Appraisal of an Electricity Project in Zimbabwe

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Abstract

This study is an instructive tool in the appraisal of electricity projects, supplements the Public Investment Management Guidelines (PIM Guidelines) and the Public Investment Management Manual (PIM Manual). It is designed to aid public officials working within the electricity sector of Zimbabwe, primarily those who play a role in the planning, regulation, appraisal, development, selection, budgeting, and implementation of electricity projects. It outlines the procedural stages required to conduct a robust appraisal, starting with project conception through the development of a Project Concept Note (PCN) and continuing into the Pre-Feasibility Study (PFS) and Feasibility Study (FS) stages.

Keywords: Cost Benefit Analysis, Electricity, Public Investment, Zimbabwe

JEL Classification: D61, H54, O55

1.1 INTRODUCTION

1.2 Purpose of the Manual and its Relationship with Public Investment Management Guidelines

This manual, an instructive tool in the appraisal of electricity projects, supplements the Public Investment Management Guidelines (PIM Guidelines) and the Public Investment Management Manual (PIM Manual). It is designed to aid public officials working within the electricity sector of Zimbabwe, primarily those who play a role in the planning, regulation, appraisal, development, selection, budgeting, and implementation of electricity projects.

The Electricity Projects Appraisal Manual (EPAM) is aimed at strengthening the institutional and technical capacity of Contracting Authorities (CAs) such as the Ministry of Energy, Zimbabwe Electricity Supply Authority (ZESA), Zimbabwe Electricity Regulatory Authority (ZERA), Rural Electrification Agency (REA), Rural Electrification Fund (REF), Zimbabwe Power Company (ZPC), as well as to provide guidance to the Independent Power Producers (IPPs).

The EPAM provides guidance on the methodology and best practices employed in the appraisal of electricity generation and transmission projects. It outlines the procedural stages required to conduct a robust appraisal, starting with project conception through the development of a Project Concept Note (PCN) and continuing into the Pre-Feasibility Study (PFS) and Feasibility Study (FS) stages.

The analytical tools provided in this manual will assist CAs to efficiently and effectively develop and implement electricity projects that will lead to sustainable development of the economy of Zimbabwe.

1.3 Relationship of the Manual to the Public Investment Management Guidelines

The EPAM supplements the Public Investment Management (PIM) Guidelines. The PIM Guidelines provide guidance on:

i. A standardised approach to PIM, to facilitate and streamline the development, appraisal, selection and implementation of proposed Public Investment Projects (PIPs);
ii. The roles and responsibilities of various institutions involved in the PIM System (PIMS);
iii. The processes and procedures of the PIMS; and
iv. The sequencing, timing and linkages of various activities required for the smooth function of the PIMS.

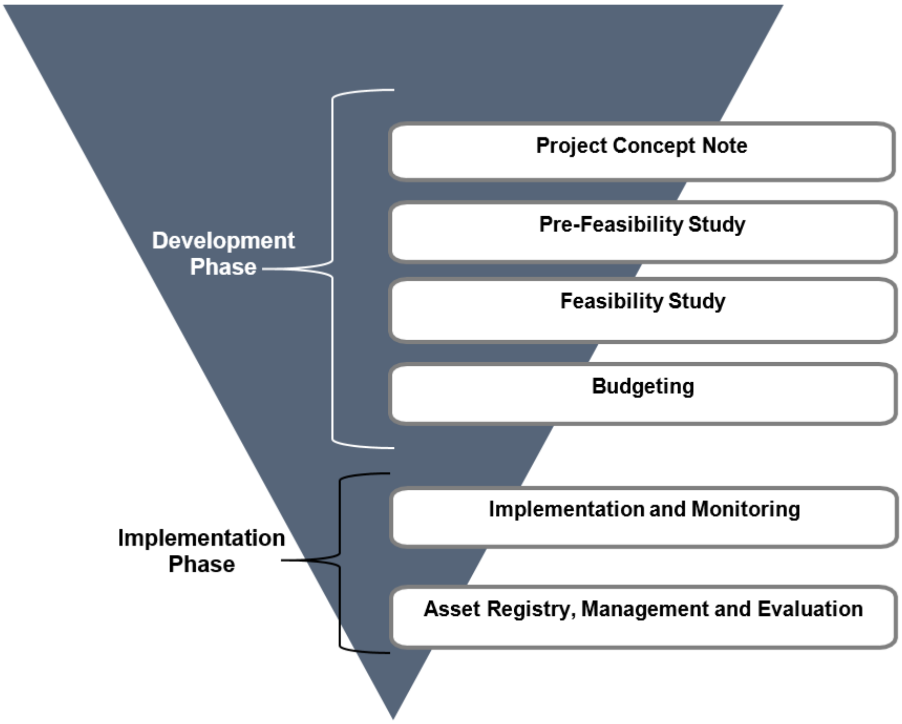
1.3.1 The Public Investment Management System (PIMS)

The PIMS encompasses how PIPs should be prepared and developed from inception to implementation and includes all the institutional processes, procedures and approvals required to get projects financed and executed.

1.3.1.1 Project Cycle

The PIMS provides a framework/system that governs the identification, formulation, appraisal, selection, budgeting, and implementation of proposed PIPs, this framework is known as the 'Project Cycle' which is presented in Figure 1. The project cycle was created to optimize the use of public resources and ensure value for money. It consists of two distinct phases; the development phase and the implementation phase. Each phase comprises of a number of different stages, which are carried out sequentially.

Figure 1. Project Cycle



To operationalise the PIMS, the EPAM has been developed as a practical guide on how to undertake the project development phase of the project cycle. Hence, the EPAM mainly focuses on how CAs should identify, formulate and appraise electricity projects.

1.3.1.2 Institutional Framework

The efficient and effective management of public resources with regards to PIPs requires the harmonious coordination of a broad range of institutions. Key institutions in the electricity sector involved in the development, selection and budgeting of electricity projects are as follows:

A. Contracting Authorities:

- **i.** Zimbabwe Power Company (ZPC)
- **ii.** Zimbabwe Electricity Transmission and Distribution Company (ZETDC)
- **iii.** ZESA Enterprise

B. Sanctioning Authorities:

i. Ministry of Energy and Power Development (MEPD)
ii. Zimbabwe Electricity Regulatory Authority (ZERA)
iii. Zimbabwe Investment and Development Agency (ZIDA)
iv. Ministry of Finance and Economic Development (MoFED)
v. Zimbabwe Electricity Supply Authority (ZESA)
vi. Rural Electrification Agency (REA)

1.3.1.3 PIM Calendar

In undertaking the development phase of the project cycle, CAs should keep in mind key dates of the PIM Calendar. Figure 2 outlines the PIM Calendar, which merges project activities, PIM activities and the budgeting activities and outlines the sequencing and linkages of these various activities and their timelines in order to facilitate the smooth functioning of the PIMS. The PIM Calendar allows for the seamless coordination of the processes and procedures undertaken by various institutions that are involved at various stages of the project development phase of the project cycle.

Figure 2. PIM Calendar

		March – April	**May - June**	**July**	**August - September**	**October**	**December**	**January – February**
Treasury	**Budget Activities**	Budget Consultations	Preparation of Macroeconomic Fiscal and Expenditure Framework for the next 3 years	Issues Budget Call Circular		Draft Budget Estimates are prepared	Budget Approval	
	PIM Activities		Decision on Pre-Feasibility Studies		Decision on Feasibility Studies			Decision on Project Concept Notes
LMs	**Budget Activities**	Development or updating (on rolling basis) of strategic plans, expenditures, and revenues for the next three years	Revised strategic priorities and expenditures	Prepare Budget submissions			Preparation of Budget Implementation Plans	
	PIM Activities	Submission of Pre-Feasibility Studies		Submission of Feasibility Studies		Submission of Project Concept Notes		

1. PROJECT CONCEPT NOTE

The submission of the PCNs to the MoFED shall be made in October in line with the Public Investment Management and Budgeting Calendar (PIM Guidelines, Article 141). Budget discussions are held from October to December and Treasury may discuss PCNs with Contracting Authorities in this period. The decision of the Treasury on the PCNs shall be issued in January.

An electricity investment project being generation, transmission or distribution investment project shall obtain a clearance from the Treasury if:

1. It is to be funded through the Government's budget, the budget of the relevant state-owned enterprise or donors funded project that will be consequently transferred to the the balance of the GoZ.
2. Power Purchase Agreement (PPA), or any other form of the off-take contract is secured by the GoZ.
3. GoZ provides any form of guarantees to the IPP.

In preparing a PCN, the CA should follow the requirements stipulated in the PIM Guidelines and the PIM Manual, the details of which can be found on pages 34-49 and pages 3-9, respectively. This chapter of the EPAM outlines the information and steps (in addition to those in the PIM Guidelines and Manual) required in preparing a PCN for a proposed electricity project to be evaluated and approved by the Treasury.

2.1 Project Information Sheet

A project information sheet is the cover page of the PCN and consists of information that gives an overview of the project and its objectives. A typical project information sheet should contain the details highlighted in Table 1.

Table 1 Project Information Sheet Data Requirements

Data Requirements	Description
Project Identification Number (ID)	The ID should clearly communicate the Line Ministry responsible for the project, the relevant department within the Line Ministry that the project falls under and the year of project initiation. The ID should be unique and comprise of the following details in alphanumeric order; Line Ministry/Department/Sequence Number/ Year An example of a project ID is shown below. **ID: MoEPD/ZPC/001/2018**
Line Ministry and Contracting Authority	The Line Ministry functionally responsible for the project and the contracting authority tasked with implementing the project should be identified in the project information sheet, as illustrated below. **Line Ministry: Ministry of Energy** **Contracting Authority: Zimbabwe Power Company**

Project Title	A short and concise project title that captures the essence of the project should be included in the project information sheet, as shown in the example below. **Project Title: AMPTA II 26MW Hydro-Electric Power Scheme**
Project Location	The location of the project inclusive of the district and province should be included in the project information sheet, as shown in the example below. **Location: Up-stream of AMPTA I, Ngarura River + geolocation coordinates**
Project Objective	A clear sentence that describes the fundamental reason for the proposed project and the direct benefits of implementing the project. An example is shown below. **Project Objective: "Addition of 26 MW of hydro capacity to the national grid to reduce the demand-supply gap currently estimated at 500MW. "**

2.2 Situation Description

This section shall provide a clear description of the situation that prevails in the absence of the project "Status before Project" and how it will be affected "Status after Project" as discussed below:

2.2.1. Status before Project

This section shall provide an accurate description of the situation if the project is not implemented. It should clearly identify and discuss the challenges and problems that are expected to be addressed by the project. Some examples of this may be as follows:

I. Shortages in electricity supply resulting in brown-outs and black-outs.
II. Outdated electricity generation plants that are inefficient and highly polluting.

2.2.2. Status after Project

This section shall provide an accurate description of the situation if the project is implemented. It should also constitute a discussion on how the challenges and problems identified in the previous section will be addressed and the benefits that society will reap as a result of the project. It focuses on the benefits that are achieved solely due to the implementation of the project, excluding those that could arise in the absence of the project. Some examples of this are as follows:

I. Increased access to electricity.
II. Improved reliability of electricity supply.
III. Reduction in pollution.
IV. Fuel costs savings.
V. Operation and maintenance costs savings.

2.2.3. Project Objective and Justification

The justification for undertaking the project involves providing a comprehensive analysis of the counterfactual situation and how it will be addressed in the implementation of the project, as outlined in the preceding sections. Project justification entails a comparison of the anticipated outcomes and the expected costs of the electricity project. A proposed project is justifiable if the expected outcomes outweigh the expected costs.

2.3 Strategic Considerations

Any proposed electricity sector project shall be in line with national and sectoral objectives. The PCN should spell out how a project will contribute to the achievement of the defined objectives. For example, an economic plan that promotes accelerated economic growth, development and, wealth creation has been developed for the nation of Zimbabwe.[1] This plan outlines the objectives of electricity sector development and management.

Following the guidance provided in Articles 203-221 of the PIM Guidelines, an electricity investment project's PCN must demonstrate how the project's expected outputs align with national, sectoral strategic, and climate change considerations.

2.4 Preliminary Cost Estimates and Sources of Funds

PCN should outline the proposed cost estimate and cost schedule of the project. Guidance on completing this section of the PCN is provided in Articles 222-232 of the PIM Guidelines. At the PCN stage, the project will still be in its preliminary phase; therefore, the cost estimates and cost schedules should be based on a proxy of projects of a similar nature and scope implemented in the recent past.

The cost estimates should include capital, operating and maintenance expenditures. Where the costs of similar projects constructed in the past are used as proxies for the proposed project, an adjustment to the project costs must be made to reflect the real and inflationary changes in costs over time.

The capital and fuel costs of the thermal generation technologies are more or less standardized for a given country and can be compared across countries of similar sizes, locations and stages of development. For hydropower, geothermal and biomass resource projects, the costs are usually unique, given that every site is different. These categories of projects require more detailed project cost assessment, even at the early stages of the project life cycle.

An important aspect linked to project costs is how the anticipated costs will be financed. Articles 233-237 of the PIM Guidelines outline the issues that should be considered when looking at how to finance a project. The PCN should include an outline of the proposed sources of funds. Funding for capital expenditures can be garnered from various sources such as the national or local budget, equity, debt and/or funding from development partners or private sector parties.

[1] Zimbabwe Agenda for Sustainable Socio-Economic Transformation (ZimAsset), "Towards and Empowered Society and a Growing Economy" – October 2013 to December 2018, Government of Zimbabwe, October 2013.

Additionally, the cost of conducting a pre-feasibility study (PFS) of the project should be included in the PCN. This amount should be a reasonable estimate based on similar PFSs conducted on similar projects.

2.5 Outcomes, Outputs, Activities

2.5.1. Outcomes

The outcomes of a project should be defined according to Articles 240 and 241 of the PIM Guidelines. Project outcomes are the results that the CA has set out to achieve through the implementation of the project; they represent the achievement of the objectives and goals defined at project inception. These outcomes may not necessarily represent a change; project outcomes may maintain the status quo or prevent an undesirable situation from occurring. The expected outcomes of implementing a proposed electricity project should be identified and presented in this section of the PCN in order of priority.

2.5.2. Outputs

The outputs of a project should be defined according to Articles 242, 243 and 244 of the PIM Guidelines. Project outputs represent the various components of the aggregated result in the completion of the project and the achievement of project outcomes. In this section of PCN, all the expected project outputs must be clearly defined and linked to the attainment of the project objectives and outcomes. The targeted outputs of a rural electrification project, for instance, maybe providing off-grid access to electricity for 2,000 households in a district.

2.5.3. Main Activities

Project activities should be defined in line with Articles 245, 246 and 247 of the PIM Guidelines. Activities that include a series of specific tasks are required to produce project outputs. Activities transform a project's inputs into outputs. The activities required to produce the project's outputs must be listed in sequential order and split up in line with the various phases of the project, as this is vital to project implementation and delivery.

2.5.4. Implementation Plan

A project implementation plan should be developed in line with the requirements defined in Article 255 of the PIM Guidelines. At the PCN stage, the project implementation plan should be indicative and propose an implementation strategy that is reasonable given the information available, timing, scale, and scope of the project. The various activities required to implement and deliver the project successfully should be scheduled using a Gantt Chart, showing the timing, sequencing, and inter-dependencies among activities. Each of the activities to be carried out under the implementation plan should include the following components:

i. The name of the activity;
ii. A summary of the scale and scope;
iii. A list of all the activities that must be completed before the initiation of the next activity;
iv. The commencement and completion date the activity;
v. The cost of undertaking each activity.

The resources required for the successful execution of each activity, including human, financial, physical and other resources, should be identified, and their procurement should be included as part of the implementation plan.

2.6 Financial Effectiveness

A project's financial effectiveness is defined in Articles 248-249 of the PIM Guidelines. An indication should be made of whether a proposed electricity project is expected to generate financial revenues or not. For instance, an addition of thermal generation capacity to the grid will generate additional financial revenues to the utility. These expected revenues shall be compared with the all-in cost of delivering electricity to the end consumers or with the PPA payment to the IPP. In case when a project does not generate financial revenues (i.e. rehabilitation of the transmission line), the financial effectiveness shall be derived by comparing the cost of the project with the cost savings to the utility resulting from the project, such as reduced transmission losses and maintenance/repair costs of the transmission. While detailed financial feasibility calculation will be conducted at the PFS stage, PCN shall indicate if the project is expected to be financially feasible or not.

2.7 Socio-Economic Effectiveness (Least Cost Expansion Plan)

At the PCN stage, the socio-economic effectiveness of an electricity project can be assessed by checking if the project is included in the least cost expansion plan. It shall be noted that the inclusion of a project in the least-cost expansion plan does not eliminate a need for a detailed cost-benefit analysis at PFS and FS stages. The least-cost expansion plan is not a substitute for the appraisal of individual investments that would be recommended by the long term least cost expansion planning process. Once an investment appears in the recommended sequence, its benefits and costs must be quantified before such investments should be recommended for implementation. This is particularly the case when private participation is encouraged in undertaking particular investments in the expansion of this sector. Therefore, the inclusion of the project in the least cost expansion plan shall only be used as justification of the socio-economic effectiveness of the project at the PCN stage. Annex A presents fundamental concepts behind the least-cost expansion plan development.

Factors like new technology, or other changes in the conditions and dynamics of the energy sector can have a significant effect on the type and sequence of power plants that come into the energy mix. It is therefore possible that the project under consideration is not included in the LEP. In situations like this, the PCN should provide a justification for the project, outlining that expected socio-economic benefits are exceeding expected economic costs of the project, or that an electricity generation project is the least cost alternative when compared to the standard alternative of delivering same quantity of electricity.

2.8 Environmental and Social Impact Assessment

2.8.1. Environmental Impacts

A project's impact on the environment is an important component of the decision-making process. The CA shall consider highlighting the potential environmental impacts that will result if the project is implemented.

2.8.2. Social Impacts

The Contracting Authority may highlight any social impacts that may arise from the project. This may include any poverty alleviation impacts of the project or provision of the electricity supply to the remote areas through the expansion of the infrastructure.

2.8.3. Gender Analysis

Electricity access may impact men and women in different ways. The PCN shall provide a starting point of gender analysis by presenting the gender disaggregating data whenever possible. In this section, the PCN shall discuss the socially constructed roles of men and women according to the project's outputs and outcomes.

2.9 Preliminary Climate Change Risk Assessment

Projects that tackle climate change risk and its related impacts on the electricity-sector investments can be grouped into three categories:

- **Adaptation Projects:** Projects that address the impacts of climate-related risks are adaptation projects. They include climate-proofing components designed to reduce or minimize the physical damages and socio-economic effects of climatic events. For instance, heat waves and drought periods cause reduction in thermal power plants' generation efficiency by reducing their water-based cooling system efficiency. Installing improved cooling systems is a potential climate-proofing option to minimize the expected costs. Similarly, lower water levels during drought periods result in lowered power production by hydropower plants. Identifying cost-effective designs to deal with water flow uncertainties is an example of an adaptation option. Adaptation projects aim to reduce the economic costs to the project's beneficiaries due to electricity supply interruptions (power outages).

- **Resilience Projects:** Projects whose objective is to ensure that communities can withstand current and future climatic conditions. A resilience project increases the capacity of communities to resist, respond to, and recover from natural hazards and maintain essential infrastructure function, both in the short- and long run. For example, decentralizing electricity generation in remote rural areas reduces the need for long transmission and distribution lines and can potentially increase the resilience of the electricity supply to extreme climatic events.

- **Mitigation Projects:** Mitigation projects aim to reduce the rate at which climate change occurs by reducing greenhouse gas (GHGs) emissions that cause climate change. Renewable energy projects that mitigate energy-related GHG emissions by displacing fossil fuel power generation are examples of mitigation projects in the electricity sector. The standard measurement unit to quantify the economic cost of GHG emissions is equivalent tonnes (tCO2e) or kilograms (kgCO2e) of carbon dioxide. This value is determined by the project's generation capacity that displaces more polluting generation sources. The dollar value of GHG missions saved by the project can be estimated by multiplying the annual GHG emissions (tCO2e) by carbon price per tCO2e. The carbon price reflects the economic benefit of mitigating one unit of carbon and is determined at a national or international level.

It should be notified here that the main focus of this manual is on adaptation and resilience projects. Mitigation projects must follow the due processes and procedures outlined in PIM Guidelines. However, the following provisions should be considered for climate-related impacts when appraising Mitigation Projects. Electricity sector projects contribute to GHG emissions. Therefore, in appraising electricity projects, CAs shall:

i. Identify and quantify the negative environmental and climatic impacts the project's output will generate, e.g., increased GHG emissions.

ii. Add the economic costs associated with the project's GHG emissions based on the carbon price per equivalent tons of carbon dioxide.

iii. Report the economic feasibility of the project both inclusive and exclusive of the costs associated with increased GHG emissions.

Caution should be taken to avoid double-counting the impacts when comparing mutually exclusive projects (project options). For instance, when comparing renewable and coal generation technologies, the economic value of GHG emissions should only be considered either as an additional benefit to a renewable energy project or as an additional cost to thermal power projects.

Electricity-sector projects are vulnerable to changes in the frequency and intensity of climatic events. Table 2 presents some of the potential climate change risks and their likely impact(s) on electricity generation infrastructure.

Table 2: Potential impacts of climate change risk on electricity projects

Climate Change Risk	Likely impact by generation Source			
	Hydro	Fossil fuel	Wind	Solar
Temperature increases (heat waves)	Lowered generation output due to increased surface evaporation	Lowered efficiency and generation output	No or insignificant impact	In very hot temperatures, lower cell efficiency and energy output
Extreme changes in historical precipitation patterns				
• Drought	Lowered generation output due to reduced water levels	Increased fuel consumption due to reduced efficiency of water-based cooling system	-	-
• Flood	Damages to infrastructure	Damages to infrastructure (location specific)	Damages to infrastructure (location specific)	If due to increased rain, lowered generation output due to less solar radiation
Changes in wind speed	-	-	Uncertain generation output	-

Contracting Authorities (CAs) should screen projects for climate-related risks. Different international organizations have developed or embedded several risk screening tools to assess climate change risks at the project level. Screening projects for climate change risk at the PCN stage is a critical foundational step in managing climate risk. The outcome of these preliminary assessments provides insights for CAs in their decision-making about whether there is a need to examine further the project's exposure to climate change risk.

Climate risk screening consists of answering the following questions:

- Is the project located in an area prone to climate change-related events? Do climate change scenarios suggest that the frequency and severity of these events are likely to increase?

- Does climate change pose a high degree of risk to the project? For example, do increases in the frequency and intensity of precipitation events cause a rise in water levels influencing the project and its associated facilities?
- What will be the implications of climate risk screening for the project's costs, including the cost of rehabilitation of infrastructure, cost of service disruptions both to the project and the service users?

BOX 1: Climate Change Risk Screening Tools

The integration of climate risk management into project appraisal process has received increasing attention in various international development organizations. There is a growing body of projects implemented by these agencies and banks that explicitly include climate risk management. The following describes two examples of climate risk screening tools.

- ***World Bank's Climate Change Knowledge Portal (CCKP)***

CCKP is an online platform with available global climate data and analysis based on the latest Intergovernmental Panel on Climate Change (IPCC) reports and datasets. These datasets are processed outputs of simulations performed by multiple General Circulation Models (GCMs) developed by climate research centers around the world and evaluated by the IPCC for quality assurance. Climate risk projections can be generated from these datasets made publicly available on the World Bank's CCKP for preliminary climate risk screening of a project at the PCN stage.

- ***AWARE for Projects***

AWARE for Projects is an online tool that allows screening investment projects for climate risk. Asian Development Bank (ADB) and European Investment Bank (EIB) use this tool for climate risk screening across a wide range of project types and sectors. Using this tool does not require climate change expertise. The user simply locates the project anywhere on a world map and answers a few questions on how climate may influence the success of any given project, and the tool will generate a detailed report to guide further discussions and assessments of climate risk.

It is essential to determine how climatic conditions will change in the project's location in conducting climate risk screening (see the example in Box 2). The assessment of climate-proofing options requires interaction between different experts and involves:

a. Establishing a baseline of the existing climatic conditions in the project's locale using historical weather data.
b. Identifying data needs and required expertise; for example, climate change specialists use climate change models (also known as General Circulation Models, GCM) to project how climatic conditions will evolve over the project's economic life.
c. Determining which weather variable(s) and their expected change will impact the project and its stakeholders.
d. Constructing the most likely scenario of how climatic conditions will change and how they will impact the project.

Climate risk screening is a preliminary assessment intended to identify if the project is exposed to and vulnerable to climate change risk. Detailed climate risk assessments should be conducted at the PFS stage for projects that are anticipated to be significantly impacted by climate change over their economic life, as indicated by the climate risk screening results at the PCN stage. If a detailed climate risk assessment is undertaken at the PFS stage, CAs should draw up Terms of Reference (ToRs) for such an assessment, and its cost should be included as part of the project's overall capital cost.

BOX 2: Illustrative Example of Preliminary Climate Risk Screening

Project Summary

Suppose the Zimbabwe Electricity Supply Authority (ZESA) plans to build a 500 megawatt coal-based thermal power plant with two objectives:

(1) to reduce power outages due to generation capacity deficits and,

(2) to expand grid electricity network to unconnected areas.

Under design conditions (without climate change considerations), the plant has an annual capacity factor of 70%. The plant is expected to generate 3,066 gigawatt-hour of electricity per year.

The project's investment cost is estimated to be $800 million, without climate-proofing components (the "regular" project). Construction takes one year to be completed. The power plant generates 25% and 50% of its full capacity in the first two years of operation, and it becomes fully operational in the third year.

Summary of Preliminary Climate Risk Screening

A preliminary risk screening highlights the following potential climate risks:

- Climate models predict that the annual average temperature in the project's location will increase by 1°C over the project's economic life (20 years).
- Higher temperatures are expected to reduce both the power plant's cooling system and its generation efficiency.
- Engineering models point out that a 1°C increase in temperature reduces the power production capacity by 0.50% and increases its yearly coal consumption by 1.20%.

As summarized above, the preliminary climate risk screening indicates that higher temperatures can adversely affect the project's generation output and coal consumption. While the former would reduce the project's benefits, the latter would increase the project's operating costs. Climate change adaptation measures can be included in the project design to climate-proof the project. For example, a more robust design for a cooling tower and water treatment system prepares the power plant for rising temperatures and heat waves.

Decision: Given the potential impacts of climate change on the project's output and operating costs, a detailed appraisal of climate-proofing options should be conducted in the PFS stage.

2.10 Sources of Information

A detailed list of all the primary and secondary sources of the information used to draft the PCN should be included, and references provide for all critical input data and assumptions used for the preliminary appraisal.

2. ASSESSMENT OF PROJECT CONCEPT NOTE

The assessment of the PCN consists of two phases. The first phase entails an internal assessment of the PCN by the Line Ministry. The internal assessment shall attempt to answer two questions:

1. Is the project consistent with National and Sectoral development strategies?
2. Do the expected socio-economic benefits of the project exceed its economic costs?

Once the PCN has passed the internal screening, it should be submitted to the IMC through the MoFED for the second phase of the screening process. It should be noted that PCN submissions are made in October, according to the Public Investment Management and Budgeting Calendar defined in Article 141 of the PIM Guidelines.

The external assessment of the PCN by the IMC is a three-step process aimed at assessing the project's alignment with the Government's objectives and priorities. It also entails an evaluation of resource availability to fund the project with consideration of the fact that projects from other sectors could be vying for the same pool of resources. The three steps carried out in assessing the PCN are as follows:

i. The first stage is to evaluate the compliance of the CA with the submission process and other procedural requirements stipulated in the PIM Guidelines and this Manual. In exceptional cases, the IMC may accept early or late PCNs submissions. CAs are required to submit PCNs in compliance with the PCN form outlined in the PIM Guidelines (PIM Guidelines, Article 185). In case of missing information, the IMC may postpone the PCN pending the submission of the complete information.

ii. At the second stage of the assessment, the IMC will assess the project's alignment with the National and Sectoral Strategic Objectives. Projects that are not in line with the National development strategies and sectoral development plans will get postponed. In exceptional cases, CAs may justify projects that are not directly aligned with the strategic development plans. Such cases, for instance, may include projects that are designed to mitigate force majeure situations, such as droughts, floods, earthquakes, Et cetera.

iii. The last stage involves the IMC assessing the affordability of the project as well as the likelihood of the expected economic benefits of the project exceeding the cost of resources.

The IMC's decisions on PCNs shall be issued in January-February. Only projects whose PCNs pass both the internal assessment by the CA and the external assessment by the IMC should be allowed to progress to the PFS stage. PCNs approved by the IMC are valid for three (3) years. Once a project's PCN expires, the project should be reappraised and resubmitted to the IMC for consideration following the internal and external screening processes described above.

3. PRE-FEASIBILITY STUDY

The submission of the PFS shall be made in March-April in line with the Public Investment Management and Budgeting Calendar (PIM Guidelines, Article 141). MoFED decision on the PFs shall be issued in May-June.

4.1 Moving from PCN to PFS

The Pre-feasibility Study (PFS) phase involves the refinement of all elements of the PCN stage described in the previous chapter. Wherever possible, data from the PCN should be updated with more accurate estimates in preparing the PFS. At the PFS stage, electricity projects costs should be based on preliminary designs, land cost estimates, etc. The PFS emphasises technical, financial and socio-economic viability of the project.

The detailed siting analysis shall also be included in the annex of the PFS. The process for choosing a site for the construction of certain categories of electricity projects such as transmission lines involves an extensive study of environmental (water, wetlands, topography, soils, geology), land use, biological, cultural, and visual resource impacts. A proper analysis of this should be considered in the PFS analysis of an electricity project. Contracting Authorities shall undertake PFS or outsource the preparation of PFS to a third party.

The preparation of the PFS shall follow the requirements stipulated in the Public Investment Management Guidelines. The details on how CAs shall fill the PFS Form are provided on page 50-64 of the PIM Guidelines. This section of the Manual provides further details on how to undertake a cost-benefit analysis to fill Financial Effectiveness, Socio-Economic Effectiveness, Fiscal Effectiveness, and Risk Analysis sections of the PFS form.

4.2 Cost-Benefit Analysis to Fill Financial, Socio-Economic, Fiscal Effectiveness, and Risk Analysis sections of the PFS form

4.2.1. Methodology

This manual uses the Integrated Investment Appraisal (IIA) Methodology to appraise electricity projects. IIA incorporates financial, socio-economic, stakeholder and risk analysis in the evaluation of a proposed electricity project. IIA starts with an appraisal of the financial profitability of the proposed electricity project. In the case of the IPPs, the financial analysis shall be conducted from different points of view:

a) IPP point of view to allow electricity regulatory authority to assess the adequacy of the proposed PPA structure;
b) Electricity utility perspective enabling the utility to assess the impact of the project on the financial situation of the utility by comparing PPA payments to the IPP with revenues generated from the supply of the electricity to end consumers.

The socio-economic appraisal of the project builds on the financial module. The economic appraisal of the electricity generation projects proposed in this Manual is based on the least-cost principle. It shall compare the economic cost of the project to the economic cost of the best alternative that will address the problem. Such analysis, for instance, may compare economic costs and benefits of a solar generation project with the best alternative, such as a diesel generating plant. A clear distinguishing between the costs and benefits of the dispatchable and non-dispatchable electricity generation projects shall be made.

Using IIA, the benefits, costs, externalities, and risks accruing to each of the project's stakeholders can be adequately identified and assessed. The inclusion of the risk analysis enables the identification of project-specific risk factors that may hamper the implementation and or viability of the electricity project, allowing for mitigation measures to be formulated. IIA provides a framework to appraise an electricity project systematically and enables the identification of project strengths and weaknesses.

4.2.2. Project Model Requirements

a) Financial, economic and stakeholder analysis model must be created in Microsoft Excel format. The title of the model should indicate the model construction date, e.g., "AMPTA II PFS YYY-MM-DD.xlsx." An electronic copy of the Excel file has to be submitted to the MoFED.
b) None of the project model parts should be hidden or locked, making the model updating impossible.
c) The model should follow a clear and logical structure. It should contain a table of parameters, calculations, financial statements, and financial, economic and stakeholder results (model outputs). Only calculation formulas should be used, and no hard-coded values are allowed except for the values in the table of parameters.
d) The table of parameters shall contain all required inputs to make calculations and derive model outputs. Links to external files that are not accomplishing the project model are not allowed.
e) The project model shall be constructed in a way that allows an analyst to change any input in the table of parameters, while the model will automatically calculate the impacts of these changes on the model outputs. It should also allow conducting sensitivity analysis.
f) If the model outputs are derived from several models (several excel files), dynamic links between all files must be created to effectively link all the models.
g) The project model should be detailed enough, i.e., should contain break down of the project output (in case of few), expenditures and income items, Et cetera. The model shall be integrated, therefore linking financial, economic and stakeholder analysis together.
h) References to the model inputs used in the table of parameters shall be attached to the model.
i) Model inputs shall contain:
    - Lifetime of the project assets;
    - Project evaluation period;
    - Base year of the evaluation;
    - Project start date;
    - Construction costs;
    - Operating and Maintenance expenditure;
    - Fuel expenditure;
    - HFO price projections;
    - PPA structure;
    - Blended tariff estimate;
    - Model type (quarterly, semi-annually, annually);
    - Financial discount rate;
    - Economic discount rate;

- Macroeconomic parameters (inflation rate, exchange rate, real change in prices and salaries);
- Taxes and other fiscal payments (if applicable);
- Sources of funds;
- Gear ratio;
- Interest rates;
- Depreciation rate for project assets;
- Other key inputs.

j) The project model should contain main financial statements, i.e., profit and loss statement, balance sheet, sources and uses of funds and cash flow statement.

k) Profit and loss statement shall be constructed following the accounting and tax rules of Zimbabwe. The statement shall include revenues, earnings before interest taxes and depreciation (EBITDA), earnings before interest and taxes (EBIT), and net income.

l) The cashflow statement shall include revenues, capital expenditures, and operational expenditures. Interest and dividends payments must be included in separate lines of the cashflow.

m) If part of the project is financed through the loan, the cashflow shall indicate Cash Flow Available for Debt Service (CFADS). In this case, Debt Service Capacity Ratios (DSCRs) and Loan Life Coverage Ratios (LLCRs) shall be estimated.

n) Any past expenditures on the project shall be treated as a sunk cost and not included in projected cashflows. Such expenditures, however, shall be clearly specified in the supporting documents.

o) The sources of funds shall be linked and reconciled to the uses of funds in the Sources and Uses of Funds statement.

p) Debt service payments should be projected considering possible delays in the payment of accrued interest.

q) It is recommended to forecast cash flows in the currencies in which they are realised (receipts and expenditures are made), and then translate them to a single, final currency.

r) The cashflows shall be of the same kind (with or without inflation).

s) When calculating the project's net present value (NPV), all cash flows, including residual values, should be discounted to the base year (initial year of the forecast period).

t) The description of the financial model is made in the form of an annex to the financial model. The description should include:
- Description of the structure of the financial model;
- A description of the working mechanism of the macros used in the financial model (if applicable);
- Main assumptions and baseline data for financial forecasts, indicating sources of information;
- Other information necessary for understanding the structure, principles of construction, operating mechanism, and other features of the model.
- Description of the basis for assumptions made on the projections of the fuel prices or sources of the fuel prices shall be provided.

4.2.3. Weighted Average Cost of Capital

Weighted average cost of capital (WACC) is a calculation of a firm's cost of capital where each category of capital is proportionately weighted. The weights of debt and equity are determined by the optimal trade-off between the cost of and amount of borrowing and the cost of equity to the firms. WACC is commonly used in corporate finance and should not be used for a project appraisal in the project finance/non-recourse arrangement where a Special Purpose Vehicle (SPV) is created.

All sources of capital, including common stock, preferred stock, bonds and any other long-term debt, are included in a WACC calculation. In a situation where historically an operating corporation does not exist and is just created and funded with some initial Debt to Equity levels, WACC changes monthly or quarterly when debt and equity are drawn into a project during construction and then every six months when debt repayments are made. Therefore, there is never a single WACC for a project finance SPV. Once the debt is repaid, WACC is equal to the cost of equity. In a situation where project owners will decide to raise additional debt and keep it at a certain level, WACC becomes a useful concept as the ongoing company attempts to achieve a stable (optimal or not) debt to equity ratio. This is, however, a corporate finance situation that is not relevant to this discussion.

The relevant question, therefore, becomes what discount rate shall be used to determine a project attractiveness both from the private investor's perspective as well as from the government perspective. From the investors' perspective, in practice, the return from this investment must be at least equal to the best practically available alternative return from the deployment of the particular amount of funds or the cost of equity. The cost of equity is estimated using either the dividend discount model or the capital asset pricing model (CAPM). CAPM can be estimated using the formula:

"Risk-free Rate + Country Premium + (Alpha) + Beta * (INDEX Return - Risk-free)"

Also, there is a significant price difference for a project that has no financing arranged and a project with approved financing. A project with approved debt would be the most expensive for an investor. A less advanced project would contain more uncertainty (among which would be the uncertainty about availability, cost, size, and any associated conditions/restrictions from lenders), and the price for equity in such a project would be significantly lower. In power, the price of a project that has land, key studies done and major permits obtained, generally can be less than a half compared to a project with more complete contracts and an approved loan.

CAPM is hardly used in practice because of the lack of relevant data and complexity when applied in developing countries. The commonly used by early-stage developers rate of return ranges between 13% to 17% - the lowest target is used in better countries, and when there is a strong PPA or financing is easily obtainable or at bids. The higher threshold applies in more riskier countries or when there are lots of uncertainties. Typically, an investment committee approves a specific target rate of return for each project individually.

Equity funds investors that enter at the end of the development process near the financial close, target IRRs of 11% to 15%. This is because they approach investment at a late stage, when many uncertainties are gone, therefore they are exposed to fewer risks.

From the government's perspective, at least two situations may exist. First is the case of regulated markets. In regulated power markets, income is fixed by regulation to the cost of construction, via a rate of return that is established by the regulating commission. Historically, regulators allowed a utility to construct power plant assets so that the utility could meet its obligations to provide electricity to consumers but only provide an adequate return to investors. The cost basis for the recovery was calculated to provide a predetermined return on investment for a plant. In the case of IPPs, the regulator needs to define an allowed rate of return through the regulations and taking into consideration the country's risk profile. The PPA is then used to reduce the investment risk and attract private sector developers.

The second case is the case of deregulated markets. In this case, the legal link between cost and income is broken. Investors are required by the forces of economics, not regulation, to value electric generation power plants like any other income-producing asset. This is done by forecasting the anticipated cash flows available to investors over the useful life of the investment. The value of a plant is no longer based on the cost to construct it is instead based on its profitability. Power plant developers shall no longer be guaranteed a low-risk return (income) that matched their cost to build. Under deregulation, returns are not guaranteed, and bankruptcy is a real possibility, but potential higher returns are the new reward.

4.2.4. Financial analysis

4.2.4.1. Financial Cash Flow Construction

Financial analysis is conducted using the discounted cash flow (DCF) methodology. This method requires the construction of a cash flow statement in order to carry out a financial analysis of a project. A typical cash flow statement is organized into two distinct sections. The first section is dedicated to summarizing all of the receipts generated by the project, whereas the second section is concerned with project expenditures. The main components of the two sections of the cash flow, receipts/revenues (inflows) and expenditures (outflows) are outlined below.

4.2.4.2. IPP Point of View

A power purchase agreement (PPA), or electricity power agreement, is a contract between two parties, one which generates electricity (the seller) and one which is looking to purchase electricity (the buyer). The PPA defines all of the commercial terms for the sale of electricity between the two parties, including when the project will begin commercial operation, schedule for delivery of electricity, penalties for under delivery, payment terms, and termination terms. A PPA is a principal agreement that defines the revenue and credit quality of a generating project and is thus a vital instrument of project finance. There are many forms of PPA in use today, and they vary according to the needs of the buyer, seller, and financing counterparties.

A tariff payment under the PPA typically consists of three main components.

a) **The capacity charge** is a fixed payment that is paid each period for each kilowatt of available (not dispatched) capacity. It includes fixed charges involved in the construction, operation, and maintenance of the power plant, including charges for (a) repayment of the principal and interest of the debt used to construct the facility, (b) return on equity capital invested, (c) fixed operation and maintenance (O&M) costs that are independent of the amount of energy generated (e.g., staffing costs, administrative expenses, operator fee, insurance premiums, etc.) and (d) possible fixed costs related to fuel supply and transportation, such as demand, through-put charges, or minimum take-or-pay obligations. Invested equity is typically recovered through depreciation of power plant assets based on prescribed rates in applicable tax laws.

b) **Energy charge** is paid each period for each kilowatt-hour of energy dispatched and delivered at the agreed delivery point during that period. It includes variable costs involved in the generation of the energy delivered, including charges for (a) commodity charges for each unit of fuel used, including the cost of fuel and its transportation to the plant, (b) variable operation and maintenance costs (e.g., spare parts, lubricants, and other consumables), (c) a major maintenance sinking fund to cover the costs of required turbine maintenance based on usage.

c) **Supplemental charge** that covers other costs not included in either the capacity or energy charges, including (a) the costs of start-ups beyond an agreed number each year reflecting the cost of fuel per start-up and likely a contribution to the major maintenance sinking fund (a) the costs of ancillary services provided if such services are included in the scope of the PPA, (b) any supplemental charges for repairing damage to the facility as a result of a force majeure event, if such repair is the responsibility of the buyer. Indexation and escalation are likely to apply to reflect fluctuations in inflation and exchange rates depending on the character and type of the costs involved.

The forecasted PPA payments are revenues from the IPP perspective. Other cash inflows of an electricity project typically consist of the following items:

i. Changes in accounts receivable;
ii. The residual value of the project assets whose economic lives exceed the analysis period (e.g. land) and are not transferred to the government.

The costs from IPP perspective include all costs associated with the delivery of electricity such as:

i. Capital expenditures;
ii. Operational expenditures;
iii. Fuel expenditures;
iv. Tax payments;
v. Maintenance expenditures;
vi. Changes in working capital (accounts payable and cash balances).

4.2.4.3. Utility Point of View

4.2.4.3.1. Electricity Generation Project

From the utility’s point of view, the financial revenues of the electricity generation projects are estimated as the product of the quantity of electricity delivered to the end consumers after subtracting technical (transmission, distribution) and non-technical (commercial) losses and the blended tariff utility charges to the end consumers. The cost from the utility perspective is its PPA payment obligations to the IPP.

4.2.4.3.2. Transmission projects

For the utility that generates, transmits, and distributes to final consumers, there is no price for the transmission service independent of the distribution service. The absence of such prices makes the financial valuation of service in either component of the electric system difficult. It is therefore helpful to set an internal service price for each component of the electric system in valuing the service of generation, transmission, or distribution. One way to set this internal price for transmission is to multiply the weighted average tariff less the variable fuel and operating costs (excluding the fuel cost of generation) by the share of the transmission costs in total marginal capital costs of the system. This internal price of transmission service represents the contribution of transmission towards the total financial benefits from the sale of electricity to customers. The following formula is used in the case of the transmission project:

Financial Value of Transmission Service per kWh=

(Weighted average tariff - Fuel cost - Operating cost) * [MCT/ (MCG + MCT + MCD)]

Where MCG: Marginal Capital Cost of Generation ($/kWh)

MCT: Marginal Capital Cost of Transmission ($/kWh)

MCD: Marginal Capital Cost of Distribution ($/kWh)

Other two benefits that may arise to the utility from the transmission project include:

- **Reduction in Technical Losses**: losses in transmission lines and transformers, and losses due to failure of transmission equipment. The incremental energy saved is the difference in total losses in two situations, i.e. "with" and "without" project situations. The complexity of the calculation of these losses depends majorly on the type of transmission line being invested in. When the project involves the integration of transmission lines and transformers into an interconnected network, the assessment of incremental benefits becomes a bit more complicated.
  The financial benefits from savings in transmission losses are created because a reduction in these losses allows the system to generate a smaller quantity of electricity and still deliver the same amount of energy to its customers. Hence, the savings are estimated here by multiplying the sum of the fuel, and marginal generation capacity costs, and operating costs by the quantity of the reduced losses. In the short run, the savings in generation capacity costs may not be realized. However, in the long run, the approach used to evaluate the savings due to loss reduction takes into account the degree to which a decrease in transmission losses saves generation capacity costs.

- **Savings in Cost of Maintaining and Repairing Outdated Transmission Lines.**

- **Increase in Sales due to Increased Reliability of Supply:** This is a measure of the increase in financial revenue due to fewer outages as a result of the project. The incremental consumption due to outage reduction is distinct from the incremental demand of new users calculated earlier. The incremental consumption due to outage reduction relates to existing customers who suffer from outages. Since the duration of outages, in this case, affects the whole electric system, the value of reduced outages is, therefore, the product of the incremental energy sold because of outage reduction and the weighted average tariffs of different groups of consumers.

4.2.4.3.3. Distribution Projects

If a new distribution project is considered, the cost of the project shall be included in the cost of the power plant that will generate the electricity and consequently included in the appraisal of the viability of the power plant itself. However, a more frequent case is distribution line rehabilitation projects. In this case, the main financial benefit to the utility arises from the increased sales to the customers due to the reduction in interruption hours.

4.2.4.4. Cash flows/Model Outputs – Alternative Investment Criteria

The primary investment criterion that should be used to measure a project's financial performance is the FNPV. A financially viable project implies a positive FNPV when the real net cash flow is discounted using the appropriate opportunity cost of funds (i.e. required return on equity). From the government perspective, the financial returns of the private investors shall never exceed the minimum rate of return needed to attract such an investment. It implies that the PPA payments rate shall always be capped at a minimum rate that allows private sector investors to break-even. It is important to note that the minimum rate of return should incorporate country, sector and project specific risk factors. However, the financial gains to an IPP shall never guide investment decisions from the government's point of view.

An alternative investment criterion that can be used to gauge a project's financial performance is the FIRR. Based on this criterion, a proposed project should only be accepted if the FIRR is greater than the opportunity cost of funds. It is important to note that FNPV and FIRR often result in conflicting conclusions about a project; in such cases, it is recommended that decisions are made based solely on FNPV.[2]

Projects that utilise debt financing must be evaluated in terms of their ability to service their debt obligations (interest and principal) solely from their net cash flow. Two investment criteria are used to gauge the project's ability to meet its debt obligations; the first criterion is the Annual Debt service coverage ratio (ADSCR), and the second criterion is the Loan Life Coverage Ratio (LLCR). Both these debt service ratios (ADSCR and LLCR) should be greater than one or greater than or equal to a benchmark set by a financial/lending institution. Ratios that meet the above criteria indicate a project with a healthy cash flow can meet its debt obligations after meeting all of its operating expenditures.

The debt service capacity ratio (DSCR) is the ratio of cash available for debt service to interest and principal payments. It helps to determine the project's ability to meet its debt servicing obligations. The cash available for debt servicing is derived from the total investment point of view cashflow statement. The debt service capacity ratio (ADSCR) is calculated on a period to period basis as follows:

$$\mathrm{DSCR_t} = \frac{\mathrm{CFADS_t}}{\text{Scheduled Debt Service (Principal + Interest)}_\mathrm{t}}$$

Where: $CFADS_t$ is the net cash flow of the project before financing for period t, and Debt Service includes interest and scheduled principle payment for period t.

Loan Life Coverage Ratio (LLCR) measures the number of times the nominal cashflow over the scheduled life of the loan can repay the outstanding debt balance. The PV of nominal cash flow is estimated using the nominal interest rate on the loan as a discount rate.

$$\mathrm{LLCR_t} = \frac{\mathrm{PV\ (CFADS_t\text{:}\ CFADS_n)}}{\text{Debt Balance Outstanding}_\mathrm{\ t}}$$

Debt service coverage ratios are used by an analyst to evaluate the project's ability to repay its debt.

4.3 Use and Source of Macroeconomic Variables

4.3.1. Inflation

Planning for cost escalation due to inflation is essential, and it should be part of the financing plan. Inflation has direct impacts on the financing of investment projects, real desired cash balances, accounts receivable, accounts payable and nominal interest payments. It also has tax

[2] For a detailed discussion on the problems related to the IRR criterion the reader should refer to: Jenkins, G.P., Kuo, C.Y., and Harberger, A.C., "Chapter 4: Discounting and Alternative Investment Criteria", Cost – Benefit Analysis for Investment Decisions, (2012)

impacts on interest expense deduction and depreciation expenses. If inflation is not adequately planned for at the appraisal stage, it can affect the project outcomes drastically. The latest inflation figures can be obtained from the ZIMSTAT.[3]

4.3.2. Economic Opportunity Cost of Capital

The economic opportunity cost of capital (EOCK) or the social discount rate is the minimum economic rate of return that either a private or public-sector investment must earn if it is to contribute to the growth of the economy. The economic cost of capital reflects the real rate of return forgone in the economy when resources are shifted out of the capital market.

The EOCK is an economic price for the valuation of savings and investments and their augmentation of economic production in the coming years. Investment projects use various inputs or real resources, such as land, labour, and capital, to produce outputs that society is willing to pay for, whether directly or indirectly. Considering that the decision to fund a public project will supersede private investments and consumption and use market information, the EOCK is used as a hurdle rate to determine the desirability of implementing projects. Economic net benefits and costs, and economic externalities of the investment over the life of the project should be discounted by the EOCK. The EOCK shall be published or provided in a circular by the Treasury. If not available, it is recommended to use 12% as the EOCK. [4,5]

4.3.3. Foreign Exchange Premium

When funds are sourced in the capital market and used to purchase either tradable goods or non-traded goods, investment and consumption by others in the market are displaced. It results in the government losing tariff revenues, VAT, and other indirect taxes. Such loses must be accounted for during the economic valuation of tradable inputs of an electricity project. By calculating the foreign exchange premium (FEP), it is possible to adjust the financial price of tradables, along with other distortions like tariffs and VAT, to find the economic value. FEP shall be published or provided in a circular by the Treasury. If not available, it is recommended to use 10.7% as the FEP[6]. As an example, the steel used in the transmission line construction has an economic cost that is 10.7% higher than the financial price paid by the project.

4.4 Economic Prices

4.4.1. Estimation of Economic Prices

Economic prices may differ from financial prices for several reasons. Financial prices are market prices, which are affected by various tariffs, taxes, and subsidies. Financial and economic prices also differ because the consumers' valuation of an item may be greater than the financial price they pay. Therefore, the financial prices of inputs used in electricity sector

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[3] http://www.zimstat.co.zw

[4] For ***economic analysis***, USAID and other development institutions (including the Millennium Challenge Corporation, the World Bank, and the Asian Development Bank) use discount rates between 10% and 12% range. USAID CBA Guidelines, 2015.

[5] "Musings on the Social Discount Rate", A. Harberger, 2015 estimates social discount rate of 10% for healthy developing countries

[6] The 10.7% is the result of an estimation done using 2017 data from ZIMSTAT and ZIMRA.

projects need to be adjusted to reflect the economic cost of resources that the society pays to obtain these items. Most commonly, this will include adjustment for taxes, subsidies, and FEP.

Finally, non-tax distortions such as air pollution may also generate significant external costs or benefits (if pollution is reduced) and should be assessed and accounted for in the economic analysis, whenever feasible.

4.5 Socio-Economic Analysis

4.5.1. Measuring Benefits of Electricity Investments

In appraising benefits of the electricity generation projects, one hardly ever attempts to measure the actual benefits that users receive from such projects. Instead, the 'least-cost alternative' principle is used. This principle states that one should not attribute to a project a value of benefits that is greater than the least alternative cost one would have incurred by providing an equivalent stream of benefits in a different way.

Whereas this principle might be redundant in accounting for the benefits of some projects, or at the very most, seldom applicable, it is the determining factor in estimating the benefits of electricity projects. The reason for this is that the next-best alternative of reasonable cost nearly always exists. In fact, this alternative is often the standard way of doing things. The projects being analysed only attempt to find new or different ways of doing things. These new ways are presumably better than the standard alternative. It is, therefore, logical to say that the benefits of the "new or different" ways of doing the same things as the standard alternative would be the costs that are saved as a result of using the "new or different" alternative(s).

For instance, if we attempt to carry out a cost-benefit analysis on an electricity generation project without comparing it with the standard alternative, i.e. we assume this project stands alone, when the project is implemented, it will presumably be the newest project in the existing system. But over time, the older plants in this system will wear out, and as such, the generating capacity of the system will decline over time one after the other until some older plants are abandoned completely. It implies that the overall generating capacity of the system will steadily decline over time. Therefore, without a growing demand for energy, this would mean a market or economic price of electricity that would be steadily rising. In the more likely case of a continuously growing demand, this upward trend of price would be even a lot more exaggerated. It would take a truly terrible project to fail a cost-benefit analysis given these conditions. In fact, one can almost say that cost-benefit analysis made under these assumptions would virtually lose all its power to discriminate between good and bad electricity generation projects.

It shall be noted in bold that the 'least alternative cost' method of appraisal of the electricity generation projects is different from simple cost analysis due to the fact that different benefits are reaped from two alternative generation technologies. For instance, the cost of a 10MW solar power plant cannot be simply compared with the cost of a 10MW diesel generator. This is because the two technologies are very different in their nature (dispatchable vs. non-dispatchable), and the benefits of the two technologies are therefore different.

In contrast, appraisal of transmission and distribution projects shall be subject to the CBA that will assess if the expected economic benefits of a project will outweigh its costs. For these categories of projects, ENPV is the main criterion to decide on the inclusion of the project into the pipeline.

In order to accurately measure the benefit of an electricity project, the difference between incremental and non-incremental output must be established, as is the case with every other sector. The incremental output is the additional output produced by the project over and above what would be available in the "without-project" situation. The non-incremental output is the output produced by the project that displaces high-cost or unreliable supplies available without necessarily yielding an increase in quantity. The economic values of incremental and non-incremental outputs are referred to as incremental benefits and non-incremental benefits, respectively.

Generally, the economic benefits of electricity include the following:

a) Expansion of supply to meet demand

A project aimed at increasing the current total level of energy production in a country or a region, in order to meet growing demand, or extending the energy network to areas not currently served, typically produces this benefit. Usually, users pay a fee, but as earlier stipulated, these fees do not accurately depict the economic benefit of the project. Therefore, the willingness to pay approach is used to quantify this benefit. A reliable method of estimating the willingness to pay is the least alternative cost principle. It means that the willingness to pay for this service is the resource cost saved as a result of the project. The alternative system, in this sense, might mean the use of kerosene or any other way of generating the same amount of electricity. The reduction in the costs as a result of the project (the new supply, also known as the consumer surplus) is an additional benefit. An estimate of the average cost incurred using these alternative methods can be readily got by a simple survey in case the data is not readily available.

b) Increase of security and reliability of electricity supply

The purpose of a project might be to reduce the frequency of power outage or disruptions. Projects like the improvement of a power transformer station, or the integration of renewable energy sources in the power grid or smart grid project majorly serve this purpose. This benefit can also be measured using the willingness to pay approach. In situations where compensation is given for the disruptions, the cost of these compensations can be taken as the willingness to pay for the improved electricity supply. Albeit, if users employ alternative means of generating electricity during outages, the total costs associated with this alternative means can be used as a proxy for the willingness to pay for more reliable energy supply by users.

c) Reduction of energy costs to the utility

Another purpose that power projects serve is to reduce the generation costs incurred by utility by replacing or fixing old facilities that probably have low generation efficiency or have high operation and maintenance costs. In cases where the project does not change the tariff that consumers pay, and the project doesn't necessarily increase the quantity of energy available for users, the benefit of the project is non-incremental, and thus, it accrues to the utility, not the users. This benefit is measured by the cost savings of producing this quantity of energy. The savings include costs of resources like fuel (which is usually the major cost savings), machinery, operation and maintenance cost. These costs must be measured in economic prices.

d) Reduction of environmental pollution

This benefit clearly depends on the nature of the technology that the project employs. Thermal technologies usually produce environmental pollution. These range from Greenhouse gases (GHG) emissions to other emissions like NOx, SO2, and other particulates. For Zimbabwe, the impact of other gasses is more pronounced. And the saving as a result of a reduction in this pollution is an important benefit of electricity investments. GHG savings come to fore when there is a trade permit and, more importantly, on the global stage. In the case of a trade permit, the value of the GHG savings is simply the financial value of the trade permit. However, on the global level, the value of GHG savings is the product of the amount of GHG emission avoided as a result of the project and the social cost of carbon. This value changes every year, but the figures are readily available. The benefits of the reduction in other emissions can be measured based on the health impacts, soil and water quality impacts, and visibility (as it affects transportation) impacts. The impact on health can be measured by the health cost savings due to the reduction of these pollutants. This can be assessed on the basis of the sum of all individuals' willingness to pay to avoid adverse health externality. The cost savings on the treatment of soil and water as a result of these pollutants can be used to measure the impact on soil and water. Finally, the willingness to pay for safe travels and reduce accidents as a result of reduced visibility is a good proxy for measuring the visibility impacts.

It is therefore very important, as stated in the PIM procedural manual, that the purpose of the electricity project in question is well spelt out. This is because it is impossible to accurately measure the benefits of the project as it accrues to various stakeholders when the purpose of the project is not known.

4.5.2. Economic Benefits of Thermal Based Investments

As earlier stipulated, generation options usually include thermal technologies such as diesel, closed cycle, and combined cycle and coal plants of various sizes. The choice of technology and the size of the investment depends on the purpose of the investment. These technologies are used to provide generation and system reliability through the supply of dispatchable energy. Depending on the purpose of the project, thermal-based investments can yield all but one of the benefits stated above. It is impossible for a thermal-based investment to reduce environmental pollution. This is because the process that the technology employs cannot avoid the emission of gasses and particulates that pollute the air. The only exception to this rule occurs when the project reduces the usage of alternative sources of energy like domestic generators (which can cause significant environmental pollution) or when the project is replacing outdated and more environmentally polluting thermal technology.

Therefore, a thermal-based investment can serve to expand supply for growing demand. The method of measuring this benefit is as earlier described. Furthermore, the investment can also produce the benefit of increased security and reliability of supply. In fact, because thermal-based investments are used to produce dispatchable energy, they are very suitable for the purpose of reducing the frequency of disruptions. Thermal-based investment can also produce the benefit of reducing the cost that utility incurs in the ways described above. These benefits can be measured using the methods described in section 4.5.1.

4.5.3. Economic Benefits of Solar Investments

Unlike thermal-based electricity generation technology, solar-based technology is not used to produce dispatchable energy. This is because the production of electricity using this technology depends a lot on weather conditions which cannot be switched on and off, and it is not economical to store electricity. Therefore, a solar plant will be used mainly to give some respite to an alternative source of electricity (usually thermal plants). Hence, most of the benefits that will be accrued from a solar project will be the cost savings as a result of its (solar plant) usage in place of the alternative source. It is worth noting again that the bulk of the cost savings come from fuel consumption cost savings. The method of measuring this benefit is as described in section 4.5.1.above.

The benefits from solar and other renewable energy sources depend on a number of factors:

a) The amount of electricity generated by renewable plants per hour. The greater the amount of electricity generated by the renewable plants, the less the usage of thermal plants and consequently, the greater the amount of fuel cost savings. Amount of energy produced by each plant in a specific hour "*I*" is obtained as:

$$Energy_i = PlantCapacityFactorInHour_i * InstalledCapacity$$

The capacity factor for solar plants depends on solar speeds.

b) As the system load demand increases during the peak demand hours, there might be a need to utilize more thermal generation capacity. Because the thermal plants are brought into operation ranked from the lowest marginal running cost to the highest marginal running cost, the fuel savings from renewable energy sources will be greater during the hours when electricity demand is the greatest. The positive correlation between the renewable energy source and the system load demand will increase the value of the fuel cost saved by the renewable energy source. In this case, renewable energy sources will be substituted for the most expensive (in terms of fuel cost) thermal plants.

c) Since the economic value of renewable energy systems is typically measured on the basis of cost saving from not using alternative thermal plants, the fuel efficiency of alternative thermal plants is an important factor in determining the economic value of the renewable energy system. The reduction in operation hours of a relatively inefficient thermal plant by a renewable source of electricity would increase the economic value of the solar plants.

d) Factors such as expected change in demand for energy (changes in the shape of load curve over-time), future changes in fuel prices (changes in the relative prices of fuel, oil, gas, and coal) will affect the economic value of renewable energy systems. Higher fuel prices will increase the cost savings by renewable energy plants.

Another benefit of a solar-based electricity project is the local pollution reduction. This can be measured using the methods described in section 4.5.1 above.

4.5.4. Economic Benefits of Wind Investments

Whereas the cost implications and technical details of solar and wind plants might be different, the benefits and the methods of measuring the benefits of both technologies are quite similar. The points listed above on the factors that affect the benefit of renewable energy sources also apply here. It must be noted, however, that a wind plant typically generates electricity during off-peak hours. This fact, as mentioned earlier, will reduce the economic value of the cost savings. Again, forecasting the average daily speed of wind flow requires employing advanced techniques and often results in a significant forecast error. Hence, estimating the economic value of wind projects with accuracy requires a very extensive wind study of the site of the wind farm.

The difference in the value of the cost savings, especially as a result of an increase in demand for energy comes from the quantification of the value of the new energy supplied. All other benefits, including the reduction in environmental pollution, is as those obtained from the solar-based investment.

4.5.5. Economic Benefits of Hydro Investments

Hydropower plants range in capacity from large power plants that supply electricity to a large number of users to small and micro plants that individuals operate for their energy needs or with the aim of selling to utilities. The size of the hydropower plant plays a significant role in the benefits that the project produces. Generally, the total amount of electricity generated by a hydropower plant depends on the water flow, the height of the waterfall, and the turbine efficiency.

Power (KW) = Height of Dam (feet) x River Flow (Cubic feet) x Turbine Efficiency (%) / 11.8

The major types of hydropower plants are the run of the stream, daily reservoir, pump storage hydro plant, large storage dams and multipurpose dams.

A run of the stream plant naturally depends on water flow and water flow isn't the same every time of the day and every season of the year. It, therefore, means that an alternative has to be readily available for the times when the water flow is not enough to produce the required amount of electricity. It must be noted, however, that the benefit of a typical run-of-the stream hydropower plant is the cost savings from using other alternatives. Thus, the savings during peak hours is more than the savings during off-peak hours.

Hydropower plants with daily reservoir, however, are such that water that could have wasted in the off-peak period is saved and used when in the peak hours when water flow might be quite low. Hence not only do these plants accrue benefits during the off-peak period, but they also accrue more benefits when they are used in the peak period. As mentioned earlier, the value of resource cost savings is higher during the peak period.

Another technology is the hydropower plant with pump storage. This is similar to the plants with daily reservoir. Here, pump storage technology is used to store water during the off-peak hours for usage during peak hours. During off-peak hours when the cost of generating electricity is low, this electricity is used to pump water from a low elevation to a reservoir at a higher elevation. Then during peak periods when the cost of alternative thermal generation is high, water is released from the upper reservoir to power generators. Again, the benefits from this technology are measured by the alternative resource cost savings.

Large storage dams are mainly used to store water for use in the dry season. These periods when the fluctuation in water flow isn't based on peak or off-peak hours, but it is in those periods when the rivers, in fact, sometimes dry up. The benefits accrued here is also the resource cost savings of alternative source of electricity. The peak and off-peak analysis is also valid here.

4.5.5.1. Large Hydropower Plant

The definition of hydropower sizes varies. However, we can safely say that a large hydropower facility is such that it has a capacity of more than 30 megawatts (MW). It is typical of a large hydropower plant to be used to expand the supply of electricity. Either to increase the total level of energy production in a country or a region in order to meet growing demand, or to extend the energy network to areas not currently served. The quantification of the benefit of this kind of project is, as explained in section 4.5.1 above.

4.5.5.2. Small and Micro Hydropower Plant Investment

Again, there is no universal definition of what a small or micro hydropower plant is. However, a small hydropower plant is typically a plant that generates about 10 MW or less of power. Similarly, a micro hydropower plant can be said to be a plant that has a capacity of about 100 kilowatts. These plants are usually used to produce enough electricity for a home, farm, ranch or a village. It can be otherwise used to supply electricity to the electricity grid for eventual distribution to homes and businesses.

In Zimbabwe, it is more likely that the small and micro hydropower investments be channelled towards supplying electricity to the main electricity grid for eventual distribution. It means that most of the benefits that will be accrued as a result of these investments will be a reduction in the cost to the utility. Nonetheless, these technologies can be also be used to expand supply in order to meet growing demand. The method of estimating these benefits is discussed in section 4.5.1 above.

Another benefit of hydropower investment is that it also reduces environmental pollution. Especially when it is used to replace thermal plants. This benefit can be measured using the method described in section 4.5.1 above.

4.5.6. Economic Benefits of Transmission Projects

As is the case with electricity generation, economic benefits from transmission projects are mainly from the resource cost savings of alternative media:

- The transmission project will connect new customers to the grid. These are people who didn't have access to electricity without the transmission project. The benefits accrued here is measured using their willingness to pay for the electricity supplied by the project. This willingness to pay can be measured by the resource cost (usually fuel) of generating their own electricity of similar quantity as the project supplies. The resource cost savings represent the maximum willingness to pay of the new users.
- In addition to the benefits from increased consumption, the project also reduces the losses experienced by the utility. These losses are extra costs to the utility. Therefore, the benefits are measured as resource cost savings as a result of transmission losses.
- The economic benefits from the reduction of outages are estimated by multiplying the difference in energy provided in the "without" and "with" project by the cost of power outages. Users usually incur costs to cater for the frequent outages. Therefore, their willingness to pay for a reduction in outages is the maximum resource cost incurred to cater for the outages in the without-project scenario.

4.5.7. Economic Benefits of Distribution Projects

The economic benefits of the distribution rehabilitation projects arise from the improved reliability of the electricity supply. However, the economic value of the increased reliability almost always exceeds the financial value to the utility. This is because the economic value of the increased reliability has to be measured based on the consumers' willingness to pay for it, which is frequently multiples of the electricity tariff.

4.5.8. Economic Benefits of Electricity Projects and Gender

The social-cultural roles of women and young girls in many places imply that they bear most of the brunt of unreliable or lack of electricity in the household. The absence of electricity and modern energy sources implies that everyday household activities such as cooking and cleaning can be labour and time-intensive. The emissions from the use of biomass fuels, present many health risks to the users. Clean and efficient sources of energy not only reduces the health risks faced by women and young girls but also reduces the time spent on household chores, thus, allowing more time for education, employment and income-generating activities. The value of time saved by women and girls, and the value of reduced incidents of diseases (that stem from emissions from biomass fuels) as a result of the project, can be used as a measure of the benefits of the electricity projects to women and girls.

4.6 Stakeholders Analysis

The objective of the stakeholder analysis is to identify, quantify and allocate the impacts that a proposed electricity project will have on all its stakeholders. Various stakeholders incur certain costs or derive certain benefits from the implementation of a project. Using stakeholder analysis, the question, "who gains or losses because of the project and by how much?" can be answered.

Stakeholder analysis is conducted by estimating the externalities generated across various groups that are directly or indirectly impacted by the project. It also, includes project sponsors and lenders as they have a financial stake in the project. The financial impacts arising from the project are assessed in the financial analysis. Project externalities are derived by finding the difference between the financial and economic values of the project's inflows and outflows.[7] The present value of these externalities therefore represents the costs or benefits accruing to each stakeholder.

A stakeholder analysis is composed of the following steps:

[7] The following relationship should be hold when considering the impacts of a project:

$$NPV_e^{EOCK} = NPV_f^{EOCK} + PV^{EOCK} \sum Ext_i$$

Where: NPV_e^{EOCK} is the net present value of net economic costs or benefits

NPV_f^{EOCK} is the net present value of the net financial cash flow

$PV^{EOCK} \sum Ext_i$ is the sum of the present value of all externalities generated by the project

1. Identification of externalities.
2. Estimation of the magnitude of the externalities, measured by taking the difference of the economic value of resource flows and the real value of financial cash flows.
3. Estimation of the magnitude of the externalities over the life of the project by finding their present values (PV) using the EOCK.
4. Allocation of the PV of externalities among the project's stakeholders.
5. Summarization of the distribution of project externalities and net benefits according to the key stakeholders.

Reconciliation of the economic resource flow and financial cash flow statements with the project's externalities.

4.6.1. Contingent Liabilities

As a result of contractual agreements entered into by the government in IPP electricity projects, such as revenue guarantees, the government may be exposed to contingent liabilities. Contingent liabilities represent future expenditures that will have an impact on the budget due to commitments that are made in the present to support or make projects more attractive to the private sector. Contingent liabilities leave the government exposed to fiscal impacts whose magnitude and timing are uncertain.

4.6.2. Fiscal Impacts

A contingent claims analysis should be included as part of the overall stakeholder impacts accruing to the government. The analysis should endeavour to estimate the value of the anticipated cost the government will have to shoulder if and when a contingent liability comes due. Furthermore, the anticipated cost should be analysed in terms of how it will impact the government's budget. Based on the contingent claims analysis a provision should be made by the government as part of the overall budget to cover this downside risk if the proposed electricity project is to be implemented. In accordance with the requirements stipulated in the PIM Manual, the fiscal impacts that may result from a proposed electricity project should be reported in the PFS using a fiscal effectiveness form, whose structure and contents are illustrated in Table A.5 of Annex A.1 in the PIM Manual.

4.7 Risk Analysis

An analysis of electricity in CBA would not be complete without taking the project's risks into account. As the benefits and costs of an electricity project are projected into future periods, uncertainty exists with regards to their realization and, in turn, the attainment of the required financial and economic returns as well as the intended outcomes set out for the project. The financial and economic variables that pose a risk to the project's overall financial and economic performance should be identified and their impacts assessed at the PFS stage using sensitivity analysis. For example, since electricity demand and tariff forecasts are the backbones of the financial and economic analysis, deviations in anticipated electricity demand and tariff should be tested at different levels in order to measure their impact on the project's outputs such as FNPV. The identification of project risk variables and their financial and economic impacts can be used as the basis for formulating measures to reallocate or mitigate such risks so as to make the project viable and/or sustainable.

4.8 Preliminary Environmental and Social Impact Assessment[8]

As stipulated in Articles 316 and 317 of the PIM Guidelines, the appraisal of an electricity project at the PFS stage should include an Environmental and Social Impact Assessment (ESIA), which is used to determine the impact the proposed project will have on the environment and society directly or indirectly linked to the project. ESIAs are regulated under the Environmental Management Act (EMA)[9], which stipulates the requirements and procedures of preparing an ESIA report.

4.8.1. Environmental Impact Assessment

An Environmental Impact Assessment (EIA) is useful in identifying and where possible, quantify the potential environmental impacts of a proposed project. Electricity projects can have various negative or positive effects on the environment. It shall be noted that the emissions generated by the thermal generating alternative are costs to the global economy rather than the economy of Zimbabwe only. Apart from identifying the environmental impacts resulting from an electricity project, the EIA should also outline the appropriate measures that can be taken to mitigate or manage such impacts.

4.8.2. Social Impact Assessment

A Social Impact Assessment (SIA) is necessary for identifying the direct and indirect, short or long-term impacts that a project will have on the society influenced by the project. Electricity projects can have numerous impacts on society; for example, the emissions of toxic gases will increase pollution. Similarly, a hydro generation (dam) project may result in the displacement and relocation of people. The SIA should outline appropriate measure that can be taken to mitigate or manage the social impacts that ensure the implementation of a project. The social impact assessment should be disaggregated to account for the impact of the electricity project on gender, different age groups in the society, and other relevant demographics.

4.9 Detailed Climate Change Risk Assessment

The assessment of projects at the PFS stage of the project cycle consists of four steps, that is;

1. The assessment of the economic viability of the regular infrastructure investment project;
2. Estimating the benefits of climate proofing the project and assessing options to climate-proof the project;
3. The assessment of the economic viability of climate-proofing; and,
4. Decision making.

Step 1: Assessment of the Economic Viability of the "Regular" Infrastructure Investment Project

[8] For more information regarding the ESIA the reader should refer to the PIM Manual.

[9] Environmental Management Act 13 of 2002.

The term 'Regular Infrastructure Investment Project' refers to a project that does not include a climate-proofing component and will be referred to from here on out as 'Project A'.

All projects (i.e., 'regular infrastructure investment projects') should be quantitatively assessed with respect to their technical, financial, and socio-economic viability. Net present value (NPV) and internal rate of return (IRR) should be estimated from both financial and economic perspectives:

1. Financial viability: based on financial metrics such as the financial net present value (FNPV) and the financial internal rate of return (FIRR).

2. Socio-economic viability: based on economic performance metrics such as the economic net present value (ENPV) and the economic rate of return (ERR).

BOX 3: Illustrative Example of Evaluating the Economic Viability of the Regular Infrastructure Investment Project

Project Summary

Benefits: Electricity generated by the proposed power plant will be used to meet the unserved grid-electricity demand (it is assumed in this example that there are no benefits from reducing generation costs by displacing less efficient power plants):

- *Existing consumers:* the generation capacity added by the project will improve the reliability of electricity service for existing consumers who currently experience frequent power outages. These economic benefits are valued using consumers' WTP for improved reliability, that is a function of backup expenditures during power outages (e.g., expenditures on candles, kerosene and diesel generators). The economic benefits from improved reliability are estimated to be \$50, \$100, and \$200 million in year 1, 2 and 3-20, respectively.
- *Newly-electrified consumers:* the proposed power plant will also supply electricity to un-electrified communities. With-project, these consumers can utilize electricity for improved lighting and purposes other than lighting (e.g., watching TV). A lower bound for these economic benefits is resource cost savings as a result of displacing off-grid energy expenditures (such as kerosene, firewood and candles). The economic benefits from grid electricity consumption by newly-electrified consumers are estimated to be \$75, \$150, and \$300 million in year 1, 2 and 3-20, respectively.

Investment cost (without climate-proofing): all investment costs including the cost of expanding transmission and distribution (T&D) lines to un-electrified communities, are estimated to be \$800 million.

Operating costs:

- Annual cost of coal: \$75, \$150, and \$300 million in year 1, 2, and 3-20, respectively.
- Other O&M costs: \$15, \$30, and \$60 million in year 1, 2, and 3-20, respectively.

NPV of Regular Project	Note
ENPV = \$81.66 million	The project is economically viable as ENPV > 0. However, the project must be assessed for climate risk before it is implemented to determine if any climate-proofing interventions are necessary.

Note: All values in the tables are expressed in real terms and discounted using an economic opportunity cost of capital (EOCK) of 12%.

Step 2 – A: Estimating the Benefits of Climate Proofing a Project

Before CAs decide to climate-proof a project and spend resources evaluating the costs and benefits of climate-proofing, a detailed appraisal of the status quo (when climate change is not considered in project formulation) should be undertaken. If the 'Regular Infrastructure Investment Project' is deemed economically viable (the project should exhibit an ENPV > 0, as outlined in step 1), a detailed quantitative climate risk assessment should then be conducted.

The climate risk assessment, which is a continuation of the climate risk screening conducted at PCN, is performed to determine the benefits of climate-proofing the project. The benefits of climate-proofing are the avoided expected costs from climate change if the project were not climate-proofed (i.e., the cost of repairing damaged infrastructure and the associated economic losses). In the case of a power plant project, increases in temperature over the project's economic life will reduce generation capacity and fuel efficiency. While reduced generation capacity negatively affects the project's benefits, decreased fuel efficiency increases the power plant's operational costs. If temperature increases over the project's economic life in the same pattern forecasted by the climate change models, the project's ENPV is expected to be lower without additional climate-proofing investments.

It is worth noting that the benefits of climate-proofing a project should be estimated based on the most likely climate change scenario, and extreme scenarios such as highly pessimistic or highly optimistic should be disregarded. A standard base-case scenario should be developed based on the most likely evolution of climate change over a given period. This scenario should be utilized consistently amongst projects from all sectors.

BOX 4: Illustrative Example of Estimating the Benefits of Climate-proofing

Climate change impacts

1. Quantifying the impact of 0.50% reduction in power production

   The modeling assumption here is that increase in temperature occurs gradually and cumulatively over the project's lifetime (0.05°C per year). This translates into annual generation output losses over the project's operation life, a minimum of 0.38 (GWh) and a maximum of 15.33 (GWh) in the first and last years of operation, respectively. Over the project's economic life (20 years), the present value of climate-induced generation output losses amounts to $6.90 million.

2. Quantifying the impact of 1.20% increase in coal consumption:

   Similarly, annual coal consumption will increase: 9 tons in the first year of operation and up to 360 tons in the last year. Over the project's economic life (20 years), the present value of climate-induced coal consumption amounts to $9.93 million.

   Also, this additional climate-induced coal consumption increases the amount of air pollutants emitted by the project, including particulate matter (PM_{10} and $PM_{2.5}$), oxides of nitrogen, and sulfur dioxide (SO_2). If the existing emission control equipment in the project design has sufficient capacity to capture these additional pollutants, no action is necessary. If not, the cost of expanding emission control's capacity has to be taken into account. Such an investment in expanded capacity of emission control is an example of climate change mitigation project.

NPV of Regular Project (W)	NPV of Regular Project Adjusted for the Impacts of Climate Change Risk (Y)	NPV of the Benefits of Averting Climate Change Impacts on the Project (Z) = (W) – (Y)
ENPV = $81.66 mil.	**ENPV = $64.82 mil.**	**ENPV = $16.83 mil.**

Note: All values in the tables are expressed in real terms and discounted using an economic opportunity cost of capital (EOCK) of 12%.

Should climate proofing options be explored?

Yes, climate proofing the project should be explored because there is a negative impact on the project's ENPV after including the expected costs of climate change over the project's economic life. In particular, the present value of climate-proofing benefits (as a result of averting climate change impacts) the power plant amounts to $16.83 million. Therefore, the power plant should be climate-proofed, if feasible and viable options (both technically and economically) are available.

Step 2 – B: Assessment of Options to Climate Proof a Project

When adverse impacts of climate change on the project are known, CAs should evaluate the potential climate-proofing options to minimize those impacts. Climate-proofing options can range from "doing nothing" to various engineering- and non-engineering adjustments (see Box 5). Based on an understanding of expected and current climate change impacts on project components, the project team can identify a list of climate-proofing options, which are selected from among several options such as changes in engineering designs, non-engineering measures, and the "do nothing" option.

BOX 5: Climate-Proofing Options in the Electricity Sector

Asian Development Bank's Guidelines for climate-proofing investments in the electricity sector broadly categorizes climate-proofing options into three groups:

- **Engineering options:** more robust materials and design specifications generally allow structures to withstand more extreme climate conditions.

- **Non-engineering options:** better-coordinated land use planning (e.g., rezoning land use, so future power infrastructure is in less vulnerable areas), policies to improve energy security, decentralized local planning and generation, and integration of climate change and disaster management planning are a few examples of non-engineering options.

- **Do nothing option:** Maintaining status-quo or "do nothing" approach should always be retained as a possible option. For example, the preliminary climate risk screening findings may indicate that the project's exposure to climate change risk is insignificant. Or, despite the medium or high degree of climate change risk, the upfront capital investment and recurring O&M costs of any technically feasible climate-proofing option may be so high as to be outweighed by the climate-proofing benefits. In both cases, not investing in climate-proofing in the context of a particular project is the best course of action from the economic efficiency perspective.

To determine which climate-proofing option reduces the project's exposure to climate risk, climate specialists and engineers should work together on estimating the likely range of projected climate variations over the project's lifetime. The outcome of a detailed analysis provides insights to CAs to identify cost-effective designs (new plants) and modifications (existing plants) to deal with specific risks identified for the site. Electricity projects have different designs and components and, therefore, climate-proofing them requires diverse options. Table 3 lists the most common climate risk impacts on project components and their potential climate-proofing options.

As shown in Table 3, climate change affects both supply and demand sides of the electricity system. An example of supply-side impact is the reduced efficiency of thermoelectric power generation capacity due to increased temperatures, resulting in an overall reduction in the total amount of power a plant can produce. On the other hand, an example of demand-side impact is the additional costs to electricity consumers because of the increased frequency of power outages. Increased frequency and intensity of floods will damage electricity generation, transmission, and distribution, leading to frequent and prolonged interruptions in the electricity supply. These power outages translate to economic costs in the forms of backup equipment costs and forgone production.

Table 3: Climate risk impacts and potential climate-proofing options in the electricity sector

Climate risk	Project component at risk	Potential climate-proofing options
Increases in temperature	Thermal: ▪ Reduction in power generation capacity due to loss in generation efficiency Hydro: ▪ Reduction in power generation capacity due to increased surface evaporation Renewables: ▪ Reduction in solar panel efficiency and output due to damages to the solar PV array, inverter, and cables caused by very high temperatures. Transmission & distribution: ▪ Increase in transmission losses due to damages to transmission lines ▪ Increase in distribution losses within transformers and substations	Thermal: ▪ concentrate investment in locations where projected temperatures are likely to be cooler ▪ decentralize generation Hydro: Construct water storage reservoirs Renewables: ▪ Improve airflow beneath the mounting structure to reduce heat gain and increase outputs. ▪ Specify heat-resistant PV cells and module components designed to withstand very high temperatures. Transmission & distribution: ▪ Specify more effective cooling for substations and transformers.
Increases in precipitation and flooding	Thermal: ▪ Fuel unavailability due to interruptions in the fuel supply chain ▪ Reduction in power generation capacity due to damages to boiler/furnace, turbine/generator and cooling system ▪ Interruptions in electricity supply due to damages to buildings, storage, generating plant Hydro: ▪ Interruptions in electricity supply due to damages to dams and other structures Renewables: ▪ Reduction in solar panel efficiency and output due to decreased solar radiation Transmission & distribution: ▪ Increase in T&D losses due to damages to T&D lines caused by flooding ▪ Interruptions in electricity supply due to flooding of distribution substations	Thermal: ▪ Develop flood control (e.g., dikes, reservoirs, and higher channel capacity) ▪ Improve drainage and reroute water pipes ▪ Protect fuel storage ▪ Redesign cooling facilities Hydro: ▪ More robust design specifications for heavier flooding ▪ Identify cost-effective designs (new plants) and modifications (existing plants) to deal with specific risks identified for the site Transmission & distribution: ▪ Build a resilient high-capacity transmission system. ▪ Design improved flood protection measures for equipment mounted at ground level in substations.
Drought or precipitation decrease	Thermal: ▪ Reduction in power generation capacity due to loss in cooling system efficiency Hydro: ▪ Reduction in power generation capacity due to reduced water levels behind dams.	Thermal: water management plans to withdraw less water from the source and consume less water internally (once-through or recirculating system) Hydro: ▪ Optimize reservoir management and improve energy output by adapting to changes in rainfall or river flow patterns ▪ Construct water storage reservoirs
Higher wind speed	Thermal: ▪ Interruptions in electricity supply due to damages to buildings, storage, generating plant; Renewables: ▪ Reduction in power generation capacity (wind turbines cannot operate in very high or very low winds) ▪ Reduction in system reliability due to unpredictable wind patterns. Transmission & distribution: ▪ Interruptions in electricity supply due to damages to overhead lines	Thermal: Develop and implement higher structural standards for new or renovated buildings Renewables: ▪ Design turbines able to operate with and withstand higher wind speeds ▪ Choose sites that take into account expected wind speed changes during the lifetime of the wind turbines. Transmission & distribution: ▪ Reinforce existing T&D structures and build underground distribution systems.

Source: Adapted from ADB's Guidelines for Climate Proofing Investments in the Energy Sector

At this stage, a key consideration is the cost-effectiveness of the chosen option to climate-proof the project. In deciding which climate-proofing option cost-effectively addresses the impacts of climate change on the project, CAs should ensure that the cost of any climate-proofing option does not exceed the benefits from adopting that option.

Two inputs are required to evaluate the cost-effectiveness of climate-proofing options:

1. The effectiveness of each climate-proofing option: the benefits from climate-proofing a project are unlikely to be technically and economically efficient to completely eliminate the project's exposure to climatic risk. Therefore, the benefits of climate-proofing should be adjusted by the chosen option's effectiveness to consider the impact of unmitigated risk or the "residual risk".

2. The technical design and the estimated cost of each climate-proofing option: This information should be provided by engineers in the project team, based on the outputs of the models used by climate change experts to determine the likelihood and magnitude of climate change forecasts over the project's economic life.

BOX 6: Illustrative Example of Assessing Climate-Proofing Options

Thermal power plants heat water to produce steam to drive the turbines for electricity generation. After passing through the turbine, the steam is cooled with water drawn from a river. The amount of water consumed by the power plant depends on the type of cooling system used. With increasing temperatures, power generation capacity can be negatively affected due to loss in cooling system efficiency. Engineering studies point out that an improved cooling system such as a closed-loop cooling tower can effectively maintain the power plant's rated efficiency even in high temperatures.

Climate Proofing Options:

Engineering studies point out that an improved cooling system such as a closed-loop cooling tower can effectively maintain the power plant's rated efficiency even in high temperatures.

- Option A - Closed-loop cooling tower for water use efficiency and reuse: The project can adopt a closed-loop cooling tower instead of the current one-through-release cooling tower, considering lack of water resources due to drought. Closed-loop cooling tower has an installation cost 40% higher than a one-through system.

- Option B - Dry cooling systems use little or no water, but are 3 to 4 times more expensive than other water-based recirculation system

Climate-proofing options	PV (climate-proofing costs) ($ million) (A)	PV (climate-proofing benefits) without adjustments for residual risk ($ million) (B)	Estimated Effectiveness of Climate-proofing Option (C)	**PV (climate-proofing benefits) with adjustments for residual risk ($ million) (D) = (B) * (C)**
Option A	5.00	16.83	60%	**5.10**
Option B	20.00	16.83	90%	**- 4.85**

Note: All values in the table are expressed in real terms and discounted using an economic opportunity cost of capital (EOCK) of 12%.

When there are multiple options to climate-proof the project, the preferred option should be the most effective and efficient over the project's economic life. In other words, it should be the option that maximizes the ENPV of climate proofing.

Step 3: Assessment of the Economic Viability of Climate Proofing a Project

The climate-proofed project's costs should be weighed against the residual-risk-adjusted benefits to determine the economic feasibility and viability of climate-proofing a project. ENPV is used to measure the economic efficiency of Project B in addressing the impacts of climate change.

In determining the preferred climate-proofing option to implement, CAs should also take into consideration:

a. Technical feasibility,
b. Financial affordability,
c. Capacity and experience of the CA to implement the option,
d. Environmental impacts,
e. Legal implications.

Step 4: Decision Making

As highlighted in the preceding sections, it is crucial to determine if both Project A (the regular infrastructure project "without" climate-proofing) and Project B (the regular infrastructure project "with" climate-proofing) are economically viable. ENPV evaluates the project's economic viability over its entire life, and therefore, it should be used as the primary decision-making criterion. From the economic efficiency perspective, only projects with positive ENPVs should be chosen. Such a decision-making criterion ensures that projects are selected based on economic efficiency in achieving targeted outcomes, not politically motivated objectives.

The decision criteria for climate-proofing investments in the electricity sector are outlined in Box 7, and an illustrative example is provided in Box 8.

BOX 7: Decision making criteria for climate-proofing investment projects

1. If **ENPV Project A < 0, do not proceed with the project.** In such a case, climate-proofing will not be explored as the project will not be implemented given that it is not economically viable.

2. If **ENPV Project A > 0**, and **ENPV Project B < 0, proceed with project A and not project B.** In such a case, climate-proofing is not a viable option as there are no technically and economically efficient climate-proofing options available. Therefore, the best course of action is to implement the regular infrastructure project that is not climate-proofed and deal with the impacts of climate change if and when they occur.

3. If **ENPV Project A > 0**, and **ENPV Project B > 0, proceed with project A and B**. In such a case, climate-proofing the project is a viable undertaking. Hence, the regular infrastructure project should be implemented with a climate-proofing component.

Notes:
a. Project A refers to the regular infrastructure investment project that does not include a climate proofing component.
b. Project B refers to the climate-proofing option that will enable the project to withstand climate change impacts to a certain degree.

BOX 8: Illustrative Example of Decision Making

NPV of Regular Project Adjusted for the Impacts of Climate Change Risk ($ million) (Project A)	NPV of Cost-effective Climate Proofing Option ($ million) (Project B)	**NPV of Climate-Proofed Regular Project ($ million) (Project A) + (Project B)**
64.82	5.19	**69.92**

Note: All values in the table are expressed in real terms discounted using an economic opportunity cost of capital (EOCK) of 12%.

<u>Decision on at the PFS stage</u>

- ENPV of Regular Project > 0 and ENPV of Climate-Proofing Option > 0
- Proceed with Both Projects

Notes:
a. Project A refers to the regular infrastructure project that does not include a climate-proofing component.
b. Project B refers to the climate-proofing option that will enable the project to withstand climate change impacts to a certain degree.

4. ASSESSMENT OF PRE-FEASIBILITY STUDY

The assessment of the PFS involves checking the robustness and effectiveness of the proposed project according to its ability to meet financial and socio-economic outcomes while adhering to national and sectoral objectives and goals in addressing the identified problem.

The assessment of the PFS consists of two phases. The first phase entails an internal assessment of the PFS by the Line Ministry. The internal assessment shall attempt to answer three questions:

1. Is the project consistent with national and sectoral development strategies?
2. Out of a number of project alternatives, what is the preferred project alternative, and why is this the best strategy of addressing the identified problems?
3. Do the expected socio-economic benefits of the project exceed its economic costs?

Once the PFS has passed the internal screening, it should be submitted to the IMC through the MoFED for the second phase of the screening process. It should be noted that PFS submissions are made between March and April, according to the Public Investment Management and Budgeting Calendar defined in Article 141 of the PIM Guidelines.

The external assessment of the PFS by the IMC is a three-step process aimed at assessing the project's alignment with the Government's objectives and priorities. It also entails an evaluation of resource availability to fund the project with consideration of resource allocation to projects from other sectors vying for the same pool of resources. The three steps carried out in assessing the PFS are as follows:

i. The first stage is to assess the compliance of the CA with the submission process and other procedural requirements stipulated in the PIM Guidelines and this Manual. CAs are required to submit PFSs in compliance with the PFS form outlined in the PIM Guidelines (PIM Guidelines, Article 270). In the case of missing information, the IMC may postpone the PFS assessment, pending the submission of the complete information.

ii. At the second stage of the assessment, the IMC will assess the project's alignment with the National and Sectoral Strategic Objectives. Projects that are not in line with the national development strategies and sectoral development plans will get postponed. In exceptional cases, CAs may justify projects that are not directly aligned with the strategic development plans. Such cases, for instance, may include projects that are designed to mitigate force majeure situations, such as droughts, floods, earthquakes, Et cetera.

iii. The last stage involves the IMC assessing the affordability of the project as well as the likelihood of the expected economic benefits of the project exceeding the cost of resources.

The IMC's decisions on PFSs shall be issued in May-June. Only projects whose PFSs pass both the internal assessment by the CA and the external assessment by the IMC should be allowed to progress to the FS stage. PFSs approved by the IMC are valid for a period of three (3) years. Once a project's PFS expires the project should be reappraised and resubmitted to the IMC for consideration following the internal and external screening processes described above.

5. FEASIBILITY STUDY

The submission of the FS shall be made in July in line with the Public Investment Management and Budgeting Calendar (PIM Guidelines, Article 141). The decision on the FSs will be issued in August-September to allow the inclusion of the projects with approved FS for financing in the coming budget year. Projects without Positive Decision on FS shall not be considered for financing (PIM Guidelines, Article 133).

The FS builds on the analysis developed in the PFS. To provide clearer insight into the project's feasibility, the FS should make use of primary data, and in situations where such data is not available, studies should be undertaken to obtain accurate information about the project's costs and benefits. This data should replace the secondary and/or proxy data from projects of similar nature, which have been used to conduct the PFS. The FS should form a more accurate picture of the project's technical, financial and socio-economic prospects to aid decision-makers in allocating resources efficiently.

The financial, economic, stakeholder, and risk analysis model developed at the PFS stage should be updated with primary data retrieved from the FS. FS shall also include:

a) **Electricity Market Analysis:** Electricity energy supply is a service capable of being bought, sold, and traded. The Utility might own the generation facilities, or it might contract out the supply of electricity capacity and energy from IPPs or suppliers from neighbouring countries. A detailed analysis of different costs of electricity generation and the prices charged to final consumers is required in FS since prices charged for the service will have a major impact on consumer demand.

b) **Technical Analysis:** The engineering aspects of the electricity generation or transmission project should be assessed to ensure that the project is technically feasible. The technical design of the project will influence the cost structure. Cost estimates at this stage should be based on the final engineering designs of the electricity project. A draft procurement plan should be drawn up with a comprehensive list of all materials and equipment required to construct the power plant.

c) **Labor and Administrative Analysis:** Human resources required to develop, implement and manage the project during both construction and operations should be quantified and included in the capital and operations and maintenance cost schedules. The sources of all labor required for the project should be identified.

The preparation of the FS should follow the requirements stipulated in the PIM Guidelines. Guidelines on how a CA should compile an FS are provided in pages 65-81 of the PIM Guidelines. This section of the Manual provides further details on the following items:

a) Environmental and Social Impact Assessment
b) Monitoring, Review, Action and Reporting Plan
c) Project Governance Structure

6.1 Environmental and Social Impact Assessment

6.2.1. Environmental Impact Assessment

The FS of electricity projects should include an Environmental and Social Impact Assessment (ESIA) study in order to identify and quantify the potential environmental and social impacts of a proposed project. This should be done by updating the preliminary ESIA conducted at the PFS stage with the changes made to the FS based on new and more accurate project data.

Environment Management Act (EMA), 13 of 2002, exists to provide for the sustainable management of natural resources and protection of the environment. It also provides a guide regarding what the Environmental Impact Assessment (EIA) is and how it should be conducted. The EMA defines EIA as an evaluation of a project to determine its impact on the environment and human health and to set out the required environmental monitoring and management procedures and plans.

According to the EMA, the EIA report should:

1. Give a detailed description of the project and the activities to be undertaken in implementing it;
2. State the reasons for selecting the proposed site of the project;
3. Give a detailed description of the likely impact the project may have on the environment or any segment thereof, covering the direct, indirect, cumulative, short-term and long-term effects of the project;
4. Specify the measures proposed for eliminating, reducing or mitigating any anticipated adverse effects the project may have on the environment, identifying ways of monitoring and managing the environmental effects of the project;
5. Indicate whether the environment of any other country is likely to be affected by the project and any measures to be taken to minimize any damage to that environment;
6. Have an analysis of the biodiversity impacts of the project, land tenure system, soil as well as a hydrological analysis;
7. Be accompanied by attachments of soils, hydrological and topographical maps, and make an analysis of the impacts of the project to the current environmental baseline.

When conducting the EIA, public consultations should be done with LMs, certain departments at Local, District, Provincial and National level. These consultations should also include other institutions related to the project as well as the neighbouring land users.

Environmental Management Plan should be submitted to the Treasury during the FS stage. Table 4 below displays how the plan should be presented.

Table 4 Biophysical Environment Management Plan Sample

Impact Statement	Process/Activity responsible for impact	Proposed Mitigation on impact	Monitoring and Management Agency	Management and Monitoring activities	Time frame	Budget
Siltation	Loose soil can potentially result in siltation during the rainy season	Backfill loose soil immediately.	ZINWA, EMA, Contractor	Inspections	Construction	Negligible

Impact

The final certificate from the Director-General should be obtained at this stage. The certificate should be attached as an Annex to the submission of the FS study. It is important to note that this certificate is valid for only two years with the possibility of an extension if deemed necessary; otherwise, the whole EIA process will have to be repeated.

6.2.2. Social Impact Assessment

The social impact assessment (SIA) is carried out to understand the possible social and cultural impacts of the proposed project. SIA is the process of managing the social issues associated with development. Unlike the EIA, the SIA focuses on social considerations rather than biophysical issues. Social impacts start even before the construction of a project. The following steps are taken during an SIA:

1. Understanding the issues
    a. Forecasting the social changes that may result from the project;
    b. Stakeholder consultations;
    c. Community assets and aspirations scoping
2. Predicting and assessing likely impacts
    a. Collaborative selection of sustainability and impact indicators;
    b. Baseline indicator data collection;
    c. Impact significance determination;
    d. Social and economic development opportunities assessment;
    e. Establishing the significance of the predicted changes and determining how the various affected groups and communities will likely respond;
    f. Identifying ways to mitigate negative impacts and capitalize on the positive impacts
3. Developing monitoring and mitigation strategies
    a. For the negative impacts, develop mitigation strategies;
    b. Monitor in case new, unpredictable impacts arise.

6.2 Reassessment of the Economic Viability of the Project without- and with-climate proofing option

The FS's objective is to assess, in greater detail, the technical, financial, and economic viability of climate-proofing projects approved at the PFS stage. CAs may undertake FS or outsource it if deemed appropriate. The FS builds on the information obtained at the PFS stage by examining all aspects of the project's costs and benefits and climate risk exposure and impact in greater detail.

CAs should prepare a final climate-proofed project design based on detailed climate risk assessments, technical studies, engineering drawings, and social and economic impact assessments.

The assessment of projects at the FS stage of the project cycle consists of three steps.

i. The reassessment of the regular Infrastructure investment project's economic viability using primary data and detailed cost estimates.
ii. The reassessment of the economic viability of the preferred climate-proofing option.
iii. Decision making.

Step 1: Reassessment of the regular Infrastructure investment project's economic viability using primary data and detailed cost estimates.

BOX 9: Illustrative Example – Reassessment of the Economic Viability of the Regular Project

Updated data from reassessment of climate risks indicate that 1°C increase in temperature increases the power plant's coal consumption by 1.50% compared to an initial estimate of 1.20% at the PFS stage.

Project Stage	NPV of Regular Project (W)	NPV of Regular Project Adjusted for the Impacts of Climate Change Risk (Y)	NPV of the Benefits of Averting Climate Change Impacts on the Project (Z) = (W) – (Y)
PFS	NPV = $81.66 mil.	NPV = $64.82 mil.	NPV = $16.83 mil.
FS (updated data)	NPV = $81.66 mil.	NPV = $62.34 mil.	NPV = $19.32 mil.

Note: All values in the tables are expressed in real terms and discounted using an economic opportunity cost of capital (EOCK) of 12%.

Should climate proofing options be explored?

Yes, using the updated data at the FS stage, the NPV of climate-proofing benefits is still economically significant, $19.32 million. Therefore, climate proofing the project should be considered if the evaluated climate-proofing options at the PFS stage are still viable (both economically and technically), given the updated information at the FS stage.

Step 2: Reassessment of the Economic Viability of the Preferred Climate-Proofing Option

The preferred climate proofing option identified at the PFS stage is reassessed at FS based on updated climate change models.

BOX 10: Illustrative Example – Reassessment of the Economic Viability of the Preferred Climate Proofing Option

Climate Proofing Options:

- Option A: Closed-loop cooling tower
- Option B: Dry cooling system

Climate-proofing options	PV (climate-proofing costs) ($ million) (A)	PV (climate-proofing benefits) without adjustments for residual risk ($ million) (B)	Estimated Effectiveness of Climate-proofing Option (C)	PV (climate-proofing benefits) adjusted for residual risk ($ million) (D) = (B) * (C)	**NPV of Climate Proofing ($ million)** **(E) = (D) – (A)**
Option A	5.00	19.32	60%	11.59	**6.59**
Option B	20.00	19.32	90%	17.39	**- 2.61**

Is the climate-proofing option still viable after the reassessment?

Yes, using the updated data at the FS stage, Option A is still the cost-effective climate-proofing option with a positive NPV, and Option B is still not a cost-effective climate-proofing option.

Step 3: Decision making

The same decision-making criteria presented at the PFS stage (see Box 8) should be used to make a decision at the FS stage

BOX 11: Illustrative Example - Decision Making at the FS stage

NPV of Regular Project (Project A) Adjusted for the Impacts of Climate Change Risk ($ million)	NPV of Cost-effective Climate Proofing Option (Project B) ($ million)	**NPV of Climate-Proofed Regular Project ($ million)**
62.34	6.59	68.93

Note: All values in the table are expressed in real terms discounted using an economic opportunity cost of capital (EOCK) of 12%.

Decision on at the FS stage

- ENPV of Regular Project > 0 and ENPV of Climate-Proofing Option > 0
- Proceed with Both Projects

Notes:
a. Project A refers to the regular infrastructure project that does not include a climate-proofing component.
b. Project B refers to the climate-proofing option that will enable the project to withstand climate change impacts to a certain degree.

6.3 Monitoring, Review, Action and Reporting Plan

6.3.1. Monitoring, Review, and Reporting

As stipulated by the National Monitoring and Evaluation (M&E) Policy[10,] it is the role of the Line Ministries, local authorities and public entities to develop and implement monitoring plans and to disseminate periodic reports. The Line Ministry must specify the frequency of the monitoring and reporting cycle. The PIM Guidelines outline the need for well-designed and realistic key performance indicators (KPIs), as agreed by all key stakeholders. These indicators should clarify the project's intentions and should aid in the assessment of achievements.

MoEPD shall carry out its Monitoring and Evaluation function using monitoring plans submitted by CAs at the FS stage. The MoFPD oversight of the project's implementation stage must ensure that the project aligns itself with objectives that were agreed upon during the FS phase. Its purpose is to determine if the outputs, deliveries, and schedules planned have been reached so that action can be taken to correct the deficiencies as quickly as possible.

It is important to develop an M&E plan before beginning any monitoring activities so that there is a clear plan for what questions about the project are to be answered. It will help the program

[10] Government of Zimbabwe. (2015). *National Monitoring and Evaluation Policy.* Harare

staff decide how they are going to collect data to track KPIs, how monitoring data will be analysed, and how the results of data collection will be disseminated both to the donor and internally among staff members for program improvement. It must be noted that considering how significant the potential impacts of electricity projects can be on women and girls, the data must be disaggregated by gender, as much as possible. The M&E plan will help make sure that data is being used efficiently to make programs as effective as possible and to be able to report on results at the end of the program.

Steps to develop an M&E Plan include:

1. Identify project goals and objectives
2. Specify KPIs
   - Progress indicators to track the progress of the project. They help to answer the question, "Are activities being implemented as planned?"
   - Outcome indicators track how successful the project activities have been at achieving the set objectives. They help to answer the question, "Have project activities made a difference?"
3. Define data collection methods and timeline
   - After creating monitoring indicators, it is time to decide on the methods for gathering data and how often various data will be recorded to track indicators. This should be a conversation between program staff, stakeholders, and donors. These methods will have significant implications for what data collection methods will be used and how the results will be reported.
4. Identify M&E roles and responsibilities
   - Line Ministry should identify stakeholders responsible for monitoring outputs delivery. It is important to decide from the early planning stages the responsible parties for collecting the data for each indicator. Data management roles should be decided with input from the key stakeholders so that all parties are on the same page and know which indicators they are assigned.
5. Plan for Report Dissemination
   - The last element of the M&E plan describes how often and to whom data will be disseminated. Line Ministries must spell this out guided by the National M&E Policy

6.3.2. Action

The Monitoring, Review, Action and Reporting Plan should also include a section on the Action Plan. This section should list the steps needed to achieve the project's goals and objectives. It should clarify and break down the resources and timeline for tasks needed to reach those goals. An action plan makes it possible to monitor the project's progress and take each task step-by-step, therefore allowing for efficient project handling. The advantage of doing this is to allow MoEPD to execute a structured plan for the end goal that they intend to achieve. Moreover, it provides the team with appropriate foundations, therefore prioritising the amount of time to be spent on each task. This will then prevent any diversions that may occur.

The section should consist of several action steps or changes to be brought about in the community. Each action step or change to be sought should include the following information:

- **What** actions or changes will occur
- **Who** will carry out these changes
- **When** they will take place, and for how long
- **What** resources (i.e., funds, personnel) are needed to carry out these changes
- **Communication** (who should know what?)

6.4 Project Governance Structure Plan

Institutional Analysis reviews the capacity of the implementing organisation(s) to contribute to the planned project. Weaknesses in the organisation may be addressed through formal and informal links with partners.

The description of the main participants, the scheme of their interaction, and the project management scheme in the investment and post-investment periods. Submission of the project's institutional scheme is guided by Table 5:

Table 5 Projects Institutional Scheme

#	Project Participant	Information about the project participant	Functions of the project participant	Responsibility of the project participant
1.	Line Ministry			
2.	Contracting Authority			
3.	Project Assets' Holder			
4.	Project Operator			
5.	Other Project Participants			

6.5 Project Implementation Plan

As part of the FS, a proposal that outlines how the project will be implemented should be included. The implementation plan should clearly delineate the scheduled timing of the activities within each phase of the project's implementation plan and should be accompanied by the relevant cost schedules. The successful implementation of the project is subject to the availability of resources required to undertake the project; therefore, the implementation plan should ensure that the financial, human and input resources required to execute the project are adequately available. Consideration should be given to contractual structures such as supply contracts and forward and futures contracts to secure key inputs. Additionally, secondary sources of all resources must be identified so as to guard against the inability of primary sources to meet the project's needs. The implementation plan should also outline how the implementation process will be management by assigning responsibilities to the parties most suitable to carry out the given role.

6. ASSESSMENT OF FEASIBILITY STUDY

The assessment of the FS involves checking the robustness and effectiveness of the proposed project according to its ability to meet financial and socio-economic outcomes while adhering to national and sectoral objectives and goals in addressing the identified problem.

The assessment of the FS consists of two phases. The first phase entails an internal assessment of the FS by the Line Ministry. The internal assessment shall attempt to answer three questions:

1. Is the project consistent with national and sectoral development strategies?
2. Is the proposed solution technically optimized?
3. Do the expected socio-economic benefits of the project exceed its economic costs?

Once the FS has passed the internal screening, it should be submitted to the IMC through the MoFED for the second phase of the screening process. It should be noted that FS submissions are made in July, according to the Public Investment Management and Budgeting Calendar defined in Article 141 of the PIM Guidelines.

The external assessment of the FS by the IMC is a three-step process aimed at assessing the project's alignment with the Government's objectives and priorities. It also entails an evaluation of resource availability to fund the project with consideration of resource allocation to projects from other sectors vying for the same pool of resources. The three steps carried out in assessing the FS are as follows:

i. The first stage is to assess the compliance of the CA with the submission process and other procedural requirements stipulated in the PIM Guidelines and this Manual. CAs are required to submit FSs in compliance with the FS form outlined in the PIM Guidelines (PIM Guidelines, Article 341). In case of missing information, the IMC may postpone the FS pending the submission of complete information.

ii. At the second stage of the assessment, the IMC will assess the project's alignment with the National and Sectoral Strategic Objectives. Projects that are not in line with the National development strategies and sectoral development plans will get postponed. In exceptional cases, CAs may justify projects that are not directly aligned with the strategic development plans. Such cases, for instance, may include projects that are designed to mitigate force majeure situations, such as droughts, floods, earthquakes, Et cetera.

iii. The last stage involves the IMC assessing the technical feasibility of the project, the affordability of the project as well as the likelihood of the expected economic benefits of the project exceeding the cost of resources.

The IMC's decisions on FSs shall be issued between August and September. Only projects whose FSs pass both the internal assessment by the CA and the external assessment by the IMC should be selected for inclusion in the National Budget. FSs approved by the IMC are valid for a period of three (3) years. Once a project's FS expires the project should be reappraised and resubmitted to the IMC for consideration following the internal and external screening processes described above.

7. ANNEX A: LEAST COST EXPANSION PLAN

7.1. Importance of Least Cost Expansion Plan

Least cost planning is a strategic planning process that uses the principles of benefit-cost analysis as its underlying evaluative framework. It has been developed by the electric utility industry as a method for selecting the most cost-effective measure to cater for the projected increase in demand for electricity. The least-cost expansion plan is the set of investments to be made in generation, transmission and distribution, including their operating strategy over time that is expected to minimize the present value of total costs that will supply the forecasted demand for electricity within a set of technical, economic and political constraints.

The total costs of modern least cost expansion planning should include not only the direct costs of planning, construction, operation and maintenance but also external costs like pollution. Risks and uncertainties are treated explicitly, hence requiring a more flexible and responsive planning approach to deal with them.

7.2. Projection of Electricity Demand and Load Factor

Before a least-cost expansion can be undertaken, a projection must be made of the growth of the demand for electricity per period over the planning horizon. In addition, the pattern of the quantities demanded over the hours of each period must be taken into consideration.

In forecasting electricity demand, the nature of the macroeconomic growth of the economy and the pricing of electricity relative to other sources of energy are two important considerations. The macroeconomic variables include the growth in gross domestic product, the growth in household disposable income, population growth, and projection of the number of urban and rural households connected to the electricity system. Price factors, on the other hand, are related to the pricing policies for electricity as compared to other energy sources.

Demand for electricity fluctuates hourly, daily, monthly, seasonally (Figures 3). It is generally not economical to store electricity. Hence, electric generation systems must match electricity demand at any point in time.

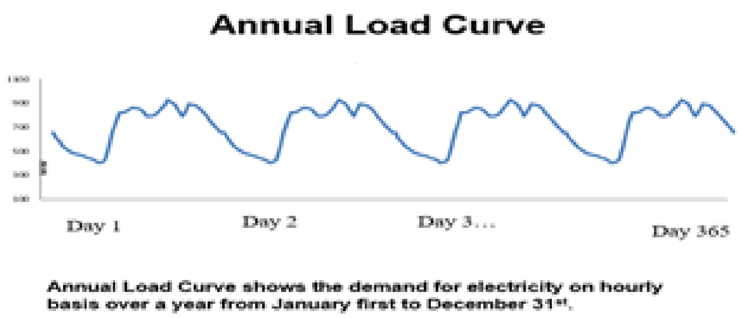

Figure 3. Annual Load Curve

Factors to be considered in electricity demand projections are discussed below:

a) Economic Growth

Economic growth is a key determinant of electricity demand. Whether growing industries are electricity-intensive or not is a critical factor in developing an electricity demand forecast. Although there is no one-to-one relationship between GDP growth rates and electricity demand growth rates, there usually is a strong positive correlation. This means that electricity consumption typically increases with increasing GDP growth.

b) End-user prices and subsidies

In addition to growth factors, the demand for electricity depends on the price of electricity and the price of alternative sources of energy. In general, the higher the price for electricity, the lower the overall consumption level (ceteris paribus). This reduction in consumption can be a result of energy savings, profitable energy efficiency measures, or substitution of electricity for other energy sources. Furthermore, subsidies for certain types of energy consumption can influence the demand considerably, as they change the relative prices for different energy sources, including electricity. Other subsidies, like support for better insulation of buildings, may reduce the overall level of energy consumption within households or office buildings.

End-user prices are not only a function of the wholesale electricity price, but also of the charges for transmission and distribution along with any government consumption taxes, including VAT.

c) Peak load and seasonal variation

It is very expensive to store electricity. Therefore electricity has to be produced at the same time it is demanded. This means that as demand varies from instant to instant, and from season to season, the generation supply system must accommodate these fluctuations. In order to meet demand, the system must have the ability to generate the demanded energy over a certain time period and the capacity to meet demand in hours of peak demand. Hence, electricity demand consists of the demand for energy, measured in kWh or MWh and the capacity to generate, which is measured in kW or MW.

In addition, because of the variability of the minute by minute demand for electricity by consumers, there is a need to have flexibility in the supply response by generators to rapid change in generation levels in order to balance the system's demand and supply. Stability in voltage and having constant accessibility to the electricity service are critical factors for most customers. This demand is mostly automated or coordinated by system operators. The demand profile and the need for flexibility do affect not only the cost of generation but also the environmental impact of electricity generation.

d) Technological Developments and Energy Conservation

New technologies that help to save energy and "optimize" energy consumption can also have a significant impact on the demand and the demand profile over the year. For example, one aspect that may change the consumption profiles, are hourly meters. This opens up the opportunity for demand management either by centrally managed quantitative controls over demand, such as cutting the electricity for non-essential uses during periods of peak demand or by time of the day pricing of electricity. The use of differential prices depending on the time-related costs of the supply of power and leaves the decision of whether or not to consume up to the final consumer. This system relies on the incentives consumers face due to prices that are adjusted to follow the cost of supplying the electricity in different periods of the day or year.

e) The Annual Load Duration Curve

The annual load duration curves, as shown in Figure 4, summarizes both the energy demanded in a given year as well as the shape of the demand over the year for two years that are ten years apart. Figure 4 shows the ranking of the hourly electricity demands as shown by the annual load curve (Figure 3) over a year, starting from the hours of maximum demand by the customers of the system (Maximum MW required) and declining towards off-peak hours. The annual load duration curve shows the demand for electricity (MWh) in terms of the number of hours in a year that each level of capacity (MW) is required. The area under the annual load duration curve represents the energy demanded during the year, expressed in MWh. As the demand for electricity grows over time, it will shift upward and, at the same time, its shape may change as the structure of the economy changes.

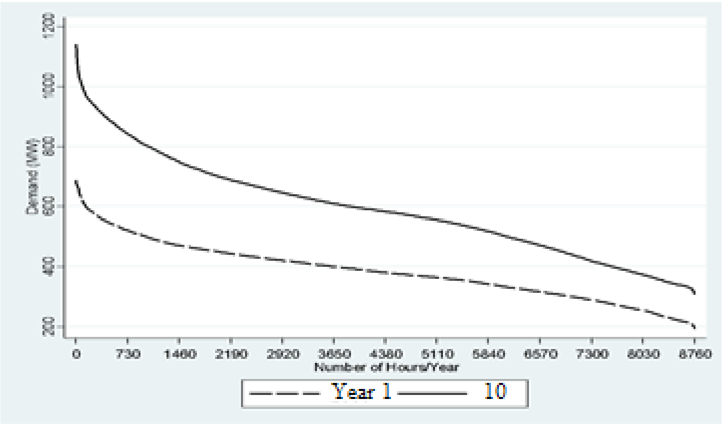

Figure 4. Annual Load Duration Curve

7.3. Use of Screening Curves to Identify Appropriate Generation Technologies

A screening curve is used to evaluate optimal generating mix for serving a load supposing the lowest cost units adequate to meet demand are often chosen for dispatch. Considering a load duration curve, a screening-curve algorithm can be used to determine how frequently each set of unit will run, depending on marginal operating cost (MOC), and will choose suitable units for investment by optimizing operating costs and capital contract to the expectation of hours operated as depicted in Figure 5. These curves do not account for plant start-up costs, ramping constraints, system considerations or minimum turndowns like transmission and ancillary services. They solely approximate actual unit commitment. However, this first-order approximation can be useful for capacity-expansion planning.

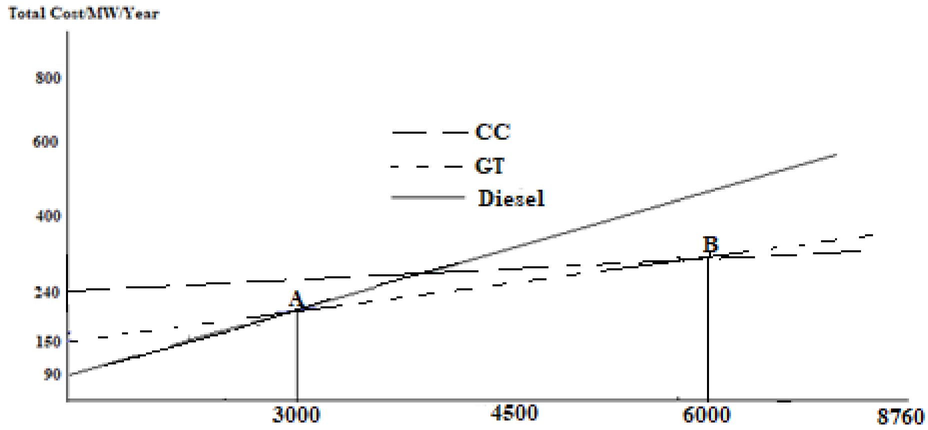

Figure 5. Illustration of the Screening Curve Method

Screening curves allow the utility to compare different technologies for different kinds of applications. The curves are generated on a "per MW of capacity" basis. In using the screening curve, we do not need to know the size of the facility, since we are still planning. Screening curves are also generated on a "per year" basis. The unit is usually measured as the cost of supplying electricity per MW of plant capacity per year (spread out over n years). There are two basic components of costs that are crucial in using screening curves, the capital cost (fixed capital cost, annualized) and the variable costs (the fuel cost and O&M).

It is important to pro-rate the initial investment cost over the useful life of the plant. The annualized capital cost that spreads the fixed investment cost over the life of the plant is referred to as the "Fixed Charge Rate." This is the rate per MW at which the capital costs are spread over the life of the project. This is based on the cost of capital and other factors. The variable cost, on the other hand, is the slope of the screening curves. This slope reflects the marginal operating costs of the plant per megawatt-hour of operation. If we know the number of hours the plant will operate, then we can add the variable operating costs to the fixed costs to determine the total costs of the MW of plant capacity available and running the plant for a specific number of hours in the year.

Figure 5 presents three different technologies, diesel power plants (Diesel), closed (single) cycle gas turbine (GT) generation plants and combined cycle gas turbine (CC) plants. The total annual installed capital cost for the diesel power plant plus the cumulated variable costs for different levels of its capacity (hours per year) is shown by the solid line. The total installed cost plus the cumulated operating cost of the single-cycle gas turbine plant for different levels of capacity is shown by the dotted line. Finally, the annualized capacity cost per MW plus the cumulated variable costs of generation for different levels of capacity for the combined gas turbine plant is denoted by the dashed line in Figure 3. Each one of these total cost curves has a different annualized capital cost and a different marginal operating cost/MWh of generation. Considering the capital cost axis, the diesel power plant has the lowest capital costs but has the highest marginal operating costs. On the other hand, the combined cycle gas turbine plant has the highest annualized capital costs, but the lowest marginal operating costs. The single-cycle gas turbine plant will have capital costs somewhere between these extremes. Its marginal operating costs will be lower than that of the diesel generators but higher (less efficient) than the combined cycle plants.

The two intersection points of the three screening curves, as shown in Figure 5, are very important. They show us the capacity factor (or the average number of hours of operation per year) at which the total annual costs of operating one technology begins to exceed the total annual cost of another technology. For example, the point of intersection (A) between diesel plant and closed (single) cycle plant, tells us that if you are going to run a plant above 3000 hours in a year, then it is cheaper to operate a single cycle gas turbine plant than a diesel power generation plant. If the plant is only required to be operated less than 3000 hours, then it is more efficient to use a diesel generator. From Figure 5 one can conclude that if a plant is running from 3000 up to 6000 hours per year (B), the lowest total generation costs per year is given by single-cycle gas turbine plants. For plants that are required to operate more than 6000 hours and up to 8760 hours a year (baseload), the combined cycle plants will have the lowest total costs/year of the three technologies described here.

Now we wish to integrate the analysis from the screening curve analysis with the quantity and shape of the demand for electricity over a year for the country or community in question. The nature of the demand for electricity is summarized by the load duration curve (LDC) shown in Figure 6.

By combining the LDC and the screening curves, we can find an optimal solution to utility planning. It is important to note that screening curves tell us nothing about actual plant capacities required, just the total costs per MW and the minimum capacity at which each generation technology should operate. It is the application of these hourly constraints to the load duration curve that allow us to estimate the efficient levels of capacity for each of the technologies.

As seen in Figure 6, the peak is 10,000 MW. The load level will never get higher than 10,000 while at 8760 hours, and the load will never get below 2,000 MW.

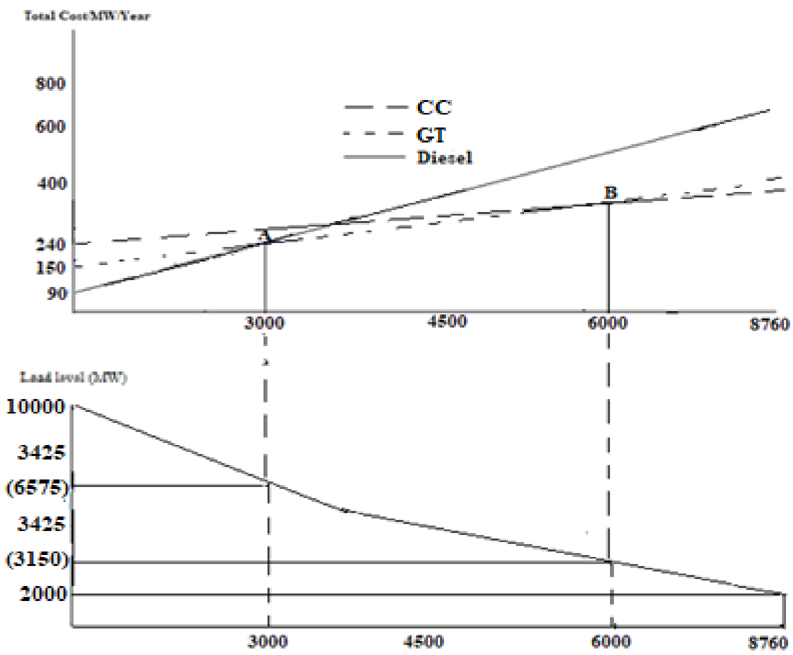

Figure 6. Screening Curves and Load Duration Curve

In drawing vertical lines from the intersection points of the screening curves, we can now use the load duration curve to tell us how much of each technology we should invest in to generate the amount of electricity demanded at the lowest cost. If the utility installs baseload generation plants (combined cycle) that will give us a cumulative capacity of approximately 3150 MW, this will be the most efficient technology to use for most of the hours in the year because it is fuel-efficient and hence has a low MOC. The lower MOC over many hours more than compensates for the greater annual capital charge of the CC plants over the next best alternative. All these plants will be running for 6000 hours a year or more.

For operation capacity factors of between 6000 hours and 3000 hours, the single-cycle plants will supply electricity at the lowest annual cost. The total MW of capacity of this size of generation that would be optimal in this case is approximately 3425 MW. The most efficient of these plants (the newest) will be running approximately 6000 hours a year, while the least efficient will be running approximately 3000 hours per year. In this case, with these particular sets of capital and variable costs, if the generation plant is expected to operate for less than 3000 hours a year, the diesel generation technology will have the lowest combined fixed and variable costs for a capacity factor of fewer than 3000 hours per year. To supply all the electricity demanded during these peak demand hours, the utility will need to install at least another 3425 MW of diesel generators.

Screening-curve estimates of the optimal system mix of generating and transmissions investments that will need to be considered for an overall cost benefit analysis of these identified projects. It is useful to identify obvious technology choices or develop a large pool of candidate technology mixes over a range of input assumptions without delay. This analysis is the first step in the development of a least-cost strategic plan of the mix of generation and transmission investments that will need to be made over a period of 20 or 30 years. A screening curve analysis is the first step in the development of a least-cost expansion plan that will identify the approximate least-cost mix of alternative generation technologies. The choice is made from a number of different types of plants with varying levels of capital costs and different running costs (fuel costs). To carry out this analysis three steps need to be followed;

i. Calculate marginal running cost of each plant
ii. Calculate the annual capacity charge for each type of plant
iii. Using the annual capacity charge and the marginal running cost for each type of plant, then calculate the minimum number of hours (H) to run each type of plant so that it would still have a lower cost than the plant that had the next lowest cost to supply (H) hours over a year of generation

Technical considerations alone are not enough for electricity choices; cost is an important factor. It is often less economical to run plants that have high capital costs for a small fraction of the time; in such a mode of operation, technologies with low capital costs but high operating costs have an advantage. Those generating sources that operate for a large fraction of the time, say more than 65%, are called baseload. Those that operate only for short periods, during the hours of peak demand, are called peak sources. There are also technologies that are not at either extreme and are called intermediate sources. Most of the capacity expansion being planned is of the baseload type. However, the main challenge of the current system is in meeting peak demand. Therefore with any expansion that meets this peak shortage, some of the combined capacity (existing and additional) would lie idle for significant fractions of each day. Therefore, adding further baseload capacity is not cost-effective.

7.4. Development of the Investment Sequencing for Least Cost Expansion Plan

Assume that the capacity requirements of the least cost technologies to meet current demand are obtained, this optimal choice could be altered over time. This will happen as the demand for electricity grows over time and on the supply side, the generation plants after being operation will begin the depreciation process. Associated with the wear and tear will be an increase in the running costs of existing installed technologies and at the same time technological advances will reduce the running costs of new plants. Introducing a new, more efficient plant will change the utilization of the existing plants. Hence, the planned sequencing of new investments must take into consideration both the growth in the demand for electricity over time but also must recognize that the generation plants wear out over time and hence need to replace. In such a situation, the benefits of adding a new generation plan that is more efficient will also include fuel savings on the existing electricity load as well as provide additional capacity to meet the growth of electricity demand over time.

Suppose a new technology appears with lower fuel cost. Let us also assume that the marginal running cost of a new plant (#4) is lower at MRC4 per MWh. The question is whether or not we should introduce a new plant now or later.

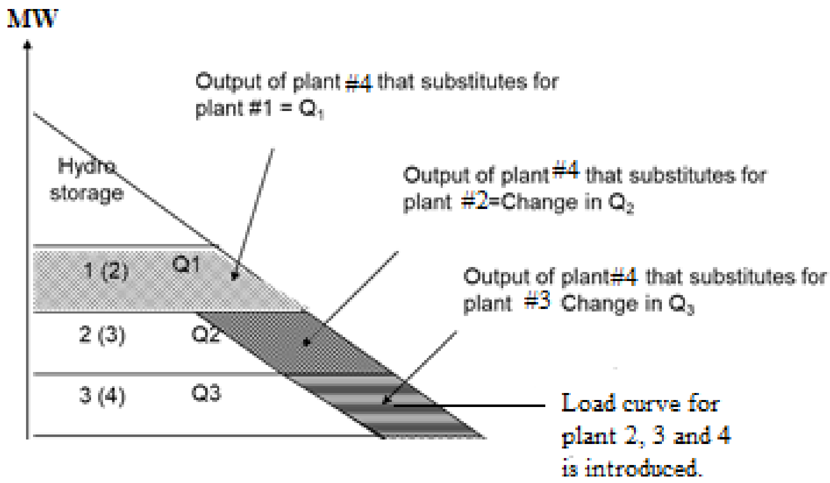

Figure 7. Illustration of the Savings of Running Costs

Figure 7 illustrates the savings in running costs in period (t), assuming the peak demand is supplied by hydro storage generation. If the new plant is built and utilized, we use the most efficient plant first and then use the next most efficient and so on until the demand is fully met. Assuming that plant #4 can be run for 8760 hours. In this case, while the production levels of plants 3 and 2 are reduced by the amount of the capacity of plant 4, the plant 1 (the most inefficient plant) is likely forced out of service. Part of the time, plant 4 is effectively substituting for plant 3, part for plant 2, and all the time for plant 1.

Now the question is how to estimate the benefits of plant #4 that is now operating to compensate for the forgone production of plants 3, 2 and 1. The new plant 4, with MRC4, is used to substitute for part of the other plants that now do not produce as much as previously.

Benefits:

Let Q1, Q2, and Q3 be the amount of electricity previously produced by plants 1 to 3 and let MRC1, MRC2 and MRC3 be the marginal running cost, respectively, of these plants. Hence the first year savings in running costs of introducing the new more efficient plant 4 will be,

$\Delta Q3$* (MRC3- MRC4) plus

$\Delta Q2$* (MRC2- MRC4) plus

$\Delta Q1$*(MRC1- MRC4)

Equals

Total savings in running costs (A)

The value of A represents the benefits of running cost in the first year the plant is in operation. If A is greater than the annual capital charge for plant 4, then plant 4 should be added in period t provided that its net present value is positive over its lifetime.

In general, as our calculations show, the benefits attributable to an investment in new capacity (when there is no growth in overall demand) are the savings in system costs that the new plant makes possible over its lifetime. The investment in the new plant should be undertaken when the present value of the benefits of the new plant (fuel savings and operating costs) over its lifetime are greater than the capital cost of the new plant. The annual benefits of the new plant 4 will change over its lifetime as old plants are retired, and other new efficient plants are introduced into the system.

Development of investment sequencing for least cost expansion planning is a complex optimization task to ensure that the power system will meet the forecasted demand and the reliability criterion, along the planning horizon, while minimizing investment, operation and interruption costs. The main objective is to decide where, when and what transmission reinforcements should be placed in the power network. In order to achieve better results, these decisions must be plainly coordinated with generation and sub-distribution reinforcements.

Energy mix describes the range of particular types of electricity generating units in a power system designed to provide the balance between electricity generation and demand at any time with the lowest cost. The development of the national energy mix is a complex task driven by technical, economic constraints and political decisions. Moreover, the estimation of the energy mix must be considered in the long-term perspective due to inertia in power system investments. Therefore, the achievement of proper energy mix design requires sophisticated tools, majority of which are optimization models.

Traditionally, energy mix is represented in two dimensions; power and energy balance in the power system. Models that take into account power balance, often consider annual peak load, sometimes seasonal ones. The energy balance is represented by a cumulative value of annual electricity generation. However, such an approach does not include important information about short-term power system operation, especially the effect of the rapid development of variable RES (wind turbines and PV panels) on the power system stability and security of electricity supply. There are various approaches to address the issue of variability of RES in the long-term generation expansion planning models. One of them is to measure the flexibility of the power system. However, the application of such an approach requires small time steps (lower than one hour) that leads to maximum calculable time horizon of several years or shorter. The other method is the approach taken in this discussion so far, where the representation of power and energy balance is done by the use of the load duration curve (LDC). Load duration curves are commonly used in optimization models

7.5. Output of the Least-Cost Expansion Plan

The least-cost expansion plan for the electricity sector shall result in a list of proposed electricity generation projects clearly differentiating between dispatchable and non-dispatchable technologies. Thermal technologies such as diesel, closed cycle, combined cycle and coal plants of various sizes do provide generation and system reliability through the supply of dispatchable energy.

Solar generated electricity, and wind electricity generation are not dispatchable; hence, they do not add to the ability of the electric utility to improve the reliability of the overall electricity service. The benefits of these technologies arise primarily through the fuel savings they create due to the displacement of the operations of thermal and hydroelectric generation plants.

The least-cost expansion plan shall also provide investment plans for transmission and distribution. Some of the investments in transmission are generation plant-specific, such as the transmission from a hydro, geothermal, wind, or thermal plants (particularly coal generation plants). These need to be included in the cost of the particular generation option that they are associated with. In addition, investments must be made in the overall transmission system to deliver power to the areas where the clients are located and also to maintain the reliability of the overall electricity service. Distribution investments in lines and transformers must be made to service the customer base as the overall demand for electricity grows in different areas of the country. Special attention must be given to policies toward rural and village electrification that might not be cost-minimizing for the systems plan but are required to meet social and long-term development objectives.