Technical Report:

RERA's Capacity Building Program for Regional Regulators

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Please see each individual module for a list of relevant definitions and acronyms.

6. PROJECT OVERVIEW

6.1. Introduction

Southern Africa Trade Hub (the Trade Hub) is working with governments and regional institutions, such as the Regional Electricity Regulators Association of Southern Africa (RERA), to strengthen capacity for regulating the clean energy sector in the region. Developing a transparent, robust and predictable clean energy regulatory regime in the region is critical to attracting Independent Power Producer (IPP) investment to the sector. An increase in IPP clean electricity generation capacity will contribute to improved security of supply, climate change mitigation, economic growth, trade competitiveness, poverty reduction and food security within the region.

The majority of RERA's member agencies in the region, including their board members and commissioners typically have inadequate experience in energy regulation in general, and, particularly, with emerging renewable energy regulation issues. Additionally, regulatory board members and commissioners are changed regularly, new sector regulators are being established continually, and newly established regulators are expanding to deliver on their mandates. Proper capacitation of the regulatory boards, commissioners, and other technical staff is crucial for efficient, effective and consistent formulation of energy policy direction, regulation, and management that are all in line with international best practice.

Regulatory agencies play a pivotal role on multiple fronts, including protecting consumers, ensuring the viability and sustainability of utilities and promoting investment, while guiding policy and facilitating the development of the energy sector. This task is becoming all the more complex with the evolution of new market structures, growth in renewable and distributed generation technologies, increased private sector participation, market competition and the continued focus on climate change mitigation. These complexities are often further compounded by prevailing political and socio-economic objectives including rural electrification, affordability and poverty alleviation.

Given this challenge, regulators must have access to the tools and resources essential for delivering on their mandates. Such tools and resources comprise policy, laws, financial resources and high quality staff.

The importance of proper focused training should thus not be underestimated. Inadequate skills and insufficient regulatory capacity introduce regulatory risk or can even result in regulatory failure, both of which either lead to increased cost of doing business or to depressed sector growth and poor investment levels.

6.2. Project Objective

The overall goal of this project is to establish a regional platform for sustainable long-term capacity building for RERA's regulatory agencies, including board members, commissioners, and other technical staff.

The Trade Hub is collaborating with RERA and its member regulatory agencies to help RERA institutionalize a capacity building program for RERA members through developing a "train the trainers" program.

The program aims to improve on RERA's past approach to training, make training courses more predictable (announced in advance) for better planning by the members, and make a stable pool of experts accessible to RERA and member regulators as needed for regional and in-country regulatory training. In addition, the design of the program will be based on sustainability principles, including clear knowledge and skills transfer and reusable reference source material.

6.3. Project Structure

Taking account of the importance, scale and scope of the project, the overall program has been designed to be implemented over four phases as set out briefly below.

6.3.1. Phase 1: Needs assessment:

Status: Completed

Assist RERA in conducting updated training needs assessment among member regulators.

6.3.2. Phase 2: Development of Curriculum

Status : Current Scope of Work

Develop a training curriculum based on outcomes of the Phase 1 Needs Assessment

6.3.3. Phase 3: Development Training Modules and Mechanism for training

Status: Selected modules are completed by the Trade Hub, some remaining modules to be completed by RERA.

6.3.4. Phase 4: Piloting and Training the Trainers

Status: To be completed

6.4. Scope of Work – Phase 2: Development of Curriculum

This report deals with the scope of work associated with Phase 2 identified above, in accordance with the Trade Hub's Work Plan FY2015 and building on the findings of the Phase 1 training needs assessment.

The tasks associated with the Phase 2 scope of work are being implemented by two individual consultants, namely Mr. Marc Goldstein and Prof. Jorry Mwenechanya (the Consultants), under the management of the Trade Hub's Clean Energy Team Leader.

The three tasks implemented under the Phase 2 of assistance are summarized below.

6.4.1. Task 1: Develop Training Course Curriculum

The Consultant will develop an outline and set of guidelines for the course curriculum. These guidelines will set out the aspects that should be taken into consideration when developing the training material for each of the course modules within the curriculum. The curriculum will be broken down into modules within each major section. The modules will comprise various topics and areas of study. The Main Modules will be designed to build increasing level of skills required to deal with the Core, Traditional and Evolving regulatory requirements as identified in the Phase 1 Needs Assessment. These components are discussed in more detail below.

6.4.2. Task 2: Attend Meeting(s)

The Consultants will attend meetings, as necessary, to discuss and present the curriculum to the relevant stakeholders

6.4.3. Task 3: Finalize Curriculum.

The Consultants will amend and finalize the curriculum based on the feedback and comments received from the stakeholder meetings.

7. NEEDS ASSESSMENT SUMMARY OUTCOMES

7.1. Assessment Overview

In November 2014, the Final Report of the “Regulatory Capacity Development & Training Survey” or needs assessment was released. The report noted the following Objective –

“Specifically, this survey is the cornerstone of a needs assessment, which is ultimately geared towards working with governments and regional institutions, such as RERA, in order to strengthen capacity for regulating the clean energy sector in the region.

Developing a transparent, robust and predictable clean energy regulatory regime in the region is critical to attracting Independent Power Producers (IPP) investment in the sector. An increase in IPP clean electricity generation will contribute to security of supply, climate change mitigation, economic growth, trade competitiveness, poverty reduction and food security in the region.

There is significant global change in the skills requirements of energy regulators as markets evolve and renewable energy becomes ubiquitous. Additionally, the Commissioners change frequently, new regulators are being established, and newly established regulators are expanding. The capacity of the Boards, Commissioners, and other technical and support staff of the regulatory agencies to apply best practices are crucial for efficient and consistent formulation of energy policy direction, regulation, and management.

In addition, the accelerated evolution and development of renewable energy markets, distributed generation, increased demand-side participation and smart grids, amongst other factors, also serve raise the importance of training, skills development, capacity building and information sharing as a continuous activity for RERA members.”

The survey assessed the regulator’s skills across several topics including policy, economic, technical, legal, consumer, oversight/compliance and general management.

The survey questionnaire was structured to provide an assessment of the ***traditional skills*** and needs of an energy regulator, the ***evolving needs*** due to emerging issues and changes in market structure and technology as well as areas representing regulatory ***core competencies***.

7.2. Assessment Recommendations

Two immediate recommendations that emerged from the assessment relate to (i) inadequate staffing and (ii) the need to embed that training program by training regulatory members to become facilitators of training courses.

The assessment also made immediate recommendations regarding the prioritization of training modules to be developed. These included the following:

7.2.1. Traditional Regulation

1. Managing trade-offs between competing policies
2. Creating, managing and monitoring of subsidy instruments
3. Managing governance and consumer related issues such as complaints

7.2.2. Evolving Regulation

1. Evolving Policy: Private vs. Public Sector, Energy Efficiency, Carbon

2. Renewable Energy: Technologies, Pricing/ Costs, Market Implications, Intermittency
3. Embedded Generation: Pricing, Safety, Wheeling, Revenue Impact, Quality and Security of Supply
4. Innovation: Smart Grids & Meters, Storage, New Technologies
5. Evolving Market Structures: Trading & Procurement, Network Pricing, PPAs, 3rd Party access, Losses, Long Term Pricing, Ring Fencing, Regional Harmonization

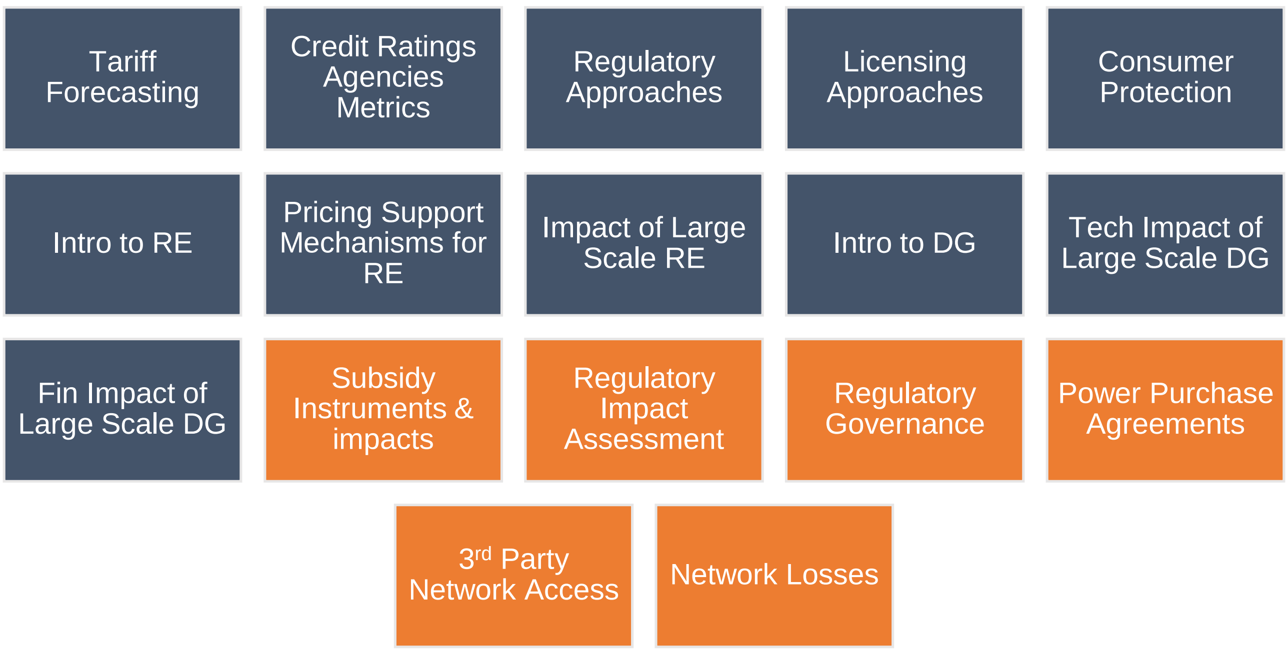
7.2.3. Core Competencies

1. Interconnected Operations (Technical)
2. Scheduling & Dispatch (Technical)
3. Long Term Price Modelling (Technical)
4. Rating Agencies Metrics & Rations (Economic & Financial)
5. Subsidy Instruments (Economic & Financial)
6. Impact of Regulatory Decisions (Economic & Financial)
7. Procurement (General Business)
8. Stakeholder Management (General Business)
9. Advisory Services (General Business)

7.3. **Modules Covered in this Report**

Due to budget and timing constraints, it was not possible to develop the curricula for all of the topics identified above. By virtue of the nature of the electricity sector, many of the identified areas are overlapping and connected, therefore some of the developed modules have been integrated. Furthermore, six training modules were developed immediately i.e. without the initial development of the curriculum prior to the development of the training module.

Figure 1: Training Curriculum covered in this report



The curricula covered in this report, are depicted in the figure above – the blue blocks represent the each curriculum topic and the orange blocks represent those topics which have already been converted directly into training modules.

This report therefore covers a subset of the full set of recommendations, which have also been categorized by their level of complexity. The differences in subject matter will require an increasing level of economic, technical or financial competence from Trainees, as one progresses from “Basic” through “Moderate” to “Advanced”. These are:

Table 1: Modules Covered in this Report

Module	Level of Complexity	Comment
Regulatory Approaches for the Electricity Sector	Basic	Mainly theory and structure of regulation. No specific technical, economic or financial skills required
Licensing Approaches for the Electricity Sector	Moderate/ Advanced	A good understanding is required of the structure and alignment between regulation & legislation. Some technical understanding of key issues that relate to power plants and the grid.
Tariff Regulation & Forecasting	Moderate/ Advanced	Ability to grasp key financial concepts that relate to managing viability of electricity sector.
Credit Ratings Agencies Metrics for Utility Management	Moderate/ Advanced	A solid understanding of finance and utility economics is required
Consumer Protection in the Electricity Sector	Basic	An introduction to protection of consumers in the electricity sector
Introduction to Renewable Energy Technologies	Basic	A basic overview of RE technologies
Support Mechanisms for Renewable Energy	Basic	An introduction to programs and incentives used to support the implementation of RE
Implication of High Levels of Renewable Energy Penetration in Electricity Systems	Moderate	A moderate understanding of the impact of intermittent plant on the grid and associated consequences
Introduction to Distributed Generation	Basic	An introduction to DG and types of DG systems

Technical Implications of High Levels of Distributed Generation Penetration	Moderate/ Advanced	Although there are significant technical implications of high levels of DG, this module has been written for an audience with a moderate to advanced understanding of key technical concepts with regard to DG and systems operations
Financial Implications of High Levels of Distributed Generation Penetration	Moderate/ Advanced	Proposes a number of options for calculating the benefits and consequences of DG on Systems Operations which requires moderate to advanced understanding of technical, financial and modelling of issues.

8. COURSE STRUCTURE

The Needs Assessment and subsequent curriculum development (1st orange circle below in Figure 2: RERA training system) is a small part of the RERA training system as envisaged below.

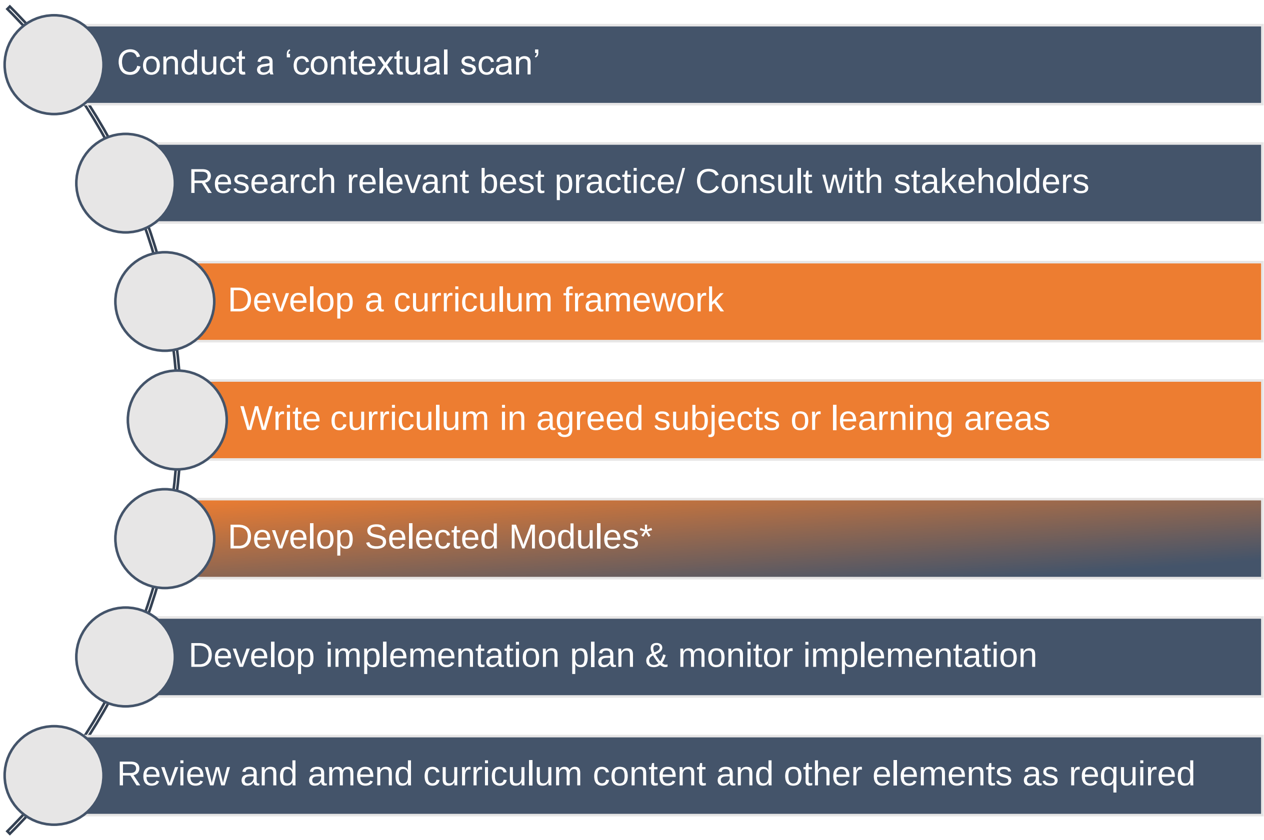
Figure 2: RERA training system

There are a number of other requirements that need to be met in order to finalize the development of the training courses and then implement them. The process in the diagram above, shows the next steps following on from the curriculum and module development including: identifying useful training materials, appointing and "training the trainer", selecting training venues and keeping the material relevant.

8.1. Module Design Process

Each module follows a similar design process along the following discrete steps:

Figure 3: Module Development Steps



RERA is currently focusing on steps 3 & 4 (in orange above) with the support of USAID. Once all of the modules have been developed, RERA can refocus on the requirements to ensure successful implementation of the training courses.

Six selected modules have already been developed and an outline of their contents is presented in the final chapter of this report (Chapter 21, page 136). Each full module is available in MS PowerPoint format from RERA.

8.2. Core Competencies Required by Trainers & Attendees

These curricula have been written as a basis for the development of training modules – as such they provide a good indication of the skills required by both Trainer and Course Attendees, in order to fully appreciate the subject matter.

The categorization of the courses in Table 1 provides a clear reference for the level of skills required. In general, both trainers and attendees for these courses should have the following skills and experience in order to fully comprehend and benefit from these modules.

1. Comprehensive knowledge of MS Excel or similar spreadsheet tools for technical staff who wish to develop models

2. Functional/working knowledge of MS Excel or similar spreadsheet tools for board members and commissioners
3. Comprehensive understanding of power systems and power plant economics (tertiary education level)
4. Comprehensive accounting and financial skills (tertiary education level)
5. Moderate understanding of electricity market structures
6. Moderate understanding of supply & demand in electricity markets

8.2.1. Language Skills

The course material will be prepared primarily in English and all key definitions and concepts will be explained in the English language. Attendees are therefore expected to be fluent in written and spoken English in order to follow the material and participate in discussion.

It is recognized that several RERA members have alternative first languages and it is recommended that once the curricula are developed, that they are translated into other relevant languages.

8.3. Training Materials to be used

These modules should be delivered using MS PowerPoint or a similar product. References can be made to Excel based models where appropriate in order to demonstrate specific modelling techniques.

9. HOW TO USE THIS REPORT

This report is intended for the use of training module developers as well as the module trainers themselves. Each curriculum covered in this report follows the same basic structure as depicted in the figure below.

The first three sections (Introduction, Purpose & Overview, Key Definitions & Concepts) together, will provide guidance on the content that should be covered in the course as well as providing a rationale and context for the material. They should also provide insight as to what within the material is specifically relevant to Regulators.

The Module Structure section provides a proposed structure for the training module itself in order to ensure that the material is logically presented. It is acknowledged that each trainer and/or module developer may adjust this based on their own experiences and understanding of key issues. Module materials should be developed in MS PowerPoint for delivery to course attendees.

Finally, the last two sections are focused on module attendees as well as trainers. The recommended reading list provides guidance on helpful and interesting research already completed in the subject area. This will give attendees a starting point in order to ensure they gain the most from each course attended. It is also possible that professional trainers may be contracted, who have a background in the power sector, but without current expertise in the module being presented. In that case, the reading list will provide a useful starting point from which they can immerse themselves.

Figure 4: Curriculum Structure and contents

Module Introduction	• Intro to the topic • Context for the Attendee • Rationale
Module Purpose & Overview	• Why is this important for the regulator • What will they learn • What is included in the curriculum
Key Definitions & Concepts	• This section must provide anyone developing the final modules and/or the trainer with an excellent understanding of the key issues and touch points, methodologies, technical approaches, modelling requirements etc. to be discussed with anyone being trained.
Recommended Reading	• There are many relevant papers on each of these subjects. • This section should list each of these and briefly summarise the key concepts, ideas, methodologies etc. that are contained therein.
Outcomes	• In order to ensure that course attendees understand and have assimilated the training, this section will propose some questions and discussion points that can be used by the trainer to embed the concepts once the module is finished being presented.
Module Structure	• An outline of how the module should be structured in MS PowerPoint when it is developed. • This will ensure that all of the key concepts previously discussed are included, presented accurately and linked together in a logical manner

Typically, within the Key Definitions & Concepts section, there is first a table listing some key definitions for that specific curriculum. Thereafter, the key concepts are summarized in a blue text box (see below), with notes below the box (where appropriate) to expand on the key concept presented. The size of the boxes and notes vary depending on the complexity of the topic and the number of issues that are relevant.

Example Text Box:

> This is an example text box used throughout the document to present Key Concepts that will need to be incorporated into the training modules. The Key Concepts also provide a good outline for the module structure presented in each curriculum.

10. REGULATORY APPROACHES FOR THE ELECTRICITY SECTOR

10.1. Module Introduction

This module deals with a fundamental principle of power sector structures - namely the concept of and approach to regulation of the sector.

It is well accepted that there is no perfect regulatory system and many would argue that regulation is a poor substitute for perfect competition, but it has been nominated as the best alternative. Perfect competition does not exist in practice, particularly not in the electricity supply sector, which is characterized by natural monopoly elements which do not lend themselves to competition. Regulation is thus necessary to protect consumer interests and reduce investment risk for market participants. Regulation also needs to address safety, and environmental concerns.

Regulation and regulatory approaches are not static and must, firstly, be tailored to suit each individual regulatory jurisdiction or country and, secondly, must be adjusted over time to keep abreast of power market developments and evolving technologies. Regulation must therefore be subject to continuous improvement and adjustments.

Regulatory boards, commissioners and internal technical staff need to have a reasonable appreciation of these objectives, to serve as a robust foundation for carrying out their regulatory mandates.

10.2. Module Purpose

The purpose of the module is to address the various issues highlighted above, including aspects around:

- The need for regulation
- What can/should be regulated
- Who can/should regulate
- Regulatory principles
- The institutional framework and hierarchy of regulatory instruments
- Different regulatory approaches or models that may be applied.

10.3. Key Definitions & Concepts

10.3.1. Key Definitions

Table 2: Definitions - Regulatory Approaches

Vertical integration	Arrangement in which the value chain (or supply chain) of a company/utility is owned by that company (e.g. generation, transmission, distribution)
Horizontal integration	Where a company/utility creates or acquires production or supply capability for outputs which are alike - either complementary or competitive (e.g. ownership of multiple generation plants)
Ex-ante regulation	“Before the fact” or forward looking regulation to prescribe or induce market behavior in markets/sectors that do not have sufficient competition, typically applied by sector-specific regulators (e.g. electricity, telecoms).

Ex-post regulation	"After the fact" or backward-looking regulation based on historical evidence of abuse, typically with the imposition of penalties or fines for non-compliance by non, sector-specific regulators (e.g. completion tribunal)
Command and control regulation	Imposition of standards/rules backed up by legal sanctions if the standards are not met
Self-regulation	Typically businesses or a trade associations developing, monitoring and enforcing own rules of performance
Incentive-based regulation	Measures to encourage particular behavior or performance improvements and to limit or stop undesirable activity by granting bonuses and imposing penalties.
Market power	Ability of a company/utility to manipulate price by influencing supply, demand or both (i.e. act alone in driving the price up)

10.3.2. Key Concepts

Why is Regulation Necessary?

This is the introduction to the module and will provide context and an overview of the role of the regulator and drivers for regulation. The training module introduction should expand on the legacy of traditional regulation while discussing some of the challenges faced in regulation including, for example balancing trade-offs between seemingly contradictory objectives and potentially misaligned and divergent policies and legislation.

Examples of these include balancing sector (or utility) financial viability/sustainability with affordability, or limiting price increases for consumers whilst still promoting procurement of renewable energy technologies that may be more expensive than alternative technologies and increase the marginal cost of power.

Electricity sectors have traditionally been considered natural monopolies. For the most part they have evolved with (primarily) vertically integrated geographic entities that were either owned by the government or state, or privately held and subject to regulation of both pricing and market entry.

The fundamental components of the electricity supply value chain (including generation, transmission and distribution), were integrated within individual electric utilities. These utilities in turn had de facto exclusive franchises to supply electricity to large industrial, commercial and residential end-users within defined geographic areas.

In general electricity markets as natural monopolies are regulated to ensure:

1. Cost efficiency (e.g. to simulate the impact of competition);
2. Consumer protection (e.g. to ensure affordability);
3. Social development (e.g. to ensure universal supply);

4. Ensure quality of supply and service (e.g. via technical and service standards)
5. Ensure security of supply (to keep the lights on).
6. Environmental and pollution protection (e.g. to reduce harmful emissions such as CO_2 , SO_2 and prevent water contamination amongst others);

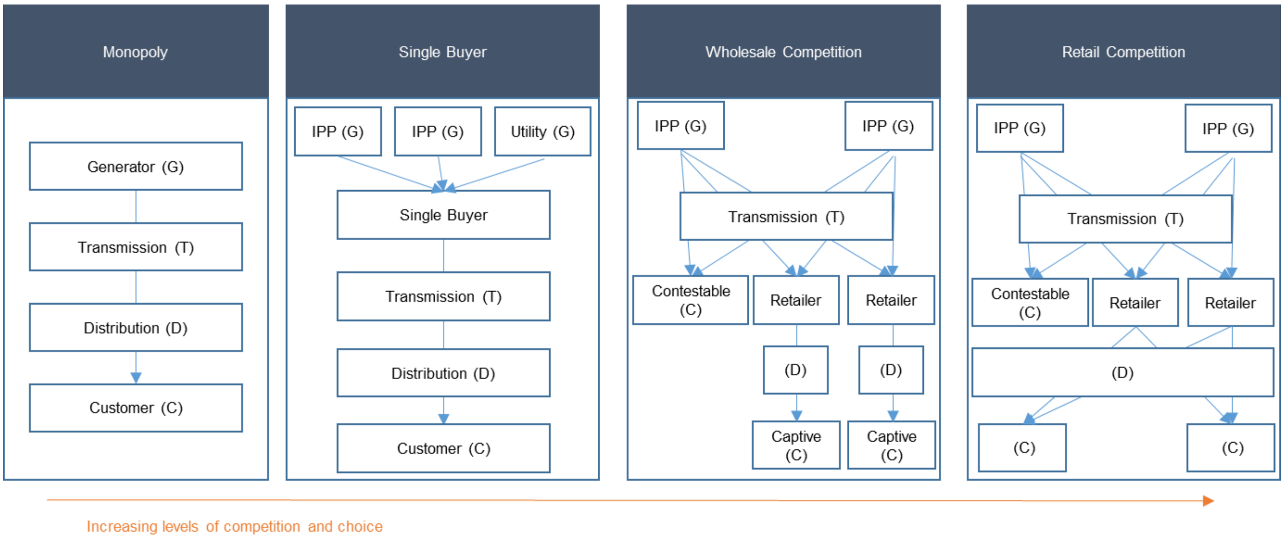
What can be regulated?

This section must describe the different market structures available and highlight the key differences in the role and focus of the Regulator in each instance. There are several differing electricity sector structures in both the developing and developed world. The main variations are in terms of:

- Level of competition
- The degree of integration i.e. vertically or horizontally
- Ownership (number of public or private participants across the levels)
- The overall market structure and the maturity of the market participants
- Types of electricity trading and how customers are defined
- Key issues within technical, financial and economic regulation for different market structures

There are a variety of ownership models for each component including public, private and Public Private Partnerships (PPPs), management concessions and other hybrids. Generation may be undertaken on a monopoly basis or subject to competition. Transmission and distribution, due to the underlying nature of the assets themselves, will normally be provided on a monopoly basis.

Figure 5: Common electricity market models[1]



[1] Reproduced from Hunt, S. and Shuttleworth, G. (1996) Competition and Choice in Electricity, Chichester: Wiley.

In principle, moving from left to right, each of the basic models introduces greater levels of market flexibility relative to the vertically integrated monopoly model that historically characterized electricity supply in most countries. Inevitably, this move to accommodate additional suppliers (IPPs) and distributors or retailers also introduces additional regulatory complexity. This complexity understandably needs to be offset against the anticipated benefits of the desired market model adopted.

Whatever the electricity industry structure and its state of development, the following key electricity supply functions may be regulated:

- Generation
- Transmission
- Distribution

In addition, it is important to highlight that as markets evolve and competition is introduced it may be appropriate to unbundle electricity (energy) supply from the network business. This is particularly important if energy trading is allowed between third parties that require access to the transmission or distribution networks. In this case “wholesale” and “retail” supply” may be regulated separately from the networks.

Depending on market structure and the licensing approach adopted, other regulated functions or activities may include the single/central buyer, market operations and system operations. The extent and nature of regulation is thus intimately linked to the electricity market structure and the module should aim to unpack this link in more detail.

Finally, the scope of regulation may be broken down into a number of other dimensions including, for example,

- Technical aspects (e.g. technical standards)
- Economic regulation dealing with market entry and access (concessions/licensing) and price/tariff regulation
- Consumer protection and compliance (e.g. quality of supply/service standards)

Who Regulates?

The independent or impartial energy regulator is becoming a common model for regulation of the energy sector, particularly where parts of these industries have been transferred to the private sector. However, this is not the only model, and in some countries - even where the industry has been privatized - a central government agency will retain either the whole regulatory function or part of it.

Key issues here are:

1. the concept of an independent regulator
2. which government agencies or bodies may take on this role
3. why impartiality is so important for a level-playing field for all participants
4. the issue of jurisdictional conflicts between various agencies and bodies
5. the concept of deregulation and the move towards competitive markets

Whether it is a government department or a regulator who has the primary role, there will often be other bodies with a role in regulating the energy industry. The following bodies can all be involved in regulating the energy industry:

- Government departments
- Specialist utility or energy regulatory agencies (including rural electrification and energy efficiency agencies);
- Generalist competition regulators
- Environmental regulators
- Local authorities
- Courts and tribunals

It is noted furthermore that as electricity markets evolve, private players are brought in and the level of competition increases, there may be a need in the market for both regulated and negotiated or competitively determined prices. The co-existence of regulated tariffs and negotiated price understandably introduces an additional level of regulatory complexity. Regulated tariffs would typically fall under the regulatory jurisdiction of the energy or electricity regulator applying an ex ante regulatory model, while negotiated (i.e. competitive) prices often fall under the broader jurisdiction of competition law administered by the relevant competition tribunal or commission, that may apply an ex post regulatory model.

Unless managed and coordinated proactively, this could lead to a functional and jurisdictional overlap. This is often referred to as “forum shopping” and occurs in many sectors where there multiple parties are responsible for differing aspects of regulation and market participants “shop” for preferential regulatory treatment when facing regulatory decisions or rulings.

These jurisdictional issues should be recognized and can be addressed, for example, via an agreed cooperation approach or memorandum of understanding between the two regulatory agencies.

Regulatory principles

There is understandably a vast array of regulatory principles that may be obtained from different regulatory jurisdictions. In essence, however, it is important to highlight three basic principles on which a regulatory system should be built, namely:

- Independence and impartiality
- Transparency, predictability and consistency
- Investor/consumer protection

This section of the module should establish an understanding of and expand on these principles. Reference should also be made to the AFUR regulatory principles and framework that have already been developed. These are referenced below. Regulatory principles are often prescribed within the relevant governing legislation and policy for each market. These are more full explored in the next key concept.

The importance of having some level of regulatory independence, while controversial at times, should not be underestimated. It is recognized that in many countries regulatory boards and commissioners are appointed by, and answerable to, the government. Under these circumstances, true independence is not possible and the concept of “impartial regulation” becomes a more pragmatic approach, restricting the extent of government interference in regulatory decision-making allowed. Independence, or at least impartiality, is crucial to the regulator's task, particularly as increasing numbers of private participants enter the electricity market.

Transparency, predictability and consistency are key to attracting and retaining efficient investment in the sector as it creates confidence in the commitment of government and the regulator to set and stick to fair policies and practices over time. Absence of regulatory transparency, predictability and consistency can significantly undermine investor appetite and confidence in the sector.

It is also the regulator's role to strike a balance between affordability (consumer protection) and cost-reflectivity (enabling sectoral investment). The regulatory agency and supporting framework must thus support investment by on the one hand protecting investors from government actions, whilst at the same time simultaneously protecting consumers from abuse by firms with substantial market power.

AFUR Regulatory Principles

In November 2003 AFUR produced a set of general principles for utility regulation.

In 2004, Prof. Jorry M. Mwenechanya prepared a survey report for RERA on "Regional Electricity Regulatory Principles". The survey showed that:

- Members of RERA have made a good start to implementing internationally accepted regulatory principles and practices.
- Regulators have adopted procedures for assuring transparency, accountability, information dissemination and stakeholder participation.
- Regulators were encouraged to continue to expand the scope and sophistication of methods in these areas.
- Governments need to pay greater attention to legislative frameworks in order to better guarantee regulatory autonomy and to give investors stronger assurance regarding the stability of regulatory frameworks.

AFUR Regulatory Framework

The AFUR Regulatory Framework focuses on a set of high-level core regulatory principles:

- Minimum regulation (to achieve regulatory objectives)
- Transparent decision-making and due process
- Independent (or autonomous) regulation where possible
- Accountability towards government, investors and end-users
- Non-discrimination when not in conflict with policy prerogatives
- Investor protection against physical & regulatory expropriation
- Promotion of competition by limiting anti-competitive behavior

In conclusion the module should take guidance from the AFUR regulatory principles and framework and unpack the various other curriculum aspects discussed.

Regulatory Hierarchy and Regulatory Instruments

It is important to highlight that regulation takes place within the context of an overarching institutional and regulatory framework.

Such framework essentially comprises the combination of agencies and market participants plus policy, legislation, regulations, licenses/concessions, rules, codes, guidelines and methodologies into a comprehensive, integrated and coherent set of instruments and mechanisms that provide direction and clarity on the way the power market will develop and how it will be governed/regulated. This is illustrated in the figure below.

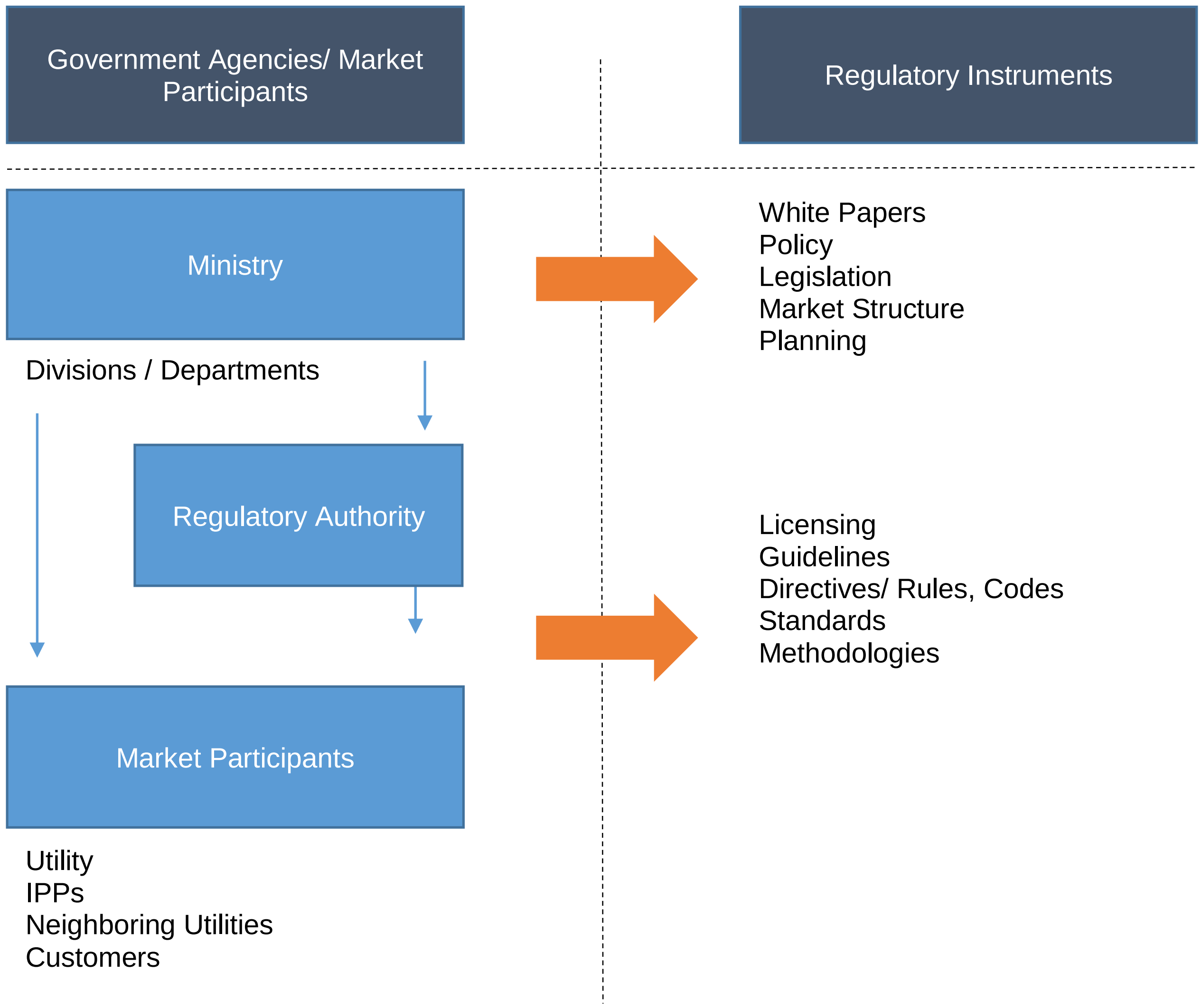


Figure 6: Institutional and Regulatory Framework

There is a hierarchy associated with these documents such that the prescribed regulatory mandate is not violated.

Regulatory authority is typically created through legislation. The regulator's legal mandate flows from a hierarchy of executive and legislative authorities. At the highest level is government policy (green paper, white paper, cabinet decisions). Governments pass legislation in accordance with this policy. The energy or power ministry typically makes regulations. The energy or electricity regulator typically develops rules, codes, guidelines and/or methodologies and issues licenses/concessions to give effect to the legislation and regulations.

Unfortunately in many countries, legislation and subordinate regulations etc. are often developed in a policy vacuum (i.e. without clear vision and guidance on the overall power sector strategy and direction). Also many regulatory frameworks have internally inconsistent or conflicting rules and/or overlapping jurisdiction between different institutional agencies (i.e. ministries or government departments) as well as between different legal and regulatory instruments. This inevitably increases regulatory risk and undermines investor confidence.

It is important for regulatory decision-makers to recognize and understand the different sector role players and institutions together with their respective mandates, roles/responsibilities and rights/obligations. In addition, it is also vital to understand the hierarchy of policy and regulatory instruments that may be applied in governing and regulating the sector.

Types of Regulation

There are many different types of regulation, each with their own advantages and disadvantages. There is no single approach or solution to suit all countries, so each market must be assessed to determine its key characteristics and only thereafter can an appropriate regulatory system be designed and implemented.

This section examines the three key different types of regulation commonly in use, including:

1. command and control
2. self-regulation and
3. incentive-based regulation methods.

Generally, command-and-control regulation is imposed by government, self-regulation involves the private sector managing its own regulatory scheme, and incentive-based regulation can be considered as regulation in between those two, i.e. reward vs. penalty regulation; "reward" for the private sector or utility to act, "penalty" for the regulator to wield when policy objectives, operating KPIs or other targets are not sufficiently met.

Each of these approaches should be examined further in some detail. For each type of regulation the advantages and disadvantages must be presented and compared. Finally some other market controls available for regulatory purposes can be presented including, trading certificates, contractual regulation and competition legislation protecting consumers.

Power sector reform has been in progress over the past two decades in developing countries. Typically, the reforms have involved some combination of evolving market structure including unbundling and private participation. Legislative reform and the creation of an independent regulatory body has also been a key element of the overall process with the majority of the regulatory functions moving away from a government ministry. The objectives of the regulatory reform were ultimately to create a level the playing field for all participants in the sector in the face of the incumbent monopoly and to protect consumer interests. The appropriateness of applying one of these types of regulation depends on the available competences at regulatory and private sector level, and on the historical relationship between the government and the given sector.

Command & Control

> This portion of the module must assess the key characteristics of "Command & Control" regulation. This should include a description of advantages i.e. direct approach with clearly defined limits and outcomes. There should also be some explanation on the weaknesses of the approach: requirement for co-operation and information sharing between the utility and regulator; complexity and rigidity of rules; lack of innovation and difficulty in enforcing standards.

Command and control regulation is typically the imposition of rules, codes and technical/ financial standards backed up by legislative sanctions if the standards are not met – for example if a generator does not comply with relevant standards or regulation, the regulator may withdraw their license to generate. The sector legislation and regulatory rules & codes are therefore used to define and prohibit certain types of activities or force certain types of behavior. Standards can be set either through government legislation, or by regulators empowered by regulatory legislation to define rules, codes etc.

Self-regulation

> In this section, Self-regulation could be portrayed as a form of DIY (do-it-yourself) command and control. Some of the key advantages to discuss, are the high levels of involvement and interaction by private companies (in order to avoid government interference); flexibility and wide spread understanding of this complex environment. There are of course disadvantages which need to be adequately described, namely, the pervasive self-interest inherent in the system, potential for consumer abuse through market power and the lack of transparency.

Frequently, it is formed by an industry body, private companies or trade associations that develop their own rules, codes and standards of performance, which they then also monitor and enforce. Sometimes there is a degree of government oversight of the self-regulation, but, usually, it is seen as a way of business pro-actively attempting to avoid government intervention and control in their industry. This is not a very common approach in the electricity sector today, due to the nuances of the market structures and the historical context of sector regulation.

Incentive-based regulation

An incentive may be informed by policies, legislation, rules, codes, standards or procedures that seek to modify the behavior of persons or companies by changing the costs or benefits associated with particular decisions, behaviors and activities.

Arguably, all regulation is in fact based on incentives of one kind or another to promote certain types of behavior. In the case of Incentive-based regulation, the utility or other regulated entity is rewarded with increased profits for reducing costs and improving services (for example).

The key concept behind incentive-based regulation is the desire to encourage particular behavior or performance improvements and to limit or stop undesirable activity by granting bonuses and imposing penalties - in other words a “rewards vs. penalties” approach to ensure a technical, financial, economic, social development or environmentally desirable end.

Some of the benefits to discuss include: clearly defined baselines, benchmarks and rewards – little requirement for interpretation or discretion; the regulated entity has some autonomy in that it can choose when to aim for a reward or accept a penalty; it can be used to promote specific goals and lead to better performance; it aligns the interests of the utility and consumers.

It is of course critical that rules are correctly set in order to ensure that the right behaviour is encouraged and to ensure that operational performance is not compromised in order to achieve cost reductions (for example).

On the other hand, the regulator will penalize or limit an undesirable activity by imposing taxes or other penalties to achieve an operational, technical, economic or financial outcome. In order to apply incentive-based regulation, regulators need to set baselines and benchmarks against which entities are then measured. These baselines are then constantly adjusted in order to target on-going improvements.

Perhaps the most common type of incentive-based regulation is performance-based regulation (PBR). In this case, rewards (usually financial incentives) are tied to improvements in operational performance, efficiency in capital expenditure, tariff reductions and service quality improvement.

The main aim of PBR is to promote the sharing of benefits between the regulated entity and their consumers. The regulated entity will benefit from better performance, lower costs, higher profits and ultimately an improved return on investments for its shareholders. Consumers will hopefully benefit from lower tariffs and improved quality of service.

Market controls

There are a range of market-based mechanisms that can be used to regulate activities. Market-based regulations (e.g. regulation by contract) can prove cost-effective, and minimize regulatory interference in the day-to-day operation of companies. Some of the more common market-based mechanisms that can be assessed, include:

1. Competition laws
2. Regulation by Contracts
3. Trading Certificates
4. Disclosure

Competition laws are typically non sector specific laws used to control the behavior of companies to ensure that the market delivers services by limiting undesirable activities such as predatory pricing or cross-subsidization.

By specifying contractual conditions, governments can use contracts to drive socially desirable objectives, such as a specified proportion of renewable power used in the production of goods or levels of local content in manufacturing. Regulation-by-contract is sometimes regarded as a short term solution, worth considering when trying to increase regulatory robustness rapidly in the short term.

Trading of certificates is an increasingly important approach for limiting carbon dioxide emissions following the development of the various mechanisms and markets for registering and managing these programs. A specified level of acceptable emissions is set by the government, and market participants are granted an allocation of allowances up to that limit.

The participants can then chose to reduce their emissions below the allocated limit and trade their excess allowances, or to buy allowances to allow them to exceed the limit. In addition, participants may also choose to exceed the limit and pay a penalty rather than buy additional allowances.

Disclosing the source of a products energy, utilized during manufacturing, has been applied in some countries to ensure that information is provided on the generation mix used to produce or manufacture goods. The mechanism allows consumers to choose a preferred source of generation (e.g. renewable generation rather than fossil fuel), but it depends on the reliability of the information presented. It also assumes that consumers will make the “right” choice to achieve the desired end.

10.4. Recommended Reading

The trend towards deregulation and increasing competition in the electricity market has been thoroughly documented and explored by both academics and professionals. There are also a number of research papers that provide useful insight into the concept of regulation. The documents listed in the table below, provide a useful starting point for attendees that wish to prepare themselves for the course.

Table 3: Recommended Reading - Regulatory Approaches

Title	Source	Description
Sustainable Energy Regulation And Policymaking For Africa - UNIDO & REEEP	http://africa-toolkit.reeep.org/	In 2004, REEEP commissioned the development of an initial training package entitled “Regulation and Sustainable Energy”. This training package focused on the situation in developed countries, with case studies from Europe, the United States and Australia and was completed in April 2005. REEEP then requested UNIDO to adapt and expand the training package to a developing country context, in the light of present experiences in, as well as constraints of, energy policy and regulation in developing countries. See Chapter 5 – “Structure, composition and role of an energy regulator”
Council of European Energy Regulators	http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICA	The CEER have a wide range of papers produced on approaches to regulation from 2001-2015. They can be accessed and downloaded from the URL listed to the left.

	TIONS/CEER_PAPERS/Electricity	
Styles of Regulation: The Choice of Approach to Utility Regulation in Central and Eastern Europe	http://facultyresearch.london.edu/docs/RIpaper34.pdf	A useful comparison of regulatory approaches adopted across selected countries in Europe and a comparison of their advantages and disadvantages. Will provide insight into how to choose the right regulatory approach, given a specific set of market conditions and desired outcomes.
Transparency And Confidentiality In Competitive Electricity Markets	http://www.naruc.org/Publications/EnergyDataTransparencyRpt0609.pdf	A USAID and NARUC collaboration. A Discussion Paper on the data elements needed to develop competition and to carry out effective monitoring of electricity markets, and to address the issue of the need to have standard regulatory reporting made available. The primary objective of the paper is to establish a working definition for data transparency—both for the regulator and for the public—and criteria for determining what confidentiality is justifiable based on the need for effective competition and monitoring. A more advanced document to stimulate thought on regulation in RERA.
Electricity Sector Reform In Developing Countries: An Econometric Assessment Of The Effects Of Privatization, Competition And Regulation	http://regulation.upf.edu/bath-06/10_Parker.pdf	This paper provides an econometric assessment of the effects of privatization, competition and regulation on the performance of the electricity generation industry using panel data for 36 developing and transitional countries, over the period 1985 to 2003. The study identifies the impact of these reforms on generating capacity, electricity generated, labor productivity in the generating sector and capacity utilization. The main conclusions are that on their own privatization and regulation do not lead to obvious gains in economic performance, though there are some positive interaction effects. By contrast, introducing competition does seem to be effective in stimulating performance improvements.

10.5. **Outcomes**

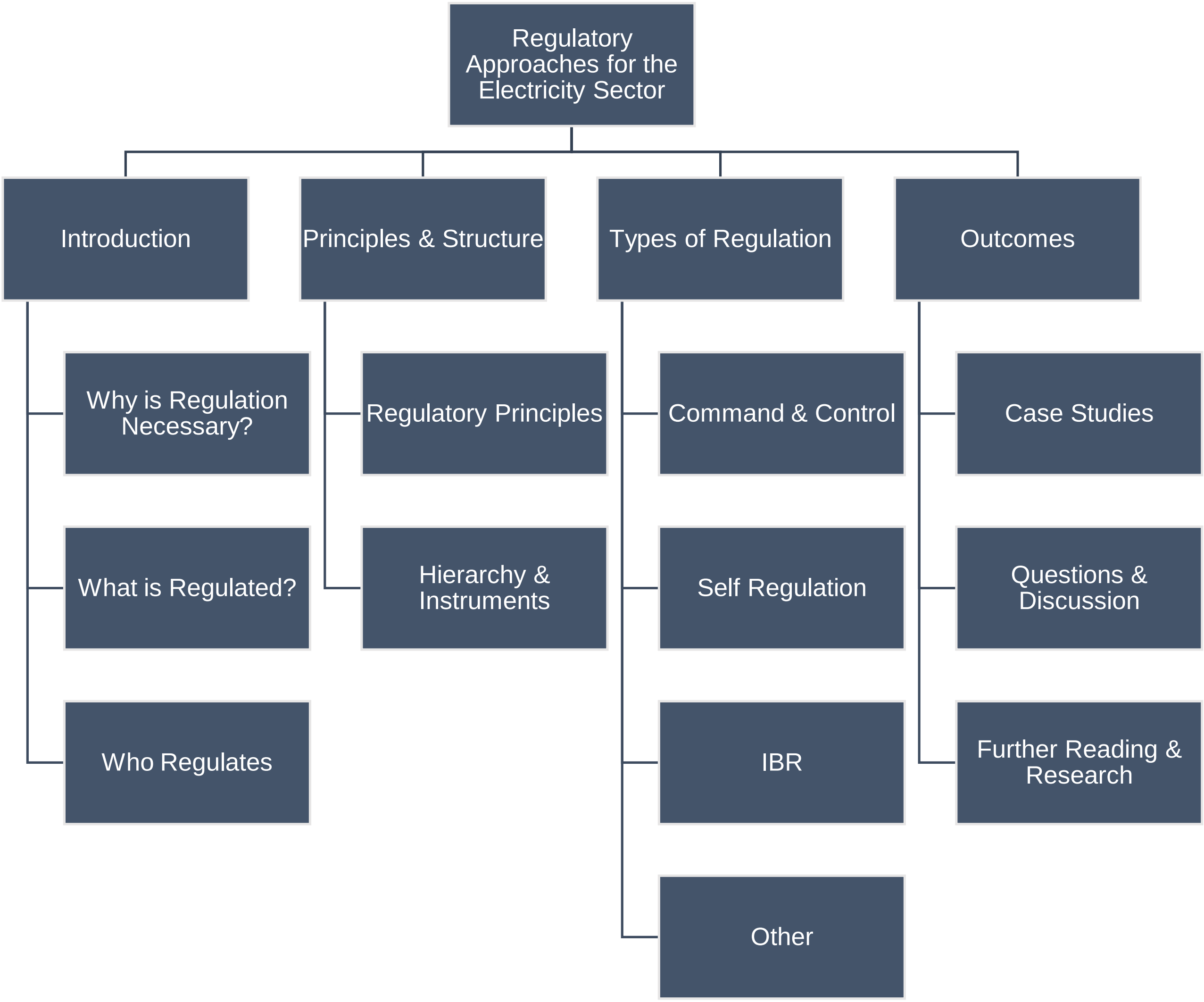
Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1. What is the single most important aspect of regulation that your agency provides in your market?
2. Is the Regulator in your market an independent body? If not, who does it report to? Does this compromise your ability to effectively regulate?
3. Which are the key principles that your regulator has adopted and how has this informed your approach to the sector
4. How is the Regulator in your market mandated? Is there specific policy and legislation defining your remit?
5. Which type of regulations is most effective for your market?
6. How can the current status quo be improved?
7. Is IBR an option in your market? Has IBR been implemented and if so, has it proved successful?

10.1. **Module Structure**

This is a relatively simple module to develop with three distinct content sections to be presented, as described in the figure below. The "Outcomes" section is to be sued in order to ensure that course attendees understand and have synthesized the material for practical application.

Figure 7: Module Structure - Regulatory Approaches



11. LICENSING APPROACHES FOR THE ELECTRICITY SECTOR

11.1. Module Introduction

The licensing of specific functions or activities represents a fundamental tool for power sector regulation. Licensing provides a means for governments to further important energy policies, ensure compliance with specific sector rules and protect customers from market power abuse. Licensing also entrenches specific rights and obligations for market participants, thereby providing much needed certainty for potential investors.

As power markets have changed over the past 2-3 decades and continue to evolve, licensing approaches need to be adapted to ensure that they continue to achieve the stated objectives and support sustainable market development. This module will outline salient licensing principles and approaches as well as key issues for regulators to consider in establishing or refining their licensing regimes.

11.2. Module Purpose and Overview

The module sets out the role of and typical approaches to electricity sector licensing. In so doing, it provides context around the role of licensing within the broader institutional and regulatory framework, including, for example the potential interrelationship between licensing and other regulatory instruments such as regulations, codes, rules and guidelines.

Key power market developments that have an effect on licensing are outlined. These include widespread market reforms aimed at increasing the level of competition and private sector participation, as well as the greater role that distributed/embedded generation and mini-grids are expected to play.

Important principles underpinning the licensing framework are set out – these are aimed at minimizing regulatory risk and reducing compliance costs.

The module then unpacks salient considerations for different licensing approaches, noting the important decision to be made between combined versus individual licenses for the various power sector value chain activities/functions. The need for fast-track registration and license exemptions is also highlighted.

The importance of a properly articulated license application process and clear license evaluation criteria is outlined, with reference to associated processes around, for example, integrated resource planning, new capacity procurement approaches, and project viability assessment.

The rationale for providing pro-forma license templates to serve as a basis for licenses to be issued is set out together with a guiding high level outline of key headings/provisions to be covered.

Finally, the module introduces key considerations around license fees and penalties and proposes the inclusion of a properly maintained license register.

The topics covered are by no means exhaustive and the recommendations are not intended to be prescriptive. Rather the module aims to stimulate structured thought and debate around these important topics, so that the overall licensing approach adopted is robust, effective and efficient.

11.3. Key Definitions & Concepts

11.3.1. Key Definitions

Table 4: Definitions - Licensing Approaches

Combined licenses	Licenses that combine the rights and obligations associated with multiple electricity supply functions (e.g. generation, transmission, distribution) into a single license)
Individual licenses	Licenses that set out the rights and obligations associated with each identified electricity supply functions (e.g. generation, transmission, distribution, etc.) into separate individual licenses
Fast-track registration process	Mechanism to authorize small or low impact power sector functions without the administrative burden of a full license application and approval process
License exemptions	Mechanism to allow certain identified players or power market functions to participate in the market without a sector license
Integrated planning	The process whereby generation and network capacity is planned and coordinated
Procurement mechanism	The process whereby new generation and network capacity is procured (e.g. unsolicited, competitive bid, feed-in-scheme etc.)
Pro-forma licenses	Standardized license templates made available in advance for further development and refinement to simplify and standardize the licensing process and license terms
License Fees	Once-off fees payable for a license application and/or annual license fees payable by licensees
License register	A public register of all licenses under consideration, granted and revoked maintained by the regulator

11.3.2. Concepts

Role of Licensing within the broader Regulatory Environment

This section provides the context and an overview of the role of Licensing in Regulation

Licensing is a key regulatory instrument typically used to further important energy policies and goals. Governments typically implement licensing as a means of maintaining a degree of control over entities engaged in strategic industries such as energy and power and to regulate sectors that are not fully competitive (i.e. to protect customers from monopoly or market power abuse).

In the electricity sector, licensing is also used as a method of overseeing the activities of companies engaged in electricity supply and of enforcing compliance with energy, environmental and other laws or regulations.

In addition, a common purposes of licensing is to create a procedural mechanism that may be used to exercise some degree of control over the construction of new power plants or other power infrastructure. In so doing, the government may simply review new power projects as they are proposed (authorization procedure), or may take a more active planning role in determining capacity needs, soliciting proposals for new projects and selecting preferred bidder(s) via a tendering process.

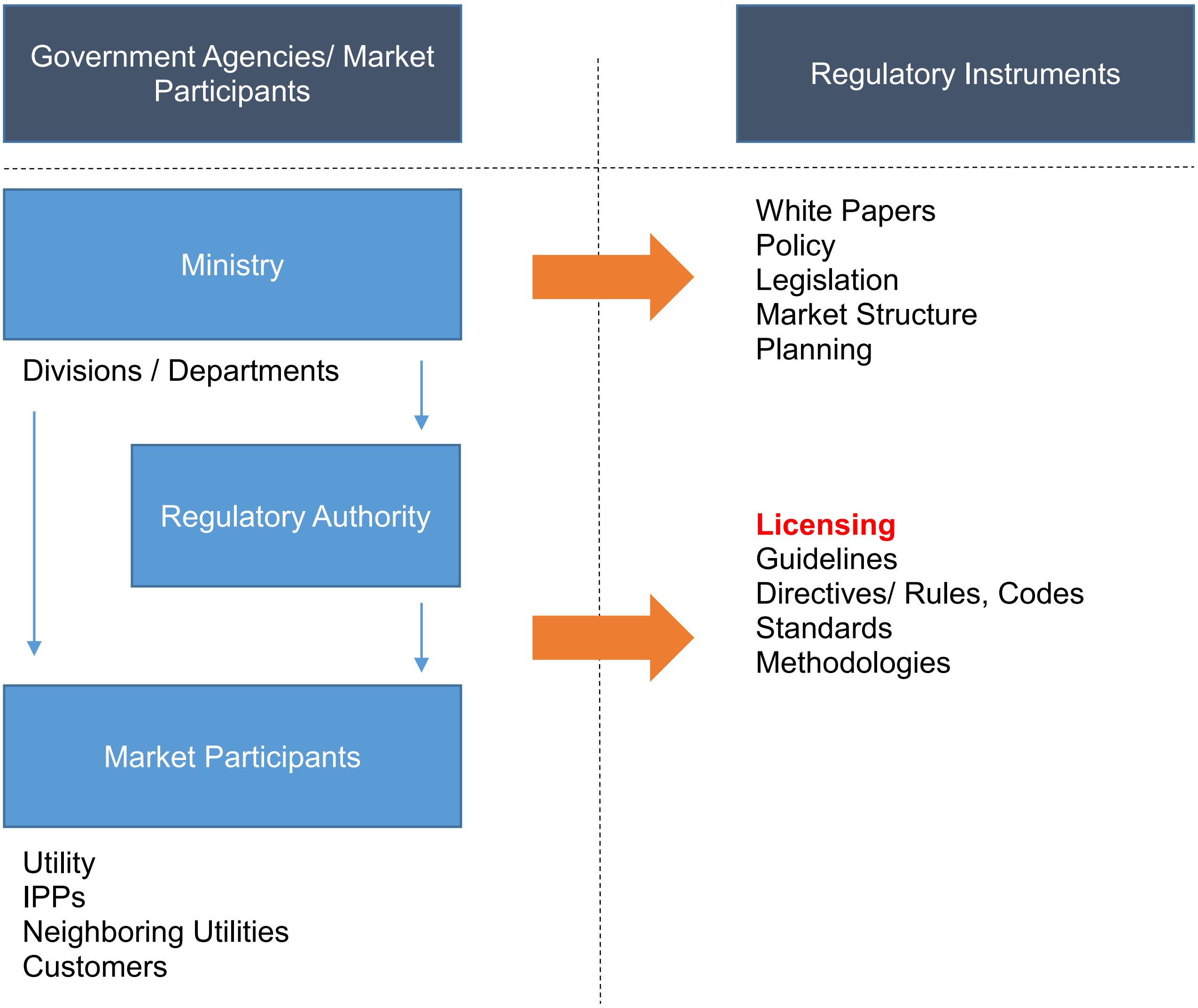
In summary, licensing in power sector may thus be used to serve a number of objectives, including the following:

- The initial licensing process may be used to ensure that entities participating in the power sector have adopted the appropriate corporate structures and have demonstrated adequate financial resources and technical ability to carry out the licensed activities.
- The licensing process may include procedures for revoking or modifying licenses in order to enable the government to monitor and enforce compliance with applicable laws and regulations.
- License conditions may impose requirements regarding accounting practices and the right of the government to review and audit a company's books and records. These conditions may assist regulators when reviewing a company's tariffs and may help protect investors and consumers from improper business practices.
- As a condition of licensing, sector participants may be required to compile and make available information on their operations that will assist the government in developing long-term national energy policy and compiling long term integrated infrastructure plans.
- The licensing process may, moreover, be used to establish the obligation of sector participants to comply with national and international technical and safety codes.
- Furthermore, if strategic investors have agreed to fund upgrades to existing facilities to improve performance or reduce pollution, the licensing process may be used to monitor compliance with these commitments

These objectives are typically achieved via license conditions imposed on the licensee. Such conditions typically establish applicable rights and obligations in a way that protects consumers, ensures a specified level of service or safety and provides a degree of investor certainty to licensees. Remedies for non-compliance with license conditions, including penalties and fines, license suspension or revocation, are also typically provided for.

As set out above, licensing forms part of a broader "institutional and regulatory framework". Such framework essentially comprises the combination of entities (agencies and market participants) plus instruments (policy, legislation, regulations, licenses/concessions, rules, codes, guidelines and methodologies) into a comprehensive, integrated and coherent framework that provide direction and clarity on the way the power market will develop and how it will be governed/regulated. This is illustrated below, with the role if licensing within that framework highlighted.

Figure 8: Institutional and Regulatory Framework



The licensing module will establish a clear link with the various regulatory instruments, highlighting that different countries tend to utilize them in different combinations, depending on the governing legislation, market environment and the overarching regulatory objectives. The module thus will deal with the different ways in which licensing can be employed within the broader regulatory framework and institutional environment.

Licenses vs. Rules

In essence, a license-based system has attributes of a contract between the government and the licensee, with the relevant terms and conditions set forth clearly at the outset. The license conditions are thus established in advance and are not easily changed.

By contrast, a rule-based system, offers the advantage of greater flexibility to meet changing market conditions, as these rules can be changed more readily and be universally applicable to all relevant market participants (subject of course to appropriate governance and due consultation processes) without the need to amend licenses.

In exploring the trade-offs between these two approaches, it is vital to acknowledge that both flexibility and stability are essential (but contradictory) attributes of effective sector regulation. It is thus noted that each jurisdiction/country will thus strive to strike its own balance between these.

One of the fundamental choices that regulators typically face is whether to rely on licenses (or alternatively so-called "franchises” or "concessions") or on more generic regulations and rules as the primary instruments of regulatory control. A license-based system establishes most of the conditions of operation in the individual license documents. By comparison, a regulation or rule based system promulgates most conditions in rules of general applicability, supplemented by specific provisions or conditions applicable to identified market participants within licenses.

There is no “one size fits all recipe” to licensing and in practice, many regulators employ a hybrid approach. In other words they seek to exploit the advantages of each of the different regulatory instruments, without introducing unnecessary risk or additional administrative burden. The training will highlight the need for regulators to address this issue proactively in establishing the overall regulatory framework, rather than having to unwind applicable rights and obligations as these inadvertently no longer serve the long term interests of the changing market.

This latter aspect has become increasingly important as markets have evolved and as new technological advances change the traditional models of electricity supply. These are discussed in more detail below.

In promoting power market development, regulators should, however, be cautioned against using licensing as a substitute for generic rule-making if they do not have the time or resources to undertake the latter. Unless carefully structured, these license agreements, which typically span 15-40 years, can become straitjackets or market hindrances as technologies advance, regulatory frameworks evolve and national priorities change over time.

This risk is exacerbated if regulators then rely too heavily on suspension and revocation of licenses as regulatory non-compliance remedies rather than fines. This is particularly problematic insofar as these remedies relate to licensed activities that are naturally restricted to one or very few potential providers (i.e. the natural monopoly areas of the sector, such as networks and system operations). In these cases, license revocation or suspension have limited impact unless other qualified operators are available to step in.

The publication of Grid Codes (including, as applicable, a market codes) as well as a tariff regulation methodologies are examples of additional regulatory instruments that can be used to incorporate common provisions and complement the licenses issued.

Power market developments affecting licensing

Power market reforms

During the late 1980s and through the 1990s, many developing countries began to explore new organizational and market models for their electricity supply sectors. The traditional monopoly view of a vertically integrated industry was superseded by a so-called standard model of power sector reform. This in essence entailed vertical and horizontal unbundling of the generation, transmission and distribution functions, and included the introduction of market competition via private sector participation, all overseen by independent regulation.

In short then, there are two primary drivers for power sector reform in Africa. These are important as they have a direct bearing on the regulation of the sector and, as such, on licensing.

- The need to attract new private sector investment to improve security of supply and meet future supply needs and limit the burden on public finances
- The need to improve the financial and technical performance of incumbent state-owned utilities

Power sector reform has conventionally begun with an initial stage of commercialization and corporatization of state-owned utilities followed by unbundling and the introduction of competition and private sector participation. While many countries have begun this reform process, most African countries are still grappling with efforts to complete the reforms required.

From a licensing perspective, these reforms, while still ongoing, have a significant implications for licensing and are expanded on below.

Following international precedent, the traditional organization of the power sector in Africa began to be questioned in the 1990s. This questioning came on the back of state-owned enterprises in many countries not performing well, insolvencies in a number of utilities, declining technical performance and poor security and reliability of supply. This was further compounded by insufficient public funding to finance the required investment to maintain and expand power infrastructure.

Firstly, the unbundling of generation, transmission and distribution has given rise to the need for separate licenses, or at least separately licensed functions for these activities. This is addressed in more detail below.

Secondly, the introduction of competition and private sector participation, primarily in the generation space via Independent Power Producers (IPPs), has given rise to additional requirements. The regulatory framework (including license conditions) needs to establish clear, enforceable and quantifiable rights and obligations in order to give investors the requisite security to fund the projects. In addition, such IPPs need to be assured of open and equitable access to make use of the transmission (and, in some instances, distribution) network(s) as well as fair and predictable treatment in terms of system operations and market participation.

Thirdly, in cases where the market reforms and associated market structure make allowance for bilateral electricity transactions between IPPs and direct customers, there is the additional need to unbundle the “energy” from the “wires” (transport). This would thus allow an IPP and a customer to conclude energy trading contracts with one another plus network access and use agreements with the network licensee.

These aspects of market reforms have material implications for the way in which the sector is regulated and licensed.

The evolution of distributed (embedded) generation and mini-grids

> It is recognized that the prevailing regulatory frameworks in most countries do not necessarily accommodate the unique requirements for distributed generation or mini-grids. For example, while it is recognized that the mini-grids may be isolated from the national grid, it is nonetheless important that the relevant technical standards and quality of supply and service criteria are upheld. This is to protect both customers as well as make provision for (future) interconnection of mini-grids to the national grid without compromising the integrity or security of the power system.
>
> Given the large number of prospective licensees in these areas as well as the lower overall technical and commercial risks associated with individual projects, the regulatory and licensing framework needs to be adjusted to manage these supply options without imposing an unreasonable burden on the regulator or the licensees

Recent decreases in the prices of many renewable energy technologies (most notably solar PV and wind equipment), coupled with incentive programs in some regions, have contributed to the rapid growth of this sector. This has allowed the cost of some renewable projects to be directly compared with conventional generation options and is leading to the increased rollout of small scale distributed generation and mini-grids. In addition to renewable technologies the market is also witnessing significant growth in other resources/technologies such as batteries, diesel generators, biomass, biogas, mini-hydro and other waste-to energy solutions.

Distributed (or embedded) generation typically refers to generation sources that are connected to (i.e. embedded in) the distribution network, as opposed to the large generators that typically connect to the high voltage transmission network(s). These distributed generation sources are often small (referred to small scale embedded generation) and typically supply demand within the locality of the generator, but they can also be large and potentially export power onto the transmission grid.

Mini-grids are defined as one or more local generation units supplying electricity to domestic, commercial, or institutional customers (e.g. clinics, libraries, schools) over a local distribution grid. They can operate in a standalone mode (i.e. off-grid) or can also interconnect with the central grid if and when available. Mini-grids are thus an important alternative to enhancing the effectiveness of central grid extension and increasing access to reliable electricity supply in developing economies with under-developed national transmission or distribution infrastructure.

Licensing Principles

Having established the role of licensing and associated high level objectives, and taking cognizance of the changing market environment, there are two additional important principles that warrant specific mention. An effective licensing approach is one that

1) Minimizes regulatory risk (i.e. does not adversely influence investment decisions); and
2) Minimizes compliance costs

The pursuit of these objectives may inevitably involve balancing various trade-offs. The overall goal, however, is to license in a manner that is consistent with the long-term interests of consumers. To this end the regulator should regularly review its licensing approach.

The section should reinforce the fact that best practice utility licensing aims to deliver a licensing regime that is ultimately in the long-term interests of consumers.

In summary, a best practice licensing regime will have the following key features:

- It addresses clearly identified objectives
- The party issuing the licenses is independent and accountable
- The party issuing the licenses performs its functions in a manner that ensures service standards are optimized and maintained
- Regulatory risk and compliance costs are minimized.

Minimizing Regulatory Risk

To minimize regulatory risk, the regulator should ensure its decisions are predictable, consistent, timely, and transparent and are based on effective consultation.

- **Predictability** – regulatory decisions should be predictable so that industry participants can invest with confidence and certainty (for example, published guidelines for license applications, license evaluation criteria, and pro-forma license conditions as set out below).
- **Consistency –** regulatory decisions should be consistent over time, across license categories and between licensees.
- **Timeliness** – regulatory decisions should be made as quickly as practically possible. Timeframes for the evaluation and decision by the regulator should be published and adhered to.
- **Transparency –** regulatory decisions should be transparent and properly substantiated with "reasons for decision" published and notified to relevant stakeholders.
- **Consultation** - all interested parties should enjoy the opportunity to participate in the decision-making process by providing information and commentary to the regulator.

Minimizing Compliance Costs

The licensing regime should aim to achieve its objectives without imposing unnecessary costs on the licensees. In order to minimize compliance costs, regulators should seek to ensure that the various processes and documents incorporate simple and targeted language, are consistent with other laws and regulations, are integrated with other approaches in the region, are flexible and are formulated with input from interested parties. In so doing, licensing provisions should be proportionate to the market issues, not be unduly prescriptive and should be the minimum necessary to achieve licensing objectives.

- **Simple and targeted language** – provisions should be simple, clear, drafted in plain language and be readily accessible
- **Consistency with other laws –** provisions should be consistent with other laws to minimize the regulatory burden on licensees and avoid conflicts
- **Integrated across jurisdictions** – with increasing regional interconnection and cross-border power trade there are distinct advantages in have a degree of consistency in the licensing regimes applied within different countries in the region.
- **Flexibility** – while providing the requisite investment certainty, licenses should remain as flexible as possible so as to minimize the compliance costs associated with the licensing regime, particularly as the power sector evolves with new technological advances. In this regard, it may be advantageous to have certain provisions (such as, for example, technical standards and detailed requirements on performance reporting) set out in regulations, codes or guidelines etc. and to have these referenced in the license rather than specified explicitly.
- **Consultation** - ensures that opportunities for minimizing compliance costs are identified.

Licensing Approaches

Combined or individual licenses

One of the fundamental decisions that regulators typically need to face is whether to issue combined (i.e. grouped) or individual licenses for the value chain functions identified. Understandably, there are, distinct advantages and disadvantages to each approach.

Again there is no single model that is universally applicable and each country would need to make the relevant trade-offs. Where feasible, it is often prudent to consider combined licenses for certain value chain functions (e.g. transmission and system operations, or distribution and supply/trading) where this does not undermine the overall power sector policy and market objectives.

A vital point to recognize in this regard is that the overall regulatory framework and licensing approach must be guided by clear and coherent power sector policy, supported by internally consistent enabling legislation. Such policy must, in turn, be guided by properly formulated sector objectives and associated clarity on desired market development and structure. In many countries this is unfortunately not the case; legislation and the regulatory framework are often developed in a policy vacuum, which introduces unnecessary uncertainty and risk and, as a result, tends to paralyze, or at a minimum, impede investment and power market development.

Based on the preceding discussion on the changing market, there is a clear rationale for the unbundling the different electricity supply value chain functions. In many jurisdictions these different functions are (or should be) clearly mapped to the relevant licensing categories or functions set out in governing legislation. Such functions would typically include the following:

1) Generation
2) Transmission
3) System Operations (and potentially market operations)
4) Distribution
5) Electricity supply or trading
6) Import and export
7) Mini-grid (and off-grid) supply

The key advantages to individual licenses include:

- Support for the overarching power sector policy direction (as applicable).
- Alignment with the need for financial ring-fencing of costs and tariffs.
- Levelling of the playing field for all licensees - so that, for example IPPs, transmission and other distribution and/or supply/trading licensees have comparable and equitable licenses and license conditions, as well as access to and use of the electricity networks.
- More transparent and effective regulation by the regulator:
- Technical and quality of supply/service monitoring and compliance by license type.
- Price regulation of unbundled charges.
- Promotion of operational and economic efficiency within the sector via specific focus on costs and performance targets/KPIs by license type
- Targeted remedies for non-compliance with license conditions – i.e. penalties or license revocation for specific licensed areas do not affect other licensed activities.

On the downside, it is recognized that individual licenses and the associated financial/operational ring-fencing (or unbundling) typically represents a significant task for incumbent utilities to undertake. This exercise inevitably introduces additional complexity and increases the administrative burden on both the utility and the regulator.

Fast-track registration and license exemptions

A further important consideration in sector licensing is the need to take cognizance of certain activities that should be either granted exemption from the need to hold licenses or, alternatively, be allowed a fast-track licensing or registration process.

As discussed above, the evolving power market is witnessing an increasing number of distributed generation sources and mini-grids deployed. Experience from various renewable energy and IPP initiatives in the region highlights that in many instances transaction and approval processes are excessively onerous, complex and expensive for these smaller IPPs and mini-grid initiatives. In addition, the growing number of these distributed generation sources and mini-grids will start to impose an unmanageable administrative burden on regulators in terms of licensing and associated regulatory monitoring.

In order to address this, consideration should be given to differentiated licensing processes for small IPPs and mini-grids. Such process could include, for example, defined criteria for market participants to qualify for a simplified fast-track licensing (registration) processes or for license exemptions respectively. The license exemption criteria and/or criteria for a fast-track registration process should take account of the evolving distributed/embedded generation and renewable energy markets

Licensing process and associated considerations

License application process, Integrated Planning, Procurement mechanisms

One of the key issues often raised by prospective licensees is a lack of clarity around the overall project development and licensing process and the way in which project developers should engage with the different government agencies to secure the necessary endorsements and approvals.

To this end, license application procedures including relevant license application forms and license evaluation criteria should be provided/published by the licensing authority.

Many countries typically undertake a process of "integrated resource planning" to evaluate the optimal portfolio of generation options and associated network expansion requirements to meet projected peak capacity and energy demand for a defined period into the future.

Such planning facilitates a process of identifying least-cost options as well as supply options that support other political or socio-economic objectives. These other objective could include, for example, a balance between imported and locally generated power, a diversified fuel and technology mix, low carbon or green energy targets etc.

While integrated resource planning clearly has ramifications beyond licensing, it is important to note that the licensing of market participants may need to take account of national power infrastructure plans. Indeed, some countries even restrict the licensing of power project developments to those contained in the resource plan.

As noted above, one of the overarching objectives and trends in power market development is the introduction of increased competition and private sector participation. Such participation is typically facilitated by some form of procurement process.

This raises the question as to how countries should go about procuring such new capacity. In principle there are a number of possible approaches. The most common of these include:

a) Unsolicited bids;
b) Formal procurement program (Competitive Bidding/Reverse Auction);
c) Feed-in-tariff scheme, net-metering, embedded generation tariffs etc.

Again, it is beyond the remit of the licensing module to deal with the relative advantages and disadvantages associated with different procurement mechanisms. It is, however, vital for the licensing process to be tailored to accommodate the procurement approach applied in the particular market in question.

Due diligence

As noted already, the role of the regulator includes protecting customers and promoting sustainable sector development. With the potential for increasing numbers of licensees, particularly with large numbers of IPPs entering the market, it is important for there to be some checks and balances in place to ensure that the credibility of project developers and sponsors as well as the viability of potential projects are vetted. This may be done as part of the planning and/or procurement process discussed above or it may form part of the license evaluation process to be conducted prior to the granting of the associated license(s).

Irrespective of the particular approach employed, such vetting should take the form of a project feasibility/viability assessment and some level of project due diligence. This vetting process and associated requirements may form part of the published license evaluation criteria, and would typically cover the following key aspects:

a) Administrative requirements (forms, registrations etc.)
b) Policy alignment (e.g. with national plans/objectives)
c) Legislative requirements (compliance with relevant acts, regulations, codes etc.)
d) Company good standing (e.g. corporate structure, shareholding, governance, taxation status etc.)
e) Competence in construction and/or operation (as applicable to infrastructure licenses)
f) Commercial and contractual requirements (e.g. power off-take agreements, fuel supply agreements, off-taker creditworthiness, network connection agreements, land lease/ownership etc.)
g) Project plan (realistic)
h) Financial viability (demonstrated via a comprehensive financial model, funding approach etc.)
i) Technical requirements (e.g. technology deployed, grid integration etc.)
j) Environmental e (e.g. environmental assessment and approvals, compliance with relevant environmental standards etc.)
k) Socio-economic aspects (e.g. benefits in terms of jobs created, foreign direct investment, tax revenue, local community etc.)

Pro-forma Licenses

In addressing the identified licensing objectives regulators may consider publishing a set of standard pro-forma licenses that serve as a basis for engagement with and the licensing of market participants. These then serve as a starting point for the engagement with prospective licensees and address the need for consistency and transparency, minimizing regulatory uncertainty or risk and reducing compliance costs.

In such pro-forma licenses, it can be clearly stipulated which provisions are fixed (i.e. non-negotiable) and which are open to further discussion and negotiation between the regulator and licensee. Clearly there will be certain provisions and schedules that will be unique to each license. In particular, unique aspects associated with the license may be included as annexures or schedules to the license.

Potential License Provisions

Without being prescriptive and recognizing the need to tailor the licenses to meet any unique requirements associated with individual countries, the module should set out some basic standardized license provisions or clauses to serve as a template or guideline for pro-forma licenses. Such provisions would cover, for example, the following areas and structure, described below.

Part 1 – The License	
Definitions and Interpretation	as appropriate
Grant of License	statement of conferral of license
Licensed Activities	specific functions/activities authorized
Conditions of License	obligation to comply with conditions as set out in the relevant sections
Term of License	duration/validity period of the license from the defined effective date
Renewal, amendment or revocation of License	associated rights of the regulator and licensee
Assignment, ceding, transferal of License	associated rights of the regulator and licensee
Authorized signatories	as appropriate

Part 2 – License Conditions	
General	any general conditions applicable
Conditions Precedent	conditions to be met or complied with for the license to become or remain valid, as applicable
Compliance with Law, Bylaw, Regulations and Codes	obligations of the licensee
Competency in Construction & Operation and Maintenance	as appropriate for licenses associated with power infrastructure (e.g. generators, transmission, distribution)
Contractual Agreements	the need to have in place relevant contractual agreements to be able to

	undertake the licensed activities (e.g. land ownership/use, servitudes, water use, fuel supply, power purchase agreement, etc.)
Insurance	need to have in place adequate insurance
License Fees	application and/or annual license fees payable
Tariffs and Prices	rules governing prices/tariffs that may be charged
Scheduling and Dispatch	for generators, rules governing the way in which the plant will be scheduled and instructed to operate
Ancillary Services	any ancillary services to be provided by the licensee, as appropriate
Separate Accounts	as appropriate, obligations in respect of financial ring-fencing and separation of accounts associated with different licensed activities or functions
Regulatory Reporting and Information Provision	statutory reporting requirements and general obligations in respect of the provision of information the regulator
Operational Performance	licensee obligations in respect of operational performance, including relevant KPIs and target levels
Dispute Resolution	mechanisms for dealing with disputes
Penalties	for non-compliance with license conditions in accordance with the governing legislation
Disposal of assets, change in capital and change in control of licensee	limitations imposed or approvals required
Lapse or Expiry of License	transfer of assets/rights, dismantling of equipment, land/site rehabilitation etc.

Annexures/Schedules	
Ownership/shareholding structure	as appropriate
Licensed Facilities/infrastructure	as appropriate

Conditions Precedent	as appropriate
Operational performance – KPI and targets	as appropriate

License Fees and Penalties

The module will address the need for and approach to various license fees as well as the way in which monies received for penalties imposed could be employed. If the objective of the license fees is to provide a mechanism to fund the regulator, consideration should be given approaches around adjusting the fees charged per license type in accordance with the proportion of effort and resources expended by the regulator for each and define a differentiated annual license fee per license type.

License application fees

License application fees are typically levied to recover the administrative costs associated with reviewing applications, conducting the necessary investigations and due diligence and granting the license.

Annual License fees

These are typically set out in relevant legislation or specific license fee regulations and may make provision for separate license fees per licensed function or activity in order to ensure a level playing field for all licensees.

There are various approaches that may be applied in determining these fees including: fixed annual fees, annual fees based on a defined percentage of gross turnover, other.

Penalties

Penalties may be included in the licensing framework as part of the compliance regime. There should be clear rules or guidelines in place dealing with the deployment of monies recovered from penalties. These should not serve as a windfall gain for the regulator. They could, for example, be offset against future license fees or deployed elsewhere as appropriate.

License Register

Given the anticipated development of the power sector in the region and associated expected increase in the type and number of licenses issued, it is sensible for the regulator to publish and maintain a license register that provides a coherent and integrated view on the various licenses within the sector. Such register could, for example, include the following type of information per license type or category

a) Licensee name
b) License type (plus defined attributes)
c) License effective date
d) License term
e) License Status

11.4. Recommended Reading

There are licensing guidelines published on the websites of many Regulators globally; however a quick search through these sites will show that there is a wide range in quality and comprehensiveness of licensing guidelines.

Licensing is touched upon as a tool for Regulators in many of the papers written on regulatory reform; however there are few that address the issues of licensing specifically as it relates to licensing of entities within power market structures typically found in RERA members. Below are listed several papers that can be used to inform best practices for this module.

Table 5: Recommended Reading - Licensing Approaches

Title	Source	Description
European best practice regarding to the licensing in the energy sector	http://www.inogate.org/documents/Licensing.pdf	A useful overview of different types of licenses available across Europe as well as regulatory bodies responsible for awarding them.
Best Practice Utility Licensing	https://www.erawa.com.au/cproot/4902/2/Best_Practice_Utility_Licencing_Jan_2007.pdf	Written by the Economic Regulation Authority of Western Australia. Provides a good overview of licensing functions, objectives and authority as well as some input on the characteristics of an effective licensor.
Best Practices Guide: Implementing Power Sector Reform	http://www.raponline.org/	The United States Agency for International Development's (USAID) Global Center for Environment, Energy and Environmental Training Program has developed the Best Practices Guide Series to provide technical information on the topics of power sector reform and regulatory practices. Chapter 6 discusses licensing of utilities.

11.5. Outcomes

Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

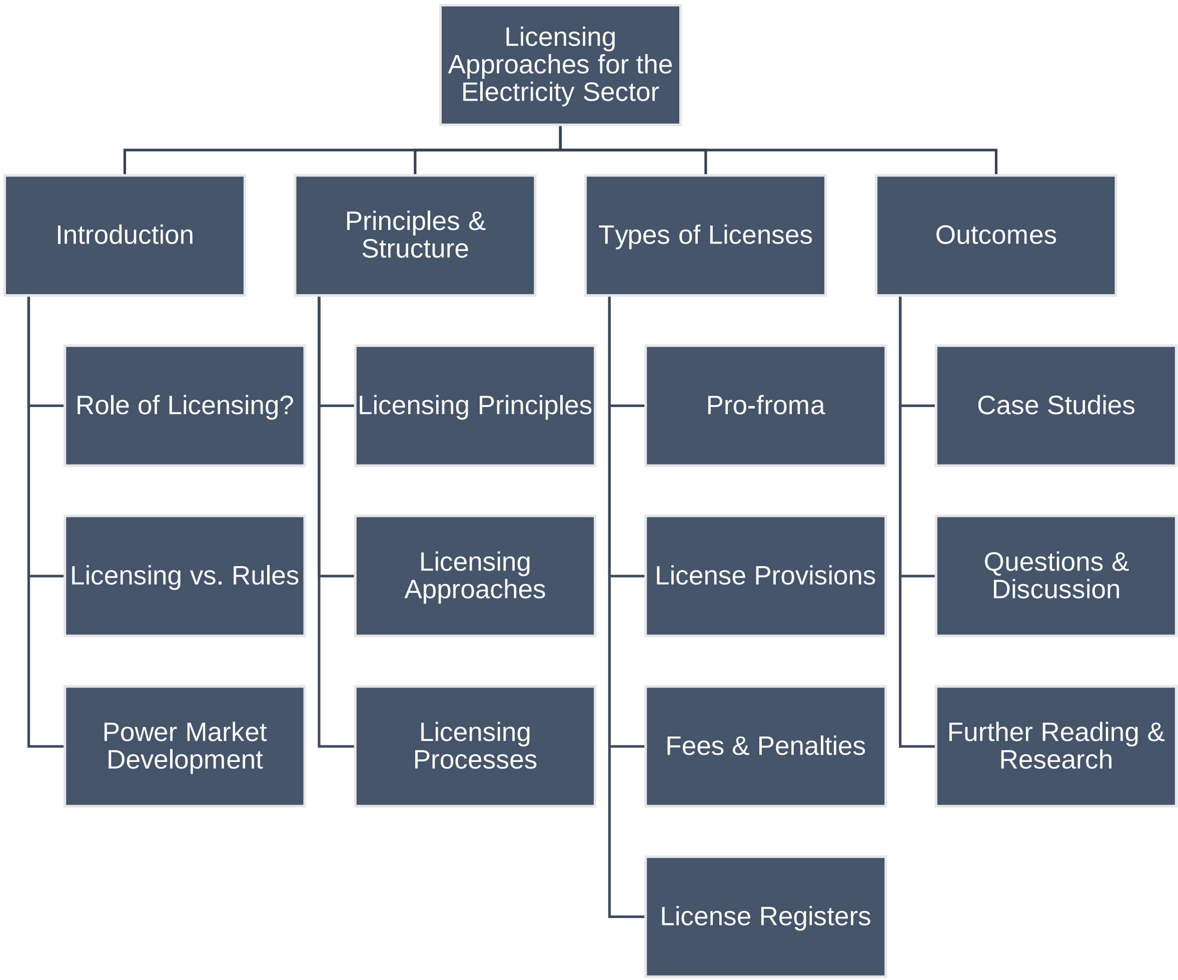
1) Describe the licensing process in your market – is it comprehensive or can it be improved?
2) Do you license all activities including generation, transmission, distribution, retail supply, trading and import/export?
3) Does your Regulator follow a predominantly rule-based approach or do they rely on the license to regulate?
4) Are IPPs active in your market? If so, does their licensing process differ from the incumbent utility?

5) Is the licensing approach comprehensive and easy to follow? Do most applicants comply? how could it be improved given the material presented today?
6) What kind of due diligence do you perform when evaluating a licensing applicant – do you a process for solicited vs. unsolicited projects?
7) What kind of license fees and penalties are prescribed by your Regulator? Are the penalties enforced?
8) Is your Regulator funded primarily through license fees and how does this impact on your independence?
9) Is there a license register in your market and would it be useful? How does the Regulator administer licenses?

11.1. Module Structure

This module has been classified as requiring a moderate/advanced skill level - a good understanding is required of the structure and alignment between regulation & legislation. Some technical understanding of key issues that relate to power plants and the grid, would also be helpful.

Figure 9: Module Structure - Licensing Approaches



12. TARIFF REGULATION AND FORECASTING

12.1. Module Introduction

Cost-reflective electricity tariffs underpin a healthy and efficient power sector. Power pricing also guides investment decisions on behalf of end-users. Furthermore, it provides an economic signal to consumers of the cost of marginal consumption and should therefore promote the optimal utilization of capacity in the power system. However; achieving cost-reflective and efficient power pricing is not easily achieved.

Investments in the power sector are characterized by significant upfront fixed capital costs, that can be considered uneven in nature i.e. capacity is added in incremental steps (every time a new power station unit or transmission line is commissioned) and it can take many years for costs to be recovered. Beyond that, costs vary based on production schedules and generation mix – this can change during the daily load profile for peak vs. off-peak consumption, seasonally, by customer category (industrial, commercial, residential, rural etc.) and according to geographical location. All of these issues will be taken into consideration when creating tariff schedules that promote optimal, cost-reflective use.

As if the technical issues behind setting efficient tariffs are not complex enough, utilities and regulators also face an on-going trade-off between promoting cost-reflectivity and affordability, especially in developing countries with a strong focus on social developmental objectives. In many cases this has led to subsidies and cross-subsidization of specific customer groups, in many cases deviating significantly from efficient pricing.

Given the role of power in society and economies in general, the implications of pricing and revenue-collection policies are enormous. For example, below-cost tariffs can seriously hinder the financial health of the provider as can high levels of non-technical losses (i.e. billing errors, electricity theft and bad debts).

Electricity tariff regulation and forecasting is a critical process for all stakeholders in the electricity sector including government, regulators, utilities, IPPs and end-users. For the government and utility, the long term tariff forecast is driven by assumptions regarding the future development and expansion of the sector. Regulators use tariff forecasts as a means to protect the short and long run interests of consumers, and end-users and IPPs both use tariff forecasts as a means to develop future business plans.

12.2. Module Purpose

As none of the RERA members have a fully deregulated competitive electricity market, this module will only cover the methodologies and processes used in regulating and forecasting electricity tariffs in *regulated markets which are traditionally dominated by a government supported utility*. That is not to say that IPPs do not play a role in these markets; however in these cases the market structure still largely reflects the monopoly status of the utility, with the IPPs providing either emergency power or as a minority supplier from (for example) renewable energy procurement programs.

12.3. Key Definitions & Concepts

12.3.1. Key Definitions

Table 6: Definitions - Tariff Regulation & Forecasting

Central Buyer (Single Buyer)	Means the component within a systems or market operator responsible for the purchasing of electricity from utility generation, IPPs or embedded generators for the purpose of the re-selling thereof to customers;
Cost plus rate-of-return tariff regulation	Regulation which allows a revenue requirement that would essentially cover the allowable costs of the regulated entity plus a return for the shareholders
Cross-subsidies	Over recovery of revenue from customer tariff classes whether intentional (e.g. electricity levies) to balance the under-recovery of revenue from customers in other tariff classes (i.e. electricity subsidies) as calculated in the cost of supply study or unintentional by way of unidentified surcharges within the ESI or as a natural consequence of cost pooling
Depreciated Replacement Cost (DRC)	DRC is derived from the modern equivalent asset value for the replacement of fixed assets that have been adjusted by accumulated depreciated taking into account the age and condition of the asset
Indexation based tariff regulation	Adjusting tariffs in line with an inflationary indicator and adjusting for certain variables defined by the regulator.
Incentive based tariff regulation	Incentive-based regulation can be defined as the specific use of rewards and penalties to encourage specific outcomes and behaviors
Modern Equivalent Assets Value (MEAV)	An asset valuation methodology whereby the current cost of replacing an asset with its modern equivalent asset is adjusted for physical deterioration and all relevant forms of obsolescence and optimization to allow reasonable return on such RAB to ensure the financial viability and sustainability of the utility while preventing unreasonable price volatility and excessive sustainability
Regulatory Asset Base (RAB)	The Regulatory Asset Base (RAB) must represent assets used to provide regulated service by each of a utility's business operations of electricity generation, transmission and distribution
Revenue Requirement	This is the total amount of money a regulator allows a utility to earn
Cost of Supply Studies (COSS)	Standard procedure for deriving and allocating costs of Supply, used for the design of tariffs
Cost Reflectivity	The pricing method to reflect the full economic cost of supplying electricity to a customer
Subsidies	The application of funds generated from taxes, levies and other sources, outside of the electricity sector, to lower the charges to particular customer categories.
WACC	The Weighted Average Cost of Capital (WACC) is the weighted average of the expected cost of equity and cost of debt.

12.3.2. Concepts

History of Tariff design and regulation

This section of the module should discuss the way tariffs have evolved over the past 70 years as electricity markets have changed and developed. Key issues to mention would be the centralization of generation, natural monopoly of transmission companies and decentralization of distribution.

"Since the supply of electric power leads to the establishment of a virtual monopoly in a commodity which has become practically a necessity of modern civilization, it should, while being left as far as possible to private enterprise, at the same time be placed under government control and subjected to regulations which shall secure the equitable supply of power, the public safety and public interests generally"

The role of foreign investment vs. state funding should be explored as well as the development of independent regulators to protect the interests of the various stakeholders. Further discussion regarding the development of licensing conditions and the inception of tariff regulation.

The central philosophy underlying tariff regulations and structuring has remained intact i.e. the recovery of prudent operating costs as well as a mechanism for the replacement and growth of the system.

Market Structure and Impact on tariffs

Attendees should acquire a working understanding of the development of the electricity industry and how this has affected tariffs. The final outcome is a coherent picture of the most common market structures in place amongst the RERA members, as well as an overview of how prices and tariffs are managed in each of those jurisdictions.

The last two decades have witnessed a significant shift in power market structure in many parts of the world via so-called market reforms, as the sector has changed from an historical vertically integrated state dominated monopoly to unbundled competitive markets characterized by increasing numbers of private generators (or IPPs).

As electricity markets have evolved and reformed, four typical basic market structures have emerged. These should be compared in more detail, to build on the outcome of the previous introduction.

The typical market models are:

1. Monopoly
2. Single-Buyer
3. Wholesale Competition
4. Retail Competition

Based on international experience from countries that have implemented and revised their own market models, and particularly lessons from market reforms in Africa, a hybrid "non-exclusive central buyer" model has emerged. This model seems to overcome many of the problems experienced in markets that implemented the classic single buyer model while retaining the important benefits. This model is either already in place or under consideration in many of the RERA member countries.

Importantly, the market structure will inform how prices are set and tariffs are either regulated or competitively negotiated depending on the parties and which area of the electricity supply value chain they take part in. Also the market structure and associated rights of who may trade with whom will determine the extent that tariffs may be bundled or should be unbundled. Depending on the specific structure different tariffs may include

- Generation tariffs/charges
- Transmission (network) tariffs/charges
- Distribution (network) tariffs/charges
- Wholesale supply tariffs/charges
- Retail supply tariffs/charges

Pricing Objectives

Electricity regulators have a number of general aims when establishing tariffs:

1) Protection of consumer interests (price and quality)
2) Ensuring non-discriminatory service
3) Ensuring industry sustainability for efficient participants
4) Promotion of industry efficiency (operational and investment)
5) Promotion of competition (if applicable)

The balance that regulator's face in managing tariffs and pricing objectives are described in the table below.

Expectations	Tariff Objectives	Description
Customer	1. Affordable	Least cost options (price should exclude inefficiencies)
	2. Non discriminatory	Tariffs should be applicable to all customers on an equal and fair basis
	3. Predictable & Stable	Customers should be kept informed and real price adjustments should be gradual
	4. Transparent	Easy to read and apply, and contains no hidden costs
Utility	5. Cost Reflective	Cover the <u>costs</u> of the business <u>plus</u> a return (profit) component

	6. Encourage efficient use	Appropriate price signals that will stimulate efficient use of electricity
	7. Implementation cost	Implementation and transaction costs should be low
Government	8. Social Support	Tariff levels and structures should accommodate social programs
	9. Self-sufficiency in generation capacity	Expansion through development of own resources
	10. SOE's to be self-funding	Electricity Sector should not rely on Government for funding
	11. Shareholder expectations	Appropriate taxation & dividends

Key components and structuring of electricity tariffs

An overview of common type of tariffs found in RERA market should be given here. This should include differentiation by customer type, voltage, geography and time of Use.

A description of common tariff components should also be given i.e. energy charge, capacity charge, network usage charges, service and reliability charges – for both generators and loads. Thought should also be given to the concept of cost-reflective tariffs and how they form the underlying basis for a viable electricity industry. Tariff components which distort cost-reflectiveness e.g. subsidies, must also be discussed as a social development mechanism.

Overview of methodologies available for setting electricity tariffs

The chosen methodology used to calculate tariffs will determine the basis for the approach in designing a tariff forecasting tool or model. It is therefore crucial the attendees are able to assess and internalize the options available and the differences between the various approaches.

Regulated Tariffs to captive customers are usually determined by way of a defined tariff methodology.

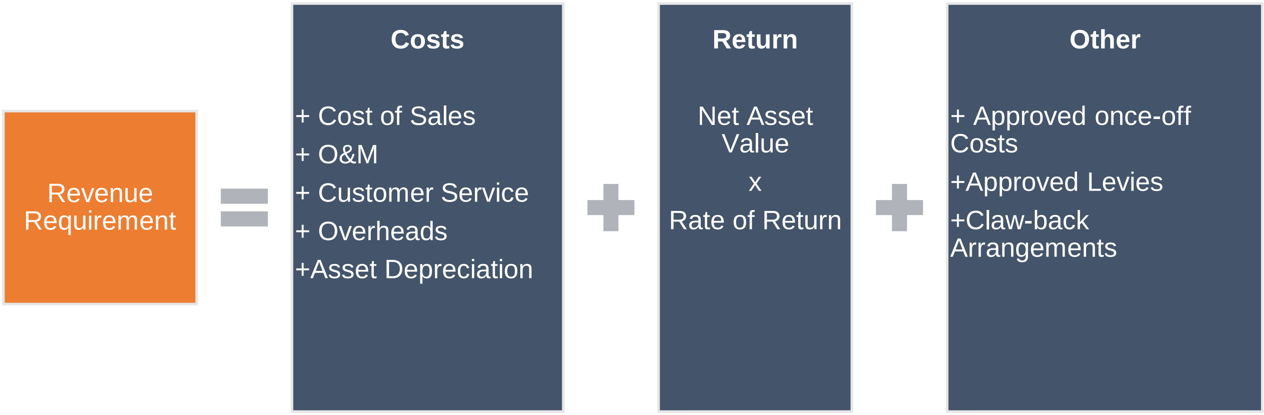
The typical methodology options are:

- Cost based (e.g. cost + reasonable return)
- Indexation based (CPI% – x% + y%)
- Incentive based (tariff set through benchmark analysis)

The module should elaborate on each of these together with the relative advantages and disadvantages.

The most common form of tariff regulation is based on a cost plus rate of return methodology. An assessment of the key components and building blocks of this methodology should be given in this section. The typical building block approach would for example include the components below.

Figure 10: Cost plus Rate of-Return Methodology Building Blocks



In essence this cost plus rate of return methodology delivers a total allowed (i.e. regulated) revenue requirement that would essentially cover the allowable costs of the regulated entity (either vertically integrated utility or generation, transmission, distribution or supply business).

Utility Revenue Requirements (Average Costing Methodology)

> The first step associated with the cost plus rate of return methodology is to determine the utility's revenue requirement as set out above. These costs are then allocated using cost drivers (Energy, Demand, Customers, and Staff etc.).

The module should provide an example of this is calculated in practice. Explain how the average tariff is projected by forecasting total costs (as above) and dividing by forecast demand (in GWh) to give an average tariff that can be used for tariff increase applications or average tariff forecasting.

Calculating Cost of Supply (CoS)

> In order to derive specific customer tariffs, it is necessary to determine exactly how much it costs to service each customer group by differentiation and scaling. The module should explain how customers are differentiated by geography, voltage type, meter, time of use and load factor. This will lead to the formation of cost-reflective customer charges, which should be described e.g. energy rates, demand rates, service rates etc.

A Cost of Supply Study is also normally required by regulators to analyze the utility's costs and tariffs.

A cost of supply methodology must set out the following:

- Cost allocation principles (causality; objectivity; consistency; transparency)
- Cost approach to be followed
- Dealing with affiliate transactions and transfer pricing (in case of a vertically integrated utility)
- Dealing with common costs

Subsidies

The final step to describe is the formation of tariffs is deviation from cost-reflectivity via subsidies. Subsidies are widely applied throughout the RERA countries either explicitly as a portion of the tariff charge, or implicitly embedded within the electricity tariff.

The development of a subsidy framework will require an entirely separate module, but this section should include an overview of the most common type of subsidies and how they are funded.

Particular effort should be made to explain how different subsidies can, over time, lead to significant distortions in tariffs which ultimately lead to poor investment and economic decisions, uneconomic bypass and over-consumption. Finally some thought should be given to explaining how to ensure that subsidies meet governments intended socio-economic objectives.

Subsidies are largely misunderstood and it is important to establish common terminology and understanding of the various types of subsidy that exist, including subsidies, cross-subsidies, levies and surcharges.

These may include (for example):

- Electrification & rural cross-subsidy
- Inclining Block Tariffs
- “Free basic electricity” cross-subsidy
- Low voltage cross-subsidy
- Rural subsidy
- Carbon tax
- REFIT
- Municipal/ Local Authority surcharges (Various)
- Environmental levy
- Government guarantees
- Non-technical losses
- Low returns
- Operational and cost inefficiencies

Introduction of IPPs & Procurement Approaches

In vertically integrated markets, the introduction of IPPs and procurement of their energy by the utility or the single/central buyer necessitates passing through of these costs as part of the utility’s cost base.

This section should discuss the way in which IPP prices are negotiated and how their energy is procured i.e. through Feed-in Tariffs, so-called “Reverse Bid” Auctions, RFP and unsolicited bids.

IPP pricing

Whilst regulated tariffs are managed via the methodologies discussed earlier, negotiated prices will mainly be driven by supply and demand factors. Key issues here are avoided costs, long run marginal costs (LRMC) and short run marginal costs (SRMC) and Levelized Cost of Energy (LCOE).

Some discussion regarding calculation, evaluation and application of LCOE using financial models should be incorporated with a basic overview of a simple LCOE building blocks. This should provide the user with a means to project long term prices from an IPP. Advantages and disadvantages of LCOE method must be discussed, as well as basic information required and assumptions.

Forecasting models and tools

Possibly an area that will attract significant interest from attendees – this section should build on the theory discussed in previous sections of this module – specifically regarding the determination of regulated tariffs.

This section should once again refresh attendees understanding of how market structure and the cost plus rate of return (or other methodology) impacts on tariffs. The forecasting tools described here will be for the average costing methodology and will not take the next step of translating that into specific customer tariffs.

A brief overview of well-known forecasting models should be given – Plexos, for example. However; it should be made clear that it is possible to build functional, efficient and accurate forecasts using spreadsheet software like MS Excel or Google Sheets. In the case of building a bespoke tool in Excel, the model will effectively be translating the regulator’s tariff methodology into a spreadsheet format.

There are several common components utilized in many forecasting tools and combined in different ways. Any bespoke tariff forecasting model will need the following basic components which should be described in detail here:

1. Supply Inputs – Capital Costs, S-curves, Fuel Costs, O&M Costs, Project Life, Discount Rates/ Returns on Assets, Asset Depreciation, Production constraints
2. Demand Inputs – Starting values for energy and demand, annual energy and demand growth, hourly load duration curve
3. System Inputs – Carbon taxation, levies, surcharges, other once-off costs, claw-backs
4. Outputs – hourly commitment and production schedules, hourly fixed and variable costs

"Cost- Plus" Model Components

This model will solve for the average tariff which can be described as the utility/ systems operator's expected revenue requirement divided by the expected energy sales.

These key model component's should be further broken down into their respective sub-components and assessed in detail – they are listed below.

Revenue Requirement

Revenue Requirement = Prudent Expenditure + Return on Assets (RoA) + Other

In this case Prudent Expenditure should be broken down into supply inputs including cost of sales, O&M, overheads and asset depreciation. Depending on the system being modelled, the cost of sales will include capital costs, fuel costs etc. as described in the section above.

The issue of a return on assets is sometimes a contentious topic. Key issues to be addressed in this section are the allowed Rate of Return that should be applied and how the Weighted Average Cost of Capital (WACC) are calculated, as well as the value of the asset base used.

Asset Values

This can be historical values, replacement values or a combination of the two for different types of assets (e.g. Transmission vs. Generation). Some analysis of the applicability of each option should be given here. Power systems assets generally have long life spans which allows assets to be depreciated more slowly – this will have an impact on the rate of increase in tariffs being modelled.

WACC

The allowed return on assets is calculated based on the WACC determined through application of the capital asset pricing model (CAPM). This approach determines the cost of debt financing and that of equity and applies a target D:E ratio to determine the WACC. It is recommended that each component of this calculation be critically assessed. State-supported utilities in a non-competitive environment (with low risk and regulated returns) would typically be awarded a lower WACC compared to private utilities internationally. The cost of equity for a state-owned corporation is more closely related to the state's (lower) borrowing cost.

Using the WACC as a proxy for the RoA, it is possible to adjust the tariff by simply lowering or raising the return expectations. This can be considered one of the key levers for adjusting tariff paths.

Other Credit Metrics

Ultimately the tariff that is set needs to ensure the viability of the regulated entity. It is not possible to simply lower the return expectations via adjusting the WACC without testing the financial viability through the assessment of other key financial ratios such as debt-service-cover-ratio (DSCR), interest-coverage ratio (ICR), loan-life-cover (LLC) and others.

These metrics are assessed by credit ratings agencies and lenders in order to gauge the financial health of the regulated entity and will impact on their ability to raise funding for system expansion through debt.

Affordability

The viability and fundability of the regulated entity need to be balanced with the affordability of the electricity being supplied. This is an important point to discuss from a social development point of view as well as an economic point of view – overpricing can erode the customer base, leading to decreased sales volumes due to lower demand. This can also result in increasing tariffs as the utility seeks to secure the same amount of revenue from a smaller group of customers.

Forecasting electricity tariffs from a “least-cost” point of view is often the starting point from which to depart; however inevitably this price path will be adjusted based on a wide range of issues, many of which are external to the electricity sector itself. Affordability is most often managed through the development of cross-subsidization between customer groups; however that is beyond the scope of this module.

Other

The “Other” category in the methodology is a catch-all for those costs or rebates that need to be incorporated into the tariff, but are outside of the issues discussed previously. An example of this is the inclusion of a carbon tax or the “claw-back” of revenues due to under-recovery of revenues due to (for example) fuel cost increases.

Model Design & Structure

The model built to forecast tariffs should therefore be able to incorporate and manage the inputs described above, as well as provide a series of outputs - tariff price path, credit metrics and key financial ratios, management accounts for various entities etc. The model also needs to be able to solve for a particular tariff i.e. provide outputs (as above) based on a tariff input by user. Alternatively the model should be able to provide a tariff projection based on the input of specific assumptions regarding cost of supply, depreciation and returns.

12.4. Recommended Reading

After gaining some theoretical knowledge regarding the design and structuring of tariffs, it is critical that anyone wishing to pursue electricity modelling gain some practical experience by either building their own models or using licensed software. It is unusual to find a single model which will meet the requirements of the user and it is not uncommon to find a “suite” of tools that have been developed by experienced modelers in the utility space, which are used on an ad-hoc basis.

There are several fora on the internet which specialize in providing assistance in best practice and modelling techniques. It is therefore possible to “learn on the go”; however it is far more important that the modeler is able to understand and translate the methodology and structure required, than it is to be able to develop complex programing.

Below are some recommended papers on tariff design, methodologies and structures.

Table 7: Recommended Reading - Tariff Regulation & Forecasting

Title	Source	Description
Tariff History	http://www.eskom.co.za/CustomerCare/TariffsAndCharges/Documents/TariffHistory.pdf	A useful introduction to tariff design and structuring in South Africa. Provides an overview of how the Rate of Return methodology is implemented.
Comparison Of Building Blocks And Index-Based Approaches	http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/FarrierSwierConsulting_Comparison_of_building.pdf	The discussion paper undertakes an assessment of the relative merits of building blocks and indexed approaches to regulation of monopoly prices, taking into account practical application issues, incentive effects and the objectives of regulation. The purpose of this paper is to assist policy discussion of the potential for future evolution of the approach to CPI–X price and revenue cap regulation (‘CPI-X regulation’) of monopoly prices for energy networks.
Power Tariffs - Caught between Cost Recovery and Affordability	https://openknowledge.worldbank.org/bitstream/handle/10986/3671/WPS5904.pdf	This is the first paper to build a comprehensive empirical picture of power pricing practices across Sub-Saharan Africa, based on a new database of tariff structures in 27 countries for the years 2004–2008. Using a variety of quantitative indicators, the paper evaluates the performance of electricity tariffs against four key policy objectives: recovery of historic power production costs, efficient signaling of future power production costs, affordability to low income households, and distributional equity.

12.5. Outcomes

Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

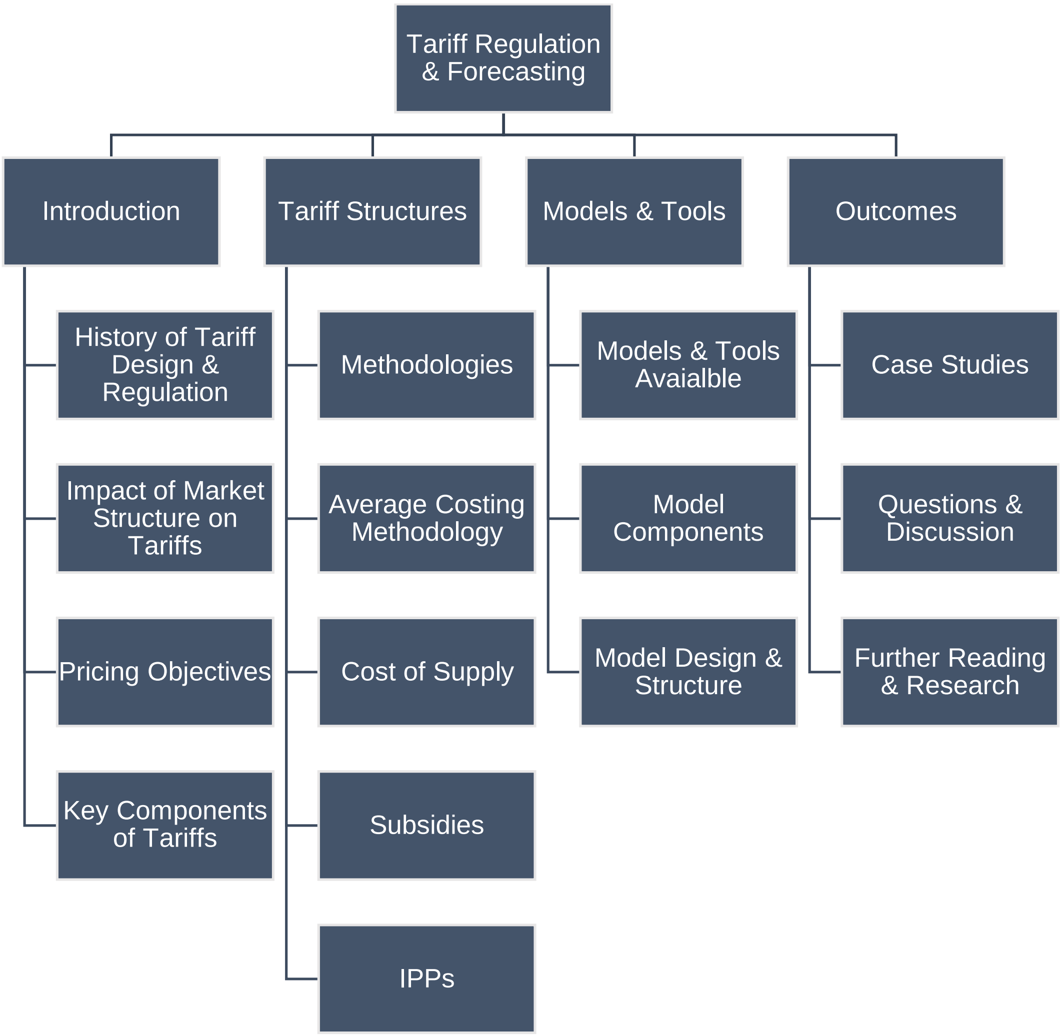
1) What is your understanding of how the market structural changes, regulation and changes in technology have impacted on tariff design?
2) Is it possible to have a full cost-reflective tariff in your market or are there variances from subsidization and political interference?
3) Which pricing objectives take precedence in your market and why?
4) Is the current tariff setting methodology appropriate? Can it be improved to become more cost reflective?
5) Which components of the methodology ae the most contentious (WACC, RAB valuation)

6) How steeply have tariffs increased over the past 5 years – are they cost-reflective?
7) Are IPPs included in the revenue requirement as a primary energy pass through?
8) How are their tariffs set – is there a FIT or procurement program?
9) When was the last CoSS undertaken in your market?
10) Have you built a forecasting tool for tariffs?
11) Are there specific issues regarding tariff structures and modelling that remain unclear and which you would like to discuss further?

12.6. Module Structure

This module has been classified as requiring a moderate/advanced skill level – attendees require the ability to grasp key financial concepts that relate to managing viability of electricity sector.

Figure 11: Module Structure - Tariff Regulation & Forecasting



13. CREDIT RATINGS AGENCIES METRICS FOR UTILITY MANAGEMENT

13.1. Module Introduction

This module contains considerable discussion about the credit metrics and ratings. Credit analysts employed by rating agencies and major bond investors (e.g. bond funds, banks and insurance companies) are responsible for comparing, contrasting and ranking public power investment opportunities. The credits ratings span country ratings (i.e. that attach a rating to the risk associated with government or sovereign debt) and individual company ratings (i.e. utilities and other large private companies). The opinions and ratings of these ratings agencies are important to public power utilities because their opinions have a direct impact on utility capital costs – a large cost component in the capital intensive utility business.

Utilities may prefer to conduct their business without concern for the opinion of these external parties. However as many utilities require considerable amounts of capital (predominantly debt) from external investors, they must be aware of, and responsive to, the opinions that influence investor decisions and cost of capital.

Any organization requiring significant debt funding from local or global markets will need to prove their ability to service that debt to potential lenders – credit ratings agencies purport to provide an independent assessment of that issue based on analysis of a wide range of factors, described in more detail in the “Concepts” section below. Therefore, the methodologies and analysis used by the ratings agencies can be employed by all of the RERA regulators in assessing their utility’s financial viability, whether or not they are also formally assessed in the market.

It should also be noted that the ratings agencies are not infallible and are regularly criticized for failing to accurately assess the true risk of certain investments - most notably during the lead-up to the recession that began in 2009, sparked by the US sub-prime mortgage crisis, a vast amount of which ratings agencies awarded an AAA rating, the highest grade.

13.2. Module Purpose

The purpose of the module is to introduce regulators to the concepts around credit ratings, and highlight the importance of such ratings. It should be acknowledged that not all of RERA’s members require or are currently assessed by ratings agencies; however the process of assessing a utility’s creditworthiness is in itself a worthwhile exercise and will fall under the remit of the majority of regulators.

There is generally insufficient attention paid to the full spectrum of analysis that is undertaken by agencies when evaluating and awarding credit ratings. In many cases, the role of the regulator and the regulatory environment contribute significantly to the final rating. After some consideration, it is clear that without regulatory certainty, the utility or IPP will in many cases not be able to confidently be assured of meeting its revenue requirement and maintaining its financial viability. Thus, it can be argued that the overall purpose of this module is to show how regulators can influence these credit ratings decisions positively, by managing their own responsibilities.

Conversely it is equally important for regulators to be aware of what they cannot influence in terms of ratings agencies metrics.

13.3. Key Definitions & Concepts

13.3.1. Key Definitions

Table 8: Definitions - Credit Rating Metrics for Utilities

Credit Ratings	A credit rating is the opinion of the rating agency on the relative ability and willingness of the issuer of a debt instrument to meet their debt service obligations as and when they arise
Credit Ratings Agencies (CRAs)	An independent company which provides investors with an independent assessment of whether a company/ country will be able to meet its debt obligations or is credit worthy
Regulatory Risk	That portion of the CRAs methodology which deals with risk associated with the regulatory environment in which the utility is based. Typically this includes the appropriate legislation, regulation and behavior of regulator in dealing with the utility
Commodity Risk	Risk associated with exposure to commodities – for utilities this may be oil, gas or coal (fuel) or steel, cement etc. for capital expenditure
Operating Risk	Performance based risk for the utility which can be assessed by examining plant performance and business KPIs as well as extraneous factors such as demand growth
Technology Risk	Risk associated with new technologies that erode the rate base and change consumer behavior e.g. distributed generation renewables (rooftop solar for example)
Financial Ratio Analysis	Utilizing key indicators to measure the utility's ability to fund its debt and operations

13.3.2. Concepts

Who assesses and applies credit Metrics?

A key outcome of this section is the history of the formation of credit ratings agencies and the incredible market power held by the top three companies.

The notion of using independent third parties, who specialized in assessing the potential risk associated with a debt, began to grow in the early 1900s when the three major credit rating agencies of today were formed. Although additional rating agencies were formed in subsequent years (there are currently more than 150), the original rating agencies – Fitch, Moody's, and Standard and Poor's (S&P) – are the most prominent. Moody's and S&P each control approximately forty percent of the market. Fitch controls about fifteen percent, with the remaining five percent allocated amongst the others.

Some attention should be given to the history of each of the top 3 companies to provide some context for the module.

It would appear that Fitch is often used to adjudicate on a debt analysis when there is significant disagreement between a rating by Moody's and S&P, which does occur due to the differences in their ratings methodologies – in layman's terms, S&P will measure the likelihood of default, whilst Moody's rates the potential length of the default.

Fitch[2]

The Fitch Publishing Company was founded in 1913 by John Knowles Fitch, a 33-year-old entrepreneur who had just taken over his father's printing business. Fitch had a unique goal for his company: to publish financial statistics on stocks and bonds.

In 1924, Fitch expanded the services of his business by creating a system for rating debt instruments based on the company's ability to repay their obligations. Although Fitch's rating system of grading debt instruments became the standard for other credit rating agencies, Fitch is now the smallest of the "big three" firms.

S&P

Henry Varnum Poor was a financial analyst with a similar vision to John Knowles Fitch. Like Fitch, Poor was interested in publishing financial statistics, which inspired him to create H.V. and H.W. Poor Company.

Luther Lee Blake was another financial analyst interested in becoming a financial publisher. In order to achieve this dream, Blake founded Standard Statistics in 1906, just a year after Poor's death. Standard Statistics and H.V. and H.W. Poor published very similar information. Hence, it made sense for the two companies to consolidate their assets, and they merged in 1941 to form the Standard and Poor's Corporation.

Today, Standard and Poor's not only provides ratings but also offers other financial services, such as investment research, to investors. They are now the largest of the "big three" rating agencies.

Moody's

John Moody founded the financial holding company, Moody's Corporation, in 1909. Although Moody's provides a number of services, one of their largest divisions is Moody's Investor Services. While Moody's has conducted credit ratings since 1914, they only conducted ratings of government bonds until 1970.

Moody's has grown significantly over the years. Presently, Moody's is the second largest of the "big three" credit ratings firms.

What are Credit Metrics?

Credit Metrics are the "scores" or ratings awarded by a CRA to the utility across a number of different areas. These ratings are usually in the form of a series of number and letters signifying their investment grade e.g. AAA or BA1 etc. A comparison of Fitch, Moody's and S&Ps investment grades and compared below.

[2] A brief but useful introduction to the top 3 firms can be found at http://www.moneycrashers.com/credit-rating-agencies-history/ and is provided here for ease of reference (Fitch, S&P, Moody's)

Table 9: A comparison of various credit ratings

Fitch	Moody's	S&P	Rating Grade Description	
AAA	AAA	Aaa	Investment Grade	Minimal Credit Risk
AA+ AA AA-	AA+ AA AA-	Aa1 Aa2 Aa3		Very Low Credit Risk
A+ A A-	A+ A A-	A1 A2 A3		Low Credit Risk
BBB+ BBB BBB-	BBB+ BBB BBB-	Baa1 Baa2 Baa3		Moderate Credit Risk
BB+ BB BB-	BB+ BB BB-	Ba1 Ba2 Ba3	Speculative or "Junk"	Substantial Credit Risk
B+ B B-	B+ B B-	B1 B2 B3		High Credit Risk
CCC+ CCC CCC-	CCC+ CCC CCC-	Caa1 Caa2 Caa3		Very High Credit Risk
CC C	CC C	Ca		In or near default with possibility of recovery
DDD DD D	SD D	C		In or near default with little possibility of recovery

Overview of Credit Metrics Assessments

The top 3 agencies all have a different approach to ratings of regulated utilities, although inevitably there is some overlap at a high-level in their methodologies.

In their efforts to assess and compare a utility's credit strength, the rating agencies consider a variety of credit characteristics – both objective and subjective in nature. This section of the module should provide a basic overview of the following key areas associated with the evaluation of a utility including the following qualitative and quantitative risks:

1) the political environment
2) the regulatory environment (tariff setting; cost-reflectivity; cost-recovery mechanisms, transparency of decision making, predictability of decision making)
3) the company's structure & sovereign risk (legal basis; corporate structure; size)
4) operations & business risks (commodity exposure; customer base; KPIs on performance, budgeting)
5) the company's financial strength (balance sheet, quality of assets) and liquidity (associated cash flows, debt burden)

The module developer can refer specifically to the methodologies for regulated utilities published by the CRAs for more insight on how the metrics differ and how they contribute to the overall ratings assessment.

The Political Environment

There are some counterintuitive concepts that can be explored regarding political risk in developing countries.

Traditionally, African countries have fared poorly in this regard; however there are numerous countries (especially in Sub-Saharan Africa) that have improved their governance, reduced conflicts and are generally regarded as relatively attractive investment destinations.

In their favor, these markets are less fragmented and competitive than many developed markets, with a much closer relationship between the utility and the sovereign. In these situations, there is a greater chance of sovereign support in the event that the utility requires financial reinforcement.

Due to the monopolistic structure, there are often less stakeholders involved in the electricity value chain, with simple, clear jurisdictions and responsibilities.

Regulatory Risk

It is interesting to note that all of the CRAs look at the Regulatory Framework initially - before proceeding to look at any of the other factors that will impact on the rating. The key concept for the trainer to present here is that unfavorable regulatory policy, legislation or rules will hamper a utility's ability to:

1) recover its prudent and efficient costs effectively
2) meet its debt obligations
3) maintain a specific quality of service
4) allow shareholders to make an adequate return on investment

Due to the nature of the utility business, it is almost impossible for a utility to address the risks of an inconsistent regulator or one which may be subject to political interference. As mentioned in the introduction, this is one of the most important concepts for regulators to consider for this module – Moody's have weighted this issue with a full 25% of the total assessment value! Finally, CRAs will also inspect the potential for change in the regulations themselves, with possible negative consequences.

Finally, possibly the most critical aspect of regulatory risk reviewed by CRAs is the methodology and practice of tariff setting, with a heavy emphasis on consistency in application.

In their methodology they explain this as follows:

"*For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to*

Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions."[3]

Corporate Structures

There are two key issues to be dealt with in this section:

1. Corporate and legal structure of the utility
2. Franchise or concession term of the utility (if appropriate)

Corporate structure can impact on a utility by virtue of its relationships with either subsidiaries, parent companies or in some instances the sovereign shareholder. The key issues to highlight here are:

1. Is the utility financially aided by or burdened by its relationships
2. Does the shareholder rely on dividends in order to support other non-regulated businesses or in the case of a government as an input to the fiscus
3. Is there legal interdependence which would align the entities credit ratings
4. Is there any legislation limiting the funding support from the parent/shareholder
5. Is there adequate legislative protection for debtors to the utility

There are no RERA members subject to a franchise or concession term; however if this were the case, CRAs would assess the terms of the concession for issues which would increase their risk factor.

Operations & Business Risks

There are some notable risks that need to be addressed in this section of the module. Much of the operational risk that sits within a utility is also carefully regulated in order to manage financial variances which may impact on consumer tariffs. The key risks can be listed as:

1. Changes in Demand & Customer Base
2. Operational Performance
3. Commodity Risks (diversification issues)
4. Exchange Rate Risks
5. Competition
6. Technology
7. Management & Strategy

Even those utilities that operate in monopolistic or largely uncompetitive environments face distinct operational risks that they need to manage carefully.

[3] Moody's Rating Methodology: Regulated Electric and Gas Utilities, August 2009 – this has subsequently been updated in 2013, but is aligned on this point

Depending on the regulatory methodology and the efficiency and prudency of these variances, the utility may be able to claw-back some of the variance; however if it has no recourse, these may have a serious impact on their financial viability – and lead to a downgrading of their credit rating.

Some further comment on these issues is provided below.

Changes in Demand & Customer Base

Whilst utilities are often insulated from changes in a country's overall economic performance with relatively predictable cashflows, poor operational and business management can still result in variances from the regulators allowed revenue requirement.

Economic uncertainty and poor performance can lead to changes in demand forecasts, which ultimately impact on the utility's ability to meet its revenue requirement. A useful example in 2015, is the downturn in demand for global commodities led in part by shrinking demand from China. This has led to a number of energy intensive companies, in the primary sector, cutting back on production and lowering their demand for electricity. It is unlikely that any utility in RERA would have foreseen this threat to their demand forecasts, but the consequences could have a material impact.

Further examples include changes in customer base – utilities with poor geographic of consumer diversity face serious risks if there is an unforeseen issue with a particular geographic area or a customer category.

Operational Performance

Utility performance is often measured through KPIs that reflect operational status e.g. Energy Availability Factor (EAF), Planned and Unplanned Capability Loss Factor (PCLF & UCLF), etc. These ratios provide a useful insight into the performance of the fleet and a historical examination of trends in these ratios can reveal serious issues in staff management, maintenance and technical capability (for example). CRAs will assess these trends and any deviations will be analyzed to gauge the impact on the business. A decreasing UCLF and EAF will inevitably signal a performance risk in the utility's ability to ensure security of supply, which in turn threatens its ability to meet its revenue requirement – this would be considered a significant credit risk.

Commodity Risks

CRAs often assess a utility's exposure to commodity risks e.g. coal, oil, gas with regards to fuel for power stations and steel, cement etc. for capita build projects. Often regulators will allow a "pass-through" for increases in the price of these costs, but will not always allow for variances in volumes. Any variances in volume will usually be checked for prudency and efficiency by the regulator and will not necessarily be awarded. In the case of a utility that relies heavily on one fuel source (i.e. there is little diversity in their fuel mix), the CRA will be particularly concerned with assessing the impact of this risk. Even in the case of a regulator allowing a "pass-through" or tariff increase to cover these cost variances, there will generally be a lengthy process before these costs are actually recovered, which will require the utility to pre-fund and carry the costs before they are refunded.

It should be noted that in general, diversity in customer base, fuel mix, generation types etc. will be looked on favorably by the CRA in mitigating these operational issues.

Exchange Rate Risks

Developing countries may earn revenues in local currency, but face exposure to foreign currency denominated debt. This can be a serious issue in the case of a large capital build program of on-going fuel pricing exposure, where local currency volatility can seriously strain the liquidity of the utility and ultimately inflate the total cost of new build projects. these unforeseen costs will need to be accounted for an will generally be passed through to consumers leading to tariff increases, unless there is shareholder (government) intervention.

Competition Risk

In many developing markets with incumbent monopolies, competition risk can manifest from the introduction of IPPs. The utility will now be benchmarked against another competitor and if not found to be able to compete in terms of efficiency and costs, the utility may find itself being sidelined as further IPPs are allowed in to the market. It is often stated that competition is in fact the best form of regulation and this may prove advantageous for both IPPs and consumers; however this will prove a serious threat for the monopoly utility and will be judged accordingly by an CRA.

Technology Risk

The timeframes in which utilities make investment decisions (sometimes over 60 years for certain assets), exposes them to certain technology risks. A useful example is the recent trend towards self-generation via distributed generation renewable energy technologies. The drop in prices of PV panels, coupled with feed-in incentives and rising consumer tariffs has led to massive uptake in self-generation in developed markets. It is expected that this will in turn be taken up in developing countries which additionally suffer from poor security of supply, a further incentive for uptake.

Once these new installations reach a certain threshold, there may be an impact on the ability of the utility to meet its revenue requirement due to the decreasing demand, with consequences for their credit rating.

Management & Strategy

CRAs will evaluate the businesses management and strategy for coherence and sustainability. Key issues to be assessed beyond operational performance are the skills, experience and institutional capabilities within the utility itself. Without capable staff, it is likely that KPIs for service quality will deteriorate, amongst others. Due to the nature of the utilities position, it will be required to interact frequently with government and the regulator and credible and trustworthy management should be appointed that can adequately manage these crucial relationships.

Financial Strength

When reviewing the financials and especially the forecasts, the CRA analyst will undoubtedly stress-test the business by running adverse scenarios based on a deterioration in the issues already uncovered or suspected to materialize.

Key areas here are:

1) Liquidity
2) Capital structure (debt vs. equity; type of debt; debt schedules and maturity)

3) Financial Ratios & Benchmarking

Not surprisingly, a large portion of the CRAs assessment will focus on the details of the utility's financial strength. There are several issues to present in this section that warrant detailed attention; however a key principle to be presented, is the emphasis on cash-flow analysis. In short, the CRA will assess whether the utility is able to meet its debt service and operational funding requirements via a number of key ratios which will be described below. These key ratios and the cash-flow analysis will typically be both historical and future focused in order to determine any alarming trends in the utility's finances – a snapshot of the current situation will not provide adequate insight.

It is important for the presenter to contextualize the positioning of the financial analysis after assessing the political, regulatory and operational environments. The financial analysis should present empirical evidence of the issues that the CRA has already intuited from their prior assessments and is therefore an outcome of issues that presented earlier.

Liquidity

As stated above, cash-flow analysis techniques form the bulk of the liquidity assessment to ensure that the utility is able to meet its forecast debt and operational funding requirements. Typically CRAs will assess debt schedules and operational budgets to form a baseline assessment of the liquidity position. These will then be adjusted according to a number of scenarios to test the utility's ability to flex and adjust to various unforeseen funding requirements or constraints.

A liquidity analysis will therefore start with an assessment of Funds From Operations (FFO) also referred to as Cash Flow from Operations (CFO). From this, the analyst will usually deduct working capital requirements (for day to day operations), capital expenditure (build programs, maintenance) and dividends for the shareholder. Following this, the CRA will then assess whether or not the remaining funds are sufficient to meet any debt requirements, guarantees or other liabilities not taken into account earlier.

Capital Structure

The utility's capital structure is essentially the structure of their equity and debt. Critical issues here are the ability of the utility to adjust to their structure to meet their on-going operational requirements, service debt interest and principal and manage any foreign exchange risk. Debt schedules will typically provide some insight into risks arising from refinancing requirements.

Financial Ratios & Benchmarking

Ratio assessments are typically most often recognized as part of the CRA analysis, but only form part of the overall assessment. Below are some of the key ratios assessed and what they mean:

Table 10: Selected financial ratios for utility management

Ratio	Description	Note
FFO	Funds From Operations – the cash flows generated by a business	Two primary indicators of whether a utility will be able generate enough funds to meet its operational and debt funding requirements
EBITDA	Earnings before interest, taxes, depreciation and amortization	
FFO interest coverage/ EBITDA interest coverage	Essentially FFO or EBITDA divided by Interest Payments	Ratios that are used to assess a company's financial durability by examining whether it is at least profitably enough to pay off its interest expenses. A ratio greater than 1 indicates that the company has more than enough interest coverage to pay off its interest expenses
FFO fixed-charge coverage/ EBITDA fixed-charge coverage	Essentially FFO or EBITDA divided by fixed charge (plus interest)	A ratio that indicates a firm's ability to satisfy fixed financing expenses, such as interest and leases. It is calculated as the following
FFO to Debt	Funds From Operation (FFO) to total debt is a metric comparing earnings from net operating income plus depreciation, amortization, deferred income taxes and other noncash items to long-term debt plus current maturities, commercial paper and other short-term loans.	The lower the FFO to total debt ratio, the more highly leveraged the company is. The higher the FFO to total debt ratio, the stronger the position the company is in to pay its debts from its operating income.

Typically CRAs will evaluate these ratios against standard benchmarks to award a rating. In doing so they will consider general guidelines for corporate entities as well as a more detailed assessment of applicable standards for utilities (in essence their peers).

13.4. Recommended Reading

All three of the main CRAs have published methodologies on how they evaluate utility risk and measure their investment rating. These provide excellent insight and are a critical starting point. The CRAs also release reports detailing their assessments following a change in a utility's investment rating – these provide further understanding into their rationale and assessment process.

Table 11: Recommended Reading - Credit Rating Metrics for Utilities

Title	Source	Description
Fitch Methodology	http://www.globalclearinghouse.org/InfraDev/assets%5C10/documents/Fitch%20-%20Credit%20Rating%20Guidelines%20for%20Regulated%20Utility%20Companies%20(2007).pdf	As above – an overview of the methodology and process for the RCAs assessment of regulated utilities
Moody's Methodology	http://www.rmgfinancial.com/core/files/rmgfinancial/uploads/files/7%20Regulated%20utilities%20RM%202009.pdf	As above – an overview of the methodology and process for the RCAs assessment of regulated utilities
S&P's Methodology	http://www.maalot.co.il/publications/MT20131127143752a.pdf	As above – an overview of the methodology and process for the RCAs assessment of regulated utilities

13.5. Outcomes

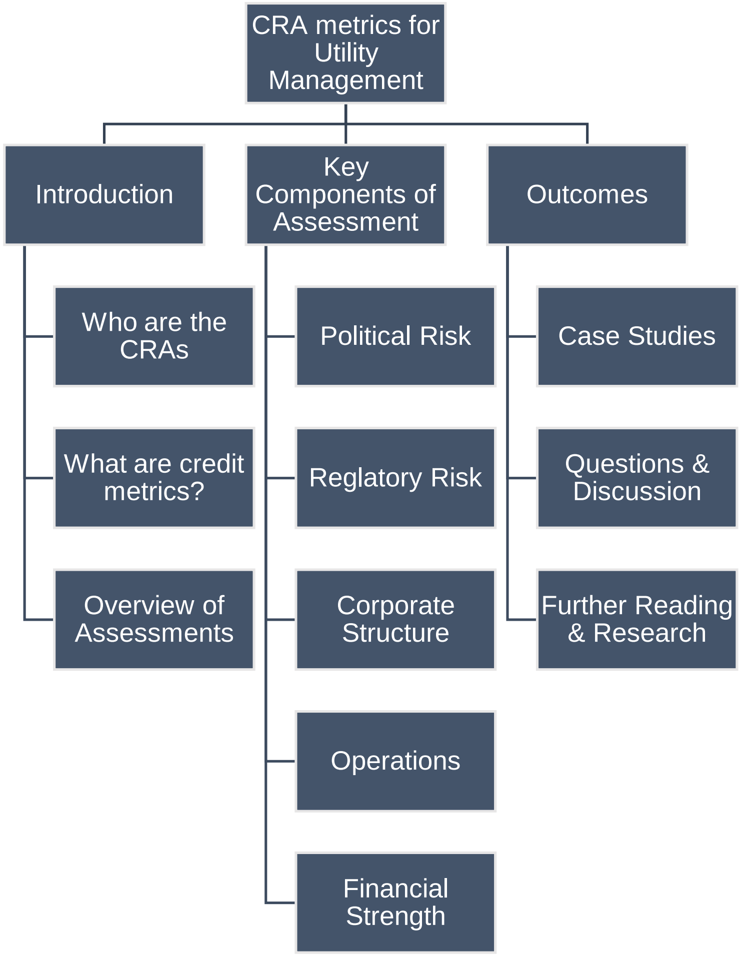
Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1) What is the difference between "investment" grade and "speculative" or "junk" grade ratings and how will they affect a utility's cost of debt?
2) What are the key components assessed by CRAs when they analyze a utility?
3) Why is regulatory risk such an important component of the assessment?
4) How will regulatory inconsistencies impact on a utility's ability to meet its revenue requirement?
5) How does the relationship between the utility and its shareholder, impact on the utility's credit rating?
6) Which performance indicators will a CRA assess and why?
7) What is the main component of the financial analysis?
8) What are the three key areas a CRA looks at when undertaking a financial analysis?
9) Which credit metrics ratios are most highly used and why?

13.6. Module Structure

This module has been classified as moderate/advanced – a solid understanding of utility finances and accounting is required.

Figure 12: Module Structure - Credit Rating Metrics for Utilities



14. CONSUMER PROTECTION IN THE ELECTRICITY SECTOR

14.1. Module Introduction

The significance of consumer protection was recognized early in the history of the electricity industry. The largely monopolistic market structure prevalent in both developed and developing countries (with generation, transmission and distribution often held in one company) meant that there was potential for market abuse and overpricing. During the initial development of power infrastructure it was acknowledged that given the size of capital investment required and the asset lives, it did not make sense to promote competition in all areas of the market, if any. At the same time the remarkable uptake and use of electricity in both industry and daily living, led to electricity being frequently considered a “public service” along with other common services such as waterworks, sanitation and refuse removal.

The provision of electricity was not seen as a profit making enterprise and as such, prices were kept as low as possible. This structure is currently still prevalent in many developing countries with monopoly utilities managed by government departments, taking responsibility for all areas of the electricity value chain. One of the outcomes of this historical structure was the common practice of setting tariffs lower than the cost of supply in order to support social developmental and industrial policy goals.

In a vertically integrated structure, an independent regulator that can manage the utility and protect consumer rights has become paramount in ensuring that there is a balance between profit and affordability. In fact, where IPPs have been introduced on fringes of a market, the regulator will protect their rights to open network access and affordable network charges.

During the deregulation and unbundling of many electricity markets over the past two decades, it has become clear that establishing competition in certain portions of the market will result in healthy competition, increasing quality of service and efficient pricing. In general, therefore consumers are best served by efficient and competitive markets – where competition replaces the need for regulation and explicit consumer protection.

This has been most effective in Generation, where consumers are able to choose their supplier. However; the structure of Transmission and (in some cases) Distribution grids still requires a monopoly approach – it does not make technical or financial sense to try and operate several independent transmission systems. In this case regulation and consumer protection is still very necessary.

14.2. Module Purpose

The purpose of this module is to discuss and explore the various options available to ensure the protection of consumers’ interests and rights within both regulated and unregulated markets.

This includes a discussion of who is responsible for consumer protection and the methods available to implement appropriate measures. The module will provide an overview of common policy and legislative options for consumer protection and will discuss what consumers can reasonably expect from both the utility (standard of supply) and from the regulatory.

14.3. Key Definitions & Concepts

14.3.1. Key Definitions

Table 12: Definitions - Consumer Protection

Ex-ante regulation	"Before the fact" or forward looking regulation to prescribe or induce market behavior in markets/sectors that do not have sufficient competition, typically applied by sector-specific regulators (e.g. electricity, telecoms)
Ex-post regulation	"After the fact" or backward-looking regulation based on historical evidence of abuse, typically with the imposition of penalties or fines for non-compliance by non, sector-specific regulators (e.g. completion tribunal)
Universal Access	The right for all consumers to be granted some form of connection to and supply from the electricity grid
Electrification Authority	A body or organization specifically tasked by the government with electrifying rural and unconnected urban areas to the grid.
Grid Code	The set of standards and rules governing connection, operation, usage and cost of the Transmission & Distribution grids.

14.3.1. Concepts

Who can protect Consumer Rights?

The introduction to this module should consider the different organizations available to provide consumer protection. The following five organizations can generally be considered as the main protectors of consumer rights:

1) Customer Service department within the utility
2) Special Interest groups
3) Industry bodies
4) Consumer Protection agencies
5) Electricity Regulators

Protection can be grouped into "pro-active" or "re-active" and is sometimes referred to as ex-ante (before the fact) or ex-post (after the fact). Customer service and consumer protection agencies are generally reactive i.e. they act to right a wrong. On the other hand, regulators generally act pro-actively by setting rules, codes, standards and methodologies to guide stakeholders and ensure that each party is aware of its responsibilities.

Regulators are also important because they are generally capacitated with people who have the specialist skills, experience and knowledge to effectively solve consumer issues in a sometimes complex technical environment.

Further, there are issues with jurisdiction overlaps that should be discussed along with the role of legislation.

It makes sense to allow the utility to remain the first “port of call” for any issues with regard to customer service issues, specifically security and quality of issues, as they can most easily provide a solution. However; there is an obvious conflict in that the utility will always put its own needs before the consumer.

Special interest groups and industry bodies will represent groups of consumers with common interests or causes. The group will carry more weight in negotiating with the utility than any specific individual and will be able to address common issues that impact on all parties.

Consumer protection agencies can generally only perform to rectify an issue after the fact and often the legislation governing these agencies is not formulated specifically for the electricity sector, therefore they are not always able to effectively protect consumer’s interests.

Why is there a Need for Consumer Protection?

As has already been demonstrated, any monopolistic structure (whether government or privately owned) will limit the incentive for efficient and effective performance, whilst it is acknowledged that competition generally drives superior execution. Therefore within RERA, there is a notable requirement for regulation in all member markets, given their market structures.

The regulator will be needed to:

1) set affordable tariffs
2) set connection and quality standards
3) set penalties and rewards for performance thresholds
4) adjudicate and resolve complaints

Policy & Legislation Protecting Consumers

Consumer protection is usually listed as one of the overarching aims within the "powers and duties" of the Regulator and should be written into any governing legislation establishing the role and functions of the regulatory body. Further specific objectives for regulators that may be included in legislation are:

1) ensuring that the interests and needs of consumers are supported and met
2) promoting competition and ultimately, end-user choices
3) balancing the interests of all stakeholders (end-users, licensees, investors etc.)
4) supporting universal access for consumers
5) setting standards and enforcing performance
6) enforcement
7) manage investigations and enquiries
8) adjudicating disputes

The trainer can present relevant legislation from certain RERA members as well as international markets, to compare different approaches and inform debate on best practice for legislation and the establishment of an independent regulator.

Meeting Interests and Needs of Consumers

A first step in meeting consumers' needs is providing them with access to the regulator on either an ad-hoc basis or via public hearings on specific topics. The regulator will need to allow public consultation via workshops and consultation processes for key regulatory processes e.g. tariff setting, changes in methodologies/ rules/ codes etc. Finally there should be a specifically described process for the resolution and adjudication of complaints – this may require support and consumer education for customer categories that wish to understand and utilize these processes.

Promoting Competition

Intuitively, this is a principle that regulators will find hard to comply with in a market dominated by a monopoly utility. It must be acknowledged that competition at a generation level is generally sanctioned by the government and regulators are only required to manage the licensing and efficient operation of competing generators. For the "wires" portion of the business (Transmission & Distribution) there is little need to promote competition, therefore where appropriate, the regulator can focus on competition within the retail portion of the business.

In some cases government will promote competition in generation through specific procurement programs – in this case the regulator will be needed to manage the licensing of IPPs that are awarded contracts. Depending on the manner in which the power is procured, it could be argued that the government is implicitly taking on the role of protecting consumer's rights by procuring the most affordable power.

Balancing of Interests

The power sector has a diverse set of stakeholders, each with their own set of unique interests and requirements. The regulator will often be required to balance on-going and contradictory stakeholder interests in order to ensure the viability of the industry. One of the most common is the tension between cost-reflectivity (for the utility) and affordability (for the consumer). Another example is the implementation of environmental objectives via a carbon tax, which raise tariffs for large energy intensive industrialists.

These conflicts are often caused by a misalignment at policy level, with the regulator left to manage the implications. Finally, the regulator may be required to protect the interests of specific customer groups through the regulation of subsidy programs.

In some cases regulators may be asked to adjudicate on technical issues which arise between utilities and their customers e.g. the apportioning of network costs for new connections that require both shallow and deep network strengthening. In these cases, it is critical that the regulator has defined the process for dividing the costs within a set of rules e.g. grid code.

Supporting Universal Access

In this context, universal access describes the right of each person within a market to access an electricity supply of some sort. This is critical in developing countries and regulators will work closely with other government bodies to support this objective. Government will often appoint an "Electrification Authority" to support this initiative, but the right to universal access will usually be described in the legislation governing the regulator as well as other act and rules. Where appropriate the regulator will manage any subsidies or cross-subsidies used to support the implementation of electrification or other access schemes. These can include subsidized or free connections, free energy allocations for the poor etc.

Setting Standards & Enforcement

Often regulators will use incentives in order to enforce or encourage appropriate compliance with standards. In the absence of competition, the "reward" or "penalty" is used to motivate the utility to operate efficiently and to meet consumer's expectations. Standards can include technical codes and rules – importantly they must also define those areas and times where the utility is not obliged to perform e.g. if a consumer connects to the network illegally.

The setting of standards is a regulators first step in effectively ensuring performance. The regulator will define and set adequacy benchmarks for a die variety of issues including:

1) service levels
2) connections
3) reliability & quality
4) maintenance
5) operational KPIs
6) safety
7) metering & billing

Enforcement of standards requires regular evaluation, which is often difficult due to the asymmetrical nature of access to relevant information - the utility will not always make all of its operational data available to the regulator. Often it is only during specific processes like tariff applications, that a utility will provide the regulator with insight into its compliance with all standards.

Investigation & Enquiries

As discussed above, regulators will need to define appropriate mechanisms to investigate and adjudicate on any complaints which consumers may raise. Fines or penalties may be used to award or compensate consumers; however it may be argued that this is a "reactive" last resort. The setting of effective standards and active evaluation of performance, will prove a more effective regulatory tool.

14.4. Recommended Reading

Table 13: Recommended Reading - Consumer Protection

Title	Source	Description
Best Practices Guide: Implementing Power Sector Reform	http://www.raponline.org/docs/RAP_BestPracticesGuideImplementingPowerSectorReform.pdf	A Best Practices Guide Series created by USAID to provide technical information on the topics of power sector reform and regulatory practices. This guide is for regulatory staff members, members of regulatory bodies, government officials and professional interested in or working on establishing or restructuring the power sector, particularly those involved with regulation or establishing or restructuring regulatory functions. Chapter 10 deals with consumer protection issues.
The Policy Of Consumer Protection In The Electricity Market	http://www.doiserbia.nb.rs/img/doi/0013-3264/2008/0013-32640879157F.pdf	The rise of electricity prices and the process of liberalization of the electricity market are the two main factors which have made it necessary to modify the current traditional ways of protecting vulnerable customer categories. The aim of this paper is to analyze the current forms of vulnerable customer protection from the critical point of view and to point out possibilities for their application. It uses Serbia as a case study.

The Role of Consumer Organizations in Electricity Sector Policies and Issues	http://www.naruc.org/Publications/NARUC-06CONSUMER-REPORT.pdf	This report discusses the results of a global survey of consumer associations and consumer advocates conducted by the National Association of Regulatory Utility Commissioners (NARUC) with the support of USAID in May-June 2006. The survey was developed to better understand how and to what extent consumer groups around the world interact with regulators, utilities, and government ministries on electricity issues.
Consumer Participation and Protection in Electricity Regulation	http://www.cuts-ccier.org/CPSER/pdf/Consumer_Participation_and_Protection_in_Electricity_Regulation-A_Study_of_Five_States_in_India.pdf	This study evaluates the current state of consumer participation and protection in five states in India. The selected states were chosen because they provide a diverse mix in terms of political economy, size, electricity consumer base and level of reforms initiated in the sector.

14.5. Outcomes

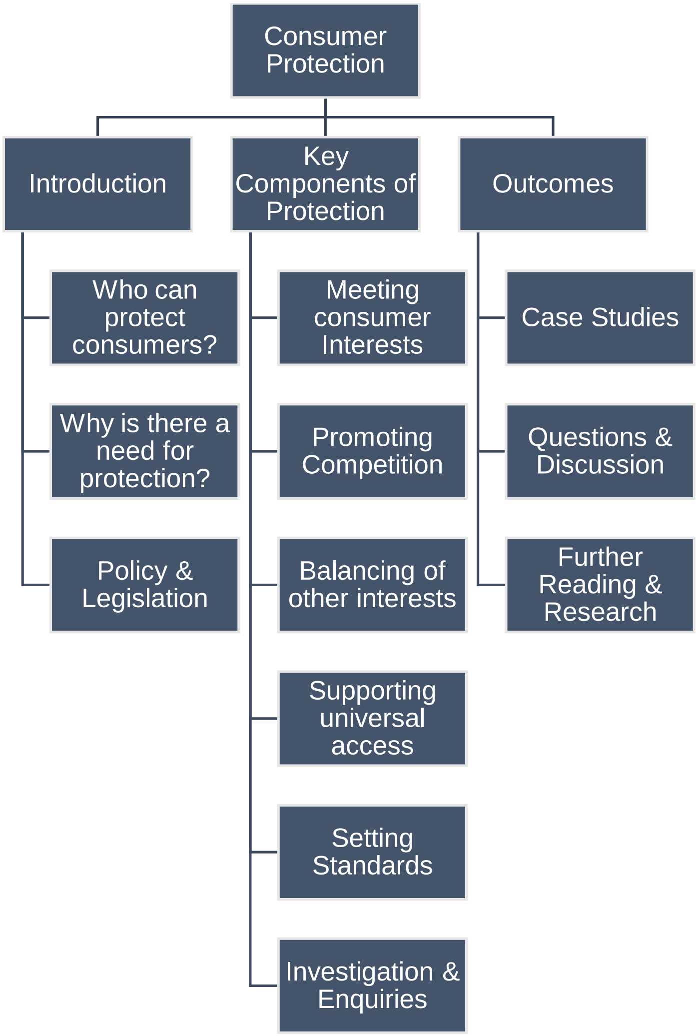
Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1) What types of protection are available for consumers in your market?
2) Do you believe that regulation can adequately compensate for a lack of competition?
3) What level of consumer participation and protection is available in your market?
4) Are the rights of consumers specified in any legislation?
5) What are the most important rights that the regulator supports in your market –is there any room for improvement?
6) Is the regulator required to promote competition –if so at what level of the value chain?
7) Are there any trade-offs or competing interests that need to be managed?
8) What standard are set by your regulator
9) How are these enforced – incentives, penalties etc.?

14.1. Module Structure

Although this module covers one of the most critical functions of a regulator, it has been rated as basic and does not require and specific or special skills.

Figure 13: Module Structure - Consumer Protection



15. INTRODUCTION TO RENEWABLE ENERGY TECHNOLOGIES

15.1. Module Introduction

From the early iterations of wind turbines and parabolic trough technology, Renewable Energy (RE) has fundamentally changed the power landscape over the past decade. The combination of increasing social consciousness regarding climate change, significant investment into "green" technologies, improved efficiency and materials, reduced costs as well as supporting procurement programs have ensured that the installed capacity of RE has increased from 85GW at the start of 2004 to 560GW at the start of 2014.[4]

These "disruptive" technologies have had an extensive impact on the entire power sector, form a financial, economic, technical, legislative and regulatory point of view. Not only do Systems Operators have to adapt to the effects of vast increases in intermittent generation capacity (for example), but regulators in many emerging markets, now face the task of creating a level playing field as RE IPPs enter their markets for the first time.

This module is not intended as an advanced course on some of the deeper issues that the upsurge in RE have brought about. Rather, it provides an introduction to RE technologies and an overview of how they have changed the energy landscape.

15.2. Module Purpose

The purpose of the module is to introduce the salient characteristics of the most common renewable energy technologies that RERA regulators are likely to have to deal with. Trainers and module developers should include the following concepts:

- basic overview of the different technologies,
- comparative Levelized costs, screening curves and a discussion on cost reductions
- common technical and non-technical barriers faced by RE developers
- regulatory and legislative support
- procurement programs (this will be dealt with in detail in another module)
- some statistics on increases in capacity and their global distribution

Following on from this module, attendees should feel comfortable with the more detailed analyses contained in "Support Mechanisms for RE" & "Implications of High Levels of RE Penetration".

15.3. Key Definitions & Concepts

15.3.1. Key Definitions

Table 14: Definitions - Introduction to RE

Wind energy	Electrical energy produced by a wind turbine

[4] Excludes hydropower, from "Renewables 2014 Global Status Report", REN21

Solar Energy	Electrical energy produced by photovoltaic panels (PV) or solar thermal concentrators and a steam turbine (CSP)
Biogas Energy	Energy produced from combusting gas resulting from anaerobic digestion of raw materials such agricultural waste, municipal waste, sewage, food waste etc.
Biomass Energy	The oldest form of RE –includes the burning of food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes.
Geothermal Energy	Is thermal energy generated and stored in the earth resulting from the original formation of the planet and from radioactive decay of certain materials.
Hydro Energy	The production of electrical power through the use of the gravitational force of falling or flowing water. Can be differentiated by run-of-river/ diversion, dam/ reservoir.
Levelized Cost of Energy (LCOE)	The present value of all costs of generation divided by the present value of energy produced
Screening Curves	Screening curves provide a view on the units costs of production at different generation load factors or capacity factors
Feed in Tariff (FIT)	A fixed price tariff offered to RE project developers as a policy mechanism intended to promote investment into RE

15.3.2. Concepts

What is a RE technology?

This section should provide an introduction to the different renewable energy technologies, including wind, solar, bio-energy, hydro, and geothermal energy. It is fundamentally important to identify what is considered to be renewable energy and what is not as well as the criteria applied in making this distinction.

One way of defining renewable energy is to establish a set of characteristics such as:

- Unlimited supply – as opposed to fuel types with bounded or limited reserves (such as fossil fuels)
- “Green” – as opposed to greenhouse gas emitting or other polluting sources
- Indigenous – thereby excluding fuels that are imported

Key characteristics of the various technologies should be explored – different technical designs, standards sizes of key components etc. – a basic overview of the technology produces electricity must be given. It may be useful to consider some of their strengths and weaknesses here.

Many countries have their own definitive lists that may vary from others. Another of the more recent challenges in this definition process is how to deal with hybrid energy solutions that combine renewable and non-renewable resources (e.g. solar PV plus diesel generation or biomass plus coal co-firing or off-season fossil fuel supplementation).

How do the Levelized Costs of RE compare?

One of the other key aspects to consider is the comparative cost of renewable energy technologies. It is important to recognize that a direct comparison of each technology is not straightforward as many of the renewable energy technologies are not directly substitutable. Most notably, the production profiles (e.g. hourly and seasonal variations) and energy produced per MW of capacity (i.e. capacity factor) can vary widely across technologies. Moreover, many factors affect comparative costs and different sources of information can use significantly different criteria for estimating applicable costs.

Levelized costs of technologies can be compared as well as using other approaches including the use of "Net Systems Benefit" analysis – where all the benefits (savings) to the system as well as the costs are offset. People often quantify the value-add of RE by using a life-cycle approach to quantify the offsetting of carbon (for example) over the lifetime of the plant.

These technologies often have high up-front capital costs but very low operation and maintenance costs and may have vastly varying energy output profiles. Levelised cost of electricity (LCOE) is a very useful way of comparing such life cycle costs and should be covered.

A key issue to be discussed is the quantification of environmental benefits of renewable energy technologies (i.e. the so-called externalities). These cost savings through lower pollution levels, greenhouse gas emissions reduction and less damage to the environment, are notoriously difficult to take into account.

Screening Curves for RE

Screening curves are an additional tool that may be applied in proving more meaningful cost comparison between different technologies. Screening curves provide a view on the units costs of production at different generation load factors or capacity factors.

Screening curves are often used by analysts to determine the optimal energy mix for a system given a particular demand. However; they are most often used with conventional dispatchable resources and are not necessarily the most effective approach to designing a system with a high share of renewable energy resources.

This section can briefly discuss how increasing intermittency from RE capacity will require:

1) greater load following flexibility through ancillary services and reserves
2) an adjustment to the load duration curves uses –taking into account a "net load" i.e. load minus intermittent renewable production

Renewable Energy Benefits

The benefits of renewable energy are generally well understood conceptually. These benefits need to be offset against the technical complexities and higher costs of generation – although in 2015, there have been many instances where RE is priced either below or at the marginal costs of conventional thermal capacity (notwithstanding the differences in production profiles). As such this section of the module should provide attendees with a robust understanding of the different benefits that are often quoted as:

- A reduction in harmful emissions & pollutants
- Improved and reduced costs of public health
- Sustainability of supply of energy resources
- Declining costs coupled with increasing efficiencies
- A more reliable, robust and resilient energy system via increasing diversification
- Distributed nature of certain renewable options to:
    - provide off-grid rural solutions
    - reduce grid expansion requirements
    - lower energy losses
    - provide small scale solutions
- Creating new jobs
- Low O&M costs

These benefits can be expanded on and debated more fully during the module – there are many academic and professional research papers on each of these subjects; however it may be useful for the module developer/ trainer to focus on some of the more relevant issues for RERA members e.g. rural electrification and distributed generation of RE; job creation, diversity of supply etc.

Intermittency & Solutions

One of the key issues hampering further installation of RE is the intermittent nature of production. The variability of production and non-dispatchability have led to considerable effort being put into energy storage solutions that can be coupled with RE, to allow them to mimic more conventional resources. However; there are other options that can be explored.

This section should outline the key issues surrounding intermittency and provide a current update on any viable solutions that are being constructed. These can include:

1) Geographical diversity – ensuring that renewable resources are geographically diverse in order to ensure that a minimum capacity is always available
2) Coupling renewable resources with more conventional thermal and hydro resources (e.g. pumped storage)
3) Oversizing capacity in order to account for availability
4) Storage: electrochemical batteries; flywheels; compressed air; hydrogen cells; Electric vehicles

Regulatory & Legislative Support Framework

RE still requires support form policy, legislation and regulation in order to be incorporated into developing markets. In many cases this is due to the current monopolistic market structure as well as the fact that many of the best RE developers are IPPs - entering the market for the first time. There are also pricing and cost issues that need to be managed as in many cases, the inclusion of large portions of RE will inevitably impact on the marginal cost of generation and thereafter end-user tariffs.

The supporting framework will generally be comprised of:

1) Policy – setting implementation targets, environmental drivers
2) Legislation – there may be changes required to existing legislation to allow IPPs and RE procurement programs to be implanted
3) Regulation – amendments will need to be made to key tools such as tariff methodologies, grid codes, licensing applications etc. to cater specifically for RE
4) Panning – RE targets will need to be accounted for in generation and transmission expansion planning

Further consideration should be given to the alignment of RE specific frameworks within the larger governance structure. RE policy may contradict other existing policies e.g. industrial development, whilst complementing energy efficiency, biofuels and job creation strategies.

Procurement Programs

These are dealt with further in the following modules; however they are worth exploring in this introduction to RE. An overview of the most popular basic types of procurement program should be explored:

1) Feed in tariffs (FIT)
2) Competitive tenders
3) Auction
4) Bilateral contracts

There are several themes that can be touched on by the trainer and module developer when comparing the options, including:

1) cost-effectiveness
2) competitiveness
3) administrative burden
4) speed of the process
5) bankability
6) costs of the process
7) support from the existing utility

Recent Statistics

The success of RE has been remarkable and it is worthwhile examining some of the trends in development via the “numbers”. The amount of data available that track the development of RE in developed markets is readily available and can be used to create some compelling graphs. Unfortunately, there is not as much data available for the RERA members’ markets; however even the recent upsurge in requests for proposals by various RERA government’s, utilities and regulators, makes for compelling reading.

This section should provide some insight on the following trends:

1) historical growth in installed capacity (by country/technology/region as appropriate)
2) investment (by country/technology/region as appropriate)
3) policies (by type and support mechanisms by country)
4) planned growth in capacity (by country/technology/region as appropriate)
5) funders (by type and country/ by technology and value)
6) Costs (per technology and by country/ region)

Statistics can be used to represent actual values as well as growth rates. It may also be interesting to consider including some material on changes in learning curves per technology as opposed to forecast learning rates.

15.4. Recommended Reading

Given the interest in RE, there is a vast amount of literature available for those wishing to gain an introduction to the subject. Listed below are a small but useful subset of the research body of material.

Table 15: Recommended Reading - Introduction to RE

Title	Source	Description
Sustainable Energy Regulation And Policymaking For Africa – Module 7	http://africa-toolkit.reeep.org/modules/Module7.pdf	A basic introduction to RE and a useful starting point for those with no prior experience.
Renewables 2015 – Global Status Report	http://www.ren21.net/wp-content/uploads/2015/07/REN12-GSR2015_Onlinebook_low1.pdf	An excellent compendium of statistics and trends, tracking the development of RE globally. The report has a ten year rolling focus and other earlier version as readily available.

Procurement Options for New Renewable Electricity Supply	http://www.nrel.gov/docs/fy12osti/52983.pdf	One of many NREL reports. It provides good information and an overview of procurement options and their relative advantages and disadvantages.

15.5. Outcomes

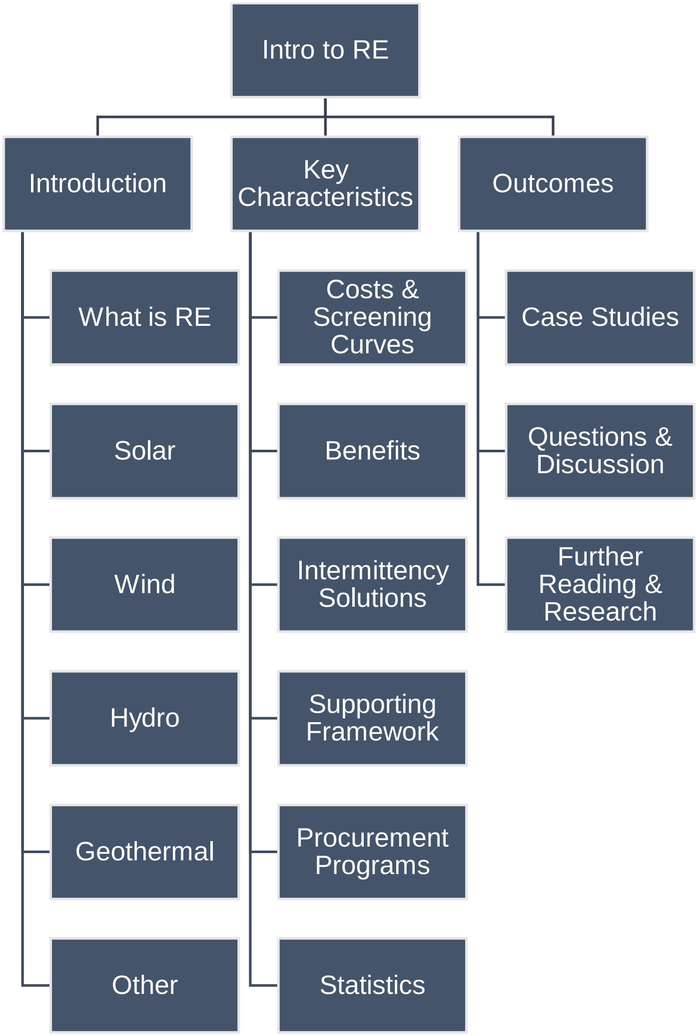
Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1) What role does RE currently play in your market and do you foresee this changing in the future
2) Is there a supporting framework for RE? Can it be improved?
3) Are there conflicting policies that will need to be aligned with RE?
4) What are the recent costs from RE developers in your market?
5) Do the costs match international or regional benchmarks
6) Do you think intermittency will be an issue for your SO?
7) Why do you think those countries with the greatest increase in RE have been so successful?

15.1. Module Structure

This module has been rated as basic and does not require and specialist skills or techniques from module developers, trainers or attendees.

Figure 14: Module Structure - Introduction to RE



16. SUPPORT MECHANISMS FOR RENEWABLE ENERGY

16.1. Module Introduction

Having dealt with the different renewable energy technology options, their technical and cost characteristics and associated benefits in the previous module, the focus should now shift to ways in which the deployment of such capacity can be promoted and supported.

The challenges involved with deploying renewable energy technologies are in many ways not dissimilar to other energy options and can essentially be summarized as seeking to balance risk and return. Basically, in order to attract investment, the investment opportunity must deliver the right balance between these. The higher the risk of failure, the higher the required return. A poor understanding of this tends to hinder many potentially viable and beneficial renewable energy projects.

This problem is compounded by the fact that in many instances, the cost of renewables is higher than conventional non-renewable alternatives, coupled to the situation in which affordability of electricity supply is an on-going challenge for many industrial, commercial, urban and rural customers.

In effect renewable energy deployment faces a number of economic and non-economic barriers that must be mitigated via a set of support mechanisms aimed at removing or lowering these barriers.

Therefore, policies and support mechanisms need to specifically target the risks associated with the deployment of renewables and find a sustainable way to remove or mitigate them. This understanding and approach typically leads to enhanced cost-effectiveness and faster deployment of renewables.

16.2. Module Purpose

The purpose of the module is to outline key support mechanisms required to promote and enable the deployment of renewable energy projects. Regulatory staff should acquire a thorough understanding of the different options available, as well as their strengths/ weaknesses, best practices in implementation and the supporting framework required to enable their success.

In developing the curriculum, the support mechanisms for renewable energy deployment may be broadly grouped to fall under four main themes, namely:

a) Political and market support
b) Legal and regulatory alignment and support
c) Utility support
d) Deployment incentives (including pricing or financial support)

Although these may not all, strictly speaking, be considered to be support mechanisms they all from part of an holistic enabling framework that must all work in harmony to create a conducive environment required for successful renewable energy deployment.

16.3. Key Definitions & Concepts

16.3.1. Key Definitions

Table 16: Definitions - Support Mechanisms for RE

Competitive Solicitation	Vendors are solicited (invited) to present a proposal to meet the specifications published by the procurer (buyer). Such solicitations are referred to as requests for proposal (RFPs)
Feed in Tariffs (FiT)	A fixed price tariff offered to RE project developers as a policy mechanism intended to promote investment into RE
Bilateral Contracts	A direct, reciprocal arrangement between two parties – in this case a seller of RE (usually and IPP) and a buyer (possibly an energy intensive consumer)
Auction	Under a formal auction framework, IPPs bid into the auction expressing a willingness to sell a given capacity or production of electricity at a specific price, soliciting from others their willingness to buy at that price. Has been converted in some cases to a “reverse auction” where developers blindly bid in their best price
Power Purchase Agreement	A power purchase agreement (PPA) is a contract between two parties, one which generates electricity (the seller) and one which is looking to purchase electricity (the buyer)
Renewable Energy Certificates (RECs)	Are tradable, non-tangible energy commodities in the that represent proof that 1 unit of electricity (kWh or MWh) was generated from an eligible renewable energy resource
Grants	A sum of money given by a government or other organization for a specific purpose
Exemptions	In this case an exemption for RE generators or consumers from payment of specific taxes or levies
Allowances	In this case a tax allowance or adjustment used as a support mechanism for RE developers e.g. accelerated asset depreciation

Capital Subsidies	A capital grant made available to project developers or equipment manufacturers by the government to support the implementation of RE projects or local equipment manufacturing facilities.

16.3.2. Concepts

Stakeholder Roles & Support

A successful RE procurement program will require the support of a wide range of political and market stakeholders including:

- The Presidency & Ministries
- Local communities
- State owned entities
- Funding Institutions (banks, DFIs, etc.)
- Project developers
- Original Equipment Manufacturers (OEMs)
- Consumers

This section should address the critical elements required to garner the support of these different stakeholder should be addressed.

Typically, this would encompass a properly articulated renewable energy vision, with clear government commitment, supported by appropriate policy and defined procurement process(es), expansion planning guidelines with well-defined roles, responsibilities, rights and obligations. This aspect should furthermore provide support in respect of important project agreements (e.g. joint development agreements, implementation agreements and direct agreements).

Enabling Framework

Experience in the region has shown that, in many instances, the policy and process followed is not fully aligned with the associated sector or other governing legislation and regulations. In addition there are a number of supporting regulatory instruments that regulator should be aware of.

This section should thus cover key aspects such as

- Enabling legislation and supporting regulations – aligned with policy,
- Clear licensing rules and process (including fast-track licensing/registration and/or license exemptions) as set out in the licensing training module already presented above
- Grid Codes and standards,
- Fair and balanced PPA terms,
- Adequate tariff/pricing levels (together with other pricing or financial support mechanisms discussed below)
- Cost pass-through provisions for the buyer of the renewable energy (as applicable)

Role of Utility in Monopoly Markets

Often the incumbent utility is the buyer of the renewable energy produced and is also the provider of the transmission and distribution network infrastructure. As such the utility could potentially in itself represent a barrier to entry if not managed properly.

The majority of RERA markets have some experience of IPPs as providers of emergency power, but often they are not seen as long term market participants. The success of RE procurement in developed markets has gradually found its way to Africa and there has been a recent surge in activity for procurement of RE as a means of portfolio diversification and to meet policy goals.

Unless carefully managed, utilities can become a serious restraint on the successful implementation of RE procurement programs.

Utility support should thus cover aspects such as

- Grid access (clear process to secure access and fair and equitable charges for this)
- Identification as designated off-taker (as applicable)
- Credit support arrangements to ensure project bankability

An Evaluation Framework

Every RERA member will have different market structures, goals and nuances, which will need to be assessed in order to develop a complementary procurement program. This section of the module should therefore provide the outline for development of an evaluation framework that can be utilized to design an appropriate support mechanism.

Some of the main items that will need to be included in the assessment include:

1) Alignment with existing policy, legislation and regulation
2) Support from key stakeholders
3) Cost-effectiveness
4) Competitiveness
5) Complexity to administer and implement
6) Cost (of program management and for participants)
7) Speed (of procurement process)
8) Responsibilities of stakeholders (utility, government ministries)
9) Potential Risks and Bottlenecks

Key Components of a RE Procurement Program

There are some basic components that need to be addressed in a procurement program – these may vary depending on the procurement approach, but it is useful to discuss them in general terms. This section should provide Regulators with a broad understanding of which components to include and how they fit together.

The following components can be included here:

1) Reference to the governing legislative and planning environment the mandates the procurement of RE

2) Institutional arrangements – who will run the program and with what support
3) Intergovernmental Frameworks – financial guarantees, responsibilities and relationships between various ministries participating in program e.g. Departments responsible for Energy, Finance, Water, Environmental Affairs, Mineral Resources etc.
4) Allocation of capacity – by level and technology
5) Procurement process and timelines
6) Application or bidding guidelines – depending on whether it's a Feed in Tariff (FiT), competitive tender or auction
7) Evaluation Criteria – must be consistent, transparent and fair
8) Socio-economic developmental goals
9) Standardized project structures and documentation – to ensure bankability and support from lenders
10) Pricing – will depend on procurement approach but requires some consideration Grid Access

Traditional vs. New Procurement Strategies

There are four main approaches that can be evaluated in this section, being:

1) Competitive Solicitation via Request for Proposal (RFP)
2) Bilateral Contracting
3) Feed in Tariffs
4) Auctions

The following basic components of each program should be presented:

- Basic design
- Comparative Differences
- Strengths & Weaknesses
- Global adoption rates
- Alignment with RERA members market structure

Bilateral contracting has been included here as it provides and interesting option for those markets with large energy intensive users that may wish to procure energy directly from IPPs. They also provide a means for supporting the deployment of smaller Distributed Generation RE e.g. rooftop PV.

Other Financial Incentives & Support

Procurement programs are not the only means available to drive the support and implementation of RE. These may include:

1) Feed in Premiums – to top up generators tariffs
2) Renewable Energy Certificates (RECs) – tradable certificates attracting a premium for "green" power or for carbon offsets
3) Deployment or Manufacturing grants – grants or low-interest loans to stimulate the production of locally manufactured RE equipment
4) Exemptions – from certain taxes and levies associated with energy production or consumption
5) Tax allowances or adjustments – for example accelerated depreciation to allow for larger upfront tax deductions
6) Capital subsidies – for the installation of RE or energy efficient equipment to support demand side management initiatives

There are other forms of incentives and support, but these provide a basic overview of the options available.

Best Practice

Given the amount of RE installed over the past decade, there are a number of case studies and benchmarks available for presentation that can guide attendees as to the most appropriate solution for their market.

These should be presented her in the form of case studies as well as via statistics – some analysis should be undertaken to assess the relationship between installed capacity, price and supporting frameworks, to see which programs have shown the most success.

It is critical that the module developer and trainer establish the key reasons for the program's success – this can be ascribed to various possibilities e.g. reduction in risk, cost effectiveness, efficiency etc.

16.4. Recommended Reading

There is a remarkable volume of research and literature on the topic of support mechanisms for RE. Some of the more popular and informative documents are listed below.

Table 17: Recommended Reading - Support Mechanisms for RE

Title	Source	Description
Best Practices Guide: Implementing Power Sector Reform	http://www.raponline.org/	The United States Agency for International Development's (USAID) Global Center for Environment, Energy and Environmental Training Program has developed the Best Practices Guide Series to provide technical information on the topics of power sector

		reform and regulatory practices. Chapter 2 discusses procurement and IPPs.
Procurement Options for New Renewable Electricity Supply	http://www.nrel.gov/docs/fy12osti/52983.pdf	This report explores utility-driven procurement options for incremental supply of renewable generation. This is a solid overview of the various support mechanisms and their distinguishing characteristics.
What is the best choice of regulatory instruments/tools for Renewable Energy promotion?	http://regulationbodyofknowledge.org/faq/renewable-energy-and-energy-efficiency/what-is-the-best-choice-of-regulatory-instrumentstools-for-renewable-energy-promotion-based-on-efficiency-and-effectiveness-of-reaching-policy-targets-fit-versus-green-certificates-versus-central-pr/	Another useful introduction to RE support tools.
South Africa's Renewable Energy IPP Procurement Program: Success Factors and Lessons	http://www.gsb.uct.ac.za/files/PPIAFReport.pdf	An excellent analysis of key success factors of the REIPPP in South Africa.
Evaluation of different feed-in tariff design options – Best practice paper for the International Feed-In Cooperation	http://www.renewwisconsin.org/policy/ARTS/MISC%20Docs/best_practice_paper_2nd_edition_final.pdf	A European focused assessment of various FiT programs and their relative success across markets.

16.5. **Outcomes**

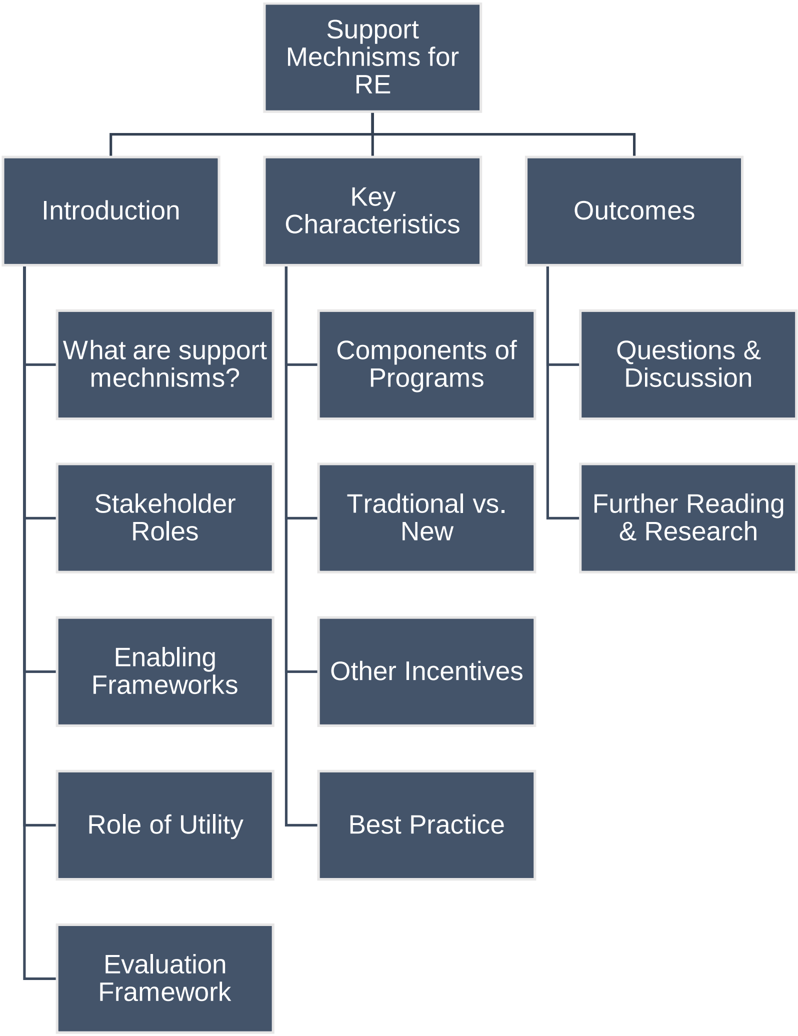
Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1) Which stakeholders are responsible for RE procurement in your market and have they provided a supporting framework?
2) What roles do each of the stakeholders play in the program? How does the utility in your market feature – offtaker, grid access, competitor?
3) How will/did your market choose a RE procurement approach? What evaluation criteria were used?
4) What are the key components of the program? How have funders and other stakeholders reacted to the approach?
5) Are there other financial incentives used to support RE in your market?

16.6. Module Structure

This module has been rated as basic and does not require and specialist skills or techniques from module developers, trainers or attendees.

Figure 15: Module Structure - Support Mechanisms for RE



17. IMPLICATION OF HIGH LEVELS OF RE PENETRATION IN ELECTRICITY SYSTEMS

17.1. Module Introduction

The growing success of Renewable Energy (RE) as contributor to global electricity systems has led to a significant amount of research on the potential implications of high levels of RE on the design, management and operation of electricity systems.

The growing share of RE as well as forecast targets have stimulated wide debate and interest into the issues and implications from high levels of RE penetration on electricity systems. This is not yet an issue for the majority of RERA members, given the small share that RE currently has in the total generation mix. However; given the relatively small size of some of the RERA markets, it is possible that even one or two large RE installations (of 100MW+) could have a serious impact on the system's stability.

The implications are not merely for the consideration of the planners and systems operator in each market – large scale installation of RE also has potential environmental impacts that should be considered.

17.1. Module Purpose

The purpose of this module is to examine some of the common issues and perspectives that have emerged from the on-going research on this area. It will examine the implications on capacity expansion planning, systems operations and the technical and regulatory measures that will be needed to successfully integrate these new technologies in an efficient and secure manner.

Regulators face numerous challenges as changes in technology and government policy force markets to adopt new ways of operating and new business models.

RE generators to be considered for this module are:

- Onshore wind
- Offshore wind (fixed bottom)
- CSP with and without thermal storage (only air-cooled)
- Utility-scale PV
- Distributed rooftop PV
- Biomass and Biogas
- Co-fired biomass with coal
- Geothermal
- Hydropower

Significant renewable energy capacity understandably impacts a number of aspects of the power market. In particular, systems operations and planning encompasses a diversity of time spans geographic scope as indicated in the figure below.

The module should explore the impact of increasing levels of renewable energy on these various market aspects.

17.2. Key Definitions & Concepts

17.2.1. Key Definitions

Table 18: Definitions - Implication of high levels of RE

Dispatchable generation (dispatchability)	Generating plant whose energy output can be predicted and controlled by the power plant operator or system operator
Non-dispatchable generation	Generating plant whose energy output is intermittent due to factors beyond the control of the operator (e.g. wind or solar resource profile/patterns)
Curtailment	Need to limit the output from a non-dispatchable generator to prevent oversupply or manage network constraints
Capacity Value	The proportion of nameplate capacity associated with non-dispatchable generation that can be (statistically) counted toward planning reserves
Energy Storage	Technology or plant that is able to store energy produced at one point in time and provide operating reserves and/or deliver such energy at a different point in time to better match demand – important to enhance the value of energy from non-dispatchable plant
Resource sharing	A market approach or mechanism that effectively increases the area over which demand is met by supply from a portfolio of intermittent (or non-dispatchable) generators

17.2.2. Concepts

A Framework for Impacts

As a first step in this module, it is useful to contextualize the types of impacts that can occur from large scale penetration of RE. These can be roughly grouped according to the following major themes:

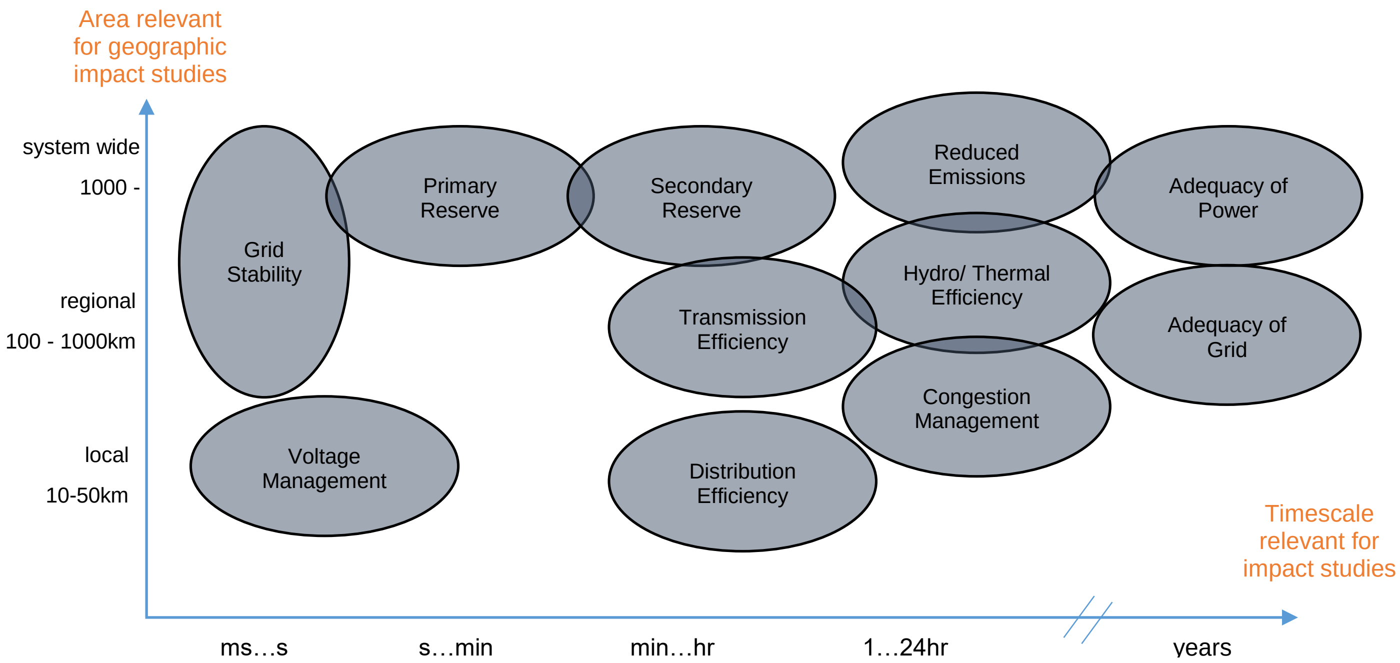
1) Technical impacts
2) Environmental
3) Economic
4) Financial/ Commercial

To date the majority of research has been conducted on the technical implications of large RE installations, however regulators will need to assess a wider range of issues as a part of their remit.

Technical Impacts

The technical issues for both the Systems Operator (SO) and expansions planners arising from large scale RE can be assessed across geographic and temporal spans as is shown in the figure below[5].

Figure 16: Technical Issues for consideration with high levels of RE



Environmental

Environmental impacts are generally calculated using a Life Cycle Analysis (LCA) approach. These can generally be categorized into:

1) Land Use Impacts
2) Human Health and Well-being
3) Wildlife habitats
4) Geo-hydrological resources
5) Emissions

Economic

The majority of markets with large-scale installations of RE have the support of a procurement program with some form of support, via feed-in tariffs, incentives and grants. RE also has significant cost implications which impact on tariffs. Further, sovereign guarantees are often required in developing markets to support bankability of projects. There are therefore a wide range of economic impacts that can be explored.

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[5] Recreated from Holttinen, H., Meibom, P., Orths, A., O'Malley, M., Ummels, B. C., Tande, J. O., et al. (2011). Impacts of Large Amounts of Wind Power on Design and Operation of Power Systems: Results of IEA Collaboration. **Wind Energy**, 179-192.

Financial

Large scale RE generally requires a commensurate amount of project finance and presupposes local market liquidity, especially in the case of developing markets which are exposed to exchange rate volatility. There are also potentially serious financial implications for the entity which takes the position of offtaker in the market. Regulators will need to ensure that there is a market mechanism to manage the financial impact of these transactions.

Expansion Planning & Systems Operations

Renewable resources and their output vary by location and, in most cases, by the time of day and season. The electricity output characteristics of some renewable energy technologies also vary in their degree of dispatchability. This relates specifically to the ability of the plant operator and the SO to predict and control power plant output. The implications of this intermittency and lack of dispatchability can become more formidable with the penetration of large RE capacity in one system.

Expansion planners have a number of options available to tackle these issues:

1) Geographical dispersion and oversizing of RE capacity to mitigate regional impacts
2) Introduction or increased flexible load
3) Energy storage
4) Utilization of conventional thermal plant
5) Resource Sharing
6) Demand Side Management

Module developers and trainers can touch on the issue of RE capacity value as it relates to systems operations and management. The capacity value of conventional dispatchable resources represents the proportion that can be counted towards planning reserves. With regard to PV and Wind (for example), because the SO cannot rely on them to deliver their capacity as needed, their capacity values are usually well below their nominal capacity. The impact of this is exacerbated in areas with larger RE installations as the likelihood of changes in output from more plant increases.

In order to manage this issue, increasing levels of dispatchable capacity will need to remain available with attendant cost implications to the system.

Operating Reserves

It may be interesting to reflect on the changing role of conventional thermal plant – as RE capacity increases, some of these plant may take on the role of providing “reserves” as opposed to “energy” for the system – albeit these will be limited to spinning reserves. Trainers can also include some material on the role of demand side management in mitigating the requirement for operating reserves.

Planners and the SO need to manage the demand/ supply balance over a variety of different timescales. Operating reserves are required to cope with changes in demand over relatively short timeframes – sometimes measures in seconds to minutes. The key concept to present here is that the greater the penetration of RE, the greater the need for these reserves in order to manage short term changes in supply.

SOs in many markets are able to forecast load demand up 36 hours ahead, with a fair degree of accuracy. Analysis of production forecasts from Wind plant, have shown that forecasts for 1-2 hours can vary by 5-7%, but by as much as 20% for 24 hour forecasts. This margin for error reflects the requirement for additional operating reserves to deal with large RE penetration.

Geographical Dispersion

The nature of RE resources will typically dictate the most favorable areas for new capacity development, in many cases far from traditional load centers. Not all countries have the opportunity to incorporate a variety of RE resources (solar, wind, hydro, geothermal etc.); however planners can promote diversity by specifying and incentivizing development of RE in geographically diverse areas. This will mitigate the impact of intermittency, but may require “oversizing” of capacity in order to meet demand requirements, with cost implications.

Geographical dispersion in RERA markets may only be possible through a resource sharing approach in the future, given the currently limited opportunities for RE development; nevertheless these issues are relevant for regulators looking to the future of their electricity systems.

Flexible Supply Options

One of the most common consequences of large scale RE is the requirement for increasing of flexible supply side options. This can be in the form of mid-merit plant with fast ramp-up rates e.g. gas fired CCGT plant or peaking plant liked pumped-storage hydro schemes. The value of these types of generation to the system becomes greater, with the penetration of further RE.

This assumes that Wind and PV will maintain their position as the dominant RE technologies of choice, but CSP and energy storage technologies may also find increasing favor in the future, depending on their increasing efficiency and reducing costs. In this case, these technology options will displace the requirement for conventional load following capacity due to their “dispatchability”. At a utility-scale storage technology options include: molten salt (for CSP) pumped-storage hydropower, compressed air energy storage, and batteries. In order for storage to really make a notable contribution, it would need to provide “firm” capacity and be able to be counted towards planning reserves.

Demand Side Management (DSM)

This section should provide an overview of curtailment or Demand Response Programs (DRP) which can be used to load shift in the event of intermittency. These options may not prove effective depending on the nature of the load profile in a market and the demand response options available. DRP and DSM uses price signals to shift consumer behavior – offering a premium or incentive in order to load shift. DSM programs can also use capital grants or exemptions in order to reduce overall demand via increasing efficiency.

Another effective means for shifting load is ensuring cost reflectivity of tariffs in order to ensure that an accurate economic signal is provided to consumers – this may be the first step for RERA members.

Conventional Thermal Generation

As has already been mentioned, conventional thermal resources are already providing reserves to the system at part load. These can continue to be utilized or increased based on their diminishing requirement to meet overall demand as RE overtakes their position. The overall potential will be based on an analysis of their current utilization as well as their operating parameters – not all plant will be able to flex in the manner required depending on their age and ramp rates.

Resource Sharing

In markets with power pools, bilateral contracts and adequate transmission interconnector capacity, another option for managing intermittency is the concept of resource sharing. This involves pooling of both demand and supply over a larger geographic area in order to manage demand and supply variations. Sharing will increase diversity and smooth load variances, whilst at the same time smooth generator variability and mitigate production forecasting errors.

Maximizing the benefits of resource sharing is contingent on two factors, one, market conditions that allow resources to be shared over large areas, and, two, adequate transmission capacity. In Sub-Saharan Africa neither of these conditions is currently adequately met to make resource sharing a reality. However; the potential of resource sharing and the importance of regional cooperation should be highlighted in the module.

Transmission Infrastructure

Because regions with cost-effective renewable resources are often located at a distance from load centers, the need for and associated investments in new transmission increases with higher levels of renewable energy supply. These needs are somewhat mitigated as existing transmission lines become available if conventional generation is displaced, but this freed transmission will probably be insufficient to fully accommodate the needs of increased renewable energy deployment.

Some discussion will be required to investigate the issues of increased transmission losses, backbone strengthening, substation capacity and the incentivisation of RE generators through appropriate transmission charges.

Land Use Impacts

A key concept is the “land use” impact of large scale RE. On a per-MW basis, RE technologies will generally require more geographical space, but it is arguable that the impact on the land is far less than a coal fired power station for example). RE plant have also been successfully combined with existing agricultural endeavors in some cases.

In this case the location of RE plant far from traditional load centers, can be a positive attribute as it does not necessarily impact on existing land use requirements. However; little research exists on the effort or time required to restore land that has been used for RE plant.

Wildlife and Habitat Impacts

The impact on plant and animal habitats, has traditionally been the major hurdle for certain types of RE plant developers e.g. CSP in the USA. This is primarily due to the fact that there has been very little research conducted on the impacts as the technologies are relatively immature.

Most of the impact to date is based on hypothetical analysis and will be closely linked with the biodiversity of the site. This in turn will be measured by species density on the site. There are various formal assessments of biodiversity which can be presented on this module. These include:

1) tropical rainforests
2) tropical grasslands
3) deserts
4) shrublands
5) forests
6) grasslands
7) savannah

Geo-hydrological Impacts

Large RE penetration may impact on other environmental concerns with regard to soil quality, erosion, water purity and groundwater recharge. It is possible to mitigate these impacts, but as with other environmental concerns, research to date has been largely hypothetical.

Emissions

A key motivation for the installation of RE plant are perceived reductions in harmful emissions and pollutants from traditional thermal power plant. It is worthwhile drawing attendees attention to the fact that RE plant which are developed in areas with high biodiversity will need to be carefully assessed.

Trees and brush which are removed in order to avoid shading of PV panels (for example), will negatively impact on the overall emissions reductions.

Economic Impacts

Large scale implementation of RE will undoubtedly have economic implications. These may include:

1) Fiscal implications of sovereign guarantees
2) Tariff increases due to cost of RE power
3) Increases in Foreign Direct Investment
4) Socio-economic development of local communities

The potential economic impacts can be both positive and negative and will need to be assessed on a case-by-case basis for each market.

Financial Impact

As mentioned above, implementation of large scale RE also implies:

1) A bankable offtaker to purchase the power
2) Sufficient local market liquidity to support the RE project developers

Both of these issues require careful consideration and can impact on the success of any RE procurement program. Finally, existing conventional generators may be negatively impacted based on the contracting arrangement with the RE IPPs. Where these generators production is reduced in order to accommodate forced procurement of RE generation, this may impact on the viability of the conventional generator.

17.3. Recommended Reading

Table 19: Recommended Reading - Implication of high levels of RE

Title	Source	Description
Impacts Of Intermittent Renewables On Electricity Generation System Operation	http://www.iit.upcomillas.es/batlle/Publications/2012%20Impacts%20of%20intermittent%20renewables%20on%20electricity%20generation%20system%20operation%20v2.0%20_%20P%C3%A9rez-Arriaga%20&%20Batlle.pdf	A useful introduction to the technical issues relating to large scale RE implementation

Managing large scale penetration of intermittent renewables	https://mitei.mit.edu/system/files/intermittent-renewables-whitepapers.pdf	This paper examines how a strong presence of intermittent renewable generation will change how future power systems are planned, operated and controlled. The change is already noticeable in countries that currently have a large penetration of wind and solar production.
Environmental impacts from the installation and operation of large-scale solar power plants	http://www.sciencedirect.com/science/article/pii/S1364032111001675	A USA focused academic paper that identifies and appraises 32 impacts from these phases, under the themes of land use intensity, human health and well-being, plant and animal life, geo-hydrological resources, and climate change.

17.4. **Outcomes**

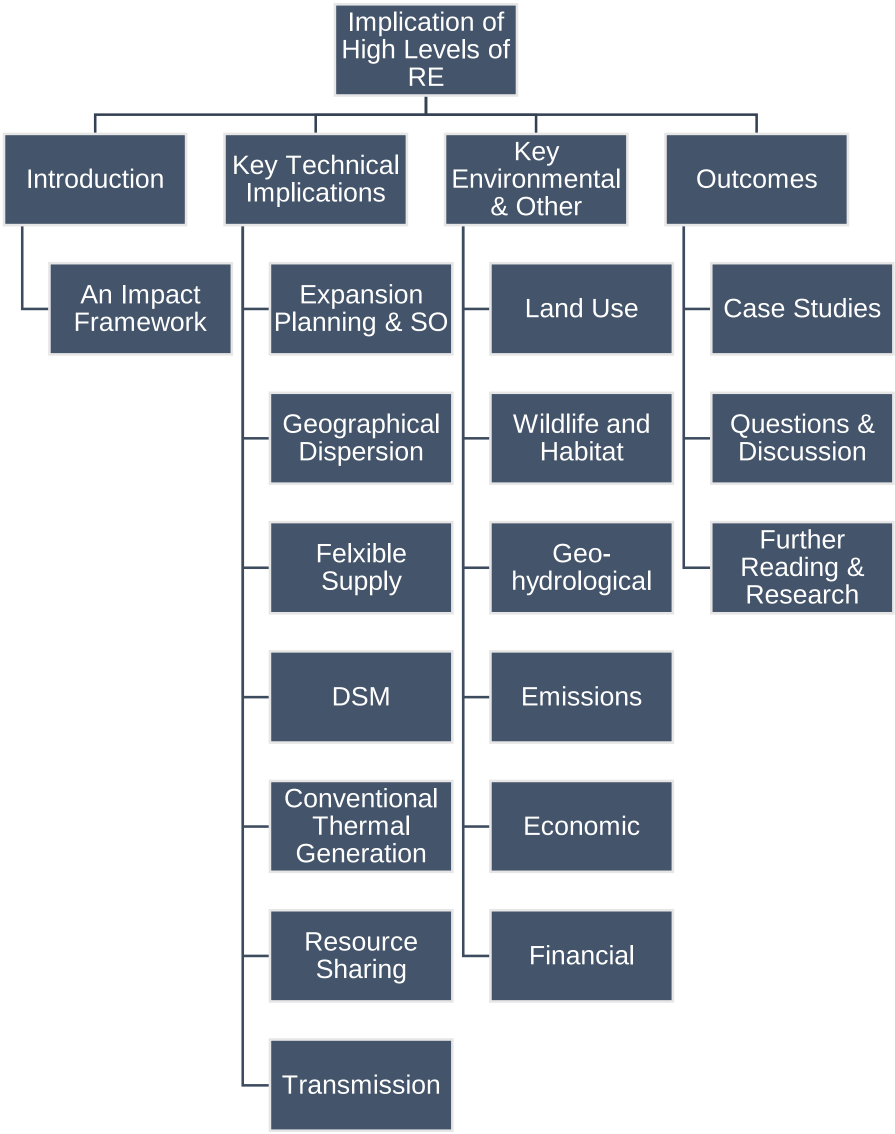
Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1) What proportion of generation capacity will RE form over the next two decades in your market?
2) Has sufficient consideration been given to managing the related impacts?
3) What framework is used to plan for RE programs?
4) Which is the most critical impact for regulators to manage in your market?
5) Are there options for resource sharing in your region?
6) Do you think that the economic and financial impacts carry greater significance than the technical
7) What DSM options are available in your market?

17.1. Module Structure

This module has been rated as requiring a moderate skills level. Attendees should have a good working knowledge of systems operations and RE.

Figure 17: Module Structure - Implication of high levels of RE



18. INTRODUCTION TO DISTRIBUTED GENERATION

18.1. Module Introduction

Distributed Generation (DG) is not a new phenomenon. Prior to the advent of alternating current and large-scale steam turbines - during the initial phase of the electric power industry in the early 20th century - all energy requirements, including heating, cooling, lighting, and motive power, were supplied at or near their point of use.

Technical advances, economies of scale in power production and delivery, the expanding role of electricity in general life, and its concomitant regulation as a public utility, all gradually converged to enable the network of gigawatt-scale thermal power plants located far from urban centers that we know today, with high-voltage transmission and lower voltage distribution lines carrying electricity to many businesses, facilities, and homes in each market.

At the same time this system of central generation was evolving, some customers found it economically advantageous to install and operate their own electric power and thermal energy systems, particularly in the industrial sector. Moreover, facilities with needs for highly reliable power, such as hospitals and telecommunications centers, frequently installed their own electric generation units to use for emergency power during outages.

These “traditional” forms of DG, while not assets under the control of electric utilities, produced benefits to the overall electric system by providing services to consumers that the utility did not need to provide, thus freeing up assets to extend the reach of utility services and promote more extensive electrification.

Over the years, the technologies for both central generation and DG improved by becoming more efficient and less costly. Today, advances in new materials and designs for photovoltaic panels, micro-turbines, reciprocating engines, thermally-activated devices, fuel cells, digital controls, and remote monitoring equipment, among other components and technologies, have expanded the range of opportunities and applications for “modern” DG, and have made it possible to tailor energy systems that meet the specific needs of consumers.

These technical advances, combined with changing consumer needs, and the restructuring of wholesale and retail markets for electric power, have opened even more opportunities for consumers to use DG to meet their own energy needs, as well as for electric utilities to explore possibilities to meet electric system needs with distributed generation.

18.2. Module Purpose

The purpose of this module is to provide an outline and description of distributed generation; otherwise known as distributed-grid or mini-grid systems. It considers the options and technologies used in distributed-grid systems.

The module also reviews the requirements for planning such systems and the issues to consider. Finally it reviews the mechanisms required on the policy, fiscal and infrastructure level to support effective implementation of distributed grid systems.

The information contained in this module is intended to explain the basic operation of such systems, to understand their strengths and weaknesses and hence to have a better grasp of the benefits and the barriers faced by them.

18.3. Key Definitions & Concepts

18.3.1. Key Definitions

Table 20: Definitions - Introduction to DG

Distributed Generation (DG)	generation capacity located close to the point of consumption, obviating the need for extensive transmission or distribution connectivity
Mini-hydro powered systems	mini-grid systems making use of small hydropower plants, often run-of-river type
Hybrid powered systems	a combination of wind, PV, hydro and diesel power (e.g. PV/diesel, wind/diesel or PV/wind)
Biomass powered systems	based on either biomass combustion or gasification technologies
Biomass combustion	systems that burn biomass fuel in a boiler or engine
Biomass gasification	process by which a synthesis gas (syngas) is produced from biomass material

18.3.2. Concepts

What is DG?

The module should start with a brief overview of the history of DG and its evolution. Key concepts to be discussed here are:

1) differences between DG and conventional centralized generation
2) some explanation as to why it has become more popular recently
3) technology options
4) current applications (off grid/ back-up etc.) for customer groups

DG is often referred to as Small-scale generation or Small-scale Embedded Generation (SSEG) or sometimes decentralized generation. Some discussion is required to provide context on how power markets have evolved from mini-grids with localized DG, to centralized large scale generation and now to increasing use of mini grids with DG again. An overview of the various technology options is also required, being:

1) PV
2) Wind (micro& mini turbines)
3) Gas Turbines
4) Reciprocating Engines
5) Mini/ Micro Hydro
6) Fuel Cells

What is Driving DG uptake?

The resurgence in the attractiveness of DG can be traced to a number of drivers, which should be discussed in this section. These have been listed as:

- Market reforms and liberalization
- Procurement incentives
- On-going efforts to provide basic services (in developing RERA markets)
- Cost reductions & technology improvements
- Environmental Concerns
- Increasing costs of conventional power
- Reliability and Resilience

It could be argued that a combination of all the factors listed above have combined to drive uptake in DG. Certainly the flexibility in scale, reduced costs and rising tariffs or Time of Use (ToU) differentiated tariffs, have created the necessary conditions for enormous interest in rooftop PV (for example).

Environmental concerns and supporting government mandated policy and incentives have created a clear economic case for investment by consumers (mainly in developed markets). For those who require standby or back-up power (hospitals etc.) the arguments remain the same.

Also of interest here is the impact that DG will have on the role of the utility – a possible shift from energy provider towards a provider of greater back-up reserves and other ancillary services - although this is discussed in more detail in the following modules.

Key Systems Characteristics

In order to provide attendees with some further context for DG systems, module developers and trainers can include some schematics and an overview of the basic components of a few common DG installations e.g. rooftop solar – these should be relevant for RERA markets.

As an example, rooftop solar components would include discussion on PV cells, modules & arrays, tracking systems, inverters and some analysis of systems efficiency. A diagrammatic approach would be most effective here.

Costs & Benefits of DG

It would be useful to provide a table here, cataloguing and comparing the various benefits of DG, to see which provide the most value in meeting the varying needs of different consumers.

A sample of the potential benefits are:

1) Cheaper fuel
2) Clean/ green power
3) Increased efficiency or co-generation
4) Support services to the grid (voltage control, power quality etc.)
5) Delaying more costly capital investments (transmission & distribution expansion or refurbishment)
6) Reliability/ Resilience
7) Load shifting
8) Reduced Transmission & Distribution Losses
9) Shorter Construction times (relative to centralized power)

Costs will vary depending on technology and fuel type. In developed markets, a large portion of DG relies on natural gas as a fuel source. Given the current price of gas in the US (for example) and medium term forecasts, these installations are probably cost competitive and provide ample opportunity for peak shaving.

In developing markets, there may be other drivers, especially security of supply and in many cases DG may be the only possible supply. In these markets, the technology choices may require hybrid PV/diesel/ Wind micro-turbine or even mini hydro solutions.

Trainers and module developers should make it clear that not all the benefits are applicable to each technology type, and are not all achievable in general – each DG opportunity is specific and they will be evaluated on an ad-hoc basis. The decision to proceed will be on an ad-hoc basis and depends on whether the cost benefit analysis is positive in terms of the underlying need to be met e.g. the requirement for a hospital to ensure their back-up supply will probably have a greater cost threshold than a residential consumer who is considering the installation of rooftop PV.

Regulatory & Legislative Support Framework

Regulators face a series of challenges in that DG will require amendment of various sets of rules, codes and methodologies. For example, DG raises serious issues with regard to grid connection at a distribution level, which will require amendment of existing grid codes. Existing licensing processes may also prove a burden or restraint on small DG installations, forcing regulators to give some thought as to how they are segmented and managed in the future.

As with RE and other trends in the power sector, DG will require a supporting framework to ensure that it is successfully implemented and managed as a part of each market.

From a policy point of view, there may already be some support in the form of environmental policy e.g. renewable energy procurement programs, emissions reductions, electrification, socio-economic upliftment or industrial development. Without specific policy support, DG risks remaining a poorly supported opportunity and it may also attract negative sentiment from existing utilities that are threatened via a loss of revenue.

Trainers and module developers can refer to significant expertise and research built up in developed markets to illustrate best practice for RERA attendees wishing to successfully regulate the incorporation of DG in their markets.

DG Restraints

This section should provide some background to the various issues currently restraining further implementation of DG.

As mentioned previously, DG systems will be assessed on a case-by-case basis, therefore there is little alignment with current utility's standard business model. In fact most of the more obvious benefits are for the customer offering little incentive for utility support. This lack of familiarity has contributed to a perception that DG is risky and offers poor financial reward.

There are some tariff related restraint which can be explored – for example many utilities or distributors refuse to publish cost-reflective net-metering rates or ToU rates in order to support load shifting and in order to compensate DG at the marginal cost of generation.

Finally, there are some technical aspects to DG which require some thought – for example, the issues regarding islanding and other safety hazards which may arise from DG systems.

By far the biggest restraint to be discussed is the threat faced by utilities for the potential loss of revenue, represented by DG. This may result in actions by the utility to ensure their revenue stream e.g. raising fixed charges to make up for the losses in variable (energy) charges.

Other restraints already touched on include expensive and unnecessary licensing and grid connection requirements, fees for grid studies, insurance requirements and indemnification.

18.4. Recommended Reading

Table 21: Recommended Reading - Introduction to DG

Title	Source	Description
Distributed Generation: Definition, Benefits And Issues	http://feb.kuleuven.be/ete/downloads/ETE-WP-2003-08.PDF	This paper starts from the observation that there is a renewed interest in small-scale electricity generation. The authors start with a survey of existing small-scale generation technologies and then move on with a discussion of the major benefits and issues of small-scale electricity generation. Different technologies are evaluated in terms of their possible contribution to the listed benefits and issues.
Distributed Generation System Characteristics and Costs in the Buildings Sector	https://www.eia.gov/analysis/studies/distribgen/system/pdf/full.pdf	A statistical reference guide form the USA Energy Information Administration regarding costs and characteristics of residential and commercial DG systems.
The Potential Benefits Of Distributed Generation And Rate-Related Issues That May Impede Their Expansion	http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Study_Sep_07.pdf	A USA Department of Energy report on the benefits of DG. An excellent starting point and overview of many of the salient issues regarding DG.
Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues	http://www.raponline.org/document/download/id/4572	This paper covers technical requirements, procedures and agreements to preserve the safety, reliability, and service quality of electric power systems and make interconnection as predictable, timely, and reasonably priced as possible.

18.5. Outcomes

Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

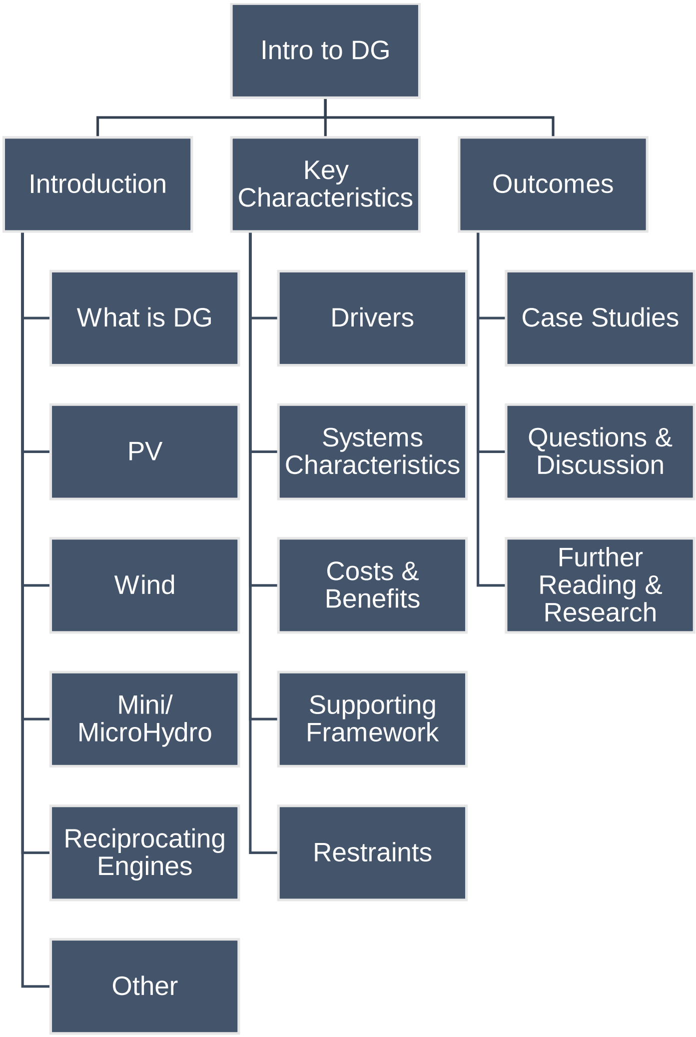
1) Has your market seen increase interest in DG?
2) Which technology types do you think are most attractive for your market and why?
3) What kind of supporting framework exists? Can it be improved?
4) Have any cost benefit analyses been undertaken for DG projects in your market? What was the outcome?

5) Have existing regulations been assessed and aligned with requirements to support DG?
6) What regulatory processes will be implemented to support licensing applications and grid connections for DG?

18.1. Module Structure

This module has been rated as basic and does not require and specialist skills or techniques from module developers, trainers or attendees.

Figure 18: Module Structure - Introduction to DG



19. TECHNICAL IMPLICATIONS OF HIGH LEVELS OF DISTRIBUTED GENERATION PENETRATION

19.1. Module Introduction

The recent upsurge in interest for DG systems has led to on-going research on their impact on traditional power systems, especially from a grid connection perspective. In developed markets, the combination of increasing tariffs, reduced costs, technological advancement in materials as well as policy support, have led to a huge amount of new DG installations. Other factors include the low cost of gas as a fuel source and targets for RE power production which have induced significant interest in new residential and commercial DG PV installations.

However; the trend in DG has also forced utilities and regulators to carefully consider some of the implications of high levels of DG penetration in existing power systems. Whereas in the past DG was seen as a way of providing power for mainly off-grid and back-up generation, it has now become attractive to a much wider group of potential customers in both residential, commercial and industrial sectors.

DG resources impact on the electricity system in a number of ways. First, they represent a fundamental shift away from the centralized power station generation model which has dominated for so long. This has resulted in a reassessment of the standard utility business model, as well as a rethink on the operations and maintenance of transmission and distribution systems. DG has forced changes in the allocation of grid connection costs, licensing application procedures, and has catalyzed a growing body of research presenting the benefits and issues that large scale DG offers.

19.2. Module Purpose

The purpose of this module is to highlight the technical implications of high levels of DG penetration so that these can be appropriately addressed within the regulatory framework, covering aspects around planning, licensing, grid code compliance and technical standards.

Whilst much of the current research focuses on developed markets in the US and Europe, there are many valuable lessons to be learnt and best practice which RERA members can assess and adopt as appropriate.

Course attendees should gain a detailed appreciation of the issues they need to assess in the support of Dg in their own markets.

19.3. Key Definitions & Concepts

19.3.1. Key Definitions

Table 22: Definitions - Technical Implication of high levels of DG

Ancillary Services	An ancillary service is anything that supports the transmission of electricity from its generation site to the customer. Services may include load regulation, spinning reserves, non-spinning reserves, replacement reserves and voltage support.
Black Start Capability	A black start is the process of restoring a power station to operation without relying on the external electric power transmission network.

	Normally, the electric power used within the plant is provided from the station's own generators.
CHP	Is an acronym for Combined Heat and Power. By using CHP Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power.
Congestion	Congestion occurs on electricity networks, when there is insufficient network capacity to transmit energy to meet demand.
Protection coordination	Potential need to adapt circuit breakers, fuses, and other fault-protection systems on the distribution system to be adapted to deal with bi-directional power flows with increasing DG penetration
SCADA	Is an acronym for Supervisory Control and Data Acquisition. SCADA generally refers to an industrial computer system that monitors and controls a process. In the case of the transmission and distribution elements of electrical utilities, SCADA will monitor substations, transformers and other electrical assets.
Systems Operations and Communications	Need for distributed control centers to be able to manage fast reacting local power generation from DG and effectively communicate with the interconnected transmission control systems.
Time of Use (ToU)	Time-of-use electricity tariffs (TOU) are segmented by broad blocks of hours (e.g., on-peak, off-peak etc.) across days and by season. Prices are usually fixed for each block.
Unintentional islanding	Potential for a portion of the distribution system to continue to run even when the larger power system is down as a result of increased levels of DG
Voltage Control	Challenges in maintaining desired voltage levels with increased DG penetration

19.3.2. Concepts

DG Systems Overview

This module requires an initial overview of DG systems form a technical perspective in order to provide some context for the following sections. Key technical characteristics of DG should be presented, along with technology types and application. Course attendees should already have a working knowledge of DG and it would be useful to structure this section so that it reflects the status quo in developing RERA markets.

Global standards for DG reflect segmentation by both technology and size – factors which impact on the technical requirements, project agreements and procedures required for connecting to the grid. It would therefore be useful here to distinguish between and present a number of examples to illustrate typical system designs for carious applications.

DG Interfaces with Transmission & Distribution

As mentioned above, many if the issues relating to DG are linked to the manner in which they connect to the grid. Therefore, this section must address provide a basic overview on grid connection procedures including supporting legislation and regulations. It is critical that attendees gain an understanding of what the relevant policy, legislation and regulation is trying to achieve.

Generally speaking the aims of the above can be listed as:

1) Ensuring the quality, safety and service levels of the network
2) Allowing open access to all stakeholders by supporting cost-effective, transparent, standardized connection rules and procedures

It will be critical for RERA regulators to maintain this when considering the inclusion of high levels of DG in their networks.

Fuel Source & Output Advantages

A key advantage of DG systems is their proximity to and the opportunity to utilize local fuel resources e.g. gas, waste products, hydro, solar. This can provide greenfield generation options as well as co-generation for increased efficiency and cost reductions. In developed markets this can supplement heating requirements as well. Whilst there are many opportunities for heating requirements amongst industrial and commercial customers, the benefits of combined heat and power (CHP) technology for residential users will not be as important to RERA members.

Cogeneration procurement programs will become more attractive in RERA countries as tariffs rise towards cost-reflective levels and are structured by Time of Use (ToU). An additional benefit will be the potential reduction in harmful emissions by utilizing RE and co-generation DG.

Land Use & Lead Times

Localization of generation by DG and especially the use of rooftop PV (for example) will lead to a more efficient use of land. This obviates many of the requirements for land use permits as well as right of way permits – this has often been acknowledged having the longest lead times for Transmission projects. From a construction point of view, timeframes are much smaller for DG and it is arguable that the public participation processes will be far easier then with a large conventional power station.

Trainers can use examples of both DG and conventional power to quantify and graphically illustrate the differences.

Congestion & Losses

Hypothetically, on-site or localized generation has the opportunity to greatly benefit both Transmission and Distribution networks by reducing both congestion and network losses. It has been suggested that high levels of DG penetration may in fact delay or even reduce the requirements for network extensions, strengthening or refurbishment. In the following module, some options for evaluating these benefits will be presented.

As utilities and network operators will probably remain the suppliers of last resort, it is difficult to easily quantify the exact amount of savings – in most cases networks will need to be adequately structured to supply energy in the event that the DG is offline. However; it is plausible that DG can delay investments – this will need to be judged on a case by case basis and will ultimately be determined by detailed assessment of the feeder line in question.

Reliability & Ancillary Services

DG technology can provide network support and contribute to ancillary services (e.g. reactive power production), thereby improving reliability and quality of supply for customers.

Properly operated DG systems can improve the continuity of supply. This can be done on two levels. When a power outage occurs on the main upstream network the so-called islanding procedure allows disconnecting a portion of the systems from the main network. The disconnected portion is then supplied by the DG present there. When a power outage occurs at local level, DG may help restore power in a short time.

Diversity & Resilience

The increased penetration of renewables and other DG technologies could help security of supply by displacing energy imports and contributing to a more diverse energy portfolio. It is arguable though that this would require a very high level of DG across a geographically diverse area.

DG can also stimulate competition in supply and may ultimately allow more players access to the market. Depending on the market structure they could compete with others to supply the utility or network operator backup electricity, voltage and reactive power support, reserves and other ancillary services. This becomes especially valuable when the loads being supplied are far away from traditional generation sources.

In the case of potential load-shedding or any other unplanned outage event DG has traditionally provided resilience via back-up supply. At high-levels it is arguable that DG could provide “black-start” capabilities to the system and could significantly improve resilience.

Voltage Control

Whilst DG offers many potential benefits, one of the key concerns to be presented in this module is that of the impact on voltage control. Introducing DG on distribution systems will change power flows patterns and perhaps more significantly, will also affect local voltage and fault current levels. Therefore there is a need to assess and (where appropriate) to redesign local protection systems. In effect this redesign must be able to manage increased voltage and fault current values, whilst at the same time being able to deal with bidirectional power flows.

Voltage problems are the most commonly reported problem associated with high penetration of DG.

As an example, utilities are required to keep voltage at the customer's load within a narrow operating range, typically within ±5% of the nominal voltage. However; when power is injected into the electric system, the voltage at that location increases. Arguably, it is possible that high penetrations of DG might raise the voltage beyond the acceptable range, requiring the addition of voltage-regulating equipment.

As was discussed in the previous module, this will need to be assessed on an ad-hoc basis and will ultimately depend on the feeder's characteristics i.e. voltage rating, wire size, location of the DG and loading pattern. Higher penetrations of DG can cause increased wear and tear due to increases in insolation, potentially requiring accelerating equipment replacement.

Of most interest to regulators will be the processes and rules they implement to manage this issue without restraining the implementation of DG. In many developed markets, this is accomplished by limiting the total capacity on each feeder according to a specific methodology. This will also be informed by distribution network studies that each network owner will need to perform. There is established precedent and best practice from several established DG markets that can be referred to.

Protection Control and Unintentional Islanding

In addition to voltage control, two other key concerns with DG are protection coordination and unintentional islanding.

Within the current traditional distribution network, power usually flows in one direction - from a central generation unit (or a transforming substation) to a "passive load". However, a two-way power exchange may result from the increasing installation of DG power units in the grid. This means that distribution control systems will need to be redesigned or set to handle two-way power flows on distribution lines.

Protection coordination refers to the potential need to adapt circuit breakers, fuses, and other fault-protection systems on the distribution system. These devices typically rely on overcurrent conditions to sense a problem. The addition of any DG can provide an alternate source of current, thereby reducing the current flow through the protection device and potentially causing improper operation.

Unintentional islanding refers to the unlikely potential for a portion of the distribution system to continue to run even when the larger power system is down. While this might sound like an advantage, an unintentional island can cause equipment damage and safety concerns.

For example, there is a significant safety hazard to workers if they are working on a line which remains "live".

Systems Operations and Communications

Where DG is fueled from RE, there are issues with intermittency that DG systems will need to address. In effect, the DG control centers must be able to manage fast reacting local power generation. In addition, they must be able to effectively communicate with the interconnected transmission control systems, in order to make the proper power reserve available in the systems. These operations and communications requirements will need to be properly addressed by regulators in their codes and rules for DG connections.

Data collection needed for the control of the distribution system as well as of the DG units can be a very complicated matter. In fact, the distribution system is generally not controlled by SCADA (Supervisory Control And Data Acquisition) systems used in the transmission operation. Also, the application of priority dispatch mechanisms - at transmission and distribution level - may become increasingly more difficult (e.g. signaling for dispatch of resources becomes more complicated).

Technical Regulatory Guidance

Some formal presentation of regulatory best practice should be given in this module to provide insight into how regulators in developed markets have dealt with these issues. These should address the following key areas.

DG Procedures:

- rules that explain the application process
- provide transparent rationale for review and awarding of applications
- ensure that adequate connection studies are completed
- ensure that the connection is safe
- protect the quality of other consumer's power
- is compliant with required legislation

Technical Screens:

- Regulators can develop "screens" to easily asses key issues common to all DG systems and stream applications by size, technology etc. Failing to pass screens will result in more detailed studies to meet safety and technical assessment requirements

Equipment Certifications & Technical Requirements:

- equipment standards to ensure safety and quality
- technical standards as per IEEE or other relevant governing bodies

Other:

- Insurance requirements
- Dispute Resolution
- Apportioning of costs of studies

There are several well tested and developed "toolkits" for Regulators that can be assessed during this section.

19.4. Recommended Reading

Table 23: Recommended Reading Technical Implication of high levels of DG

Title	Source	Description
The Potential Benefits Of Distributed Generation And Rate-Related Issues That May Impede Their Expansion	http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Study_Sep_07.pdf	A USA Department of Energy report on the benefits of DG. An excellent starting point and overview of many of the salient issues regarding DG.
Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues	http://www.raponline.org/document/download/id/4572	This paper covers technical requirements, procedures and agreements to preserve the safety, reliability, and service quality of electric power systems and make interconnection as predictable, timely, and reasonably priced as possible.

Impacts of Distributed Generation	http://www.cpuc.ca.gov/NR/rdonlyres/750FD78D-9E2B-4837-A81A-6146A994CD62/0/ImpactsofDistributedGenerationReport_2010.pdf	This report provides an overview of the current status of California's distributed energy generation resources and highlights some of the current challenges and activities around interconnecting these resources to the utility grid
Technical and Economic Impacts of Distributed Generation on Distribution System	http://waset.org/publications/70/technical-and-economic-impacts-of-distributed-generation-on-distribution-system	A basic introduction to some of the technical issues relating to DG

19.5. Outcomes

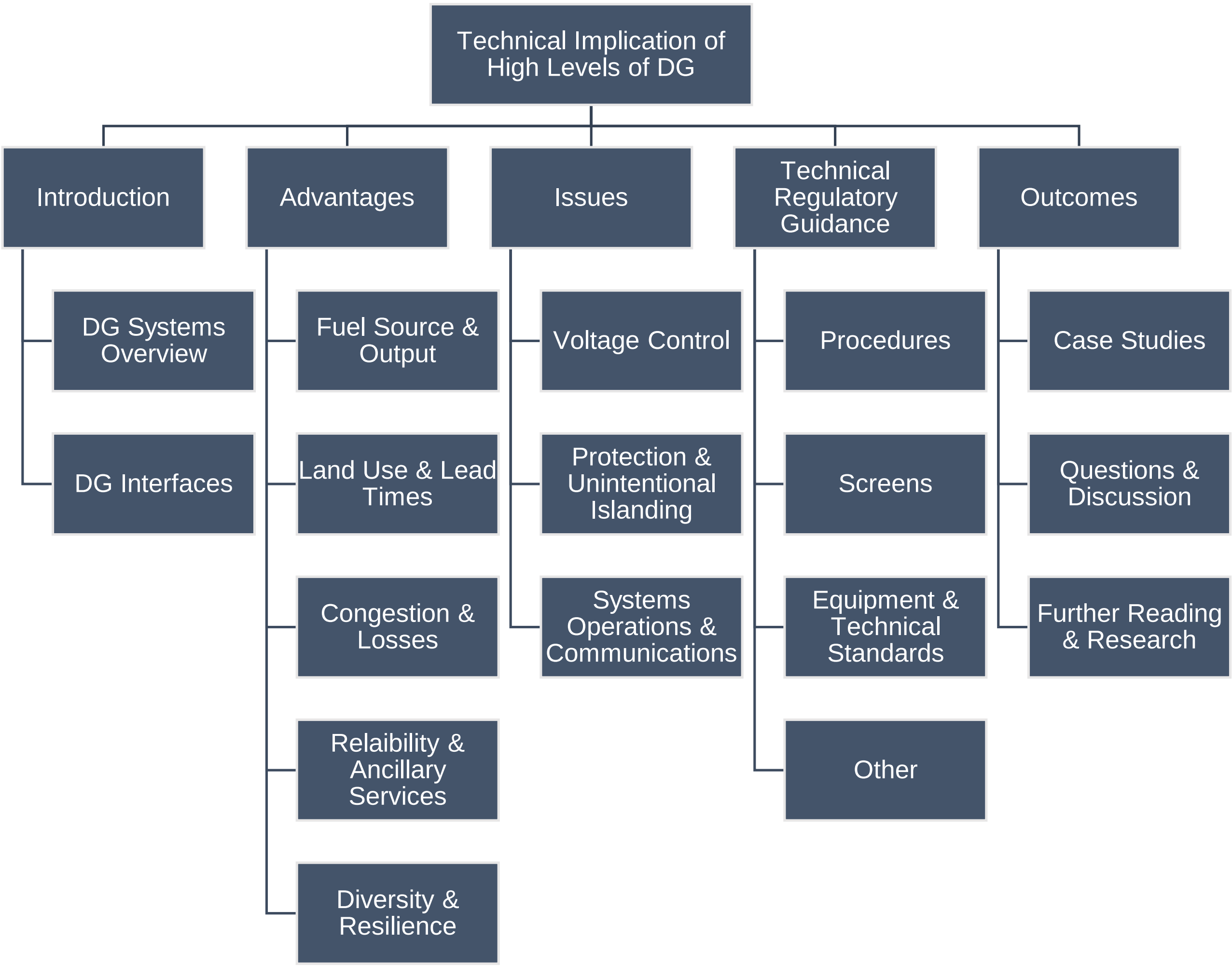
Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1) What do you understand to be some of the key advantages of DG to electricity systems?
2) Are DG providing any of these benefits in your market?
3) Can DG be employed to delay investments or reduce congestion is high load areas?
4) What issues do you expect to find with high levels of DG in your market?
5) How will you manage communications and controls issues at a distribution level?
6) Design your own application procedures for small scale DG project i.e. between 2MW - 5MW

19.1. Module Structure

Although there are significant technical implications of high levels of DG, this module has been written for an audience with a moderate to advanced understanding of key technical concepts with regard to DG and systems operations.

Figure 19: Module Structure - Technical Implication of high levels of DG



20. FINANCIAL IMPLICATIONS OF HIGH LEVELS OF DISTRIBUTED GENERATION PENETRATION

20.1. Module Introduction

In the previous modules regarding DG, a general overview and an assessment of the technical implications of DG were presented. In this module, an in depth analysis of the financial implication of increasing DG is presented.

It can be argued that without a thorough understanding of the economic and financial implications of DG, regulators will not be able effectively manage these promising technologies. For RERA members, DG offers a small-scale, cost-effective solution to serve rural and off-grid communities.

Beyond operational and safety issues associated with DG has financial implications for consumers, network operators and generators (normally the incumbent utility in RERA markets). Utilities are immediately concerned that DG will cause them to lose revenue as more customers choose self-generation. Moreover, it may be difficult through traditional rate design practices to recover the costs associated with DG programs from the DG customers. Both factors can lead to increased rates for the non-DG customers, financial losses to the utilities, or both.

For industrial, commercial and residential consumers, DG represents a means to ensure security of supply and potentially lower their overall electricity costs by peak shaving (for example). There is an added benefit in allowing consumers to choose a “greener” or more environmentally friendly source of generation, which could have financial implications in markets which tax emissions.

20.2. Module Purpose

This module examines the many financial challenges that DG poses, as well as the ways that utilities can address these challenges and encourage DG development without unduly burdening other customers or adversely impacting utility operations and fiscal stability. It provides background on what DG is and the different pricing mechanisms utilities are using to compensate distributed generators. It also discusses the financial implications of DG, and ways different utilities have attempted to mitigate its impact on their bottom lines. The final section details the types of programs and rates that public power utilities have implemented to ensure rate equity.

20.3. Key Definitions & Concepts

20.3.1. Key Definitions

Table 24: Definitions - Financial implication of high levels of DG

Ancillary Services Benefit	The value of DG in respect of their ability to provide ancillary services to the system
Energy Benefit	Value of DG in its ability to displace the highest-variable-cost alternative generation source
Environmental Benefits	value of avoided emissions due to DG

Feed in Tariff (FiT)	A long term, fixed tariff paid to generators for electricity supply, most commonly associated with RE programs.
Generation Capacity Benefit	The proportion of nameplate capacity associated with DG that can be (statistically) counted toward planning reserves or could reliably be used to offset conventional capacity
Losses Benefit	Value of avoided or reduced transmission and/or distribution losses due to DG by virtue of its proximity to the load
Net Metering	Net metering is a billing system enables DG to be compensated for any excess energy they provide to the grid. This entails calculating the difference between consumption and production with DG plant owners being charged or credited depending on the net outcome of their usage.
Network Capacity Benefit	The value of DG in terms of transmission or distribution network congestion or reliability improvement as well as potential avoided or deferred network strengthening or expansion

20.3.2. Concepts

Which Stakeholders are impacted by DG?

As a starting point for the module, trainers should present an overview of all stakeholders in the electricity system and the physical and financial flows in the system. This can be presented as a "before" and "after" schematic, in order to illustrate the impact of DG on the overall system.

In many RERA markets, the monopoly utility will play the role of generator, network operator and distributor, but it would be useful to separate these roles in order to ensure that there is a clear understanding of the physical and financial impact of these changes.

It is not necessary at this stage to quantify the value of the changes in financial flows - the rest of the module will focus on unpacking options for understanding and quantifying these changes.

From Physical to Financial

Whilst the first section of the module presented high level flows, the next step is to detail what those physical flows represent in terms of benefits and costs. As discussed in the previous module, DG does not merely provide energy to consumers, it also provides potential costs and benefits to distribution and transmission network operators. A starting point from listing benefits and costs for each stakeholder is provided in the table below.

Table 25: Potential Costs & Benefits from DG

Stakeholder	Potential Benefit	Potential Cost
Utility Generator	• Diversity • Resilience • Reserves • Ancillary Services • Reduced Losses • Reduced Congestion • Avoided capacity costs • Avoided emissions costs	• Lost revenue
Transmission Network Operator	• Delayed CAPEX for new assets or asset refurbishment	• DG may require additional systems control and communication equipment • Network Strengthening
Distribution Network Operator	• Delayed CAPEX for new assets or asset refurbishment • Voltage control • Power quality • Reduced Losses • Reduced Congestion	• DG may require additional systems control and communication equipment • Additional fault control equipment • Bi-directional power flow management • Grid connection & power flow studies • Network Strengthening
Consumer	• Fixed cost for energy • Green power • Security of Supply/ back-up power • Increased efficiency through cogeneration • Avoided emission costs	• CAPEX for DG equipment • Project Development Costs • Regulatory costs (licensing) • Grid connection & power flow studies • Network Strengthening

Not all of these costs and benefits will be incurred for each DG plant. Additionally, Regulators will also need to assess how the various costs are apportioned e.g. if there are network and power flow studies required, who will bear the cost of these? For DG licensing and application procedures, regulators will need to carefully assess how to maintain standards without restraining and overburdening developers.

The remainder of the module will discuss how these benefits and costs are currently being evaluated and will propose a number of options for quantifying the financial implications thereof.

Common Option for Compensating DG Supply

Although network operators have developed various formulae for compensating DG plant for the power that flows onto their grids, there are essentially two basic methods of compensation:

- Net metering, and
- Feed-in tariffs.

Net Metering

A net metering program is designed to allow consumers with DG to sell excess power (that they generate over and above their consumption) back to the grid. In effect they will be charged for periods when their consumption exceeds their generation or for the net difference between consumption and generation.

There are a variety of different mechanisms for calculating customers' accounts – in some cases customer account are balanced on a monthly basis, whilst in others, they are able to carry their balance forward. Most utilities will have a cut-off period at the end of the year, or some other pre-determined time, when accounts are cleared by being compensated.

Net metering policy differs significantly between markets – there are often limits on technology types, plant sizes and allowances for the total amount of net metering in the system

Perhaps the biggest issue is the variance between the retail rate charged by the supplier and the net metering rate credited to the DG. In a few cases where DG is being aggressively promoted, the consumer is credited with the full retail rate of actual avoided cost; however in most cases the utility will limit the net metering credit to the energy portion of the tariff in order to limit the impact on revenue and cost recovery. The meter simply records the net difference and either charges or credits the customer.

In most cases, net metering is not differentiated by time of usage (this would be administratively complex) - it therefore may over or under compensates distributed generators and may credit them with a value of generation that in some cases differs from the utility's avoided cost.

Feed-in Tariffs

Some markets offer DG plant a long term contract (via a Feed in Tariff or FiT) with a fixed price for any generation they are willing to sell to the grid. FiTs vary across markets and are a powerful incentive to support the implementation of DG; although it is generally accepted that this is not the most cost-effective means of procurement.

As with net metering, the success of the program will be based on the relationship between the retail rate charged by the utility and the FiT level paid by the utility. Any significant variance from cost-reflectivity will result in the potential for under or over-compensation.

None of these rates incorporate the value of the other benefits described above.

Key Tariff Related Issues for Utilities

In most RERA markets, electricity tariffs are based on a Rate of Return methodology which defines various building blocks that are used to calculate the average tariff. However; customers do not pay an average tariff – their actual tariffs are segmented by customer groups, geographical area and connection type (for example). Utilities have to undertake a cost of supply study to determine the actual costs to supply customers as one of the inputs to determining the actual end-user tariff.

The key concept for the trainer to present here is the implication of a DG installation on all of those calculations. DG may cause the utility to:

1) incur additional costs for power purchases from DG
2) incur losses on power sales displaced by DG
3) reduce other revenue related to non-energy charges (network costs, administration etc.

These costs do not disappear – they now need to be paid by other non-DG customers, which effectively means that DG customers could in some cases be receiving a subsidy from non-DG customers (so called "cross-subsidies"). Once again this also excludes the potential benefits that DG customers are providing.

Revenue losses can be exacerbated as DG is often employed in order to load shift away from the peak demand. For utilities this can represent a loss of their most "valuable" power sales.

Calculating Potential Benefits & Costs of DG

The remainder of the module will propose a variety of options for calculating the value of the various benefits that DG theoretically offers. Each DG case will need to be assessed on its own merits; however it will be possible to propose general approaches to quantifying these benefits. Regulators will need to develop these techniques with other stakeholders in their electricity markets in order to ensure they are appropriately designed.

The benefits can be generally grouped into the following categories:

1) Energy
2) Environmental
3) Transmission & Distribution Losses
4) Generation Capacity Value
5) Transmission Capacity Value
6) Distribution Capacity Value
7) Ancillary Services Value
8) Other Value

A thorough analysis of these options is contained in the NREL report "*Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility*

System"[6]. These have been included under each concept as a guide and reference for module developers and trainers. Whilst not exhaustive, they represent a thorough assessment of the technical options available.

Energy Benefit

In most electricity systems, generating units are dispatched by the systems operator on a "leas cost" basis i.e. they will be utilized based on ascending order of their variable costs. There are many different parameters for the SO to consider when dispatching plant include their start-up times and ramp rates, heat rates, fuel costs and in some cases even emissions restrictions.

Module presenters can utilize a marginal cost model to illustrate how DG can be used to displace certain generating capacity based on a the parameters within a given system. RERA members DG options will probably exclude gas fired plant (for the short and medium term outside of Mozambique, Tanzania and other gas-rich countries). They may include a large portion of rooftop solar PV and hybrid solar PV/Diesel plant.

Given these technologies, it is likely that they will be able to displace some peaking plant like OCGT and large scale gensets. However; detailed modelling will provide a better evaluation.

The NREL study referred to earlier proposes the following five methods for estimating which plant(s) are marginal and will be displaced:

1. Simple avoided generator - assumes solar PV displaces a typical "marginal" generator, such as a combined-cycle gas turbine (CCGT) with a fixed heat rate
2. Weighted avoided generator - assumes solar PV displaces a blended mix of typical "marginal" generators, such as a CCGT and combustion turbines (CTs)
3. Market price - uses system historic locational marginal prices (LMPs) or system marginal energy prices (system lambdas) and solar PV synchronized to the same year
4. Simple dispatch - estimates system dispatch using generator production cost data
5. Production simulation - simulates marginal costs/generators with solar PV synchronized to the same year.

Environmental Benefits

In many markets, the value of key environmental benefits has already been calculated – this reflected in the value of Carbon Tax or Renewable Energy Certificates (RECs), for example. There are several globally accepted organizations and methodologies which are used to calculate these values, which are all predicated on the basis of avoided emissions. The avoided emissions will in turn be linked to the type of fuel avoided.

DG incorporating RE or cogeneration will be most successful in capturing these values.

[6] http://www.nrel.gov/docs/fy14osti/62447.pdf

Other benefits including those linked to land and water use can be calculated using a similar approach.

Adjusting for Transmission and Distribution Losses

It has been suggested that DG (and especially at high levels of penetration) can reduce line losses and congestion at both a Transmission & Distribution level. Of course in some situations if the DG production is significantly more than the load, this could result in increased losses.

The key issue to present here is that detailed studies will probably be required in order to gauge the actual impact. Studies may include:

- distribution load flow studies
- power flow studies
- power quality studies

Calculating loss rates can be achieved through various methods described below.

The following are four common methods for estimating loss rates in DG value studies[7]:

1. Average combined loss rate - assumes PV avoids an average combined loss rate for both transmission and distribution
2. Marginal combined loss rate - modifies an average loss rate with a non-linear curve-fit representing marginal loss rates as a function of time
3. Locational marginal loss rates - computes marginal loss rates at various locations in the system using curve - fits and measured data
4. Loss rate using power flow models - runs detailed time series power flow models for both transmission and distribution.

Generation Capacity Value

Earlier in the module, it was suggested the DG can displace the variable costs of certain generating capacity; however it has the added advantage of deferring the replacement or expansion of new transmission and distribution infrastructure – thus we can also calculate its “capacity” value for Generation, Transmission and Distribution.

In this section trainers should present a number of options for quantifying that value, which is done by calculating the portion of DG capacity that can be relied on to replace some other generating capacity (taking into account loss values described above.

The following four methods can be used for estimating generation capacity value[8]:

1. Capacity factor approximation using net load - examines DG output during periods of highest net demand
2. Capacity factor approximation using loss of load probability (LOLP) - examines DG output during periods of highest LOLP

[7] As per NREL “Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System”

[8] Ibid

3. Effective load-carrying capacity (ELCC) approximation (Garver's Method) - calculates an approximate ELCC using LOLPs in each period
4. Full ELCC - performs full ELCC calculation using iterative LOLPs in each period.

Transmission & Distribution Capacity Value

As with calculating Generation Capacity Value, it has already been suggested that it is possible to calculate the DG plant's capacity value for the networks. By producing at or near to the load, there will most probably be a reduction in capacity requirements on the networks although, as the utility is the supplier of last resort, arguably it will still need sufficient capacity to ensure security of supply, thus limiting the capacity reduction value.

Further thought should be given to the need for equipment upgrades as greater penetration of DG creates the requirement for upgrading of transformers and control and protection systems. Depending on a number of factors, including size of load, size of system, location on feeder etc. DG could require an increase in costs or in benefits to all stakeholders. Each DG installation is unique and will need to be assessed individually.

The following three methods can be used for estimating transmission capacity value[9]:

1) Congestion cost relief uses Location Marginal Pricing (LMP) differences to capture the value of relieving transmission constraints
2) Scenario-based modeling transmission impacts of DG - simulates system operation with and without combinations of DG and planned transmission in a Production Cost Model
3) Co-optimization of transmission expansion and non-transmission alternative simulation - uses a transmission expansion planning tool to co-optimize transmission and generation expansion and a dedicated power flow model to evaluate proposed build-out plans.

There are six useful methods for estimating distribution capacity value[10]:

1) DG capacity limited to current hosting capacity - assumes DG does not impact distribution capacity investments at small penetrations, consistent with current hosting capacity analyses that require no changes to the existing grid
2) Average deferred investment for peak reduction - estimates amount of capital investment deferred by DG reduction of peak load based on average distribution investment costs
3) Marginal analysis based on curve-fits - estimates capital value and costs based on nonlinear curve-fits; requires results from one of the more complex approaches below
4) Least-cost adaptation for higher DG penetration - compares a fixed set of design options for each feeder and DG scenario
5) Deferred expansion value - estimates value based on the ability of DG to reduce net load growth and defer upgrade investments

[9] As per NREL "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System"

[10] Ibid

6) Automated distribution scenario planning (ADSP) - optimizes distribution expansion using detailed power flow and reliability models as sub-models to compute operations costs.

Ancillary Services Value

The previous module provided an extensive list of some of the ancillary services benefits that DG could provide to the system. These can generally be grouped under either reserves or voltage control. As with all the other sections, these values will be highly dependent on the DG installation and the local circumstances. Arguably, there will be little benefit from smaller DG systems like residential rooftop PV.

In developed and deregulated markets, the costs for ancillary services will be well understood and transparent. In developing markets, these may be harder to quantify and will require some form of Cost Benefit or Avoided Cost Analysis.

Other Value

There are some other less tangible benefits that could be assessed – for example where DG is used as a back-up source of supply its value will be judged against the Cost of Unserved Energy (COUE). In this case the COUE will vary from customer to customer as it represents the loss value (per unit of electricity) for a customer that cannot operate because it is not being supplied with electricity. For manufacturers or mining companies, this value can be very high.

Another potential value to be considered is that of hedging volatile primary energy costs such as coal or gas in particular markets. As with all of the other benefits of DG, this is extremely particular to each DG business case.

20.4. Recommended Reading

Table 26: Recommended Reading - Financial implication of high levels of DG

Title	Source	Description
The Potential Benefits Of Distributed Generation And Rate-Related Issues That May Impede Their Expansion	http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Study_Sep_07.pdf	A USA Department of Energy report on the benefits of DG. An excellent starting point and overview of many of the salient issues regarding DG.
Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues	http://www.raponline.org/document/download/id/4572	This paper covers technical requirements, procedures and agreements to preserve the safety, reliability, and service quality of electric power systems and make interconnection as predictable, timely, and reasonably priced as possible.
Distributed Generation An Overview of Recent Policy and Market Developments	https://www.publicpower.org/files/PDFs/Distributed%20Generation-Nov2013.pdf	This paper examines the many challenges that DG poses, as well as ways utilities can address these challenges and encourage DG development without unduly burdening other customers or adversely impacting utility operations and fiscal stability.
Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System	http://www.nrel.gov/docs/fy14osti/62447.pdf	This report describes the current and potential future methods, data, and tools that could be used with different levels of sophistication and effort to estimate the benefits and costs of DGPV. It focuses on benefits and costs from the utility or electricity-generation system perspective.

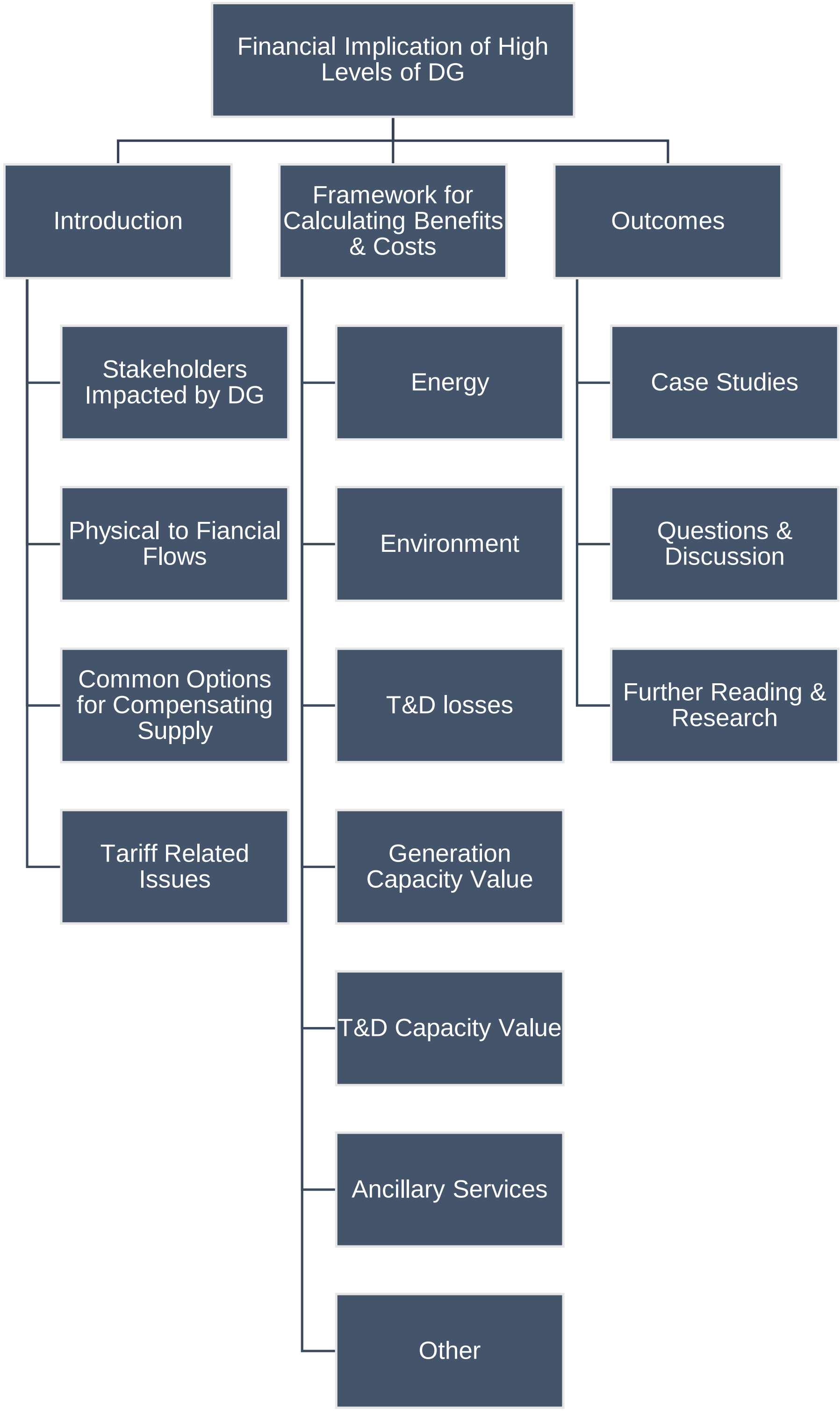
20.5. Outcomes

Following on from the presentation of the material, the trainer will hold a more interactive session in which course attendees can further interrogate specific issues they need clarified. This is also a space in which the trainer can assess how well the attendees have understood the material. This can be facilitated by the introduction of case-studies as well as by proposing certain questions. The following questions are suggested as a means to provoke debate and clarify understanding:

1) Are there Net metering or FiT programs for DG in your market?
2) How were they designed – are the credits based on marginal costs or ToU differentiated?
3) Have the program been successful in promoting DG?
4) how does the utility in your market view DG? Are they actively promoting it or do they see it as a threat to their revenue?
5) Have a studies been done to quantify the value of the DG plant to the system?
6) Is it possible that DG will defer any new capacity development at a generation, transmission or distribution level?
7) Have any consumers installed DG as a means of security of supply?

20.1. Module Structure

Figure 20: Module Structure - Financial implication of high levels of DG



21. Selected Module Overview

21.1. Introduction

This chapter presents an overview of the six regulatory training modules developed for the (SADC) Regional Electricity Regulators' Association (RERA). The six modules being:

1. Network Losses
2. Third Party Network Access
3. Power Purchase Agreements
4. Energy Subsidies
5. Regulatory Governance
6. Regulatory Impact Assessment.

This overview focuses on the pedagogical outline of each module by describing:

- Module Objectives
- Module Rationale
- Content Outline
- Intended Target Groups

There are also some comments and guidelines presented here for the instructor's use of the material. The detailed module content on the six topics has been submitted separately to RERA in MS PowerPoint format.

21.2. Structure of Modules

Each of the modules follows a standard pedagogical structure. The introduction gives the module objectives, rationale, an outline and the target groups. This information will help RERA to publicize the courses with information that members can use to nominate appropriate participants. Although a generalist approach is used in the design and content of the modules, some may appeal to the commissioners, others to staff. For instance, the main interest in regulatory governance would come from commissioners, senior staff and government officials; whereas staff may be keen to explore matters concerned with Network Losses.

Importantly, the module introduction targets the instructor and the participant in order to enhance learning outcomes. The instructor should fully appreciate the thrust of the modules especially that most of the topics could be approached from various viewpoints. In general the context of developing countries informs the modules; in particular the modules respond to the Training Needs Assessment among RERA members. Apart from its low economic status and low electricity access rates, the region is distinguished by state-owned utilities that are mostly vertically integrated. This context frames the approach to regulation and to the design of the modules.

21.3. Description of Modules

21.3.1. Network Losses

Objectives

The module enables participants to:

1. Understand the nature and impact of network losses

2. Appreciate the roles of different players in reducing losses
3. Know and be able to apply the principal regulatory instruments for reducing network losses

Rationale

Network losses can lead to the following:

- Inefficient pricing: consumers pay higher prices than they should
- Consumer resistance to tariff reviews: consumers are entitled to demand tariffs that reflect efficient costs
- Financial loss to the utility: if the tariff does not fully recover loss, utility bears the cost
- Burden on the treasury: government may need to provide subsidies to the utility

Therefore, this module will help participants to understand the nature of losses and to know the principal methods of reducing them. The task lies with the utility, but the environment provided by policies, laws and the regulatory framework will determine whether losses become a priority for utility managers

Module Outline

The nature of losses: technical and non-technical; the components of technical losses; the components of non-technical losses; effect of losses on the utility; effect of losses on consumers; why losses matter to the government, reducibility of losses

Roles for the government (policy): industry structure; legal frameworks; regulatory frameworks; private sector participation; distributed generation mandates

Utility Roles: Management focus: e.g. special units; prosecutions and publicity; reducing connection backlogs; dealing with illegal connections; working with communities

Regulatory instruments: tariffs; incentive regulation; embedded and distributed generation

Target Group

The module is appropriate for the following: Senior staff and commissioners. Participants should have an understanding of Cost of Service (or revenue requirement) regulation. A basic knowledge of electrical terms is desirable, though not essential.

21.3.2. Third Party Network Access

Objectives

At the end of this module on Third Party Network Access participants will:

1. Understand the importance of third party network access
2. Know how market structures influence network access;
3. Know the purpose and elements of a network code

Rationale

Network access refers to the ability of an independent producer of energy to supply consumers using an existing network. When the conditions for accessing the network are standardized and apply to all producers it is called an open access regime. The establishment of such a regime promotes new investment in generation. By additionally promoting competition, an open access regime is conducive to efficient capacity procurement.

To effectively discharge their obligation to promote capacity growth in as efficient a manner as possible, regulators need to understand what network access entails and how it may be regulated. This is the purpose of the module on Third Party Network Access

Module Outline

Introduction: network access and the IPP; access to markets, closing projects; the meaning of some common terms

IPP investments: IPP projects, access to markets; renewable energy generation; obligations to dispatch

Market structures: Single buyer model; other models; energy and financial flows; network ownership and operation;

System operation: ITO

Network Code: Common Objectives, specific objectives, main parts

Target Groups

This is a high level module suitable for the following:

- Commissioners or Directors
- Senior technical staff (engineers, economists, financial analysts)
- Senior government energy officials

21.3.3. Power Purchase Agreements

Objectives

At the end of this module on Power Purchase Agreements participants will:

1. Understand the use and relevance of Power Purchase Agreements
2. Know the essential features of different types of Power Purchase Agreements
3. Be able to identify the risks, their mitigation and how they may be managed

Rationale

A Power Purchase Agreement (PPA) is commonly one among a suite of documents that a project developer needs in order to secure financing and implement a project. It is entered into by a seller and a purchaser of the projected output of the generation project. Because the PPA can be highly influential in determining supply costs, and therefore retail prices, the regulator, at the very least, needs to know the terms of the Agreement. In some jurisdictions, the regulator may have the power to approve or reject an agreement.

Outline

Introduction: Power generation project finance

Project structuring: Financial contracts, SPVs, Shareholders Agreements, PPPs

The Power Purchase Agreement: Commercial Terms, Technical Matters

Related Agreements: e.g. Fuel Supply Agreements, TSA

Some Risks: for the seller; for the buyer; how to mitigate and share risks

Target Groups:

The following will benefit from this module on Power Purchase Agreements:

- Commissioners
- Senior Commission Staff
- Senior Government officers in ministries or departments responsible for energy.
- Utility staff responsible for project development and regulatory liaison

21.3.4. Energy Subsidies

Objectives

This module will enable participants to improve regulatory policies and frameworks by understanding:

1. The occurrence and design of subsidies
2. Direct and indirect subsidies
3. How impacts of subsidies may be measured
4. This module does not include subsidies in the **fuel sector** except as they may impact electricity supply

Rationale

Subsidies have a place in every economy, whether developed or developing. They may appear in the guise of tax relief, or concessionary loans or they may be direct cash transfers to the poor.

Whatever form they take, questions such as the following arise:

- Are they clear and quantifiable?
- Do they serve the policy intentions?
- Do they reach the intended targets?
- How long can they be sustained?
- What tips the balance: the benefits or the costs

The energy sector presents opportunities for the use of subsidies to advance policy priorities. For example, subsidies can promote energy access and they can stimulate investment in clean energy. It is important that regulators understand what subsidies are, how they are applied and how they impact the sector. It is also necessary that regulators recognize indirect subsidies that could have significant impact on the sector and on the economy.

Module outline

Introduction: general definitions of subsidies; meaning of 'financial contribution'; meaning of 'benefit'

Classifying subsidies: On-budget, explicit subsidies; off-budget, implicit subsidies; differences between them; examples; implications for treasury; efficient and inefficient subsidies; assessing the costs and benefits

Energy subsidies: IEA definition; policy objectives.

Tariff subsidies: cost reflectivity; below cost tariffs; implications for a) the treasury, b) the utility and c) the consumers; customer classes and cross-subsidies; objectives; regulatory fairness; universal access obligations; connection subsidies; incline block tariffs; lifeline tariffs; targeting.

Rural Electrification: Tariff subsidies in uniform tariffs; electrification (universal access) funds; application; that they are explicit subsidies; treatment of assets for regulation; off-grid rural electrification

Renewable Energy: On-grid system capacity, indirect subsidies for RE promotion; competitive bidding process; general and technology-specific bidding; advantages of competition; hurdles to competition. Renewable Energy Feed-in Tariffs: main features; what they aim for; government role; developing country context; key considerations (price discovery, sustainability, complexity) Off-grid systems; REFIT and affordability

Target Groups

- This module is suitable for commissioners and senior staff of regulatory institutions, and for senior government officials responsible for energy and finance
- Participants should have prior understanding of fundamental principles of energy regulation.

21.3.5. Regulatory Governance

Objectives

The module will enable participants to:

- Appreciate the context and necessity for regulating energy utilities
- be aware of their accountabilities and measures of effectiveness
- Assess the adequacy of institutional arrangements to achieve effectiveness
- Develop approaches to common challenges in autonomous regulation

Rationale

In a span of twenty years, from the end of the 1990s independent regulators have sprung up in sub-Sahara Africa. Even as more countries introduce similar structures, the justifications for these bodies may be lost in the quest for uniformity and perceived economic advantage. Furthermore, certain of the experiences of African regulators substantially differ from those in other regions. This suggests an evolving unique body of regulatory knowledge. This relates primarily to governance arrangements. But it also refers to adapting standard technical approaches to suit environments where different assumptions become necessary. This module will focus on governance arrangements, identifying parameters and practices that promote regulatory effectiveness.

Module Outline

Introduction: the spread of independent regulation and its purpose; the meaning of regulatory effectiveness; factors for effectiveness.

Governance elements: General and institutional; governance in theory and practice; ideal attributes for a regulator: Autonomy, and Authority; Accountability and Capacity (or Ability)

Autonomy: Appointments of commissioners and senior staff; tenure; financing and budgeting;

Authority: tariff setting as core function; licensing and conditions thereto; regulation and reform; market access; general scope.

Accountability: Participation in tariff reviews; appeals; reporting; removal from office; regulatory impact assessment

Capacity (Ability): Institutional competence; the chairman and the commission director. Staff compensation and quality; Technical ability;

Governance Failures: Appointments: political largesse; staff appointments. Tariff as contested ground; Other failures

Target Groups

This module is suitable for commission chairs, commissioners and executive heads of regulatory bodies.

21.3.6. Regulatory Impact Assessment

Objectives

The module seeks to raise awareness of the need to justify and evaluate regulatory decisions. At the end of the module, regulators should:

- Understand the concept of regulatory impact assessment;
- The relevance of RIA to good regulatory governance
- Understand the tools and methods of RIA in utility regulation
- Understand the implications of RIA on institutional capacity.

Rationale

Although governments must regulate in order to govern, an excess of laws and rules can overburden the economy and cause dysfunction. One manifestation of the concern The development of international indices for the ease of doing business arise partly from widespread concerns about the effect of overlapping, redundant and costly regulatory systems.

Regulatory Impact Assessment seeks to impose a discipline on the development and application of regulatory measures. In the first instance, utility regulators need to appreciate the economic roles that justify their establishment. This provides a context for each decision they take, examining at all times whether their actions (or inactions) advance the purposes for which they were created. Efficiency and effectiveness requires that regulators can show that their decisions are necessary, and likely to procure the expected beneficial results at minimum cost. To achieve the ends of transparency requires the participation of the affected parties in developing regulations and periodically evaluating their continuing relevance. The module presents essential building blocks for good practice in regulatory impact assessment.

Module outline

Introduction: Fundamental justification for regulation; sector and policy goals as guide posts for effectiveness; tariff setting and private investment as the key challenges; the limit of regulation as an agent for change and success.

Evaluation and Assessment: distinction to be made between regulatory evaluation and regulatory impact assessment; ex-ante and ex-post concepts; decisions vs regulatory systems

Regulatory Decisions: analyzing decisions; need to consider all options; establishing need for new regulations; the interests of consumers, operators and the government; the primacy of tariff regulation.

Regulatory Impact assessments: Rationale; Methods; Proportionality, Consistency and Targeting; criteria of assessment, what to expect from an assessment; Transparency inherent to the process

The RIA report: Basis of decision by the regulatory authority; need for rigor in supporting positions; transparency of conclusions.

Conclusion

Target Groups

This module on Regulatory Impact Assessment is suitable for Commissioners and Senior Regulatory Staff. All participants should be able to benefit from the module, especially those with two or more years of regulatory experience.

21.4. Using the Modules

The modules that follow give a detailed guide of coverage of material. By presenting them in power point format, they indicate to the instructor the approximate time required for coverage. To use these slides, the module instructor should

1. Study the whole module
2. Summarize the points on each slide
3. Produce a presentation for instruction
4. Add material, especially instructive examples from the region
5. Develop discussion points and exercises to complement formal presentation.

The instructor has room to add some material, perhaps up to twenty per cent. The limit ensures that different instructors will not deviate too far from the treatment given here and approved by RERA.

22. ANNEX 1: Other Resources

Some general resources have been listed here in order to assist module developers and trainers in the next steps of module development and presentation.

22.1. General Regulatory & Energy Research Resources

Resource	Site	Description
National Association of Regulatory Utility Commissioners (NARUC)	http://www.naruc.org/	Founded in 1889, the National Association of Regulatory Utility Commissioners (NARUC) is a non-profit organization dedicated to representing the State public service commissions who regulate the utilities that provide essential services such as energy. NARUC have supported and sponsored various training and research initiatives with RERA in the past.
Council of European Energy Regulators (CEER)	http://www.ceer.eu/portal/page/portal/EER_HOME	The Council of European Energy Regulators (CEER) is the voice of Europe's national regulators of electricity and gas at EU and international level. Through CEER, a non-for-profit association, the national regulators cooperate and exchange best practice. A key objective of the CEER is to facilitate the creation of a single, competitive, efficient and sustainable EU internal energy market that works in the public interest.
African Forum for Utility Regulators (AFUR)	http://www.afurnet.org/	The African Forum for Utility Regulators (AFUR) focuses on issues related to the regulation of energy, telecommunications, transport, and water & sanitation industries, with a particular emphasis on issues that are common across sectors (but not necessarily limited to the primary focus sectors).
World Energy Council (WEC)	https://www.worldenergy.org/	The World Energy Council is the principal impartial network of leaders and practitioners promoting an affordable, stable and environmentally sensitive energy system for the greatest benefit of all. Formed in 1923, the Council is the UN-accredited global energy body, representing the entire energy spectrum, with more than 3000 member organizations located in over 90 countries and drawn from governments, private and state corporations, academia, NGOs and energy-related stakeholders.
National Renewable Energy Laboratory (NREL)	http://www.nrel.gov/	NREL develops clean energy and energy efficiency technologies and practices, advances related science and engineering, and provides knowledge and innovations to integrate energy systems at all scales

International Renewable Energy Agency (IRENA)	http://www.irena.org/home/index.aspx?PriMenuID=12&mnu=Pri	The International Renewable Energy Agency (IRENA) is an intergovernmental organization that supports countries in their transition to a sustainable energy future, and serves as the principal platform for international co-operation, a center of excellence, and a repository of policy, technology, resource and financial knowledge on renewable energy.