions affect other consumers, they shall be classified as third party interruptions for such consumers.

On the contrary, temporary interruptions and force majeure interruptions allowed interruptions to disconnect a certain consumer due to unpaid bills and interruptions due to disconnecting consumers for the illegal abstraction of electricity or meter tampering. They are not taken into consideration for the calculation of supply quality indicators.

In addition, licensees are granted the power to use all necessary databases and information, including, but not limited to:

- A consumers database containing all the necessary information required to determine all the elements connected to the supply network chain after the implementation of a Geographic Information System (GIS) and a SCADA system by the licensee (distributor). These elements include consumer ID number, LV feeder and branch number to which the consumer is connected, the number of the MV/LV transformer to which the feeder is connected, the MV substation which feeds the transformer and the HV network which feeds the substation.
- Interruptions databases with all the details of each interruption which occurs in the licensee's supply area including, but not limited to: date and hour in which the interruption started; distribution system feeder(s) affected by the interruption; category of interruption; the number of MV/LV transformers which went out of service due to the interruption; the number of consumers affected by the interruption (to be estimated until the Geographic Information System (GIS) is implemented); date and hour in which the interruption ended.

Moreover, licensees are required to use an information system capable of both connecting the above-mentioned databases to accurately
identify all the consumers affected by each interruption that occurs in the distribution system and conducting all the necessary activities and calculations to determine all the values and calculate overall performance indicators to monitor and control supply quality correctly. The same applies to Individual Performance Indicators which have to be calculated by licensees as well.

Once EMRC approves the procedures and the structure of the database and information system, licensees shall notify the EMRC of any amendments made to the procedures, the structure of databases or information system. They shall also prepare and submit a report which describes and documents the amendment and its justifications. The Commission may reject such an amendment if it deems that such amendments affect the quality or adequacy of the indicators specified in the Performance Standards. In such a case, licensees shall disregard the proposed amendments or undo them if they were already made.

In this framework, EMRC may and shall be allowed by licensees to inspect and review the databases and information system specified in the Performance Standards to audit the procedures, data and the accuracy of the information submitted by licensees periodically, being also allowed to hire any qualified person or company to conduct such task on its behalf. Licensees are obliged to submit to the regulator a monthly report, in an organised manner within the thirtieth day after the end of the report’s month, to enable EMRC to control and monitor licensee’s compliance with distribution quality and relevant performance indicators. The information to be included are the following:

- A list of the interruptions on the MV network of the Distribution System, including MV/LV transformers, specifying the following for each interruption: affected feeder(s); the total number of affected MV/LV transformers; the total number of affected MV consumers; total disconnected capacity in nominal kVA; time of power restoration to affected consumers.

- If power is restored to consumers in several phases or groups, licensees shall submit a list of the restored power (in kVA) in each phase or for each group; time of power restoration for each phase or group; total expected energy not supplied to consumers.

In addition to what has been mentioned above, the monthly report submitted to the EMRC has to include overall performance indicators for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) for consumers connected to the network. The licensee shall also:

- Calculate the overall performance indicators as defined in the Performance Standards Code, taking into consideration the estimated number of consumers connected to each MV/LV transformer according to the size of the transformer and/or the MV/LV connected load and the estimated energy not supplied for each interruption according to the available measurements and/or the licensee’s experience with the system and the moment in which interruption occurred.

- Submit to EMRC a yearly report, in an organised manner and within the first thirty days of each year, which contains details of planning, maintenance, operation and management of the retail distribution and supply system which guarantee compliance with the overall performance indicators within the tolerance limits approved by the EMRC.

- Develop, organise and maintain databases, internal procedures and information systems which enable them to calculate and record the Individual Performance Indicators specified in the Performance Standards Code.

- submit to EMRC, every six months in January and July, a list of the procedures which they will carry out to improve supply quality to consumers who are provided with a service below the tolerance limits of performance indicators.

In case of a state of emergency, which is announced and decided by EMRC, licensees shall submit to the regulator an updated and detailed emergency plan stating the preparations and procedures taken by them to mitigate the effects of the emergency and reduce interruptions to consumers. Specifically, the procedure foresees the following steps:
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- Submit to EMRC an initial report about the status of the Distribution System within 8 business hours from the beginning of the emergency.

- Submit periodic reports every eight business hours (max.) from the beginning of the emergency until its end or until power is restored to all the consumers which were affected by the interruptions caused by the emergency, whichever is later. The reports shall include information about the MV feeders, MV/MV substations and the number of consumers affected by the interruptions.

- Submit a detailed report about the emergency, its effects and the procedures carried out to repair the faults to restore power to consumers or to mitigate the effects of the emergency in the future, once the emergency is over and within a maximum of five business days from the end. EMRC may request additional information about the emergency, and the licensee shall respond to the request within a maximum of seven business days from the date of request. Licensees shall also allow EMRC to review the necessary records and data related to supply quality.

In this regard, the regulator may request additional information about the whole Distribution System and should receive from licensees a monthly report within thirty days of the month following the reporting month – after the implementation of the Geographic Information System (GIS) by the Licensee – containing the following:

- A list of the interruptions which occurred on LV networks, including: the disconnected feeder(s), total number of affected consumers, total disconnected power in kVA and time required to restore power to subscribers.

- If power is restored to Consumers in phases or groups, a list of the disconnected power in kVA for each group or phase and the time required to restore power to each group or phase.

After the implementation of the Geographic Information System (GIS), licensees shall also calculate Overall and Individual Performance Indicators and plan, operate and maintain the retail distribution and supply system and comply with the tolerance limits approved by the Commission.

6.2.4. Tolerance limits in performance indicators and sanctioning powers for non-compliance

EMRC sets the number values for the tolerance limits for each performance indicator for each licensee taking into consideration the characteristics of the Licensee's Distribution System and load dispersion in area of supply. In addition, it also approves the tolerance limits for Performance Indicators for each Licensee at each Tariff Review Period. Tolerance limits may differ from one year to another during the Review Period. The table below gives an overview of tolerance limits for overall performance indicators:

<table>
<thead>
<tr>
<th>Overall performance indicators</th>
<th>Tolerance limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIDI (hour/subscriber)</td>
<td>3 hours/year</td>
</tr>
<tr>
<td>SAIFI (interruption/subscriber)</td>
<td>3 interruptions per year</td>
</tr>
<tr>
<td>EENS (MWh)</td>
<td>15x10^-5 of total supplied energy</td>
</tr>
<tr>
<td>Frequency of Unscheduled Interruptions Index (AFIK)</td>
<td>To be determined later</td>
</tr>
<tr>
<td>Total Time of Unscheduled Interruptions Index (TTIK)</td>
<td>To be determined later</td>
</tr>
<tr>
<td>Momentary Average Interruption Frequency Index (MAIFI)</td>
<td>To be determined later</td>
</tr>
</tbody>
</table>
At the moment, there are no tolerance limits for scheduled interruptions. EMRC will take a decision later on setting tolerance limits for performance indicators. Once such limits are approved, they shall be binding to the Licensee. Overall performance indicators, excluding MAIFI, shall be calculated for Scheduled, Unscheduled, External and Third-Party Interruptions.

If licensees fail to meet one or more overall performance indicators and/or any of the Individual Performance Indicators specified in the Performance Standards Code, they shall submit a detailed report with the reasons and justifications for such failure within 90 days of the date of notification of such failure by EMRC, in addition to an action plan of the short and medium term procedures which they will carry out to avoid failure in the future and to mitigate its effects.

EMRC reviews the proposed plan and it may request clarifications or amendments before approving it. Once approved, it will shall become binding upon licensees and it will be audited and monitored by EMRC. The distribution licensee shall abide by the tolerance limits set by EMRC with regards to overall and individual performance Indicators for each consumer. If licensees fails to abide by the tolerance limits for any of such Performance Indicators, this shall result in fines which will be deducted from the value of their revenues through:

- Fines due to their non-compliance with the set tolerance limits. These shall be calculated on a yearly basis according to the methodology set out in the Code.
- The financial value of the fines will be deducted from the Licensee's revenue requirements through the tariff in the subsequent tariff period according to the tariff methodology which applies to them.

EMRC estimates and approves the value of the fines which shall be deducted from the licensee's revenue for each category of consumers. The estimation is made by estimating the economic cost born by the consumer due to non-supplied power. This fine is considered as a revenue reduction.

At the end of any calendar year, if the licensee exceeds any of the tolerance limits approved by EMRC for overall consumer Performance Indicators for Unscheduled Interruptions, the financial fine which shall apply to such licensee is calculated as follows:

<table>
<thead>
<tr>
<th>Overall performance indicators</th>
<th>Tolerance limits</th>
<th>Applicable financial fine</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIDI (hour / subscriber)</td>
<td>3 hour / year</td>
<td>JOD 10,000/0.1 over Tolerance Limit</td>
</tr>
<tr>
<td>SAIFI (interruption / subscriber)</td>
<td>3 interruptions per year</td>
<td>JOD 50,000 per case exceeding Tolerance Limit</td>
</tr>
<tr>
<td>EENS (MWh)</td>
<td>15x10^-5 of total supplied energy</td>
<td>JOD 250 per MWh exceeding Tolerance Limit</td>
</tr>
</tbody>
</table>

Table 11: Fines for delayed tolerance limits

If the licensee exceeds the tolerance limits approved by EMRC for overall consumer performance indicators for unscheduled interruptions, the highest financial fine calculated according to the table above is applied.

Upon the implementation of the Geographic Information System (GIS) by the licensee, EMRC shall approve the values and fines for individual performance indicators, and they shall be applied by the licensee subject to the provisions of the Performance Standards Code.

If the licensee fails to provide the required reports and information within the time limits set out in the Performance Standards Code, this shall be
deemed as a lack of competence on the part of the licensee, and in this case, a financial fine of JOD 200/per business day of delay is applied and deducted from their revenue.

6.3. Recommendations

EMRC has already developed a comprehensive set of performance indicators that are in line with the international best practices, and particularly with those of the Mediterranean area, as outlined in the case studies reported above.

EMRC should now consider how to use those indicators in the context of an efficient system of rewards and penalties. This can be done either in terms of both planned and unplanned interruptions or considering only unplanned interruptions. In this regard, EMRC may evaluate the pros and cons of both options. On one side, adopting a scheme that allows utilities to reduce planned interruptions is likely to induce companies to use more efficient maintenance programs for the networks –inducing them to plan maintenance when consumption is low. On the other side, reducing planned interruptions may entail a long-term risk of insufficient network maintenance. Still, the impact of planned interruptions on consumers is certainly less disruptive than those of unplanned interruptions. This is why several European countries adopted a compromise solution, by which they are part of the incentive/penalty scheme, but with a reduced financial incentive rate thereby using a discount factor on the full rate.

A second aspect that EMRC could consider in more detail concerns exemptions. For example, when an interruption takes place on the transmission network, distribution utilities are exempted with the motivation that transmission networks are (generally) operated by a different company. Exceptional events are also exempted from a financial incentive scheme because they are considered to be out of the control of utilities. Indeed, when discussing continuity of supply regulation, the management of exceptional events is one of the more complex aspects to regulate and manage. The definition of force majeure events, or exceptional events, is rarely unambiguous enough when considering the array of different situations that may present in practice, therefore posing a problem of equitability.

Exceptional events are, by definition, rare. However, when they take place, they can have serious and lasting consequences on consumers, both from the social and economic point of view. This also translates into the number of penalties that distribution companies are requested to pay. Thus, the precision in defining what is an exceptional event and what is not is of paramount importance. For this reason, alternative solutions have been adopted for identifying exceptional events and managing the data related to continuity separately from baseline operational data. In Europe, several regulators have increased the level of detail with which they observe data flows on interruptions. They adopt statistical methodologies that study daily continuity data. These methodologies have the advantage to simplify administrative procedures, thus diminishing the costs paid by utilities and the regulator to control the correct exclusion of the event. They allow to statistically distribute the errors inherent in the identification method. They are easy to understand, as they rely on basic statistical concepts such as standard deviation and averages. EMRC could further explore the different methodologies currently in use and evaluate to adopt one for Jordan. It should be underlined that the exclusion of exceptional events from incentive regulation does not mean that the regulator should pay it less attention. On the contrary, EMRC could consider incentivising prompt operational responses by the utility in case of exceptional conditions such as severe weather.

A third aspect that EMRC could focus on is network reliability in the medium-term. The characteristics that make a distribution network reliable involve, on one side a progressive process of deterioration of the network due to the ageing and usage and, on the other side, the substitution of poorly performing assets with more advanced ones, thus improving the overall efficiency of the network. EMRC may consider that quality indicators of performance may not be sufficient to measure how medium-term network performance can be encouraged, as they often tend to focus on short-term improvements. In this regard, EMRC could try to get closer information on fault statistics and
asset management to understand what happens behind the standard quality regulation indicators. This would require the regulator to know in detail how the network utilities internally assess their conditions, and, on a subsequent step, decide how to evaluate the relationship between asset management and network quality.

EMRC should approach all of these issues incrementally, preferring solutions that can provide concrete results in the context of the Jordanian market, taking into account the institutional conditions, the starting level of quality, the industry structure and the availability of attested measurements.

6.4. International best practices in evaluating performance indicators for the calculation for power interruptions

6.4.1. Egypt

Below is a summary of EgyptERA's performance indicators:

- The concerned authority evaluates the technical performance of all electricity distribution companies through twelve technical performance indicators. There are 12 indicators are divided into seven groups:
  1. Reliability (SAIFI, SAIDI, CAIDI)
  2. Productivity (ASAI)
  3. Network characteristics (ratio of ground cable lengths to network lengths for low and medium voltages)
  4. Two indicators of network load ratio
  5. Consumer complaints
  6. Efficiency
  7. Two indicators for worker productivity.

• Indicators for each of the company's departments are calculated separately using the data provided by each company for renewing the license. Here's a definition of those indicators:

<table>
<thead>
<tr>
<th>Group 1: Indicators of Reliability:</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Average system outages (SAIFI)</td>
</tr>
<tr>
<td>- Measures the number of interruptions per 1,000 management subscribers and rewards: Total number of interruptions* 1000/Total number of subscribers in different categories.</td>
</tr>
<tr>
<td>- Unit of measurement: interruption/1000 subscribers</td>
</tr>
<tr>
<td>- The best value is the lowest value.</td>
</tr>
</tbody>
</table>

| (2) Average system breaks (SAIDI) |
| - Measures the time period of service interruption for management subscribers and rewards: Total time intervals per minute *1000 / total number of subscribers in different categories. |
| - Unit of measurement: min/1000 subscriber. |
| - The best value is the lowest value. |

| (3) Average subscriber breaks (CAIDI) |
| - It measures the average time taken for each interruption and is calculated in the following equation: Total interruption time periods / Total number of interruptions. |
| - Unit of measurement: minute/interruption |
| - The best value is the lowest value. |
Group 2: Indicators of Productivity

(1) Average subscriber electrical feeding (ASAI)
- Reflects the percentage of the period during which the subscriber is having electrical energy during the year or the registration period.
- Calculated by the equation: \((8760*60 - \text{total time periods of interruption}) / (8760*60)\).
- Unit of measurement: percentage.
- The best value is the highest value.

Group 3: Network Characteristics indicators

(1) Low voltage ground cable lengths/total lengths of ground cables and low voltage airlines.
- The best value is the highest value
- Unit of measurement: ratio.

(2) Mid-voltage ground cable lengths / total lengths of ground cables and mid-voltage airlines.
- The best value is the highest value
- Unit of measurement: ratio.

Group 4: Network load indicators:

(1) Distribution network usage factor
- Measures the ratio between the amount of energy sold to the maximum load of the distribution network. It is calculated as follows: \((\text{Total amount of electricity sold (G.O.S.) } *1000 / \text{Maximum load of the distribution network (M.O.) } *8760 \%)\)
- The best value is the highest value
- Unit of measurement: percentage.

(2) Distribution converters usage factor
- Measures the ratio between the amount of energy sold to the total capacity of electrical distribution converters. It is calculated as follows: \([\text{Total amount of electricity sold (G.O.S.) } *1000 / \text{total capacity of distribution transformer capacities (M.F.A.) } *8760] \%\)
- The best value is the highest value
- Unit of measurement: percentage.
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- Each of the previous indicators is calculated for each department in all companies and to assess technical performance and compare among different companies in a fair manner, each index value is compared to the weighted average of the same index values for all departments in all distribution companies with the same nature (urban or rural) and the same extent of electrical capacity. The management that achieved the best value of the index is determined and this value is what is called best practice.

Group 5: Complaints Index

(1) Number of complaints per 1,000 subscribers
- The number of complaints per 1,000 subscribers is calculated as follows: (Total number of complaints filed to the company / Total number of subscribers in different categories) * 1000
- The best value is the lowest value.
- Unit of measurement: complaint / 1000 subscribers.

Group 6: Efficiency Index

(1) Percentage of technical and non-technical electrical loss
- Represents the ratio between the difference between the amount of energy available and sold to the amount of energy available and is calculated by the equation: (Total amount of electricity available - total amount of electricity sold) / total amount of electricity available) %
- The best value is the lowest value.
- Unit of measurement: percentage.

Group 7: Worker Productivity Indicators

(1) Net number of employees per 1,000 subscribers.
- Represents the ratio between the net number of employees to the total number of (subscribers) participants and is calculated by the equation: (net number of employees / total number of (subscribers) participants in different categories) * 1000
- The best value is the lowest value.
- Unit of measurement: factor / 1000 subscribers.

(2) Net number of employees to the total amount of energy sold.
- Represents the ratio between the net number of employees to the total amount of energy sold.
- Calculated by the equation: (net number of employees / total amount of energy sold (G.O.S.)
- The best value is the lowest value.
- Unit of measurement: Factor / G.O.S.
• The results are divided between the best performance and the weighted average into three regions (A, B, C). A indicates an excellent practice, B indicates a good practice and C indicates acceptable practice. Beyond the weighted average divided into two areas (D, E), D indicates a weak practice, E indicates a very weak practice. Each management takes a score for each indicator from A to E depending on the area where the index value is located.

• The indicator values for each company's departments are compared with the previous years to measure the progress of performance.

6.4.2. France

Calculation of interruptions and potential penalties
The continuity of the power supply may be affected by power interruptions. They are 2 types of interruptions:
• Scheduled and unscheduled outages;
• Long (more than 3 minutes) and short (between 1 second and 3 minutes) outages.

Outages of less than one second are generally called voltage dips, which are more related to the quality of the voltage wave than the continuity of power supply.

As mentioned before, CRE has set up incentive mechanisms for TSOs (RTE) and DSOs (Enedis, local distribution companies, EDF SEI in non-interconnected areas) as part of the tariff for the use of public electricity networks (TURPE) to encourage RTE and Enedis to control their costs and improve the quality of service.

Focus on transmission
Regarding transmission, continuity of supply and quality of service can be examined from two perspectives:
• Regulatory perspective
CRE ensures that network users benefit from a satisfactory level of quality of service and supply according to the tariff they pay.

The framework of incentive regulation concerning the quality of service and supply is based on a set of indicators, allowing to evaluate the performance of operators in areas that are deemed relevant for assessing the quality of their services. The most important indicators are associated with a specific target and a financial incentive. Concerning RTE, the indicators subject to a financial incentive are power continuity indicators: frequency and duration of outages. Concerning incentive regulation of supply continuity, the main principles of TURPE 5 HVB are as follows:

• The reference targets are 2.8 minutes for the outage time and 0.46 for the outage frequency.
• For information, the frequency of outages on the RTE network has improved by almost 40% over the period 2008-2017. The introduction of a financial incentive in 2013 for the TURPE 4 HVB Tariff Period has reinforced this dynamic.
• The amount of the annual incentive is increased to 75% of undistributed energy, i.e., €17 M per minute for the average outage time per user per year, and €10.9 M per 0.1 average outage point per user per year for the outage frequency.
• Contractual perspective

In the Contracts for Access to the Public Transmission Networks (CART), RTE makes commitments to its customers (consumers, producers, distributors, etc.). All contract models are freely accessible on the RTE website and the standard frameworks are published on the CRE website when the documents are approved.

RTE’s contractual commitments relate in particular to: (i) scheduled outages due to maintenance, renewal, development and repairs of facilities; and (ii) electricity quality (continuity of supply and quality of the voltage wave). RTE makes commitments to its customers on outage durations and frequency.
6.4.3. Italy

One of the most important features of the Italian DSO regulation relating to supply interruptions and reliability is the early adaptation from the Italian Citizen’s Charter to a mechanism of transferring some unique incentive/penalty based regulatory mechanisms.

Italy began this journey in 1997 when the Autorita took over the regulation relating to continuity of supply and launched a detailed consultation to standardise the processes that were initially up to the discretion of the individual utilities under the previous Citizen’s Charter. The utilities no longer had the discretion over the metrics and a process to establish/recognise the common set of metrics kicked off through a consultation. This process was in parallel to the evolving EU electricity third party access based deregulation that was initiated and Italian Autorita emerged as an early adopter of the principle of active monitoring as opposed to just regulatory reporting. The advantage that the DSOs enjoyed was the timing of the new investments in SCADA systems which enabled the active monitoring at the MV/LV levels. Italy to this day remains one of the very few DSO systems that carry out active monitoring of the SAIDI/SAIFI indicators.

Another key feature of this regulatory mechanism was the principle of “automatic compensation for supply interruption for customers” and the mechanism of incentives and penalties for the DSOs for their supply interruptions. These two key factors stand out today and are probably the most relevant to the EMRC context:

1) The Italian KPIs were started as soon as the process of EU liberalisation was underway and this gave Italy a considerable head start on the development of KPI metrics in electricity distribution. One consequent advantage of this early start was the deployment of SCADA systems that are able to actively monitor the metrics. Even France only has a reporting mechanism but not an active monitoring mechanism in place.

The process of consultation to introduce the obligatory metrics from the optional methodology in the Citizen's Charter is the most instructive from the Jordanian perspective and is reproduced below:

Diagram 3: First Regulatory Period Consultation Process
The interesting aspect of this “continuity code” as it was called then was the participation of all DSOs as well as customer representative stakeholders in the decision process. What started as a “continuity code” over a period of consultations that ran in parallel with the distribution system unbundling process within the vertically integrated ENEL is summarised in this graphic below. The key point of learning being that this transformation from a continuity code to a set of actively monitored metrics was a long gradual one that lasted 10 years.

**Diagram 4: Timeline for Incentive Regulation Monitoring**

**Electricity Distribution in Italy:**
The DSO architecture in Italy involves 1 main DSO: erstwhile ENEL serving 85% of the Italian customers (around 36 million customers); 9 local DSOs serving more than 100,000 customers; 29 local DSOs serving between 5,000 and 100,000 customers; 88 local DSOs serving less than 5,000 customers.

**Regulation on continuity of supply**

**Measurement of continuity of supply**
Continuity is measured in each “District”. A District is the aggregation of municipalities of a province with the same concentration degree. This aggregation based on concentration degrees has led to a graduated structure for Italian distribution with municipalities with more than 50,000 inhabitants being classified as “high concentration” (where networks are mainly constituted by underground cables), followed by municipalities with no. of inhabitants 5,000–50,000 (where networks are partly underground and partly aerial) classified as “medium concentration” and then followed by municipalities with less than 5,000 inhabitants.
Standards and automatic compensations for MV customers (number of interruptions)
MV customers receive automatic compensations in case they suffer in one year several long+short unplanned interruptions due to DSO responsibility exceeding the standards set by ARERA, differentiated per concentration degree.

Standards and automatic compensations for LV and MV customers (duration of interruptions)
LV and MV customers receive automatic compensations in case they suffer interruptions longer than the standards set by ARERA, differentiated per concentration degree (DSO pays for interruptions of his responsibility. A special fund – fed by customers and operators – pays for interruptions due to force majeure and external causes).

Information to MV customers

Once a year, each DSO is obliged to provide each MV customer (around 100,000 in Italy) with information regarding each interruption his connection point has been involved in.

Experimental SAIDI awards/penalties regulation for planned interruptions

Non-mandatory, being in force as of 2017.

Data collection

Once a year, for each DSO according to obligations set by ARERA. The above continuity indicators are collected per each district, through the ARERA website, according to standardised procedures.

Data publications

Continuity data are available on the ARERA website on this page [https://arera.it/sas-frontend-cse/estrattoreEnLink](https://arera.it/sas-frontend-cse/estrattoreEnLink) in English. They can be extracted according to many selection criteria.

VOLTAGE QUALITY

As of 2015, each MV busbar of each HV/MV substation has been equipped with instruments able to monitor and record voltage dips, fulfilling EN 50160 and IEC 61000-4-30 international technical standards. Every MV customer must be informed by the DSO once a year about the voltage

(where networks are mainly constituted by aerial cables) classified as “low concentration”. In Italy, there are more than 100 provinces and around 350 districts.

**Interruption registration rules**
The registration rules must be followed by each DSO for any interruption (even according to aggregation rules for interruption events close to each other). They include data relating to beginning / end instant; concentration degree; origin (LV, MV, HV); cause (DSO, third party damages, force majeure); no. of LV customers interrupted; no. of MV customers interrupted; no. of HV customers interrupted. These are consistent with most EU member state codes that specify the interruption definitions which in turn are consistent with internationally applied standards (CIRED).

**Classification of interruptions**
Similarly, the classification of interruptions is in accordance with international standards and is done according to their duration (once applied aggregation rules above mentioned): Long: duration > 3min; Short: duration > 1sec and < 3min; and Transient: < 1sec; unplanned / planned.

**Continuity indicators**
They are measured in each district, per each concentration degree:

- **SAIDI (System Average Interruption Duration Index)** for long interruptions;
- **SAIFI (System Average Interruption Frequency Index)** for long interruptions;
- **MAIFI (Momentary Average Interruption Frequency Index)** for short interruptions;
- **MAIFI** for transient interruptions;
- **SAIFI+MAIFI** for long and short interruptions.
- **SAIDI and SAIFI+MAIFI** awards/penalties regulations (unplanned interruptions)

- For DSOs with more than 25,000 customers, for interruption of DSO responsibility (optionally extended to interruptions due to third party damages) and with origin on MV and LV networks.
- **SAIDI awards/penalties** regulation has been in force since 2000.
- **SAIFI+MAIFI** awards/penalties regulation has been in force since 2008.
dips his connection point has been involved in.

**IMPROVEMENT OF NETWORK RESILIENCE**

In 2015, ARERA launched a multi-year initiative to increase the resilience of distribution grids, intervening on three different aspects: (i) improving network planning to better consider the risk of disruptions due to extremely severe weather events, (ii) introducing new incentive (awards/penalties) schemes aimed at increasing network capacity to cope with this kind of events (e.g., ice sleeves on overhead lines in bare conductors; heat waves that cause breakage of junctions in underground cables; flooding of distribution substations caused by heavy rains or by floods of watercourses; very strong wind) and (iii) promoting faster supply restoration even under emergency conditions, ensuring appropriate customer protection from very long interruptions.

**6.4.4. Malta**

The DSO is required to provide the REWS with information related to the quality of service annually as follows:

- **SAIDI**: average customer minutes lost per connected customers per year (System Average Incidence Duration Index)
- **SAIFI**: average number of customer interruptions (System Average Incidence Frequency Index)

Moreover, the DSO also reports the percentage of customers restored within 1hr, 3hr, 18hr after planned and unplanned interruptions. The latest set of figures which indicate the improvement in operational performance across each of the headline items is provided in the table below sourced from the latest (2019) REWS annual report.

As can be seen performance metrics across each category have substantially improved over time.

**Table 13: Operational Indicators - EneMalta DSO Performance Indicators**

<table>
<thead>
<tr>
<th>Operational Outputs</th>
<th>Unit</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total units sent out</td>
<td>GWh</td>
<td>2,043.12</td>
<td>2,144.46</td>
<td>2,132.99</td>
<td>2,125.94</td>
<td>2,240.16</td>
<td>2,265.76</td>
<td>2,434.50</td>
<td>2,488.28</td>
</tr>
<tr>
<td>to the grid from all</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>sources-local fossil</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>renewables and</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>interconnector</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total units billed</td>
<td>GWh</td>
<td>1,813.08</td>
<td>1,870.82</td>
<td>1,854.48</td>
<td>1,894.31</td>
<td>2,069.20</td>
<td>2,150.63</td>
<td>2,295.17</td>
<td>2,368.42</td>
</tr>
<tr>
<td>Total no of active</td>
<td>No.</td>
<td>274,172</td>
<td>279,352</td>
<td>285,615</td>
<td>292,604</td>
<td>293,561</td>
<td>295,911</td>
<td>305,523</td>
<td>316,870</td>
</tr>
</tbody>
</table>
### Performance indicators

<table>
<thead>
<tr>
<th>Operational Efficiency</th>
<th>Unit</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total units technical and non-technical losses in distribution as a percentage of sent out</td>
<td>%</td>
<td>11.26%</td>
<td>12.76%</td>
<td>13.06%</td>
<td>10.90%</td>
<td>7.63%</td>
<td>5.08%</td>
<td>5.72%</td>
<td>4.46%</td>
</tr>
<tr>
<td>Percentage of non-technical losses in distribution as a percentage of units sent out to the grid</td>
<td>%</td>
<td>6.96%</td>
<td>8.46%</td>
<td>8.76%</td>
<td>6.60%</td>
<td>3.33%</td>
<td>0.78%</td>
<td>0.95%</td>
<td>1.12%</td>
</tr>
<tr>
<td>Percentage of technical losses in distribution as a percentage of units</td>
<td>%</td>
<td>4.30%</td>
<td>4.30%</td>
<td>4.30%</td>
<td>4.30%</td>
<td>4.30%</td>
<td>3.35%</td>
<td>3.34%</td>
<td></td>
</tr>
</tbody>
</table>

### Service Quality Outputs

<table>
<thead>
<tr>
<th>Total number of interruptions</th>
<th>no.</th>
<th>960</th>
<th>1,442</th>
<th>1,047</th>
<th>1,082</th>
<th>1,018</th>
<th>1,052</th>
<th>1,050</th>
<th>917</th>
</tr>
</thead>
<tbody>
<tr>
<td>% Customer interruptions restored in 1 hour</td>
<td>%</td>
<td>48.28</td>
<td>61.2</td>
<td>55.21</td>
<td>47.29</td>
<td>54.97</td>
<td>67.75</td>
<td>55.95</td>
<td>82.84%</td>
</tr>
<tr>
<td>% Customer interruptions restored in 3 hour</td>
<td>%</td>
<td>92.82</td>
<td>93.55</td>
<td>83.06</td>
<td>81.51</td>
<td>93.32</td>
<td>93.19</td>
<td>85.52</td>
<td>94.91%</td>
</tr>
<tr>
<td>Average customer minutes lost per connected customers per year</td>
<td>minutes</td>
<td>259.74</td>
<td>366.72</td>
<td>418.8</td>
<td>640.2</td>
<td>228</td>
<td>163.8</td>
<td>482.73</td>
<td>110.53</td>
</tr>
</tbody>
</table>

* Provisional data
The performance

No standards of performance are applicable and the DSO in the customer charter expresses the effort not to affect customers by not more than 5 planned interruptions per year per customer and to restore supply after an unplanned interruption within 24hrs. As can be seen from the data in the graphic above, planned and unplanned interruption resumption of service has improved substantially.

Since Malta now receives a significant proportion of electricity across the subsea interconnector from Italy that is managed by Terna, this has also played a part in the improvement seen in the interruption metrics thought it has to be said that the accidental shearing of the cable in December 2019 clearly took much longer than any prescribed metrics could have covered.

As regards the SAIDI/SAIFI metrics are concerned, the graphic below again substantiates the point about the significant improvement evident in Malta on the reliability metrics.

*Figure 1: SAIDI and SAIFI correlation from 2013 to 2019*
CONCLUSIONS
This chapter considers the specific examples from the four case studies that EMRC could implement. The four countries are each at a different point in their regulatory evolution and no one single country presents a situation exactly similar to the Jordanian electricity distribution context.

While Italy and France represent completely unbundled distribution and supply value chains and differing regulatory tariff and access regimes, they both offer an insight into how individual best practice elements of the four themes could be deployed in Jordan. While Italy has demonstrated its best practice in early implementation of network reliability, KPIs and their successful incorporation – following detailed consultations – in tariff incentive mechanisms, what France has been able to offer is the smart use of electricity distribution-related IT system infrastructure to develop best in class customer information processing that flows all the way into its network capital investment program and, the use of shared data links without compromising on the EU data disclosure related regulations is worth emulating. In particular, the deployment of mobile phone-based applications that enable easier and more convenient access to customer data centers and well-designed protocols for the most common customer queries stand out for their effectiveness. These are targeted and specific initiatives that EMRC could consider for implementation.

The other two case studies, Egypt and Malta, stand out in their verisimilitude to the Jordanian electricity distribution context. Both Egypt and Malta represent a model of bundled (in addition to deeply vertically integrated electricity systems) distribution and supply.

Malta DSO situation is unique as most Malta TSO functions are performed on its behalf by the Italian TSO-Terna and as such Malta is a DSO only model with a high degree or reliance on the interconnection with neighbouring Italy. Malta stands out on two fronts: the outsourcing of all utility customer service-related functions to a jointly owned subsidiary – ARMS Ltd. which is a business model worth studying and possibly adapting in the Jordanian context. The rationale behind this is that in Jordan, the three distribution areas are distinct geographic areas with the DSO in each area performing almost identical customer-related service operations but each of them possibly lacks the economies of scale. The EU experience for customer-related services offered through dedicated centres require a minimum efficient scale of operations that a low network load density system like the Jordanian system is unlikely to offer. These economies of scale though may be available if a jointly owned consolidated utility service company operating under a tightly defined monitored performance service contract can be developed. The Malta experience suggests that this approach can be very successful.

The other very encouraging insight that Malta offers is how network reliability performance indicators (SAIDI/SAIFI) once defined can help drive improvements in network performance. The rate of improvement in evidence from 2014-2018 in Malta is worth emulating.

In the case of Egypt, while the size and scale of the network are very different to Jordan, there are important aspects where the issues that Egypt has had to face in its electricity networks which are quite similar. The urban / rural network divide in Egypt is similar to Jordan as is the fact that both Egypt and Jordan face three other similar issues: 1) both countries have growing electricity demand and both countries are end user tariff sensitive to the extent that both countries have faced widespread consumer protests over
end user pricing 2) both countries are staring into a huge growth in MV/LV level connected distributed RE capacities leading to a growing pressure on their “new connections” business but also both countries have problems associated with squatter areas or growing refugee sites which need to be served safely and effectively. The Egyptian experience of electricity network undergrounding in squatter areas appears to have paid off in terms of not only safety but also in network reliability parameters according to the Egyptian Ministry’s latest annual report. The 3) area of similarity between Egypt and Jordan is the decision related to the roll out of smart meters. The key difference is that the Egypt smart meter roll out is integrated with its billing and metering business system thus enabling the possibility of having mobile app-based customer resolution systems deployed. The latest Egyptian Energy Ministry Annual report suggests that pilots for the deployment of app-based solutions are already taking shape / underway.

The EMRC thus has an opportunity to pick and choose from a menu of options for the key initiatives it might consider for implementation. Some of these are articulated above. This report has considered four themes across four countries thus offering a choice of 16 different country / theme combinations and the detailed summaries articulated in this report This is a rich set of options for EMRC to choose from in its quest for improving its quality of customer services.
ANNEX 1

EMRC OVERALL PERFORMANCE INDICATORS FOR ELECTRICITY
For the measurement of the licensee’s average supply quality, the following overall performance indicators are used and calculated for scheduled, unscheduled, external and third-party interruptions except MAIFI. The detailed description and mathematical formulas of each of them are specified according to the category of interruption:

- The average frequency of interruptions per nominal installed kVA (AFIK) index which is the number of times that the average installed capacity per kVA had an interruption during a pre-specified period.

**Table A1: Average frequency of interruptions per nominal installed kVA (AFIK) index**

<table>
<thead>
<tr>
<th>Index</th>
<th>Definition</th>
<th>Formula</th>
<th>Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>AFIKs</td>
<td>The average frequency of scheduled interruptions per nominal installed kVA of the MV network</td>
<td>$AFIK_s = \frac{\sum IC_i}{\sum IC}$</td>
<td>$\sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA)}.$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$IC_i = \text{Installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers affected by scheduled interruptions (i) (kVA)}.$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$ks = \text{Total number of scheduled interruptions during the reporting period.}$</td>
</tr>
<tr>
<td>AFIKu</td>
<td>Average frequency of unscheduled interruptions per nominal installed kVA of the MV network</td>
<td>$AFIK_u = \frac{\sum IC_i}{\sum IC_r}$</td>
<td>$\sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA)}.$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$IC_i = \text{Installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers affected by unscheduled interruptions (i) (kVA)}.$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$ku = \text{Total number of unscheduled interruptions during the report period, excluding temporary and external interruptions.}$</td>
</tr>
</tbody>
</table>
Table A2: Total time of interruption per nominal installed kVA (TTIK) index

<table>
<thead>
<tr>
<th>Index</th>
<th>Definition</th>
<th>Formula</th>
<th>Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>TTIKs</td>
<td>Average time of scheduled interruptions per nominal kVA in the MV network</td>
<td>$TTIK_s = \frac{\sum (IC_i \cdot H_i)}{\sum IC}$</td>
<td>$\sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$IC_i = \text{Installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV Consumers affected by scheduled interruptions (i) (kVA).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$H_i = \text{Duration of scheduled interruption (i) which affected the installed capacity (in hours).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$ks = \text{Total number of scheduled interruptions during the report period.}$</td>
</tr>
</tbody>
</table>

The average frequency of interruptions per nominal installed kVA (AFIK) index

- Total time of interruption per nominal installed kVA (TTIK) index which is the total time which the average installed capacity per kVA had an interruption during a pre-specified period.

Table A2: Total time of interruption per nominal installed kVA (TTIK) index

<table>
<thead>
<tr>
<th>Index</th>
<th>Definition</th>
<th>Formula</th>
<th>Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>TTIKu</td>
<td>The average frequency of external interruptions per nominal installed kVA of the MV network</td>
<td>$AFIK_u = \frac{\sum ke IC_i}{\sum IC}$</td>
<td>$\sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$IC_i = \text{Installed capacity in MV/LV transformers of the Licensee, in addition to the energy contracted with MV consumers affected by External Interruptions (i) (kVA).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$ke = \text{Total number of external interruptions during the report period.}$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Index</th>
<th>Definition</th>
<th>Formula</th>
<th>Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>TTIKs</td>
<td>Average time of scheduled interruptions per nominal kVA in the MV network</td>
<td>$TTIK_s = \frac{\sum (IC_i \cdot H_i)}{\sum IC}$</td>
<td>$\sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$IC_i = \text{Installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV Consumers affected by scheduled interruptions (i) (kVA).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$H_i = \text{Duration of scheduled interruption (i) which affected the installed capacity (in hours).}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$ks = \text{Total number of scheduled interruptions during the report period.}$</td>
</tr>
</tbody>
</table>

The average frequency of interruptions per nominal installed kVA (AFIK) index

- Total time of interruption per nominal installed kVA (TTIK) index which is the total time which the average installed capacity per kVA had an interruption during a pre-specified period.
<table>
<thead>
<tr>
<th><strong>TTIKu</strong></th>
<th>Average time of unscheduled interruptions per nominal kVA in the MV network</th>
<th>[ TTIK_u = \frac{\sum_{i=1}^{k_u} (IC_i \cdot H_i)}{\sum IC} ]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TTIKe</strong></td>
<td>Average time of external interruptions per nominal kVA in the MV network</td>
<td>[ TTIK_e = \frac{\sum_{i=1}^{k_e} (IC_i \cdot H_i)}{\sum IC} ]</td>
</tr>
<tr>
<td><strong>TTIKtp</strong></td>
<td>Average time of third party interruptions per nominal kVA in the MV network</td>
<td>[ TTIK_{tp} = \frac{\sum_{i=1}^{k_{tp}} (IC_i \cdot H_i)}{\sum IC} ]</td>
</tr>
</tbody>
</table>

\[ \sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA).} \]

\[ IC_i = \text{Installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers affected by Unscheduled Interruptions (i) (kVA).} \]

\[ H_i = \text{Duration of unscheduled interruption (i) which affected the installed capacity (in hours).} \]

\[ k_u = \text{Total number of unscheduled interruptions during the report period, excluding temporary and external interruptions.} \]

\[ \sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA).} \]

\[ IC_i = \text{Installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers affected by external interruptions (i) (kVA).} \]

\[ H_i = \text{Duration of external interruption (i) which affected the installed capacity (in hours).} \]

\[ k_e = \text{Total number of external interruptions during the report period.} \]

\[ \sum IC = \text{Total installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers (kVA).} \]

\[ IC_i = \text{Installed capacity in MV/LV transformers of the licensee, in addition to the energy contracted with MV consumers affected by third-party interruptions (i) (kVA).} \]

\[ H_i = \text{Duration of external interruption (i) which affected the installed capacity (in hours).} \]

\[ k_{tp} = \text{Total number of third-party interruptions during the report period.} \]
• SAIFI: System Average Interruption Frequency Index (interruption / subscriber) which measures the number of interruptions affecting each subscriber in a specific area during a pre-specified period. It is given by (total number of subscribers affected by the interruption / total number of subscribers).

Table A3: SAIFI – System Average Interruption Frequency Index

<table>
<thead>
<tr>
<th>Index</th>
<th>Definition</th>
<th>Formula</th>
<th>Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIFIₘ</td>
<td>Average scheduled interruption frequency</td>
<td>$SAIFI_s = \frac{\sum_{i=1}^{ks} (NC_i)}{TNC}$</td>
<td>NCᵢ = Number of consumers affected by scheduled interruption (ᵢ). TNC = Total number of licensee’s consumers ks = Total number of scheduled interruptions during a calendar year.</td>
</tr>
<tr>
<td>SAIFIᵤ</td>
<td>Average unscheduled interruption frequency</td>
<td>$SAIFI_u = \frac{\sum_{i=1}^{ku} (NC_i)}{TNC}$</td>
<td>NCᵢ = Number of consumers affected by unscheduled interruption (ᵢ). TNC = Total number of licensee’s consumers ku = Total number of unscheduled interruptions during a calendar year, excluding temporary and external interruptions.</td>
</tr>
<tr>
<td>SAIFIₑ</td>
<td>Average external interruption frequency</td>
<td>$SAIFI_e = \frac{\sum_{i=1}^{ke} (NC_i)}{TNC}$</td>
<td>NCᵢ = Number of consumers affected by external interruption (ᵢ). TNC = Total number of licensee’s consumers ke = Total number of external interruptions during a calendar year.</td>
</tr>
<tr>
<td>SAIFIₜₚ</td>
<td>Average third-party interruption frequency</td>
<td>$SAIFI_{tp} = \frac{\sum_{i=1}^{ktp} (NC_i)}{TNC}$</td>
<td>NCᵢ = Number of consumers affected by third-party interruption (ᵢ) for a period of time (Hi). TNC = Total number of licensee’s consumers ktp = Total number of third-party interruptions during a calendar year.</td>
</tr>
</tbody>
</table>
- Expected Energy Not Supplied (EENS): effective energy (KWH) that was not supplied to consumers due to interruptions during a pre-specified period.

### Table A4: EENS - Expected Energy Not Supplied

<table>
<thead>
<tr>
<th>Index</th>
<th>Definition</th>
<th>Formula</th>
<th>Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>EENSs</td>
<td>Expected Energy Not Supplied due to scheduled</td>
<td>$EENS_s = \sum_{i=1}^{ks} (EPD_i \cdot H_i)$</td>
<td>EPDi = Expected Energy Disconnected due to a scheduled interruption KW (i), taking into consideration: Information provided by SCADA systems. Number of disconnected consumers. Time of Interruption. Yearly energy of disconnected feeder, $Hi = Duration$ of scheduled interruption ($i$) which affected Installed Capacity ($IC_i$) [hours]. $Ks = Number$ of scheduled interruptions during a calendar year.</td>
</tr>
<tr>
<td></td>
<td>interruptions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EENSu</td>
<td>Expected Energy Not Supplied due to unscheduled</td>
<td>$EENS_u = \sum_{i=1}^{ku} (EPD_i \cdot H_i)$</td>
<td>EPDi = Expected Energy Disconnected due to an Unscheduled Interruption KW (i), taking into consideration: Information provided by SCADA systems. Number of disconnected consumers. Time of interruption. Yearly energy of disconnected feeder, $Hi = Duration$ of unscheduled interruption ($i$) which affected Installed Capacity ($IC_i$) [hours]. $Ku = Total$ number of Unscheduled Interruptions during a calendar year.</td>
</tr>
<tr>
<td></td>
<td>interruptions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EENS e</td>
<td>Expected Energy Not Supplied due to external</td>
<td>$EENS_e = \sum_{i=1}^{ke} (EPD_i \cdot H_i)$</td>
<td>EPDi = Expected Energy Disconnected due to an external interruption KW (i), taking into consideration: Information provided by SCADA systems. Number of disconnected consumers. Time of interruption. Yearly energy of disconnected feeder, $Hi = Duration$ of External Interruption ($i$) which affected Installed Capacity ($IC_i$) [hours]. $Ke = Total$ number of external interruptions during a calendar year.</td>
</tr>
<tr>
<td></td>
<td>interruptions</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
EMRC OVERALL PERFORMANCE
INDICATORS FOR ELECTRICITY INTERRUPTION

**EEMS: Expected Energy Not Supplied**
- **EEMS\(_{\text{sp}}\):** Expected Energy Not Supplied due to Third party interruptions
  
  \[
  EEMS_{\text{sp}} = \sum_{i=1}^{k_{\text{tp}}} (EPD_i \cdot H_i)
  \]
  
  EPD\(_i\) = Expected Energy Disconnected due to a Third-Party Interruption KW \((i)\), taking into consideration:
  - Information provided by SCADA systems.
  - Number of disconnected consumers.
  - Time of interruption.
  - Yearly energy of disconnected feeder,
  - Hi = Duration of Third-Party Interruption \((i)\) which affected Installed Capacity (IC\(_i\)) [hours].
  - k\(_{\text{tp}}\) = Total number of Third Party Interruptions during a calendar year.

**EEMS - Expected Energy Not Supplied**

- **System Momentary Average Interruption Frequency Index (MAIFI):** the number of times the consumer experiences momentary interruptions during a pre-specified period.

*Table A5: System Momentary Average Interruption Frequency Index*

<table>
<thead>
<tr>
<th>Index</th>
<th>Definition</th>
<th>Formula</th>
<th>Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>MAIFI(_{\text{to}})</td>
<td>Momentary average interruption frequency</td>
<td>NCI = Number of consumers affected by momentary interruption.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>TNC = Total number of licensee's consumers</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Kto = Total number of momentary interruptions during a calendar year.</td>
<td></td>
</tr>
<tr>
<td>MAIFI(_{\text{to}})</td>
<td>Average Time of momentary interruption per consumer</td>
<td>NCI = Number of consumers affected by momentary interruption.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>TNC = Total number of licensee's consumers</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Kto = Total number of momentary interruptions during a calendar year.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Hi = Duration of momentary interruption</td>
<td></td>
</tr>
</tbody>
</table>

Overall performance indicators are calculated by the licensee on a monthly and yearly basis. In the case of yearly calculation, the pre-specified period is a calendar year. In monthly calculation, the pre-specified period is from the beginning of the calendar year until the month in which the overall index is calculated.
Peer review for the Jordanian regulator EMRC: Improving the quality of consumer services

INTRODUCTION