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ECONOMIC ANALYSIS OF POWER PROJECTS: INTEGRATION OF CLIMATE CHANGE AND DISASTER RESILIENCE

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ABBREVIATIONS

BESS	battery energy storage system
CAPEX	capital investment expenditure
CPI	consumer price index
CSPDR	Changjiang Survey, Planning, Design and Research Co. Ltd of Wuhan, China
cumec	cubic meters per second
DSCR	debt service cover ratio
ENEE	Somalia National Electric Corporation
ENS	energy not served
EPC	engineering, procurement, construction (contract)
ERAV	Electricity Regulatory Authority of Vietnam
ERR	economic rate of return
ESP	energy service provider
FIRR	financial internal rate of return
FS	feasibility study
GCM	general circulation model
GDP	Gross Domestic Product
GEA	Guidelines for Economic Analysis of Power Sector Investment Projects (World Bank)
GHG	greenhouse gas
GW	100,000 MW
ICR	Implementation Completion Report (of the World Bank)
IDA	International Development Association
IFI	international financial institution
IHA	International Hydropower Association
IPP	independent power producer
IRR	internal rate of return
LHV	lower heating value
LIBOR	London Inter-Bank Offer Rate (see glossary)
LNG	liquefied natural gas
LRMC	Long-run marginal cost
m/s	meters per second
masl	meters above sea level
MCM	million cubic meters

NEA	Nepal Electricity Authority
NPV	net present value
O&M	operation and maintenance
OCCT	open cycle combustion turbine
OECD	Organization Organisation for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
OPEX	operating expenditure
ORB	OPEC Reference Basket (crude oils)
PAD	Project Appraisal Document (of the World Bank)
PBS	Rural Electrical Associations (Palli Bidyut Samities) of Bangladesh
PPA	power purchase agreement
PPP	purchasing power parity
PV	photovoltaics
RCP	Representative Concentration Pathway
RDM	robust decision making
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCF	standard conversion factor
SHP	small hydropower project
SLF	system load factor
SPPA	standardized power purchase agreement
SPV	special purpose vehicle
T&D	transmission and distribution
ToR	terms of reference
TTL	task team leader (at the World Bank)
UAHEP	Upper Arun Hydroelectric Project
UC	University of Cincinnati
UNFCCC	United Nations Framework Convention on Climate Change
US	United States (of America)
VRE	variable renewable energy
WACC	weighted average cost of capital
WTP	willingness to pay

All currency is in United States dollars (US$, USD), unless otherwise indicated.

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ESMAP is a partnership between the World Bank and 24 partners to help low- and middle-income countries reduce poverty and boost growth through sustainable energy solutions. ESMAP's analytical and advisory services are fully integrated within the World Bank's country financing and policy dialogue in the energy sector. Through the World Bank Group (WBG), ESMAP works to accelerate the energy transition required to achieve Sustainable Development Goal 7 (SDG7) to ensure access to affordable, reliable, sustainable, and modern energy for all. It helps to shape WBG strategies and programs to achieve the WBG Climate Change Action Plan targets.

The GFDRR is a global partnership that helps developing countries better understand and reduce their vulnerability to natural hazards and climate change. GFDRR is a grant-funding mechanism, managed by the World Bank, that supports disaster risk management projects worldwide. Working on the ground with local, national, regional, and international partners, GFDRR provides knowledge, funding, and technical assistance.

The Japan-World Bank Program for Mainstreaming Disaster Risk Management in Developing Countries is a program established by the partnership of Government of Japan and the World Bank to support client countries in enhancing their resilience against climate change and natural disasters. The Program aims to achieve this objective by funding technical assistant (TA) grants, and by connecting Japanese and global expertise and best practices in disaster risk management (DRM) with developing countries and the World Bank team.

KEY MESSAGES

- **Climate change and its hazards will affect not just the economic returns of a project as proposed, but also the *returns of the counterfactual***, which may be exposed to different types and magnitudes of climate change impacts.
- While it is easy to be clear about what constitutes a worthwhile investment on the basis of the expected value of returns (in the case of the World Bank, a non-zero net present value (NPV) at the appropriate discount rate), **there are no standards about what constitutes an acceptable level of risk in project appraisals**. This is true not just of climate-related uncertainties, but also for many other risks that are routinely faced by power system planners that are not covered by specific technical standards (such as n-1 reliability in transmission projects).
- **The dialogue between the project economists and the climate change modeling experts charged with assessing climate change resilience needs to start at the very outset of project appraisal**, preferably at the detailed feasibility study stage of project development, where there is still an opportunity to influence its physical design (and location).
- **Attempts to quantify acute impacts in the form of expected values will generally underestimate the risk to financial returns**.
- **A project that just meets the World Bank requirement that the NPV—including the costs of mitigation and adaptation—be at or slightly above the required performance standard** (ERR > hurdle rate, NPV ≥ 0), nevertheless **will still have a roughly 50 percent chance of economic returns being *below* that rate.**
- **An important question for assessing climate change and hazard resilience is the extent to which physical contingency allowances and design standards based on long-established practice need revision** as climate change results in changes in the frequency and intensity of these hazards.
- **While 100 percent reliability over an asset life can never be attained, an "acceptable" level of intended resilience is a policy and engineering choice** and may be dependent on context and the risk aversion of the decision maker.
- **The interdependent nature of components in a power system means that impacts and mitigation measures do not necessarily relate to the incumbent asset but may occur in other parts of the system** (for example, in the transmission line used for power evacuation rather than the generation project itself).
- **Economic analysis can document the trade-off between climate change risks and return, but the decision itself can only be made by decision makers** on the basis of their appetite for (or aversion to) risk.

The recommended procedure for integrating climate change–related resilience issues into the economic analysis of a project appraisal has the following steps:

- Calculate the economic returns in the absence of additional climate change risks, termed here the *baseline returns*.
- Identify the hazard events of concern; their damage costs if they do occur; and any upfront costs related to capital investment expenditures (CAPEX) or operating expenditures (OPEX) separable as adaptation costs. Add the necessary line items to the table of economic flows and add the relevant impacts for the counterfactual.

- Identify the chronic impacts of concern and add further lines to the table of economic flows to separate out these impacts (e.g., gradual changes in benefits as temperature and precipitation impacts change ambient conditions), and again with corresponding entries for the counterfactual.
- In consultation with the relevant climate change and technical experts, conduct sensitivity analyses to assess the relationship of returns with the timing of both chronic and hazard events.
- In consultation with the relevant climate change experts, set out plausible bounds for changes in hazard and chronic events.
- Frame recommendations to the consultants preparing detailed feasibility studies for consideration of resilience hardening measures in the final design.
- Finalize the summary presentation of the analysis for inclusion in the formal appraisal documents.

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1. INTRODUCTION

The objective of this Good Practice Note is to present a methodology for the integration of climate change and disaster/hazard resilience assessments into the framework of economic analysis as set out in the World Bank's Guidelines for Economic Analysis of Power Sector Investment Projects (GEA 2015). These require that the economic returns for a proposed project be calculated on the basis of economic flows, with returns assessed against a plausible counterfactual. These guidelines also mandate a sensitivity analysis to assess the impact of uncertainty in data assumptions, with calculations of switching values augmented (for large projects) by a quantitative risk assessment (such as Monte Carlo simulation) and a scenario analysis to examine the impact of plausible best and worst cases around the baseline estimate. The extent to which these tools are appropriate for assessing climate change–related risks is examined in Section 3.3.

From the perspective of economic and financial analysis, a climate change resilience assessment can be defined as an elaboration of how an investment project performs under alternative futures that are subject to high uncertainty about climate change impacts, and an assessment of the cost-effectiveness of mitigation and adaptation options to improve a project's resilience. As a matter of general methodology, this is no different to the assessment of other risks and uncertainties routinely faced in project design. The main difference is that the uncertainties are much more difficult to define: the uncertainty about the nature, timing and extent of climate change impacts is much greater than the better-known uncertainties that have long been part of project design and appraisal.

For example, analysis of hydrological uncertainty in a hydropower project has long been part of classical project design: the variance of inflows is readily established by assessment of historical inflow series based on long-established criteria for the necessary length of record. No engineer would design a large hydropower project without at least 20 years of records. But the uncertainty about how this time series will change in consequence of climate change poses new challenges, because modeling site-specific precipitation patterns in climate change scenarios is itself subject to large uncertainty.

Regardless of how it is defined, *resilience* (discussed further in Section 2.1) is therefore an attribute of an investment project that is quite different to its economic efficiency. And as with so much in the real world, there will inevitably arise trade-offs between economic performance and resilience: in most cases, making a project more robust to uncertainty involves incremental costs.

Mitigating against adverse outcomes and reallocation of risks can take many forms—futures hedging, insurance, or changes in project location, design, or operations, as discussed in Section 3.2—but all mitigations involve additional costs (under the assumption that the design in the absence of climate change considerations is least cost). The challenge is that many climate change–related risks are not well characterized, unlike many other uncertainties for which past project implementation experience provides an adequate basis for risk assessment.

1.1 THE TREATMENT OF RISK AND UNCERTAINTY IN WORLD BANK GUIDELINES

World Bank guidelines on economic analysis stipulate that investment projects proposed for Bank financing must demonstrate economic returns at least equal to the applicable hurdle rate (defined as zero NPV at the applicable discount rate), though the discount rate is itself the subject of some controversy, notwithstanding the World Bank's official guidance on the default rate (World Bank, 2016).

Traditionally, the World Bank has avoided the question of the trade-off between risk and return. In its 1998 *Guidebook on Economic Analysis*, it is stated explicitly that *variability of a project's expected NPV around its mean should not carry weight in decisions* (Belli et al. 1998).

Indeed, the official guidelines do not require quantification of the trade-off between the expected *value* of returns and the *riskiness* of returns. They merely require that the significant risks are properly enumerated and assessed (typically summarized in the World Bank Project Appraisal Document [PAD] risk matrix); that the design of the project has, to the extent practical and reasonable, mitigate these risks; and that the project proponent has put in place measures to monitor and redress ongoing operational risks. In other words, the focus is on whether the appraisal has properly enumerated, assessed, and mitigated the risks, and demonstrated that the remaining unmitigated risks do not plausibly endanger the attainment of the economic returns as bounded by the hurdle rate.

But in the modern world of increasing uncertainty, and especially when so many Bank projects involve private sector entities, such a view is no longer appropriate. The best project may not necessarily have the highest NPV; a project that is more robust to uncertainty may have a lower NPV than one with high risk. If one plots expected returns against risk, once one has eliminated any inferior options (i.e., options with lower returns *and* higher risk than other alternatives), only the decision maker can decide where one should be on the trade-off curve.

1.2 THE COUNTERFACTUAL

Climate change and its hazards will affect not just the economic returns of the project as proposed, but also the *returns of the counterfactual*. Indeed, in the cost-benefit analysis (CBA) that is typically applied in World Bank project appraisals, economic benefits are often defined as the avoided costs of the next best alternative in the case of so-called non-incremental projects, in which the output displaces that of an alternative generation project (such as hydropower as an alternative to gas combined cycle). In the case of incremental projects in which output is directed at unsatisfied consumer demand, the relevant metric is consumer's willingness to pay (WTP).

For example, one might make a calculation of the loss of benefits in a regional transmission project due to climate change–induced temperature increases that result in reduction of transmission capacity (Bartos et al. 2016). But that same temperature effect will also affect the counterfactual for which the efficiency of thermal generation and capacity of any alternative transmission project may also decrease (assuming that one of the impacts of the transmission line is to displace thermal generation in inefficient older projects or another transmission project). Thus, the counterfactual may be exposed to quite different types and magnitudes of climate change impacts.

1.3 ALTERNATIVES

Related to the selection of the counterfactual is the broader question of justification of the selected project. This is illustrated by the hierarchy of alternatives routinely used in the environmental and social impact assessment of a major generation project. An excellent example is the environmental impact assessment prepared for the World Bank-financed Trung Son hydropower project in Vietnam, which is used as a case study of procedure in Chapter 5. For example, in the case of a hydropower project:

1. Why generation and not DSM or efficiency improvement in transmission and distribution (T&D)?
2. Why hydropower and not gas or PV?
3. If hydropower, why this particular hydropower?
4. If this particular hydropower, why at this location and not further upstream or downstream?
5. If at this location, why this particular reservoir and project size?

Clearly, the resilience to climate change will vary both in type and in severity, but not all of these questions are answered by a "least-cost plan" power-systems planning model that is often at the center of project justification.

1.4 THE STANDARD SUMMARY PRESENTATION

Table 1.1 shows the standard summary presentation of the economic analysis as required by the GEA. Note the display of the composition of the major components of NPVs, and the common practice of presenting results for scenarios based on plausible best- and worst-case assumptions.

The manner in which this economic analysis, and its summary presentation, should be extended to provide a more explicit consideration of climate change and hazard resilience is the main goal of this report. This is seen as the essential foundation for supporting the World Bank's proposed Resilience Rating System, which provides an approach to assess what measures World Bank projects are taking to increase resilience to climate change and natural hazards (World Bank, 2021).

The system is designed to create incentives for donors and countries to engage in more and better climate adaptation and proactively manage risks. This rating, expressed in letter grades A+ to C, characterizes the confidence in the avoidance of financial, environmental, and social underperformance relative to the expected level. A high rating, for example, will denote higher confidence that the expected rate of return of an investment will be achieved, despite the negative impacts of climate change on the investment. With a low rating, and everything else being equal, the expected rate of return will be reached only where disasters and climate change have no material effects on the investment.

This rating metric does not provide information on whether the project is likely to fail, since the acceptable risk of failure will vary across countries and sectors, but on whether the risk of failure (which can be low or high depending on the cases) is considered and reported so that it is accounted for in the decision to proceed with the project. As a result, a project with a high risk of failure can still be highly rated, provided that this risk is accounted for in the analysis. The project may in fact be attractive despite this risk if the potential returns in more optimistic scenarios are extremely high.

TABLE 1.1: STANDARD SUMMARY PRESENTATION OF ECONOMIC ANALYSIS FOR POWER SECTOR PROJECTS

			SCENARIO			DISCOUNT RATE		
			PESSIMISTIC	**BASELINE**	**OPTIMISTIC**	**6.0%**	**8.0%**	**10.0%**
[1]	ERR	[ ]	11.6%	**18.0%**	23.0%	18.0%	18.0%	18.0%
[2]	ERR with GHG benefit [low SVC]	[ ]	17.2%	**24.0%**	29.3%	24.0%	24.0%	24.0%
[3]	ERR with GHG benefit [high SVC]	[ ]	21.5%	**28.7%**	34.2%	28.7%	28.7%	28.7%
[4]	NPV	[$USm]	76	**160**	227	245	160	102
[5]	NPV with GHG benefits [low SVC]	[$USm]	251	**334**	423	490	334	230
[6]	NPV with GHG benefits [high SVC]	[$USm]	419	**503**	612	725	503	354
[7]	**Composition of NPV**							
[8]	***Costs***							
[9]	Transmission CAPEX	[$USm]	–109	−99	−99	−105	−99	−94
[10]	Transmission OPEX	[$USm]	−11	−10	−10	−14	−10	−8
[11]	Incremental generation cost	[$USm]	−81	−54	−54	−59	−54	−49
[12]	***Benefits***							
[13]	avoided energy costs	[$USm]	241	**262**	330	357	262	198
[14]	avoided CAPEX	[$USm]	36	**61**	61	65	61	56
[15]	**NPV**	**[$USm]**	**76**	**160**	**227**	**245**	**160**	**102**
[16]	Local environmental benefits	[$USm]	0	**0**	0	0	0	0
[17]	Global GHG benefits [low SVC]	[$USm]	175	**175**	196	245	175	128
[18]	NPV incl GHG benefits [low SVC]	[$USm]	251	**334**	423	490	334	230
[19]	GHG benefits [High SVC]	[$USm]	343	**343**	386	480	343	252
[20]	**NPV incl GHG benefits [high SVC]**	**[$USm]**	**419**	**503**	**612**	**725**	**503**	**354**
[21]	Lifetime GHG savings	[10^6t]	12.3	**12.3**	13.7	12.3	12.3	12.3
[22]	average annual reductions	[10^6t]	0.41	**0.41**	0.46	0.41	0.41	0.41

Source: PAD Economic analysis for the 2 × 220 kV Djibouti-Ethiopia interconnection

1.5 SCOPE

This report has the following scope

- **Chapter 2: Basic Concepts and Definitions**: elaborates the concepts required for an understanding of the proposed methodology and procedure; definitions of risk, uncertainty, resilience, adaptation, and their quantification.
- **Chapter 3: The Impacts of Climate Change**: a brief summary of the different types of climate change impacts; should be read together with the *Good Practice Note for Energy Sector Adaptation* that enumerates impacts by project type, with indicative ranges of cost estimate for resilience measures that are needed for the economic analysis.
- **Chapter 4: Methodology**: Outlines the key points of the methodology for the procedure.
- **Chapter 5: Procedure**: sets out the step-by-step procedure by which the standard presentation of economic flows is modified to incorporate additional rows reflecting adaptation and mitigation costs as well as the impact of hazard and chronic climate change effects.
- **Chapter 6: Case Study: The Upper Arun Hydroelectric Project in Nepal**: applies the procedure to a large hydropower project, for which the economic analysis and climate change modeling were combined; demonstrates the importance of early participation of both economist and climate change specialist to ensure climate change resilience issues were reflected in the detailed feasibility study.
- **Chapter 7: Case Study: Photovoltaic Hybridization in Somalia**: applies the procedure to a fragile country where data availability at the appraisal stage was limited.
- **Chapter 8: Case Study: Distribution System Upgrades in Bangladesh**: applies the procedure for analysis of a distribution network that faces high cyclone risk and shows how remedial measures should be analyzed.

Photo credit: Russell Watkins/DFID

2. BASIC CONCEPTS AND DEFINITIONS

2.1 RESILIENCE

With increasing economic losses due to natural disasters, the term “resilience” has come into general usage in discussions of the impacts the climate change. The World Bank Resilience Rating System report (World Bank 2021) quotes the following definition:

> “The capacity of any entity—an individual, community or organization—to prepare for disruption, to recover from shocks and stresses, and to adapt and grow from a disruptive experience.”

The International Hydropower Association (IHA) Climate Resilience Guide (IHA 2019) offers a somewhat longer definition:

> “The capacity of a hydropower project or system to absorb the stresses imposed by climate change and in the process to evolve into greater robustness. Projects planned with resilience as a goal are designed, built, and operated to better handle not only the range of potential climate change and climate-induced natural disasters, but also with contingencies that promote constructive, minimally destructive failure and efficient, rapid adaptation to a less vulnerable future state.”

Recent climate change assessments have used more practical and simpler definitions of resilience. For example, the climate change assessment for the Upper Arun Hydroelectric project (UAHEP) in Nepal (Ray 2020) defined resilience as follows:

> “The climate resilience of the UAHEP project is described by its financial performance subjected to climate conditions during its lifetime.”

2.2 ROBUSTNESS

“Robustness to uncertainty” is another much-used (and related) term that requires more precision. The IHA Climate Resilience Guide (IHA 2019) defines robustness as:

> “Performing reasonably well compared with the alternatives over a wide range of plausible futures.”

This, in our view, is too vague to be useful: both “reasonably well” and “performance” could mean anything—though for economic analysis, performance is described well enough by the expected value of economic returns, and the variation of returns in the expected value by its variance.

In the context of economic and financial analysis, robustness describes the sensitivity of economic returns to uncertain futures. The NPV of an energy efficiency project or of a T&D loss reduction project may vary little across a range of global temperature increases, whereas the NPV of a hydropower project may vary greatly. In such a case, we would say that the T&D loss reduction project is more robust with respect to climate change than the hydropower project.

2.3 STRESS TESTS

“Stress tests” entered the lexicon of financial analysis following the 2008 financial crash. This is a form of scenario analysis in which resilience of an entity to very rare events that have large impacts (sometimes called “black swan” events, as proposed by Nassim Nicholas Taleb (2009) is assessed. The key issue is the difficulty of assessing the probability of such a rare event.

A stress test, as that term is generally understood, sets aside this issue by assuming that a worst-case event actually *does* occur, and then assessing the impact of that event on the cash flows (or economic returns). Once the impact of that event is established, one can test the efficacy of options for mitigating that impact.

The term “stress test” should be avoided where hazard events are translated into expected values of damage cost—which, as we shall see below, says little about the seriousness of impacts once they do in fact occur. That is not to say that expected values of damage costs should not be assessed, only that their elaboration should not be equated to a stress test.

2.4 RISK REGISTERS AND HAZARD QUANTIFICATION

The presentation of risk registers is now a routine part both of detailed feasibility studies and of World Bank appraisals: these serve to enumerate the risks, to describe their potential impact and their mitigation, and assess the severity and likelihood of the remaining risk. They are frequently accompanied by qualitative assessments of likelihood, as shown, for example, in **Table 2.1** extracted from the risk register for the Upper Arun hydropower project.

This invites the following comments on the pitfalls of a qualitative assessment:

- **Impossible to occur** means zero probability: an *impossible* event is surely not a risk.
- **Within a certain period** lacks precision: replace with “within the asset life” if that is what is meant.
- **Frequently** similarly lacks precision. It is not clear whether this means every year, every 2 years, every 5 years, or another period of time. Again, reference to asset life, or to a *return period* (see Table 2.2) is preferable.

TABLE 2.1: QUALITATIVE ASSESSMENTS OF LIKELIHOOD

LEVEL	DESCRIPTOR	DETAILED DESCRIPTION
1	Very Unlikely	Very unlikely to happen, so deemed impossible to occur
2	Unlikely	Not likely to happen within a certain period, but possible to happen
3	Possible	Possible to happen within a certain period
4	Likely	May happen several times within a certain period
5	Very Likely	Happens frequently

Source: UAHEP FS.

TABLE 2.2: PROBABILITY THAT A HAZARD OF GIVEN RETURN PERIOD WILL OCCUR ONCE DURING THE PERIOD OF ITS ASSET LIFE

	ASSET LIFE > (IN YEARS)	20	25	30	40	50
RETURN PERIOD	PROBABILITY					
10	0.1000	0.865	0.918	0.950	0.982	0.993
50	0.0200	0.330	0.393	0.451	0.551	0.632
100	0.0100	0.181	0.221	0.259	0.330	0.393
500	0.0020	0.039	0.049	0.058	0.077	0.095
1,000	0.0010	0.020	0.025	0.030	0.039	0.049
10,000	0.0001	0.002	0.002	0.003	0.004	0.005

Source: Original calculations.

Hazard quantification is a necessary prerequisite for any integration into economic analysis. Return period is a useful quantitative attribute to replace degrees of likelihood. That a hazard of given return period (=1/probability of occurrence) will occur once within a given economic life is often calculated based on the Poisson distribution (available as an Excel function). As shown in Table 2.2, the probability that the 1,000-year flood will occur once in a hydropower project that has an assumed 40-year life is .039 (3.9 percent). However, the probability that it will occur in a given year during its lifetime is lower, namely 0.001 (i.e., 0.1 percent).

However, several further points are important. First, one may assume that the probability that an event with an *n*-year return period occurs in year 1 is the same as the probability in year 5 or year 20. That assumption may be valid if the events are independent of one another. But the *consequences* of the second or third occurrence of the event may be different from the consequences of the first one.

Consider as an example an intense storm that causes a major landslide into a hydropower reservoir. In the first occurrence, early in the lifetime of the project, the released earth mass simply fills *dead storage*, that is, the volume of the reservoir that is below the intake level for hydropower generation, which over the lifetime of a hydropower project is expected to gradually fill up with sediment. This first storm would have no impact on generation benefits. But with the slopes destabilized by the first landslide, a subsequent storm of the same intensity some years later may release an additional debris into the reservoir. This added debris may now fill up part of the *active storage*—the volume of the reservoir at and above the intake level—thus reducing the ability of a project to deliver peaking power and thereby reducing benefits. Such threshold effects are particularly difficult to quantify.

Second, the consequences of hazard events may have implications on other projects; we present actual examples of such events in Chapter 5. Many hydropower projects are constructed in cascades, so damage at one project may also impact an upstream or a downstream project; for instance, loss of regulation due to reductions in active storage at a directly affected project will affect the operation of a downstream project.

Third, the impact of a climate change hazard on a project may be entirely indirect: a storm that has no direct impact on a hydropower project or a photovoltaic (PV) solar farm may still bring down a transmission line upon which its power evacuation depends, with a loss of generation benefits as a consequence.

In short, hazards come at varying intensity, and hazards of more or less well-defined intensity may occur more frequently. The greater the intensity, the greater is the potential impact on the project, and the higher is the likely repair (damage) cost. The methodological approach to quantify these events in CBA is discussed below.

2.5 RISK AND UNCERTAINTY

The literature contains much pedantic discussion about the distinction between risk and uncertainty. Risk is held to apply to input assumptions that can be characterized by well-defined probability distributions (such as hydrology variations in a stationary time series of inflows), whereas uncertainty is held to apply to input assumptions for which a definition of a probability distribution is difficult (such as *when* the average global temperature increases to 1.5°C).

In the climate change assessment literature, one finds various definitions of risk. For example, the IHA guide defines risk as follows:

> Risk is defined for a system or function as the combination of the potential loss and the likelihood of the climate event, such that
>
> $$\textit{risk} = \textit{(opportunity)} = \textit{potential loss (gain)} \times \textit{likelihood}$$

which recognizes that climate change may also have potentially positive impacts (high precipitation implies for hydropower projects higher, not lower generation).

This definition is quite restrictive, as it implies that for a particular hazard (say flood) both loss and likelihood can be readily ascertained. The reality is more complex, because the potential loss is a function both of the magnitude of the hazard and the likelihood of a particular magnitude of hazard. These are often difficult to define; events may lie in the far tail of the probability distribution of hazard magnitude, so the result of multiplying the very small probability of an extreme hazard by what may be an almost infinitely large damage cost (catastrophic dam failure with thousands of lives lost) will be highly unreliable.

This is not avoided by the more generalized definition in Ray and Brown (2019):

Eq [1]

$$Risk = \sum_{i=1}^{\text{all future states}} Prob_i \times Impact_i$$

for which under this definition, “risk” has the units of $, and is really an expected value of the monetary loss expected from the hazard in question. This formulation ignores threshold and non-linear effects: a dam may suffer little damage to seismic events below some threshold intensity (say some value on the Richter Scale) but suffer catastrophic damage beyond that value.

Two distributions require consideration: the distribution of the magnitudes of the impacts (for example the severity of a wind speed event), and the distribution of damage costs (which may vary for a given wind speed event dependent upon site conditions; see the Bangladesh case study of Chapter 8).

However, such expected value calculations for extreme hazard events may result in little change on the NPV of a project (at typical discount rates that lie in the 5 percent to 12 percent range, as illustrated in the case studies). The actual resilience of the system can only be assessed by evaluating the damages if they do occur—which is what is really meant by a stress test.

Both of these definitions of risk suffer from the aggregation problem: summing an impact in year 20 and an impact in year 5 to arrive at a "total" measure of risk is critically dependent on the discount rate. A given event (and its damage cost) that occurs in year 5 will have a much greater impact on economic returns than one that occurs 20 years hence. This is a further reason for assessment within a rigorous CBA framework that requires an explicit definition of the discount rate. Quite obviously, different discount rates may result in different valuations of risk and different investment decisions, for which reason the World Bank Guidelines require a sensitivity analysis to a *range* of discount rates. Under these new guidelines for World Bank projects, the default rate is twice the expected per capita income growth rate. In a few countries, this discount rate approaches the 10 percent rate often applied in CBA without much rigor. The issues of discount rate selection are discussed at length in GEA, Technical Note 8.

Now to lower risk, for instance in the case of a transmission line project, one can respond in several ways: (1) lower the probability of state *i* (that is, move a transmission line to a route less likely to be affected by storms); (2) build stronger towers so that if an event does occur, the damage costs are either smaller or the damage threshold (that is, how strong a storm must be for damage to occur) is higher; or (3) change the technology (underground rather than overhead, as will be illustrated in the case study of Section 8). All of these responses imply incremental costs; the avoidance of the damages caused by hazard events define the benefits.

This suggests how the table of economic flows needs to be modified to accommodate such risk accounting, with additions of:

- a row to record incremental upfront CAPEX (of the alternative transmission line routing, or of stronger towers)
- a row to record the repair/damage costs if the hazard does occur; in the absence of specific information, we can use the comprehensive list of hazards and their mitigation/adaptation costs in Annex 4 of the Good Practice Note for Energy Sector Adaptation (World Bank 2019).
- a row to show the loss of benefits (while the line is being repaired)

Transparency requires that these be separately identified, and not just included in the usual lines for CAPEX and OPEX.

2.6 ADAPTATION COSTS

Adaptation costs, defined as incremental costs expended to improve resilience, take several forms. At the project level these are of two main types:

- Additional CAPEX, typically to upgrade or otherwise harden structures and equipment against increased frequency or severity of climate change caused hazard events
- Additional OPEX, that may sometimes avoid additional CAPEX—a good example of which in distribution systems would be to prune trees on a regular basis before the monsoonal storms, likely to be much cheaper than repairs after the fact (or mitigating the impact by under-grounding)

But adaptation costs may also arise at the system level, which could include a range of measures that might involve different project locations, or selection of an entirely different technology that may be more robust to given risks than the project being proposed (though that alternative may be subject to different types of climate change risk). This will be discussed further in Section 3.2.

Such higher-level alternatives necessarily require resilience and adaptation measures be assessed not merely at the project level (say in the context of a World Bank project appraisal), but at the power system planning level, and in the case of hydropower projects, at the river basin level as well: measures to prevent overtopping at one project will reduce downstream risk—which is why Disaster Risk Management plans for hydropower are now being conducted at the cascade/river basin level.

Being explicit about adaptation costs is an important part of the dialogue with the project proponent—and whatever these may be, must be entered as distinct elements in the table of economic flows. Given the availability of climate finance expressly earmarked for adaptation measures, this has the additional benefit of facilitating the application for such finance.

3. THE IMPACTS OF CLIMATE CHANGE

3.1 CLIMATE CHANGE AND DISASTER RESILIENCE

Climate change and related disasters may encompass a broad range of events including but not limited to (Ebinger & Vergara 2011):

- Increasing air and water temperatures
- Changing (and uncertain) precipitation patterns at seasonal, decadal, and multi-decadal levels
- Changes in river flows affecting hydropower projects (due to changes in glacial melting and precipitation)
- Increasing intensity and frequency of heat waves, storm events, and flooding
- Increasing wildfires
- Sea-level rise
- Changes in wind patterns and intensity
- Interactions with air pollution, clouds, and air moisture, affecting solar insolation

These climate change–related stressors could affect power sector projects in different ways:

- **Transmission and distribution systems:** Susceptible to extreme weather events and climate change
- **Wind and solar power generation:** Changes in wind patterns (climate change impact on inter- and intra-annual variability and geographical distribution of wind) and reduced insolation (due to increased cloudiness) can impact resource availability
- **Thermal power generation:** affected by increased air temperature that would reduce thermal conversion efficiency, and an increased demand for cooling water (that itself may have higher temperature)
- **Hydropower:** Hydropower operation and even viability of new projects in certain parts of the world (notably in the Amazon Basin) require more careful consideration of climate change–induced variability (Schaeffer et al. 2013).

The World Bank *Good Practice Note for Energy Sector Adaptation* sets out in its Annex 4 a comprehensive list of impacts, organized by type of power sector project (**Table 3.1**), listing typical adaptation and mitigation measures and representative costs for each impact. These often show large ranges that need to be assessed on the basis of site-specific conditions (World Bank 2019).

TABLE 3.1: CLIMATE ADAPTATION COSTS BY TYPE OF ASSET, HAZARD, POWER PROJECT

ASSET	CLIMATE HAZARD	ADAPTATION MEASURE	IMPACTS ADDRESSED	TYPE	GENERAL RANGE OR EXAMPLE OF COST
Substation	Extreme heat	Build additional distribution substations and/or capacity to address increased load demand and increase resilience to efficiency losses	Distribution capacity and efficiency reductions	Structural	$3,000,000 to $5,000,000
Substation	Extreme heat	Install cooling and heat tolerant technologies and materials	Distribution infrastructure damage	Structural	As high as 3.6 times more than standard design materials
Substation	Extreme precipitation, Sea level rise and storm surge	Build levees, flood walls, and moats to reduce damage from flooding and pair with pumping systems	Distribution infrastructure damage	Structural	Reinforced floodwalls = $200,000/mi
					New flood walls = $$4,000,000/mi
Substation	Extreme precipitation, Sea level rise and storm surge	Elevate critical inbuilding components and systems above anticipated flooding levels	Distribution infrastructure damage	Structural	>#=$800,00 to >$5,000,000 to elevate

Source: World Bank 2019.

3.2 DIRECT AND INDIRECT IMPACTS

Climate change and disaster impacts on the power sector can be direct or indirect. Direct impacts represent those that disrupt power supply through component performance and efficiency reductions (e.g., de-rating of transmission/distribution lines and generator capacity due to a heat wave) and indirect impacts are those that are facilitated by climate hazards (e.g., increase in electricity demand for cooling). These impacts often occur in cascade, leading to compounding downstream impacts for customers and interconnected sectors. It is important that both direct and indirect impacts on the incumbent project and the counterfactual are fully considered in the economic analysis.

A good example of the complexity of direct and indirect effects is the Western Balkans, which depend on hydroelectric sources for at least one-fifth of their electricity production. Reductions in electricity production due to reduced river flow (the direct impact) would be concurrent with an increase in cooling demand (indirect effect), which is projected to increase by about 50 percent in a 4°C world (World Bank, 2014). The impact on the table of economic flows for a hydropower project follows as:

- Lower generation leading to lower benefits
- Higher value of incremental generation as WTP for air conditioning increases

Resilience measures and related investments fall into four main categories:

a. **harden the infrastructure** (e.g., change the conductor to one that can withstand higher temperatures)

b. **retreat/redesign** (e.g., find an alternative route for the transmission line)

c. **manage** (e.g., reduce loading on the line or increase the loading of lines along a parallel route (if available); reduce load at the customer end through demand response measures), and

d. **monitor** (e.g., install sensors on the line/towers to do real-time measurement of temperature and loading on the line).

All four of these measures have benefits in terms of reduced outage and/or efficiency and increased capacity of the incumbent asset. But resilience measures in all four forms entail additional investments. Thus, economic analysis of resilience can be integrated into a conventional CBA framework wherein the incremental benefits of resilience in monetary terms over the lifetime of the asset are compared against the (upfront) investments needed to build resilience.

3.3 CHRONIC AND ACUTE IMPACTS

The Good Practice Note for Energy Sector Adaptation (World Bank 2019) makes the useful distinction between *chronic* and *acute* changes. The increases in temperature or change to precipitation caused by climate change will be gradual (even in catastrophic climate change scenarios), generally felt at the timescale of decades, and hence termed *chronic*. These changes require gradual adjustment in assumptions over the lifetime of the project and are relatively easy to incorporate into the table of economic flows (and the supporting energy balance tables)—and indeed in the particular case of hydropower projects, have long been part of the economic analysis presented in PADs. When the PAD for Vietnam's Trung Son hydropower project was prepared in 2010, for instance, such assumptions were based on the estimates of changes in precipitation forecast by a Ministry of Natural Resources and Environment climate change assessment.

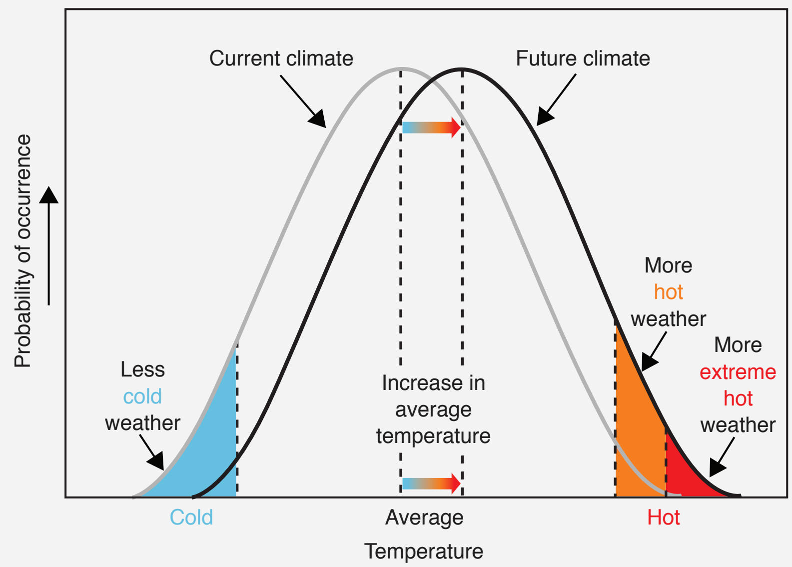
For example, general regional temperature increases will increase evaporation from hydropower storage reservoirs, the impact over time of which is captured in the water balance equations in reservoir operation simulation models (and for which the necessary data is readily available). Many other terms more difficult to estimate will also affect the water balance equations, such as losses for seepage and infiltration, which are mostly either ignored or based on rules of thumb dependent on the geotechnical conditions at site.

Integrating *acute* hazards into economic analysis is more difficult. Superimposed on the gradual temperature change will be extreme heat days; superimposed on changes in regional precipitation will be storm events that may increase in number and intensity even if total annual rainfall does not change. Critical to economic returns is *when* such hazards occur. It matters greatly to the economic returns whether an event occurs in the first or the 10th year of operation (as it does for the financial analysis, where the question will be whether the events occur during or after the debt service repayment period). As will be demonstrated below, attempts to quantify acute impacts in the form of expected values will underestimate the risk to financial returns.

Some climate change impacts have both acute and chronic effects. **Figure 3.1** shows the shift in the probability density function of ambient temperatures. Global warming will shift this curve to the right, which gives rise to the *chronic* impact (increase in average ambient temperature); what happens to the extremes gives rise to the *acute* impacts (increases the days with extreme heat). The curve may also change shape, and the temperature range may widen.

This also illustrates the potential *benefits* of climate change: warmer autumn temperatures that last longer into the winter months, and lower winter temperatures mean lower heating bills in turn reducing green-house gas emissions where this is supplied by fossil energy.

FIGURE 3.1: CHANGES IN TEMPERATURE DISTRIBUTIONS



Source: World Bank calculations.

4. METHODOLOGY

The application of cost-benefit analysis (CBA) to climate change resilience is complicated by several factors:

a. There is **no unanimously agreed-upon definition of resilience** to inform the standard that the asset is expected to meet.

b. The interdependent nature of components in a power system means that **impacts and mitigation measures do not necessarily relate to the incumbent asset but may occur in other parts of the system** (for example, in the transmission line used for power evacuation rather than the generation project itself).

c. The interdependent nature of components in a power system suggests that **the resilience measures do not necessarily relate to the incumbent asset and may occur in other parts of the system** (for example, an alternative route for transmission or demand reduction).

d. The **intrinsically uncertain nature of the disaster/hazard events calls for a methodology that can adequately model such uncertainties and can be backed by necessary data and models** (Chattopadhyay et al. 2016). Indeed, one of the problems (as noted in Chapter 5) is that the climate change scenario modelers are themselves very cautious in forecasting climate change impacts at the scale required for project level assessment, and even more reluctant to judge *when* such scenarios might occur. The clarification of these complicating factors is the objective of this note. It becomes that much more important to involve the project economist and the climate change modelers at the earliest possible stage in project design—*before* crucial design decisions have been made by those preparing the detailed feasibility study (FS), which has long been an issue.

4.1 RISK AS AN ATTRIBUTE

The fundamental challenge is that, while it is easy to be clear about what constitutes a worthwhile investment on the basis of the expected value of returns (in the case of the World Bank, a non-zero NPV at the appropriate discount rate), **there are no standards in Bank appraisals about what constitutes an acceptable level of risk.** This is true not just of climate-related uncertainties but for many other risks that are routinely faced by power system planners that are not covered by specific technical standards (such as on the largest generator in a system of given size, or the n-1 criteria in transmission planning). In other words, there are no standards that would require a project to have a probability of failure to meet the hurdle rate of, say, less than 25 percent or 10 percent. Indeed, as noted above, a project that has an ERR of 10 percent that meets a 10% hurdle rate may well still have a roughly 50 percent chance of *not* being met. Whether a 50 percent chance of failure is acceptable is a policy decision; economic analysis can only quantify the probabilities of failure.

It is not universally agreed that climate change risks need to be treated as a separable attribute. However, it is the recommendation of this report that the impact of these risk—as quantified in climate risk assessments—be included as separate line items in the table of economic flows.

In power systems planning, how quickly a system returns to acceptable performance after a failure event has long been a preoccupation of engineers, and indices that measure reliability (SAIDI, SAIFI) have come into increasing use to characterize reliability performance of power systems. While 100 percent reliability over an asset life can never be attained, an "acceptable" level of intended resilience is a policy and engineering choice and may be dependent on context.

In power system generation expansion planning, one deals with the problem of generation outage resilience by stipulating a loss of load probability—typically set on the basis of hours of outage per year, with the amount of spinning reserve dictated by adequacy to cover the forced outage of the largest single generator. Similarly, in transmission planning interconnectors are designed for n – 1 reliability.

However, little guidance is available to determine if the level of reliability should be n, n – 1, n – 2, or n–3. Governments and regulators may set targets that utilities then try to achieve, but whatever level of risk may be chosen (say, n–1), there remains the probability that the n – 2 event occurs—possibly with high costs to consumers. After a short public outcry immediately following, the realization inevitably sets in that n–2 reliability is simply too expensive. In short, one cannot avoid the trade-off between risk and cost. **Economic analysis can document the trade-off, but the decision itself can only be made by decision makers on the basis of their appetite for (or aversion to) risk.**

BOX 4.1: ILLUSTRATIVE EXAMPLES

The widespread blackout that occurred in the United Kingdom (UK) on August 10, 2019, exemplifies the n–2 event. A lightning strike on a 400 kV line caused a routine fault, with 150 MW of distributed generation disconnected automatically. The voltage control system at the UK's largest offshore wind farm did not respond as expected, became unstable, and deloaded from 799 MW to 62 MW. Shortly thereafter, the gas steam cycle Little Barford project (244 MW) disconnected from the system: within 1 second of the 400 kV fault, the system lost 1,130 MW. The biggest impact was experienced by the Thameslink railway system with 29 trains stranded and requiring emergency passenger evacuation.

The Regulator's final report was issued in early January 2020, with the usual recommendations that procedures and standards would be reviewed, and penalties assessed (Ofgem 2020). That review remains yet to be published; the key will be to determine whether the failures were primarily a consequence of shortcomings in the control equipment and procedures, or whether the reliability standards themselves should be modified.

A similar event occurred in Jordan on May 21, 2021, when the Jordanian power system suffered a 5-hour system-wide blackout during the afternoon hours. The cause was attributed to large voltage fluctuations in the Egypt-Jordan interconnection, at a time when the penetration of renewables in Jordan was high, and the system had lack of inertia. Explanations in press reports ranged from "experimental loading of electricity at the Attar substation, leading to frequency differences and automatic shutdown of all power station" to "large bird standing on network line" (MEE 2021); an official report on the incident has not yet been made public. Whatever its immediate cause, the duration was prolonged by problems in black start capability in Jordan—the point being that a mitigation measure must not just be provided, but also monitored, maintained, and tested.

Several lessons can be drawn from these examples relevant to resilience-hardening issues in World Bank investment projects:

- Whatever standards of resilience as may be set, there will inevitably occur an event that lies outside that standard. A system designed for n–1 will inevitably experience a n–2 event. In other words, events judged to be low probability still remain very real possibilities, with significant costs if (or when) they occur. The question then is whether society is willing to pay the additional cost necessary to improve resilience - decisions which in many countries is passed to regulators who determine the standard to be met by the TSO, and whose (allowable) costs can then be passed to consumers.
- The more reliable the system, the greater the impact of an outage when it does occur. The UK grid is normally so reliable that few customers bother with their own backup systems; on average, UK electricity consumers experience one interruption (from all causes) per year. In many developing countries, customers deal with poor grid reliability by installing their own backup generators (also true for remote rural areas in developed countries).
- As climate change results in more frequent and more intense thunderstorms, the associated increase in lightning strikes poses an increased risk to power systems resilience.
- Where potential vulnerabilities are identified, ongoing climate risk management plans are an integral part of improving resilience: the incremental costs of such plans will often be far smaller than damage costs when hazard events occur. Recall the example of Section 2.3 with respect to tree pruning prior to an expected storm rather than repairing the damage once it occurs.

In the case of hydropower projects, hydrology risk is well understood to mean the natural variation in hydropower project inflows. There will be wet years and dry years. That is an outcome of nature about which the designers of a project can do little—except build a dam so large as to provide multi-year storage, which is rarely possible as practical mitigation. The range of reservoir (and above all, active storage) capacity in mountainous areas is often highly constrained not merely by site-related factors, but also by cascade considerations (avoiding levels that extend into the tail water of the next project upstream) and political constraints (reservoir cannot extend into the territory of an upstream country). In the case of mainstream dams further downstream, where heads are lower, larger reservoirs often imply larger areas to be inundated, resulting in unacceptable impacts on resettlement as well as other resources. For example, the larger the reservoir, the lower average velocities through the reservoir, and the greater the impact on anadromous fisheries that require downstream passage of larvae dependent on natural flow speeds.

In short, hydrology risk is difficult to mitigate at the project level: the key lies in careful examination of watershed precipitation and inflow trends (see Box 6.1 for further discussion). The most obvious mitigant is to increase storage, but as noted, this is often highly constrained by site conditions. Whether there are system-level mitigants also deserves investigation: in large countries, spatial diversity of projects may be possible, or technological diversity within a renewable energy portfolio (in many contexts, hydropower plus wind provides good smoothing of seasonal variations).

4.2 THE TRADE-OFF BETWEEN RISK AND RETURN

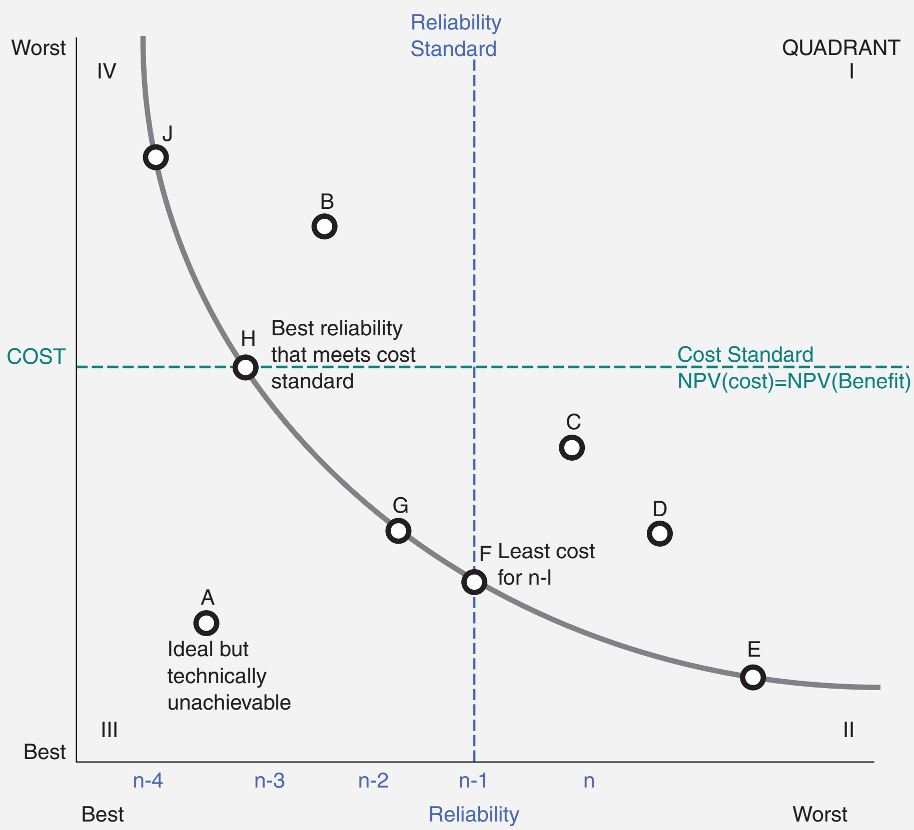
It should be clear that, as in most of the real world, there is a trade-off between risk and return of an investment project just as there is a trade-off between risk and return in a portfolio of financial assets. Alternatives with high returns (junk bonds) tend to have higher risk than alternatives with low returns (U.S. Treasury bonds). The two attributes are separable and may be displayed in a trade-off chart.

Figure 4.1 shows cost (NPV) on the y-axis, and the reliability metric on the x-axis. The performance standard for cost is that its NPV must be less than or equal to the NPV of benefits. The performance standard for reliability in this chart is set at n – 1: reliability at n does not meet this standard. Only the options in quadrant III meet both cost and performance standards.

The plot shows several solutions:

- **A** is ideal (low cost, high reliability) but infeasible. All solutions below the trade-off curve are infeasible: the trade-off curve represents that set of feasible alternatives closest to the origin.
- Options **B**, **C**, and **D** are feasible, but would never be selected because other options perform better on both cost and reliability criteria. Thus, option **D** would never be selected because option **F** does better on both cost and reliability. **D** is said to be "dominated" by **F**. **B** and **C** are also dominated.
- The trade-off curve (**E**, **F**, **G**, **H**, and **J**) is the set of options that are non-dominated. Options closer to the origin, below the trade-off curve (zero cost, infinitely reliable) are technically infeasible. But only options **F**, **G**, and **H** meet both standards.

FIGURE 4.1: COST VS. RESILIENCE TRADE-OFF



Source: Original calculations.

But which of the options that lie on the trade-off curve in quadrant III (i.e., that meet both performance standards), does one select?

- **B** is optimal for a decision maker who weighs cost more than reliability—that is, seeks the least-cost option that meets the reliability standard (here at n – 1).
- **H** would be chosen for a decision maker who weighs reliability more than cost, as this option has the highest reliability that still meets the cost standard.
- The relative weights that a decision maker would give to cost, and reliability determines which option on the trade-off curve that meets both standards. Moving from n-1 to n-2 reliability would increase the cost.

It is the purpose of the economic and financial analysis to present to the decision maker the trade-off curve. **But only the decision maker can decide among F, G, and H**. That applies to whatever reliability context is applicable. How much climate resilience is to be provided will always be a matter of trade-offs.

4.3 A FRAMEWORK FOR DECISION-MAKING

A formal decision analysis may also be useful as a tool for assessing the impact of alternative projects or design decisions. **Table 4.1** shows the choice among alternatives (the rows) as a function of their NPVs under different climate change futures.

Which project is more robust (i.e., less sensitive to which future actually comes to pass)? The variation in NPV between the best and the worst future for project A is 60, but only 20 for project B. We would say B is more robust—but that robustness comes at the price of foregoing the opportunity for the much higher return in the optimistic future, as the best return for A is 50, whereas the best for B is 30.

A variety of decision rules can be considered. A risk-averse decision maker would choose that option with the least bad outcome—so Project A, in which the worst outcome is an NPV of 10. This would be independent of the probabilities as may be assigned to the different climate change futures.

A risk-neutral decision maker would choose that project for which the expected value is maximized—thus, as shown in **Table 4.2**, would choose project A. One would then evaluate at what probability of the occurrence of the pessimistic scenario the design would change.

TABLE 4.1: CONVENTIONAL DECISION-ANALYSIS FRAMEWORK: NET PRESENT VALUES (CHOOSE OPTION WITH THE BEST WORST OUTCOME)

	CLIMATE CHANGE		
ACTIONS (I, 1. N)	1. OPTIMISTIC (SAY 1.5°C)	2. BASELINE (SAY 2°C)	3. PESSIMISTIC (SAY 2.5°C)
1. Project A	60	25	–10
2. Project B	30	20	10

Source: Original calculations.

TABLE 4.2: EXPECTED VALUES: (DECISION RULE: MAXIMIZE EXPECTED VALUE)

ACTIONS (I, 1..N)	CLIMATE CHANGE 1. OPTIMISTIC (SAY 1.5°C)	2. BASELINE (SAY 2°C)	3. PESSIMISTIC (SAY 2.5°C)	EXPECTED VALUE
Probability of future >	0.333	0.0333	0.333	
1. Project A	60	25	–10	25
2. Project B	30	20	10	20

Source: Original calculations.

A further decision rule would be based on "regrets"—which is the difference between the best result for any future and the result for each project option (**Table 4.3**). The decision criterion would be to take that option with the lowest of the maximum regret ("minimax" criterion).

This approach has been used in a wide variety of World Bank projects, including in the FS for the Upper Arun Hydropower project (select installed capacity as a function of uncertainty in generation attributable to possible climate change and value in export markets) and in the study of renewable energy options in Serbia (optimal renewables penetration given uncertainty in variable renewable energy (VRE) costs, damage costs of thermal projects, and whether or not coal would be banned). This approach is noted in the IHA Climate Change Resilience Guide and is fundamental to so-called robust decision-making (see Box 4.1).

TABLE 4.3: REGRETS: (DECISION RULE: MINIMUM OF MAXIMUM REGRETS, "MINIMAX")

ACTIONS (I, 1..N)	CLIMATE CHANGE 1. OPTIMISTIC (SAY 1.5°C)	2. BASELINE (SAY 2°C)	3. PESSIMISTIC (SAY 2.5°C)	MAXIMUM REGRET
1. Project A	0	0	20	20
2. Project B	30	5	0	30

Source: Original calculations.

4.4 MITIGATION AND ALLOCATION OF RISKS

It is a generally accepted proposition that the optimal allocation of risk is one that assigns unmitigated risk to the party best placed to absorb that risk, but that recognizes that parties who cannot themselves control a risk will be reluctant to absorb it. For example, a thermal generation independent power producer (IPP) who has no control over the price of fuel would rarely find it acceptable to assume fuel price risk. But at the same time, the power purchase agreement (PPA) should provide incentives for maximizing the efficiency of fuel use, typically provided by PPA incentive clauses that provide for some sharing of the benefits of better than agreed normative fuel efficiency. For this reason, a thermal IPP PPA will have very detailed clauses on how the IPP will be compensated for dispatch decisions made by the national dispatch center, to account for lower efficiency associated with black and warms starts and part-load operation.

It is important to distinguish between a risk ***mitigation*** **measure, and a risk** ***allocation*** **measure.** Domestic fire insurance is an instructive example: the insurance policy *allocates* the risk of damage to the insurance company. But the risk itself is *mitigated* by the installation of smoke alarms or the use of more fire-proof materials in furniture and fixtures (both can be defined as adaptation costs cost) or by not smoking in bed (a change in behavior). Most of these involve incremental costs (the cost of the insurance policy, or the cost of the smoke alarm or fireproof materials).

Risk allocation methods are many:

- **Commercial insurance policies** (now available also for wind speeds [Munich RE n.d.])
- **Self-insurance** available to a public sector entity with numerous projects (many Indian states have numerous irrigation and power sector dams, and claim to self-insure—though availability of commercial insurance would be unlikely)
- **Power purchase agreements** that expressly allocate risks between buyer and seller (e.g., in thermal generation projects, fuel price uncertainty is often allocated to the buyer)
- **Futures hedging** is applicable to thermal generation projects for management of fuel cost risk.

Insurance

The extent to which insurance costs constitute economic costs is controversial. Although this appears to be a transfer payment, and indeed some authorities insist it be categorized as such (as does the U.S. Office of Management and Budget), in World Bank practice, it is held that insurance represents a sharing of the real economic damage cost of hazard events and should therefore be included in the economic accounts (Gittinger, 1982). Certainly, in both economic and financial analysis, insurance costs should carry their own line items under OPEX in the table of economic flows and in project financials.

Power Purchase Agreements

For most power generation projects (and especially those with private equity or commercial finance) power purchase agreements (PPAs) are the principal tool for reallocating risks to the buyer. For example, the Upper Arun hydropower project in Nepal will likely generate power in the wet season that cannot be absorbed by domestic demand; the PPA between the project special purpose vehicle (SPV) and the government-owned utility Nepal Electric Authority (NEA) shifts the risk of being unable to export the electricity to India or Bangladesh to the NEA, which in turn passes the risk to the government and consumers (since the shortfall in expected revenue requires either a tariff increase, or a subsidy bail-out from the Government)—but the risk itself remains.

Now the Government of Nepal could seek to pass some or all of this risk to others by entering into an off-take agreement with potential importers in advance of construction, with stipulations of minimum off-take quantities on the importer (take or pay), or penalties on the exports for failure to deliver (deliver or pay). This may rarely be achievable in practice, if for no other reason than that in drought years, the exporter simply has no ability to deliver. This is one reason why a signed PPA between an IPP and the off-taker is the main precedent condition for financial closure of an IPP project.

4.5 QUANTITATIVE RISK ASSESSMENT: CURRENT PRACTICE

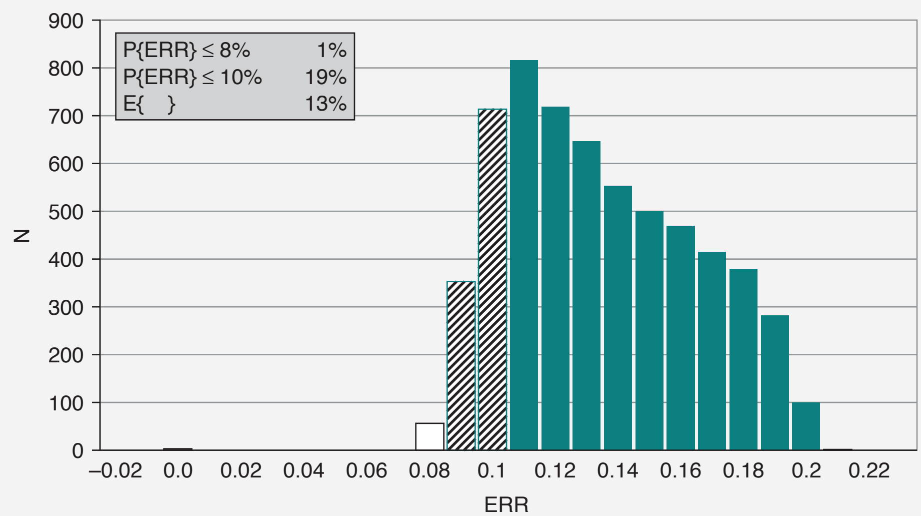
The usual main uncertainties of hydropower projects—notably construction delays, CAPEX overruns, hydrology uncertainty, and uncertainty in future fossil fuel prices (that determine the avoided costs of thermal generation typically used as a large hydropower counterfactual) have long been used to assess project risks at appraisal. In the Trung Son PAD, these risks were assessed by:

- Calculation of switching values
- Scenario analysis (stress tests for different futures)
- Quantitative risk assessment using Monte Carlo simulation

Monte Carlo Simulation

The results of a typical Monte Carlo simulation are shown in Figure 4.2. The risk of CAPEX escalation is asymmetric—cost overruns are much more likely than cost underruns (in this calculation, the range of uncertainty is from 90 percent to 200 percent of the baseline estimate), and therefore the expected value the risk adjusted returns (13 percent) is significantly lower than the conventional baseline estimate (19.4 percent), where each variable is estimated by engineers at their "most likely" value.

FIGURE 4.2: BASELINE MONTE CARLO SIMULATION



Source: Original calculations.

The key point here is that “baseline” calculations are typically prepared by engineers, who will estimate the most probable value for each main assumption (or, where costs are concerned, hedge with some rule of thumb on an appropriate physical contingency allowance). In effect, this is the **mode**, and the ERR of the “baseline” ERR, as would normally be reported in the economic and financial analysis summary in the main text of a PAD, is therefore based on **modes**. But most risk profiles will be asymmetric (cost overrun around appraisal estimates are more likely than cost underruns), so the ***expected value*** of the ERR probability distribution will differ from the baseline (the ***mode***).

The risk of this project failing to meet the 10 percent hurdle rate is calculated at 19 percent, equal to the area under the curve to the left of 10 percent, which falls to 1 percent at the lower hurdle rate of 8 percent. **Note that a project that just meets the hurdle rate nevertheless has a substantial chance of failure**. This point is frequently forgotten when task teams ask questions such as, “If the physical contingency rate is increased, and CAPEX goes up by 50 percent, do we still meet the hurdle rate?” or “By how much can CAPEX increase for the ERR to still just meet the hurdle rate?” These questions are answered by standard calculations of switching value, but the point remains: a project that just meets the hurdle rate has a roughly 50 percent chance of *not* meeting that rate.

Other caveats concerning the limitations of such assessments may be noted:

- Care is needed where input variables are correlated—for example, CAPEX and years of delay often are not independent.
- Definitions of continuous probability density functions are not always possible or reasonable but can be replaced by discrete values or inter variables (e.g., representing different reliability levels for n, n-1, n-2, etc.)
- Monte Carlo assessments may need to be embedded into alternative decision-making frameworks such as so-called robust decision-making (Box 4.2).

Scenario Assessment: Plausible Worst Cases

Quite apart from climate change risks, the definition of plausible worst cases in hydropower project risk assessment is becoming more widely used in FS for major projects—and with explicit monetization of the relevant risks. An excellent example is the geotechnical risk assessment conducted for the Upper Arun hydropower project, that not only describes the details of risk mitigation, but sets out detailed incremental cost estimates for each project component (**Table 4.4**).

The resulting impacts on ERR and NPV could then be assessed (**Table 4.5**). As in the project’s climate change assessment, no quantitative estimates of probability for these scenarios were provided, except that “the worst and extreme cases are very unlikely to happen.”

That reluctance in the FS notwithstanding, in the World Bank’s subsequent project appraisal, these bounds of incremental construction delay and cost increases were then included as variables in the quantitative risk assessment.

The plausible bounds of uncertainty will narrow in the course of project preparation. The Mpatamanga project in Malawi is a good example. The first detailed FS of 2017 estimated the overnight capital cost at $527 million; two years later, after careful due diligence of the IPP’s consulting engineers, the capital cost had risen to $874 million (a multiplier of 1.56). An analysis conducted today would not have the same range of plausible CAPEX uncertainty as in 2017.

BOX 4.2: ROBUST DECISION-MAKING

The "predict-then-act" paradigm that underpins traditional CBA becomes increasingly problematic as the degree of uncertainty increases. This is particularly the case for so-called "deep" uncertainty, characterized not just by disagreements over the likelihood of alternative futures, but also about how actions are related to consequences (different models yield different results, characteristic for example of the climate change debate), and by disagreements about objectives. The presumption in CBA is that all the stakeholders agree that decisions be made on the basis of NPV (i.e., benefits > costs), yet even among those prepared to accept maximizing NPV as the main objective, there may remain disagreement about the discount rate.

Traditional CBA: "Predict Then Act"

The difficulties with this approach for power sector investment decisions in, for instance, a fragile country like Somalia (see Chapter 7) are obvious: forecasting what the security situation will be in 5 to 10 years' time is virtually impossible. The so-called robust decision making (RDM) approach turns this around, using instead an approach based on "agreeing on decisions." This approach was originally proposed by the RAND Corporation to inform policy choices under deep uncertainty and complexity.

Agree on Decisions

In other words, given a forecast about the future, the approach does not ask what the best investment decision is and how sensitive that decision is to the assumed forecast; instead, RDM looks at a given set of decisions (or strategies) and asks which strategy is the most robust to an uncertain future, and what can be done to reduce vulnerability. Computationally, RDM tests the performance of a set of alternative strategies for a very large number of alternative futures—and then asks which strategies are the most vulnerable, and which are the most robust, and then attempts to adapt the strategy to improve its robustness.

Sources: Hallegatte et al. 2012; Bonzanigo & Kalra 2014.

TABLE 4.4: INCREMENTAL COSTS OF GEOTECHNICAL AND GEOLOGICAL CONDITIONS

	ITEMS	BASE CASES	WORSE CASES	WORST CASES	EXTREME CASES
1.	Deep Seepage Control	3.66	4.19	4.72	4.72
2.	Support of Dam Abutment Slopes	33.84	46.12	59.43	59.43
3.	Low Pressure Headrace Tunnel	99.59	104.37	112.75	126.69
4.	Pressure Drop Shaft	10	15.74	20.78	20.78
5.	Powerhouse Carven	42.36	45.2	48.94	48.94
6.	Dam Foundation Treatment	0	0	8.78	8.78
	Total	**189.45**	**215.62**	**255.4**	**269.34**
	Cost Difference	**0**	**26.17**	**65.95**	**79.89**

Source: CSPDR 2020, Annex L, Risk Analysis of Geological and Geotechnical Uncertainty, Table 7-1.

TABLE 4.5: IMPACT ON ECONOMIC RETURNS

VARIABLE	BASELINE	WORSE CASE	WORST CASE	EXTREME CASE
Project Cost	None	Increasing $26.17 million	Increasing $65.95 million	Increasing $79.89 million
Construction Duration	No delay	Two months delay	Four months delay	Five months delay
ERR	17.9%	17.2%	16.6%	16.5%
NPV(i_c=10%) (MUSD)	836	798	764	754
NPV Difference	—	38	72	82

Source: CSPDR 2020, Annex L, Risk analysis of geological and geotechnical uncertainty, Table 7-2.

Several approaches to such quantitative risk assessments are found in the literature. Instead of the 5,000 trial calculations with input assumption values picked randomly from the probability distributions (as above in Monte Carlo simulation), some studies use combinatorial methods to capture individual scenarios. In the Bangladesh power system resilience study (Mukhi et al. 2017), alternative strategies were evaluated based on all possible combinations of:

- three temperature scenarios
- three demand growth scenarios
- three fuel price scenarios
- three domestic coal price scenarios
- two natural gas supply scenarios
- three flooding scenarios

thereby creating 486 (3 × 3 × 3 × 3 × 2 × 3) futures. There is no need for a detailed elaboration of each of the 486 scenarios; only those found to be in the vicinity of the trade-off curve would need discussion. On the independence of these scenarios, it would be reasonable to suppose that flooding is independent of gas supply scenario, though it may well be that flooding and temperature may well be linked to the underlying climate change scenario.

5. PROCEDURE

This chapter illustrates the general application of the methodological principles set out in Chapter 3. Beginning with the typical calculation of baseline economic returns, as would be presented in the PAD annex for economic and financial analysis, we illustrate how the table of economic flows is modified for each step of the resilience and hazard assessment for the case of a hydropower project.

The overall procedure for climate risk assessment is straightforward, as is outlined in **Figure 5.1**. This chapter is focused on the details of what this chart describes as a stress test (red outline). The green-outlined steps—how to define risk, what level of risk is acceptable—have been discussed in Chapter 4.

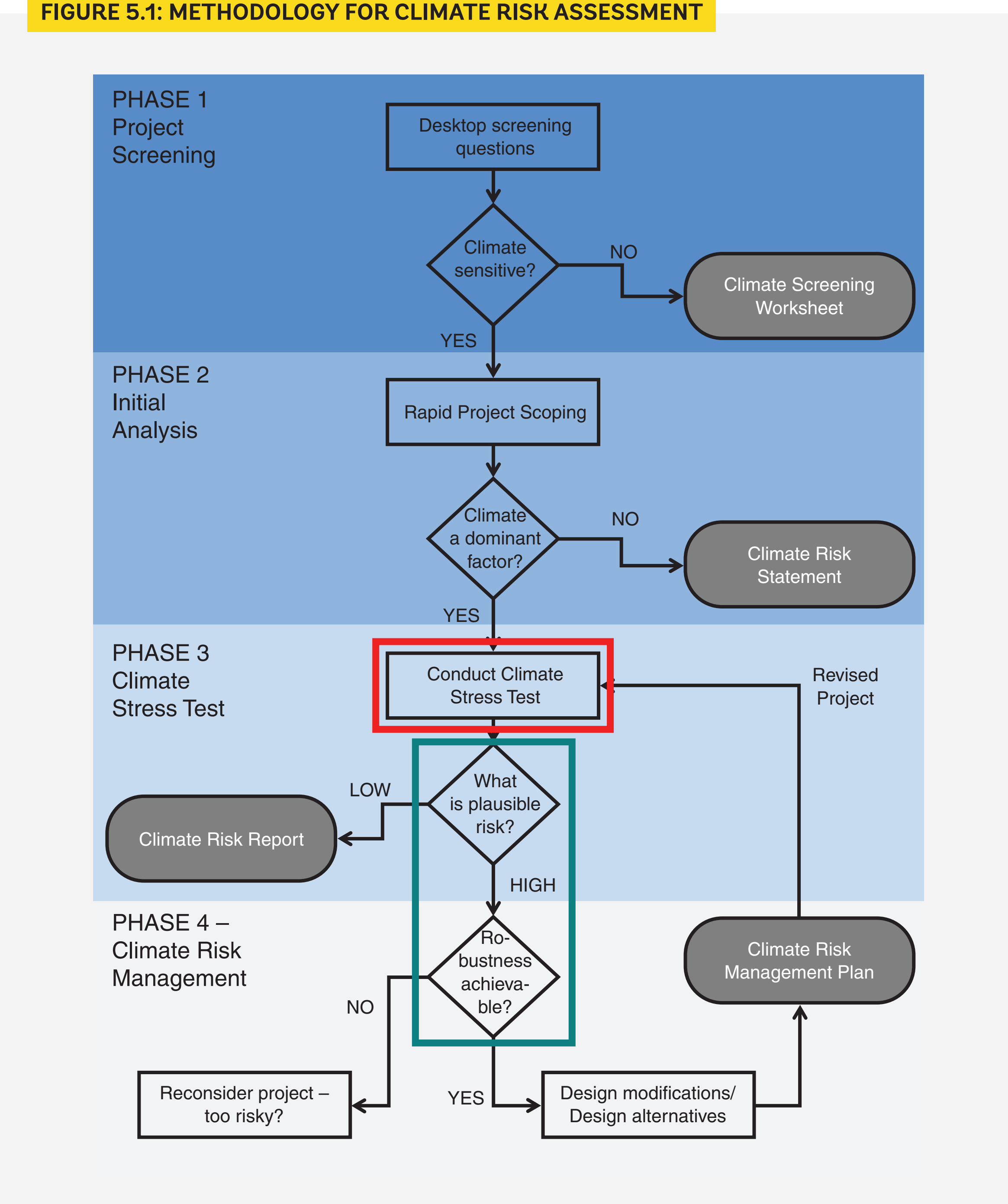
The stress test (and assessment of chronic impacts) in the context of economic analysis is about extending the standard CBA and its summary presentation (**Table 5.1**) into one that explicitly accounts for the impact of climate change–related risks and the costs of adaptation to mitigate those risks. These steps can be summarized as follows:

- Calculate the economic returns in the absence of additional climate change risks, termed here the baseline returns.
- Identify the hazard events of concern; their damage costs if they do occur; and any upfront CAPEX or OPEX related costs separable as adaptation costs. Add the necessary line items to the table of economic flows, and add the relevant impacts for the counterfactual.
- Identify the chronic impacts of concern and add further lines to the table of economic flows to separate out these impacts (e.g., gradual changes in benefits as temperature and precipitation impacts change ambient conditions), again with corresponding entries for the counterfactual.
- In consultation with the relevant climate change and technical experts, conduct sensitivity analyses to assess the relationship of returns to the timing of both chronic and hazard events.
- In consultation with the relevant climate change experts, set out plausible bounds for changes in hazard and chronic events.
- Frame recommendations to the consultants preparing detailed feasibility studies for consideration of resilience hardening measures in the final design.
- Finalize the summary presentation of the analysis for inclusion in the formal appraisal documents.

5.1 BASELINE RETURNS

Consider the illustrative example of Table 5.1. This is loosely modeled on the Trung Son hydropower project in Vietnam and shows the simplified table of economic flows. In the actual appraisal economic analysis, there were additional rows for other externalities, costs, and benefits (such as flood control benefits and loss of forestry). This and several other tables/charts that follow in the remainder of this report are based

FIGURE 5.1: METHODOLOGY FOR CLIMATE RISK ASSESSMENT



Source: Ray and Brown 2015, Figure 3.2

TABLE 5.1: BASELINE ECONOMIC RETURNS

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							1019	1019	1019	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	−202	−53.3	−53.3	−53.3	−53.3	−53.3	0	0	0	0			
[5]	OPEX	[$USm]	−22	0	0	0	0	0	−4.0	−4.0	−4.0	−4.0	−4.0	−4.0	−4.0
[6]	Benefits	[$USm]	***444***	0	0	0	0	0	81.5	81.5	81.5	81.5	81.5	81.5	81.5
[7]	Net flow	[$USm]	***220***	−53	−53	−53	−53	−53	78	78	78	78	78	78	78
[8]	ERR	[ ]	*19.4%*									*3.4%*	*7.8%*	*10.8%*	*12.9%*
[9]	GHG emissions	[10^6 tons]	*12*						0.41	0.41	0.41	0.41	0.41	0.41	0.41
[10]	Social value of carbon	[S/ton]							40	41	42	43	44	45	46
[11]	GHG emission benefit	[$USm]	***153***	0					16	17	17	18	18	18	19
[12]	Net flows incl. GHG	[$USm]	***323***	−53	−53	−53	−53	−53	94	94	95	95	95	96	96
[13]	ERR incl. NPV	[ ]	*22.6%*									*8.0%*	*12.1%*	*14.9%*	*16.9%*

Note that this snapshot omits certain rows that are added as we build up the final presentation. All of the calculations are to the assumed economic life—columns to the right are omitted for legibility reasons.

Source: Original calculations.

on the author's analysis conducted for economic analysis of World Bank projects. Interested readers should refer to the detailed PAD for a fuller description of the project and underlying data. The discussion in this report uses excerpts of the PAD analysis to provide practical examples of how the analysis should be conducted and support the theoretical discussions.

In this example, the hurdle rate is 10 percent, the ERR 19.4 percent and the NPV $220 million. With GHG emission reduction benefits included, the NPV increases to $325 million. The counterfactual is CCGT gas-fired generation.

Table 5.1 illustrates several important points that will concern the treatment of chronic climate change impacts. First, the energy generation in each year is shown as a constant value (possibly reduced by a small rate of degradation, ignored here)—the presumption being of a stationary time series with a constant long-term mean. Clearly, in reality, annual generation is not constant every year and will show variations over time. Indeed, at Trung Son, the annual generation in the first three years of operation generation was 859 GWh, 1,085 GWh, and 650 GWh—so in two of the first three years of operation, below the long-term expected value (World Bank 2020a). But as one may see in **Table 5.2**, this has a moderate impact on NPV, reducing from $220 million to $202 million, and reducing the ERR from 19.4 percent to 18.5 percent. One of the problems with ICRs is that they typically occur after just a year or two or operation. A priority recommendation for the planned World Bank study of the economic analysis of hydropower projects is that it should evaluate Bank-financed hydropower projects initiated in the 1990s and 2000s and compare longer periods of actual generation with appraisal estimates.

Of equal interest is that in the second year of operation, a massive storm hit the area from August 30 to September 1. The inflow of 3,760 cumecs on August 31 were by far the highest daily inflow on record, as it appears in the monthly averages shown in **Figure 5.2** (see **Box 6.1** for another example of increasing peak annual flows. But caution is required, because even in a stationary time series, the longer the period of record, the more likely will one encounter a value that exceeds all previous observations). Yet, despite such storm events, there is little benefit to generation—in projects with little active storage, such excess simply gets spilled.

These huge flows were safely passed by the dam and its structures, being well below the design flood. However, the storm caused severe damage to the valley slope at and immediately below the dam site, and to the newly constructed settlements that provided housing to project-affected persons. The repair expenditures amounted to some $25 million—some 10 percent of total project CAPEX.

This suggests that the table of economic flows be extended to include the costs of such hazard events. When these repair costs are included in row [8], one observes a further decline in ERR to 17.8 percent as shown in **Table 5.3**—and to an NPV of $189 million.

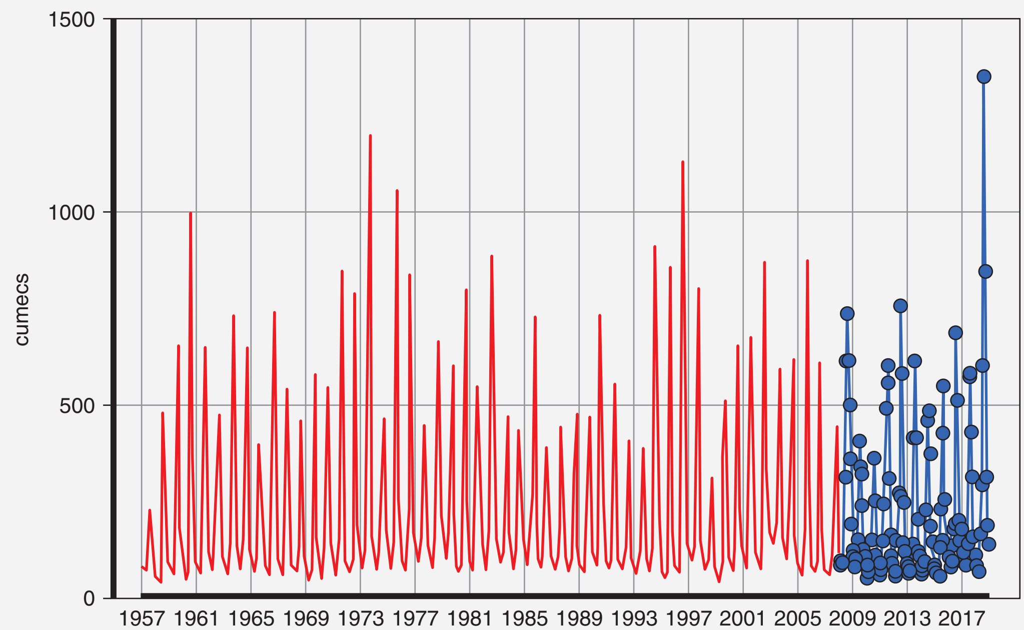
In the particular example of Trung Son, efficient construction management had the result that most of the physical contingency allowance was unspent; because the event occurred before the close of the Bank's project, funds for repairs were immediately available, causing little impact on the finances of the Trung Son Hydropower Company, and the economic returns at ICR preparation were little affected. Had the event occurred in year 5, the *financial* impact might well be more severe, even though the *economic* impact would have been lower. It is also worth noting that this particular storm impact hazard would not need consideration in the CCGT gas-fired thermal project.

TABLE 5.2: REVISED ECONOMIC RETURNS, WITH THREE YEARS OF ACTUALS

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							859	1085	650	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	–202	–53.3	–53.3	–53.3	–53.3	–53.3	0	0	0	0			
[5]	OPEX	[$USm]	–22	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefit	[$USm]	**426**	0	0	0	0	0	68.7	86.8	52.0	81.5	81.5	81.5	81.5
[7]	Net flow	[$USm]	**202**	–53	–53	–53	–53	–53	65	83	48	78	78	78	78
[8]	ERR	[ ]	*18.5%*									*0.5%*	*5.6%*	*8.9%*	*11.3%*
[9]	GHG emissions	[10^6 tons]	*12*						0.34	0.43	0.26	0.41	0.41	0.41	0.41
[10]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[11]	GHG emission benefit	[$USm]	**148**	0					14	18	11	18	18	18	19
[12]	Net flows incl. GHG	[$USm]	**303**	–53	–53	–53	–53	–53	78	101	59	95	95	96	96
[13]	ERR incl. NPV	[ ]	*21.6%*									*5.0%*	*9.8%*	*13.0%*	*15.2%*

Source: Original calculations.

FIGURE 5.2: MONTHLY AVERAGE STREAM FLOWS AT TRUNG SON



Source: Original calculations.

A second point of note, frequently forgotten, is that headline rates of return are statements of the ***end*** of the assumed economic life—here to 30 years. Note that in the example of Table 5.3, the hurdle rate is reached after seven years of operation—and with the storm damage repairs, the curve shifts (to the right) by just half a year (see **Figure 5.3**).

5.2 ADDING ADAPTATION COSTS TO THE TABLE OF ECONOMIC FLOWS

Now suppose that additional valley slope reinforcement had been built into the project at the outset. To maintain transparency, we include the $25 million for this adaptation cost in the table of economic flows as a separate row (row [8] in **Table 5.4**): we also add rows [10] to [12] for potential adaptation costs under OPEX (see Section 5.3).

Because adaptation CAPEX often occurs up front, as opposed to much later during operations, economic returns will reduce—from 17.8 percent in Table 5.3 to 16.9 percent in **Table 5.4**. The extent of the reduction will depend on the discount rate: the lower the discount rate, the smaller the difference between expenditure during construction and expenditure during the life of the project will be.

5.3 EXPECTED VALUES OF HAZARD EVENTS

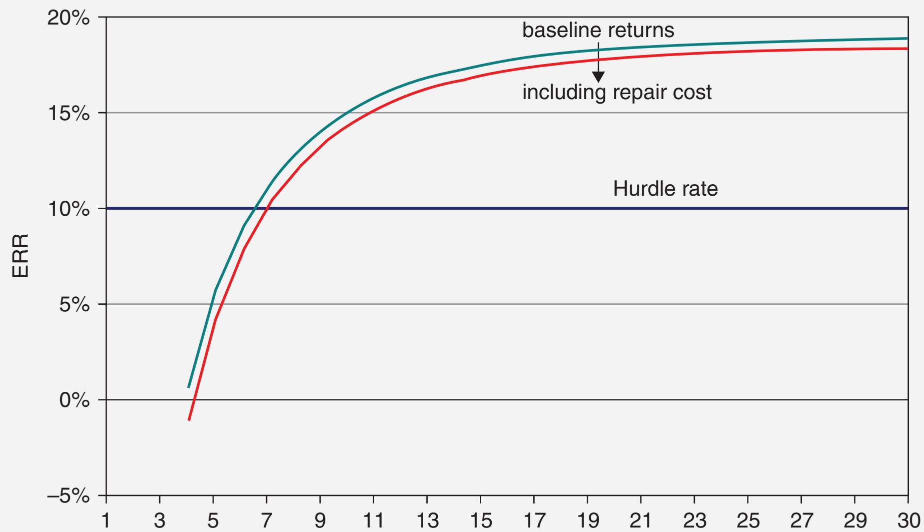
The best approach is to leave aside (for the moment) the *unknown* unknowns, but focus on the cumulative international experience of *known* unknowns that allows a definition of hazard events that can reasonably be quantified. In the case of hydropower projects, the physical design of the dam and its structures are defined on the basis of "maximum floods" that can be safely passed without damage to the project.

TABLE 5.3: ACCOUNTING FOR HAZARD EVENTS IN THE TABLE OF ECONOMIC FLOWS

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							859	1085	650	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	*–202*	–53.3	–53.3	–53.3	–53.3	–53.3							
[5]	OPEX	[$USm]	*–22*	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefits	[$USm]	*426*	0	0	0	0	0	68.7	86.8	5	81.5	81.5	81.5	81.5
[7]	***Climate change/hazard impacts***														
[8]	Repair cost	[$USm]	*–13*	0	0	0	0	0	0	–25	0	0	0	0	0
[9]	Lost benefits	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0
[10]	***Expected value of impacts***														
[11]	E{repair cost}	[$USm]	*0*	0					0	0	0	0	0	0	0
[12]	E{lost benefits}	[$USm]	*0*	0					0	0	0	0	0	0	0
[13]	***resilience improvement costs***														
[14]	d(CAPEX)	[$USm]	*0*												
[15]	d(OPEX)	[$USm]	*0*												
[16]	Net flow	[$USm]	***189***	–53	–53	–53	–53	–53	65	58	48	78	78	78	78
[17]	ERR	[ ]	*17.8%*									*–1.6%*	*4.0%*	*7.6%*	*10.1%*
[18]	GHG emissions	[10^6 tons]	*12*						0.34	0.43	0.26	0.41	0.41	0.41	0.41
[19]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[20]	GHG emssion benefit	[$USm]	***148***	0					14	18	11	18	18	18	19
[21]	Net flows incl. GHG	[$USm]	***290***	–53	–53	–53	–53	–53	78	76	59	95	95	96	96
[22]	ERR incl. NPV	[ ]	*20.9%*									*3.2%*	*8.4%*	*11.8%*	*14.1%*

Source: Original calculations.

FIGURE 5.3: ECONOMIC RATE OF RETURN VS. TIME



Source: Original calculations.

While there are many worldwide examples of dam collapses, with catastrophic downstream impacts to life and property, these are (almost) all at mining or irrigation projects that have not been designed, built, and operated to best practice—typically without proper oversight by independent experts and dam safety committees.

However, even at the best built dams, the most probable catastrophic impacts are caused by storm events for which consequential impact on inflows can be safely passed (i.e., are below the project design flood) but which for *other* reasons have serious impacts: these include (in the case of Nepal):

- **Storm and landslide damage to power evacuation lines**. Just such an event occurred in Nepal in 2014 at the 45 MW Upper Bhote Koshi hydropower project: a severe storm resulted in the failure of three transmission line towers, and power from the project was interrupted for six months as new right-of-way had to be negotiated and towers constructed. This same project was again affected by the major 2015 earthquake, when an upstream moraine-dammed lake burst upstream in China; the resulting flow overtopped the project, causing powerhouse flooding.

- **Powerhouse flooding following landslides immediately downstream of a project** that block the river, hence backing up into the tail water and powerhouse of the upstream project. This occurred immediately downstream of the 10 MW Sun Koshi power plant in August 2014. The landslide blocked the river, and early efforts by the Army to blast away the blockage failed – it took 45 days to build a canal to allow the water to drain. Within 12 hours of the slide, water had backed up to the level of the powerhouse roof. The total damage cost was estimated at $1.8 million. The project was hit again a year later by the 2015 earthquake, when the penstock was damaged (Ojha 2018).

TABLE 5.4: ACCOUNTING FOR ADAPTATION COSTS

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							859	1085	650	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	–202	–53.3	–53.3	–53.3	–53.3	–53.3	0	0	0	0			
[5]	OPEX	[$USm]	–22	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefits	[$USm]	426	0	0	0	0	0	68.7	86.8	52.0	81.5	81.5	81.5	81.5
[7]	***Climate change/hazard impacts***														
[8]	Repair cost	[$USm]	–13	0	0	0	0	0	0	–25	0	0	0	0	0
[9]	Lost benefits	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0
[10]	***Adaptation costs***														
[11]	d(CAPEX)	[$USm]	–16	0	0	0	–12.5	–125							
[12]	d(OPEX)	[$USm]	*0*												
[13]	Net flow	[$USm]	***173***	–53	–53	–53	–66	–66	65	58	48	78	78	78	78
[14]	ERR	[ ]	*16.9%*									*–36%*	*2.2%*	*6.0%*	*8.7%*
[15]	GHG emissions	[10^6 tons]	12						0.34	0.43	0.26	0.41	0.41	0.41	0.41
[16]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[17]	GHG emssion benefit	[$USm]	***148***	0					14	18	11	18	18	18	19
[18]	Net flows incl. GHG	[$USm]	***274***	–53	–53	–53	–66	–66	78	76	59	95	95	96	96
[19]	ERR incl. NPV	[ ]	*20.0%*									*13%*	*6.7%*	*10.3%*	*12.7%*

Source: Original calculations.

- **Powerhouse flooding during construction**. In July 2020, a massive storm hit the 105 MW Middle Bhote Koshi, under construction since 2013. The flood swept away much of the hydropower mechanical equipment, and the powerhouse flooded. Damages run into the tens of millions of dollars, very serious for a 10 MW project.

Indeed, the Trung Son storm noted above also falls into this general category of hazard events: the peak flows were safely passed, and the flood control storage at the dam functioned as planned, but the storm itself caused extensive damage to valley slopes at and immediately downstream of the project.

In the case of powerhouse flooding, two impacts follow. The first is loss of revenue while repairs are conducted, which may be anywhere from 1 to 12 months. The second is the repair cost itself. In **Table 5.5**, we assume a repair cost of $60 million, and a 12-month downtime with consequent loss of generation benefits. For sake of argument, we assume this occurs in year 3.

Compared to the baseline of Table 5.2, the ERR reduces from 18.6 percent to 15.4 percent, and the NPV reduces from $202 million to $154 million.

If the powerhouse flooding were to occur a year sooner (in year 2018 rather than year 2019), the impact would be smaller: the ERR drops to 15 percent (**Table 5.6**).

But how does one decide what year of occurrence should be used for such a stress test? Climate change modelers are themselves very reluctant to discuss timing of the range of long-term scenarios. So, while discussions with experts will be useful, in the first instance a sensitivity analysis is the first tool is to ask the question, "At what year would a catastrophic event result in a negative NPV?" With that information at hand, a discussion with decision makers is appropriate—an element that is a key part of so-called RDM approaches.

Instead of waiting for the damage to happen, we can avoid the repair costs in some future year by up-front CAPEX. In **Table 5.7**, we spend the $60 million additional cost up front (spread over two years). Now, even though (as noted above) the up-front expenditure inevitably carries greater weight than in some future year (at any non-zero discount rate), the important point is that we avoid the loss of revenue associated with a repair while the project is already in operation (as in Table 5.1). Therefore, the NPV loss is much smaller (from $202 million to $163 million) than the NPV with powerhouse flooding in year 3 (from $202 million to $136 million).

Because the year in which the trigger event occurs is unknown, one can use the results of Table 2.2 to calculate the probabilistic value of that risk for various asset lives. Suppose the return period of a storm sufficiently severe to trigger a powerhouse flooding is 100 years. The probability of such an event occurring in any one year is 0.01; the probability of this occurring at least once in an asset life of 50 years is 0.393.

This approach can be accommodated by adding two further rows, as shown in **Table 5.8**: row [11] shows the expected value of repair cost, and row [12] the expected value of the lost benefits—here in the case of a hazard with a 100-year return period.

The important result of this table is that the expected value calculation will tend to underestimate the impact if it *does* occur. The NPV decreases by just $6 million ($194 million), rather than to the $136 million (Table 5.1)—which is do nothing and repair if it does in fact occur.

One cannot therefore claim that calculating the expected value of hazard events is a "stress test" of the robustness of the project to such an event. However, the approach of Table 5.1, where we assess the impact of a powerhouse flooding in year 3, ***does*** constitute a stress test of the risk in question—and

TABLE 5.5: ACCOUNTING FOR A POWERHOUSE FLOODING

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							859	1085	650	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	–202	–53.3	–53.3	–53.3	–53.3	–53.3	0	0	0	0			
[5]	OPEX	[$USm]	–22	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefits	[$USm]	***426***	0	0	0	0	0	68.7	86.8	52.0	81.5	81.5	81.5	81.5
[7]	***Climate change/hazard impacts***														
[8]	Repair cost	[$USm]	–28	0	0	0	0	0	0	0	–60	0	0	0	0
[9]	Lost benefits	[$USm]	–38	0	0	0	0	0	0	0	–82	0	0	0	0
[10]	***Adaptation costs***														
[11]	d(CAPEX)	[$USm]	***0***	0	0	0									
[12]	d(OPEX)	[$USm]	***0***												
[13]	Net flow	[$USm]	***136***	–53	–53	–53	–53	–53	65	83	–94	78	78	78	78
[14]	ERR	[ ]	*15.4%*										*–4.7%*	*1.2%*	*4.9%*
[15]	GHG emissions	[10^6 tons]	*12*						0.34	0.43	0.26	0.41	0.41	0.41	0.41
[16]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[17]	GHG emssion benefit	[$USm]	***148***	0					14	18	11	18	18	18	19
[18]	Net flows incl. GHG	[$USm]	***237***	–53	–53	–53	–53	–53	78	101	–83	95	95	96	96
[19]	ERR incl. NPV	[ ]	*18.7%*									*–7.7%*	*–1.4%*	*6.5%*	*9.7%*

Source: Original calculations.

TABLE 5.6: POWERHOUSE FLOODING IN YEAR 6

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							859	1085	650	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	–202	–53.3	–53.3	–53.3	–53.3	–53.3	0	0	0	0			
[5]	OPEX	[$USm]	–22	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefits	[$USm]	***426***	0	0	0	0	0	68.7	86.8	52.0	81.5	81.5	81.5	81.5
[7]	***Climate change/hazard impacts***														
[8]	Repair cost	[$USm]	*–31*	0	0	0	0	0	0	–60	0	0	0	0	0
[9]	Lost benefits	[$USm]	–42	0	0	0	0	0	0	–82	0	0	0	0	0
[10]	***Adaptation costs***														
[11]	d(CAPEX)	[$USm]	*0*	0	0	0									
[12]	d(OPEX)	[$USm]	*0*												
[13]	Net flow	[$USm]	***129***	–53	–53	–53	–53	–53	65	–59	48	78	78	78	78
[14]	ERR	[ ]	*15.0%*										*–4.2%*	*1.1%*	*4.6%*
[15]	GHG emissions	[10^6 tons]	12						0.34	0.43	0.26	0.41	0.41	0.41	0.41
[16]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[17]	GHG emssion benefit	[$USm]	***148***	0					14	18	11	18	18	18	19
[18]	Net flows incl. GHG	[$USm]	***230***	–53	–53	–53	–53	–53	78	–41	59	95	95	96	96
[19]	ERR incl. NPV	[ ]	*18.2%*									*–6.6%*	*–1.2%*	*6.0%*	*9.1%*

Source: Original calculations.

TABLE 5.7: UP-FRONT ADAPTATION EXPENDITURE

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							859	1085	650	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX:	[$USm]	–202	–53.3	–53.3	–53.3	–53.3	–53.3	0	0	0	0			
[5]	OPEX	[$USm]	–22	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefits	[$USm]	***426***	0	0	0	0	0	68.7	86.8	52.0	81.5	81.5	81.5	81.5
[7]	***Climate change/hazard impacts***														
[8]	Repair cost	[$USm]	***0***	0	0	0	0	0	0	0	0	0	0	0	0
[9]	Lost benefits	[$USm]	***0***	0	0	0	0	0	0	0	0	0	0	0	0
[10]	***Adaptation costs***														
[11]	d(CAPEX)	[$USm]	*–39*	0	0	0	–30	–30		0					
[12]	d(OPEX)	[$USm]	***0***	0	0	0	0	0	0	0					
[13]	Net flow	[$USm]	***163***	–53	–53	–53	–53	–83	65	83	48	78	78	78	78
[14]	ERR	[ ]	*16.3%*										*1.5%*	*5.3%*	*7.9%*
[15]	GHG emissions	[10^6 tons]	*12*						0.34	0.43	0.26	0.41	0.41	0.41	0.41
[16]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[17]	GHG emssion benefit	[$USm]	***148***	0					14	18	11	18	18	18	19
[18]	Net flows incl. GHG	[$USm]	***264***	–53	–53	–53	–53	–83	78	101	59	95	95	96	96
[19]	ERR incl. NPV	[ ]	*19.3%*									*0.5%*	*5.8%*	*9.4%*	*11.8%*

Source: Original calculations.

TABLE 5.8: ADJUSTMENTS OF EXPECTED VALUE OF HAZARD EVENTS

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	**–4**	**–3**	**–2**	**–1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	Energy	[GWh]							859	1085	650	1019	1019	1019	1019
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	*–202*	–53.3	–53.3	–53.3	–53.3	–53.3	0	0	0	0			
[5]	OPEX	[$USm]	*–22*	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefits	[$USm]	***426***	0	0	0	0	0	68.7	86.8	52.0	81.5	81.5	81.5	81.5
[7]	***Climate change/hazard impacts***														
[8]	Repair cost	[$USm]	***0***	0	0	0	0	0	0	0	0	0	0	0	0
[9]	Lost benefits	[$USm]	***0***	0	0	0	0	0	0	0	0	0	0	0	0
[10]	***Expected value of impacts***		***0***												
[11]	E{repair cost}	[$USm]	*–3*	0	0	0	0	0	–0.6	–0.6	–0.6	–0.6	–0.6	–0.6	–0.6
[12]	E{lost benefits}	[$USm]	*–4*	0	0	0	0	0	–0.8	–0.8	–0.8	–0.8	–0.8	–0.8	–0.8
[13]	***Adaptation costs***														
[14]	d(CAPEX)	[$USm]	***0***	0	0	0	0	0	0	0					
[15]	d(OPEX)	[$USm]	***0***	0	0	0	0	0	0	0					
[16]	Net flow	[$USm]	***194***	–53	–53	–53	–53	–83	63	81	47	76	76	76	76
[17]	ERR	[ ]	*18.2%*										*5.2%*	*8.5%*	*10.9%*
[18]	GHG emissions	[10^6 tons]	*12*						0.34	0.43	0.26	0.41	0.41	0.41	0.41
[19]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[20]	GHG emssion benefit	[$USm]	***148***	0					14	18	11	18	18	18	19
[21]	Net flows incl. GHG	[$USm]	***295***	–53	–53	–53	–53	–53	77	99	58	94	94	94	95
[22]	ERR incl. NPV	[ ]	*21.3%*									*4.7%*	*9.5%*	*12.7%*	*14.9%*

Source: Original calculations.

based on Table 5.1, one really can say that the economic returns are robust with respect to a plausible worst case of a powerhouse flooding. Of course, there will be other components of a plausible worst case that are unrelated to hazard or climate change impacts—perhaps there is no market for excess wet season power, or perhaps power cannot be evacuated because of delays in the transmission connection. However, the framework of Table 5.1 provides a way of assessing these impacts in a transparent way.

5.4 CHRONIC IMPACTS OF CLIMATE CHANGE

Chronic impacts are conceptually much easier to deal with because the changes occur gradually over time. Even if climate change results in a gradual decline in inflows and generation over time, a greater share of wet season inflows may result from the intensification of storms, resulting in increased generation loss during flushing. But such matters are readily captured in the table of economic flows—modification of the seasonal and hour energy balances are also straightforward to model. These details are presented in Chapter 6.

In **Table 5.9**, we illustrate such a decline in generation over time. For illustrative purposes, we assume total generation decreases by 5 percent per year (with the long-term expected average generation in 2020, declining thereafter), such that by year 20, the annual generation has fallen from 1,019 GWh to 448 GWh—much more severe than the worst-case climate change scenario assessment for the Trung Son project. The ERR falls from 18.5 percent to 16 percent, but the fall in NPV is more dramatic—from $202 million in Table 5.1 to just $114 million. Nevertheless, the economic viability of the project is not in doubt.

5.5 THE REVISED SUMMARY PRESENTATION

These proposed changes to the table of economic flows lead to a revision of the summary table suitable for inclusion in the main body of a PAD (see Table 1.1 for the standard presentation). The added rows of **Table 5.10** are highlighted in green.

The key assumptions for each column are as follows:

No Climate Change (expected value of inflows in each case)

[1] The baselin—corresponding to the results of Table 5.3

[2] Powerhouse flooding year 6

[3] With upfront adaptation cost

With Climate Change (chronic inflow reduction in each case)

[4] No disaster events

[5] Powerhouse flooding year 2 and 12

[6] With upfront adaptation cost

These indicative calculations have for illustrative purposes exaggerated the various impacts. Indeed, it is not necessarily the case that the adaptation costs will improve the NPVs as in this illustration. In the case studies that follow (Chapters 6–8), the climate change and hazard estimates will be derived in more detail.

The choice of climate change scenarios is important, and one may wish to extend this table with a range of climate change scenarios (such as RCP 2.6 as opposed to RCP 4.5), as may be recommended by the climate change assessment specialists (see Chapter 6 for how this was done in the UAHEP).

TABLE 5.9: IMPACT OF CLIMATE CHANGE: REDUCED GENERATION OVER TIME

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
			NPV	–4	–3	–2	–1	0	1	2	3	4	5	6	7
[1]	Energy	[GWh]							859	1085	650	1019	968	920	874
[2]	Benefit valuation	[$/kWh]							0.08	0.08	0.08	0.08	0.08	0.08	0.08
[3]	Disbursement	[ ]		0.2	0.2	0.2	0.2	0.2							
[4]	CAPEX	[$USm]	–202	–53.3	–53.3	–53.3	–53.3	–53.3	0	0	0	0			
[5]	OPEX	[$USm]	–22	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6]	Benefits	[$USm]	**345**	0	0	0	0	0	68.7	86.8	52.0	81.5	77.4	73.6	69.9
[7]	***Climate change/hazard impacts***														
[8]	Repair cost	[$USm]	***0***	0	0	0	0	0	0	0	0	0	0	0	0
[9]	Lost benefits	[$USm]	***0***	0	0	0	0	0	0	0	0	0	0	0	0
[10]	***Expected value of impacts***		***0***												
[11]	E{repair cost}	[$USm]	–3	0	0	0	0	0	–0.6	–0.6	–0.6	–0.6	–0.6	–0.6	–0.6
[12]	E{lost benefits}	[$USm]	*–4*	0	0	0	0	0	–0.8	–0.8	–0.8	–0.8	–0.8	–0.8	–0.8
[13]	***Adaptation costs***														
[14]	d(CAPEX)	[$USm]	***0***	0	0	0	0	0							
[15]	d(OPEX)	[$USm]	***0***	0	0	0	0	0							
[16]	Net flow	[$USm]	***114***	–53	–53	–53	–53	–83	63	81	47	76	72	68	64
[17]	ERR	[ ]	*16.0%*										*4.9%*	*8.0%*	*10.2%*
[18]	GHG emissions	[10^6 tons]	*7*						0.34	0.43	0.26	0.41	0.39	0.37	0.35
[19]	Social value of carbon	[$/ton]							40	41	42	43	44	45	46
[20]	GHG emssion benefit	[$USm]	***116***	0					14	18	11	18	17	17	16
[21]	Net flows incl. GHG	[$USm]	***193***	–53	–53	–53	–53	–53	77	99	58	94	89	85	81
[22]	ERR incl. NPV	[ ]	*19.4%*									*4.7%*	*9.3%*	*12.2%*	*14.2%*

Source: Original calculations.

TABLE 5.10: SUMMARY PRESENTATION OF RESULTS

			[1]	[2]	[3]	[4]	[5]	[6]
			NO CLIMATE CHANGE			WITH CLIMAGE CHANGE		
			BASELINE	WORST CASE	WITH ADAPTATION COSTS	BASELINE	WORST CASE	WITH ADAPTATION COSTS
[1]	ERR	[ ]	18.5%	16.5%	16.3%	16.4%	11.2%	14.0%
[2]	ERR with GHG benefits	[ ]	21.6%	19.9%	19.3%	19.7%	14.9%	17.2%
[3]	NPV	[$USm]	202	152	163	122	24	83
[4]	NPV with GHG benefits	[$USm]	303	253	264	201	103	162
[5]	**Composition of NPV**							
[6]	***Benefits***	[$USm]	426	426	426	345	345	345
[7]	***Costs***							
[8]	CAPEX	[$USm]	–202	–202	–202	–202	–202	–202
[9]	OPEX	[$USm]	–22	–22	–22	–22	–22	–22
[10]	**Climate change/hazard impacts**							
[11]	Repair costs	[$USm]	0	–21	0	0	–43	0
[12]	Lost benefits	[$USm]	0	–29	0	0	–55	0
[13]	**Adaptation costs**							
[14]	d(CAPEX)	[$USm]	0	0	–39	0	0	–39
[15]	d(OPEX)	[$USm]	0	0	0	0	0	0
[16]	NPV	[$USm]	202	152	163	122	24	83
[17]	Local environmental benefits	[$USm]						
[18]	Global GHG benefits	[$USm]	101	101	101	79	79	79
[19]	NPV incl. GHG benefits	[$USm]	303	253	264	201	103	162
[20]	Lifetime GHG savings	[10^6t]	12.0	12.0	12.0	7.1	7.1	7.1
[21]	Average annual reductions	[10^6t]	0.40	0.40	0.40	0.24	0.24	0.24

Source: Original calculations.

Photo credit: Direct Relief

6. CASE STUDY: THE UPPER ARUN HYDROELECTRIC PROJECT IN NEPAL

6.1 CONTEXT

The Upper Arun Hydropower Project is a 1,040 MW high head hydroelectric project on the Arun River in Eastern Nepal for which a detailed FS has just been completed. The FS was prepared by the Changjiang Survey, Planning, Design and Research Co. Ltd of Wuhan, China (CSPDR). Under a separate contract with the World Bank, a Climate Change Risk Assessment was prepared by the University of Cincinnati (UC).

Hazard Events at Hydropower Stations

The literature is sparse, perhaps in part because there have been so few incidents: there are some 36,000 large hydroelectric dams worldwide, but just 300 accidents have been reported since the International Commission of Large Dams (ICOLD) started keeping records in 1928—and failure rates have been reduced by a factor of four over the past 40 years. The *Operation and Maintenance Strategies for Hydropower : Handbook for Practitioners and Decision Makers* (World Bank 2020b) lists five major failures between 2005 to 2017, only one of which (Sayano-Shushenskaya in Russia) was unrelated to a flood event (**Table 6.1**).

Failure or inadequate capacity of the flood discharge structure is by far the most widespread cause of hydropower project failure—obviously related to floods caused by extreme weather events or landslides (World Bank 2020b). A comprehensive review of hydropower project accidents in Japan shows that half of all major outages were related to floods (Yasuda & Watanabe 2017), and 62 percent of total down time occurred in outages of greater than one month duration (**Table 6.2 and Figure 6.1**). To be sure, Japan is particularly exposed to typhoons of a severity very rarely experienced in the Himalayas. But worldwide, flood-related incidents involving powerhouse flooding are widespread (World Bank, 2020b).

Information on the cost of repairs of accidents is no less sparse. Certainly, in the case of fires, reported damage costs for major events at large projects are between $15 to $60 million. However, in addition to the highly variable repair cost is the more predictable loss of generation, and hence revenue (or economic value), which for a typical 1,000 MW project running at 50 percent load factor and a tariff at 5 USc/kWh runs to $18.5 million per month. A typical six-month outage following a powerhouse flooding at such a project entails a $109.5 million revenue loss.

The June 2013 flood at the 280 MW Dhauliganga hydropower project in Uttarakhand, India (owned by the Indian National Hydropower Power Corporation) resulted in the total loss of generation capacity for more than six months. Its annual average energy is 1,110 GWh, so at 5 USc/kWh (JICA 2011), the revenue loss would be $28 million. This flood also affected the 400 MW Vishnuprayag project: in this case, the powerhouse (25 km downstream) was not affected, but the June 2013 flood brought so much rock and debris that the barrage was completely buried. The damage cost was estimated at Rs 400–500 million ($6.8 million).

TABLE 6.1: OUTAGES AT HYDROPOWER PROJECTS, 2004–2012

HYDROPOWER FACILITY, LOCATION	DESCRIPTION	COMMISSIONING YEAR	FAILURE YEAR
Taum Sauk Hydroelectric Power Station, Missouri, United States	Faulty gauges and inadequate control systems led to overtopping of the upper reservoir and failure of a large section of the embankment, draining more than 4 million cubic meters in less than 30 minutes. There were no fatalities but five people were injured. The failure resulted in permanent damage to the surrounding landscape. Power generation did not resume until 2010.	1962	2005
Indira Sagar, India	An estimated 300,000 people had congregated to bathe downstream from the Indira Sagar dam on the banks of the Narmada river near Dewas. Water levels rose after the dam operator opened the flood gates at night without ample warning downstream. More than 150 people were swept away. Human error and lack of dam and public safety guidelines were the main causes attributed to this accident.	2005	2005
Sayano-Shushenskaya Dam, Russia	A long chain of O&M failures culminated with excessive vibrations of one of the turbines and failure of head-cover bolts, causing destruction of the powerhouse, loss of 6 GW of power generation and 75 fatalities.	1978	2009
Dhauliganga Hydroelectric Station, India	Unprecedented flash floods in June 2013 in the State of Uttarakhand caused the complete submergence of the powerhouse. The failure resulted in massive debris accumulation, electrical equipment replacement, and loss of total generation capacity (280 MV) for more than six months.	2005	2013
Oroville Dam, United States	The spillway of the United States' tallest dam failed during operation after heavy winter rains. The emergency spillway came into operation and the slope downstream eroded rapidly. 188,000 people living downstream of the dam were evacuated.	1967	2017

Source: World Bank 2020b, Table 1.

TABLE 6.2: OUTAGES AT HYDROPOWER PROJECTS IN JAPAN, 2004–2012 (PERCENTAGE)

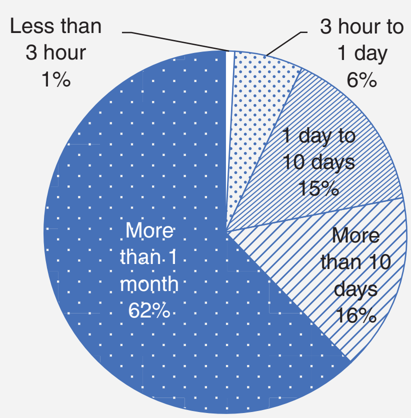
	DESIGN PROBLEM	MAINTENANCE PROBLEM	FLOOD	EARTHQUAKE	OTHER NATURAL DISASTER	OTHERS	TOTAL
Civil facilities	0.3	4.6	6.9	2.2	1.7	1.7	17.5
Turbine	1.8	8.6	1.2	0.0	0.7	2.2	14.6
Generator	1.8	4.7	1.6	0.0	0.5	1.6	10.3
Main Circuit Eq.	1.5	1.8	16.6	0.4	1.4	1.4	23.2
Station Service Eq.	0.3	1.4	2.9	0.0	0.6	0.8	6.1
Control Eq.	0.2	2.5	18.7	0.2	0.3	1.1	23.0
Others	0.4	1.6	0.6	0.4	0.8	1.4	5.3
Total	6.4	25.3	48.6	3.2	6.1	10.4	100.0

Source: Yasuda & Watanabe 2017 (Table 1)

Insurance

Traditionally for hydropower projects owned by state-owned power companies, the answer to the question of the extent to which their projects carried risk insurance has been, "We self-insure." However, with the entry of IPPs into the hydropower market, that has changed quickly—well illustrated by the experience of Indian hydropower IPPs in wake of the widespread flood damages, bearing in mind most of the information in the public domain is limited to press reports. For example, the GVK Group's Srinagar hydropower project on the Alaknanda River also suffered extensive damage in the 2013 Uttarakhand floods, and press reports

FIGURE 6.1: BREAKDOWN OF TOTAL DOWNTIMES



Source: Yasuda & Watanabe 2017 (Figure 6).

indicated that the project carried Rs 26 billion insurance for physical damage, and Rs 4 billion annual "loss of profit" insurance (Economic Times of India 2013). This project was under construction at the time of the flood, and water entered to powerhouse: press reports state that repairing the damage will add 2 to 3 months to construction time.

Subsequent to the 2013 floods, big Indian insurance companies significantly increased premiums; in response to tenders seeking quotations for reinsurance, some rates quoted were double or more than previous rates (Singh 2014). A recent review of insurance premiums at Indian small hydropower projects (SHP) suggested typical annual premiums of around 5 percent of project cost, though the coverage for an SHP typically provides much more than just flood risk (Roy & Roy 2020). The result of a comprehensive risk rating suggested the lowest risk rating justified a 2 to 3 percent premium, but high-risk ratings justified a premium of 7 to 9 percent. If premiums are at that level, insurance at large projects would be prohibitive; below, we examine the impact of insurance rates on the UAHEP.

In August 2020, a fire occurred in the control room of the Srisailam facility in India at its left bank 900 MW underground powerhouse. There were eight fatalities. Two of the six units were out of service for 2 months, three units roughly 5 months, and Unit VI, completely damaged, returned to service in May 2021. The damage cost is estimated at Rs 1.0 billion ($US13.7 million). The rough estimate of lost revenue of 30 unit-months at 25%PLF is $80 million. Notwithstanding that the most recent major accident at a large hydropower facility (Srisailam) was caused by *fire*, there is no question that the most probable hazard-related impact of climate change on hydropower projects is the widely expected increase in the number and intensity of storms. It would appear that hydropower projects are particularly vulnerable during construction, when protective works are not complete, or where temporary structures do not have the same resilience as those for the finished project.

6.2 METHODOLOGY

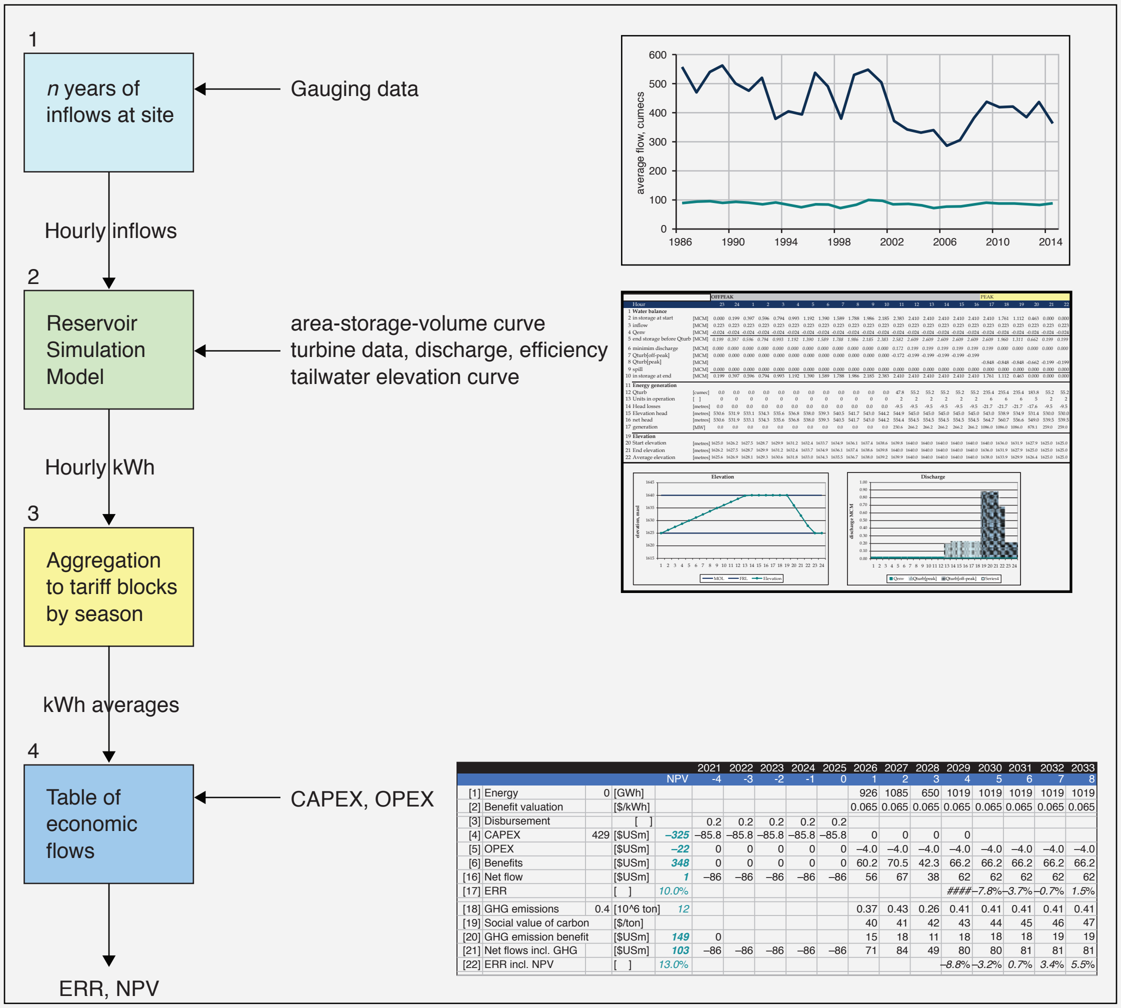
The Traditional Procedure for Economic Analysis of Hydropower Projects

Figure 6.2 illustrates the general procedure for economic and financial analysis of hydropower projects. This begins with an assessment of the historical flows at site, derived by standard methods that creates such a series from available gauging stations and precipitation records where there exists no gauging station at or immediately near the dam site. Dry season variation is typically lower than wet season variation.

The inflow data serves as input to a reservoir operation simulation model, from which hourly generation data can be determined. Averages by tariff block and season are then assembled as input to the table of economic flows or the financial model: for each such tariff block the assumption is generally made that the generation is taken at its average value for every year in the table of economic flows (perhaps varied only by a typically low degradation rate to reflect gradual loss of efficiency over time).

Based on the experience of climate change assessments conducted over the past few years, the major concern is the relationship between increasing frequency and intensity of storms (and related floods) associated with climate change, and with the resulting increase in sediment loads. In the absence of active sediment management, and even in the absence of climate change impacts, sediments would fill up the entire active storage of a typical high head daily peaking project (such as UAHEP) in a single year and inflict significant damage on turbine runners. The impact of higher sediment loads due to climate change is often of greater importance than any change in annual inflows. **Figure 6.3** illustrates the mean sediment concentration at UAHEP and its relationship to discharge.

FIGURE 6.2: FROM HYDROLOGY DATA TO ECONOMIC ANALYSIS: THE TRADITIONAL MODEL



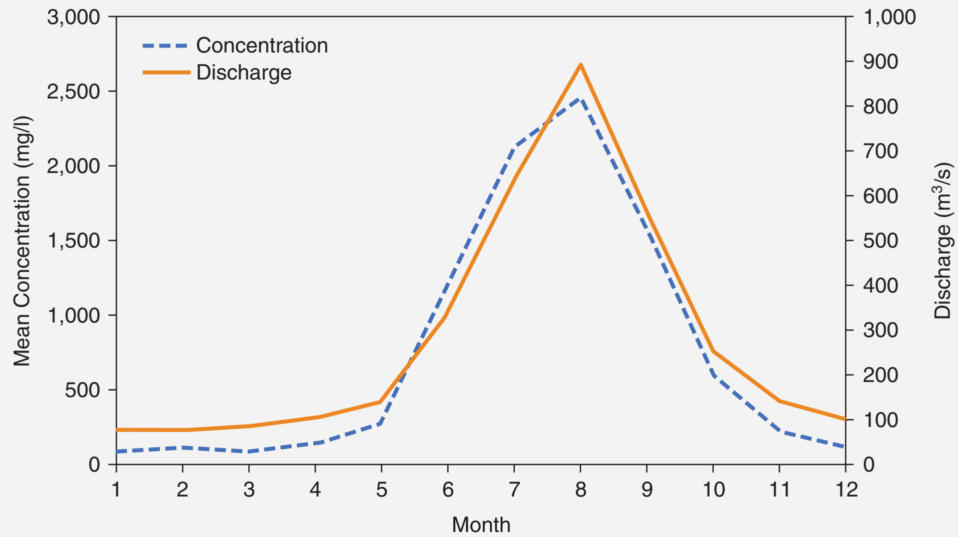
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
			NPV	-4	-3	-2	-1	0	1	2	3	4	5	6	7	8
[1] Energy	0	[GWh]							926	1085	650	1019	1019	1019	1019	1019
[2] Benefit valuation		[$/kWh]							0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
[3] Disbursement		[ ]		0.2	0.2	0.2	0.2	0.2								
[4] CAPEX	429	[$USm]	*–325*	–85.8	–85.8	–85.8	–85.8	–85.8	0	0	0	0				
[5] OPEX		[$USm]	*–22*	0	0	0	0	0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0	–4.0
[6] Benefits		[$USm]	*348*	0	0	0	0	0	60.2	70.5	42.3	66.2	66.2	66.2	66.2	66.2
[16] Net flow		[$USm]	*1*	–86	–86	–86	–86	–86	56	67	38	62	62	62	62	62
[17] ERR		[ ]	*10.0%*									*####*	*–7.8%*	*–3.7%*	*–0.7%*	*1.5%*
[18] GHG emissions	0.4	[10^6 ton]	*12*						0.37	0.43	0.26	0.41	0.41	0.41	0.41	0.41
[19] Social value of carbon		[$/ton]							40	41	42	43	44	45	46	47
[20] GHG emission benefit		[$USm]	*149*	0					15	18	11	18	18	18	19	19
[21] Net flows incl. GHG		[$USm]	*103*	–86	–86	–86	–86	–86	71	84	49	80	80	81	81	81
[22] ERR incl. NPV		[ ]	*13.0%*									*–8.8%*	*–3.2%*	*0.7%*	*3.4%*	*5.5%*

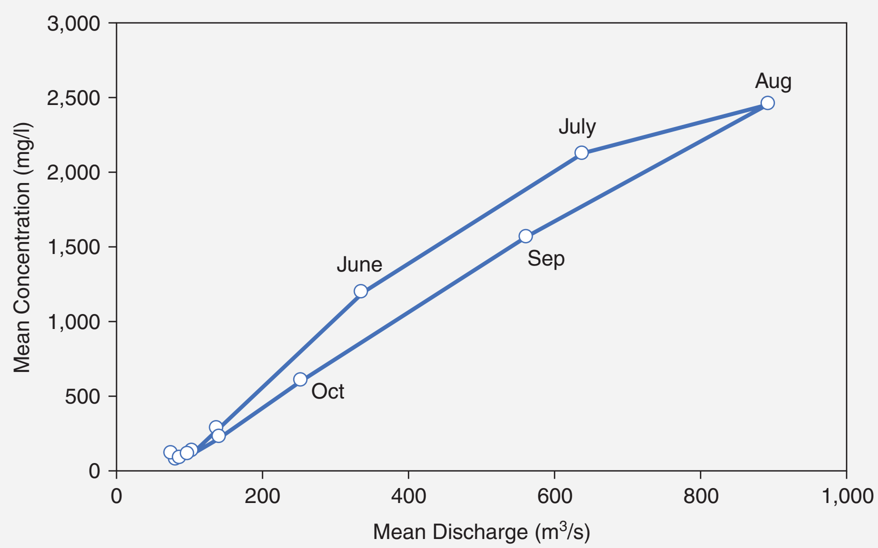
The selected mitigations for sediment management at UAHEP are flushing and only running turbines when sediment loads do not exceed certain thresholds—both of which result in reduced power generation and loss of benefits. Initially also considered were large underground desanders, but these were rejected on CBA grounds. However, the good news is that such shutdowns occur during the wet season, when the economic value of power generation is much lower than during the dry season. Losing a day of generation in August when the system is in surplus implies a loss of economic value of 3 or 4 USc/kWh, as against 5 to 8 USc/kWh for dry season peak-hour generation.

Operating Rules

Reservoir operating rules at such hydropower projects are therefore dominated by sediment management considerations, as illustrated in **Figure 6.4** for the UAHEP. Highest sediment loads are associated with storm-driven flood flows, and at such times they will not operate to protect the turbines.

FIGURE 6.3: DISCHARGE VS. SEDIMENT CONCENTRATION AT UPPER ARUN HYDROELECTRIC PROJECT

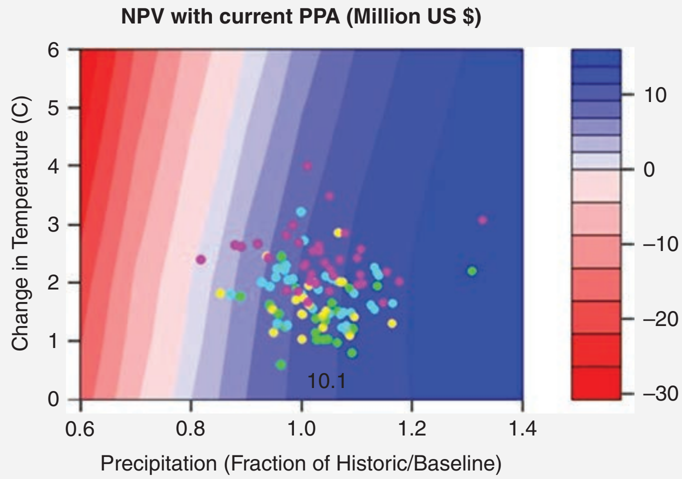




Source: University of Cincinnati, 2021.

BOX 6.1: CLIMATE CHANGE ASSESSMENT: KABELI A HYDROPOWER PROJECT, NEPAL

Kabeli A is a 38 MW peaking run of river project in Eastern Nepal, on the Kabeli River, with an expected annual average energy of 205 GWh/year. The economic lifetime of the project is 30 years, meaning that financial projections for the project must anticipate stream flow availability to the project through the year 2050, at which point the climate of the Himalayan region is likely to be substantially different from the recent past. The three main risks assessed were insufficiency of flow, flood, and increased sediment load.



Insufficiency of Flow

The project is expected to be financially profitable (NPV > 0) in all wetter future scenarios (approximately half of the uncertainty space), as well as in drier futures provided the precipitation drop is less than approximately 20 percent and the temperature rise is not more than 3°C. Neither of these conditions were considered likely within the next 30 years.

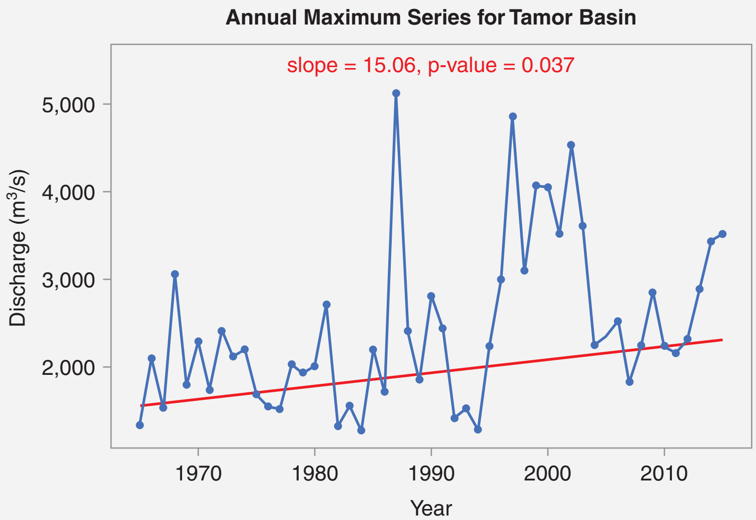
The figure illustrates the likelihood of scenarios in which NPV of financial returns under the PPA is negative (red area on the plot). (See main text below for further explanation of such response surface plots). Indeed, there are no observations in the sample space that have a negative impact on NPV: the project appears at low risk of poor economic and financial returns. However, the analysis accounts only for shifts in average annual conditions. Shifts in seasonality (or seasonal-specific results) were not closely evaluated, as the general circulation model (GCM) outputs supporting the likelihood aspects of such evaluations were not considered to have sufficiently high confidence.

Increased Flood Risk

The design flood for the KAHEP facility is the 1,000-year stream flow. Because we do not have available estimates of the consequences (either to the structure or to the downstream population) of exceedance of the 1,000-year flood, we cannot evaluate all aspects (impact and likelihood) of flood. However, the figure shows that the magnitude peak annual stream flow appears to be increasing throughout the period of the historical record (since the middle of the 20th century) and is likely to further increase in the future.

(*continues*)

BOX 6.1: CLIMATE CHANGE ASSESSMENT: KABELI A HYDROPOWER PROJECT, NEPAL (Continued)



GCMs cannot be consulted directly for credible information on the future behavior of extreme precipitation. However, when the local historical trends in extreme precipitation and stream flow are evaluated and the information from the subset of GCM that capture the monsoon processes well are reconciled, it was concluded that the magnitude of flood peaks will likely continue to increase.

The current design flood (1,000-year) magnitude is likely to correspond to a much smaller return period (i.e., it may occur every 500 years in the hydro-climate of the next century instead of every 1,000 years). When the structure was designed for what the designers understood to be a 1,000-year return period flood, the designers anticipated a risk characterized by a chance of "not failure" of the structure during the project life of .99930, or about a 3 percent chance that a 1,000-year flood would happen at least once within the project lifetime. Accounting for the historical climate trend, as well as the somewhat qualitative information from the GCMs, it was determined that the magnitude of what was historically a 1,000-year flood better corresponds to a 500-year return period flood in the project lifetime. The probability that the flood magnitude would be exceeded during the project lifetime is now 1 – .99830, or about 6 percent.

High Sediment Loads

The sediment load impact of climate change on the annual energy production was analyzed by calculating the number of days the power plant would be shut down due to excessive sediment in the river. This was accomplished by using an empirical relationship between stream flow and suspended sediment. The analysis does not take into account rolling bed load. With an increase of precipitation by 20 percent, up to a 50 percent increase in the average annual sediment concentration is expected, with a reduction in annual average energy of 2.7 GWh/year, or about 1.3 percent of the expected annual average.

BOX 6.1: CLIMATE CHANGE ASSESSMENT: KABELI A HYDROPOWER PROJECT, NEPAL (Continued)

The authors state that this increase in sediment concentration "could more than double the expected cost for turbine replacement" in the project lifetime. The report continues,

> In response to the risk of increased sediment load, this report proposes installation of coated turbines, which would increase the initial investment by 40 percent, but could help reduce the potential loss in the energy with power plant shutdown. In addition to reduction of shutdown days, coated turbines also reduce the efficiency loss associated with sediment erosion, though these improvements were not explicitly quantified in this analysis.

Such conclusions require great caution. First, it is unlikely that ceramic coating increases initial investment by 40 percent, although the 40 percent might apply just to the cost of turbine runners. Second, the economics of turbine coating are not straightforward, since they are only one option in the complex trade-offs between desanders, flushing, bypass tunnels, turbine selection (including, for a given total MW, how many and of what size), reservoir operation and cascade-wide strategies for sediment management.

Several further points are to be noted:

The calculations of NPV assume that the project experiences the climate changed future already in the first year of operation. As discussed in the text, this is unrealistic, given the judgment that extreme climate changes are unlikely over the next 30 years.

The recommendation for coated turbines highlights the difficulty of distinguishing between what is standard practice, and what could be classified as an adaptation measure. This goes beyond mere semantic differentiation; it is relevant to the ability to access new concessionary financing sources earmarked for meeting the costs of adaptation.

The impacts of insufficiency of flow and sediment load increases in wetter climate futures is more easily incorporated into standard benefit cost analysis than catastrophic events associated with floods—as will be discussed further in Annex I.

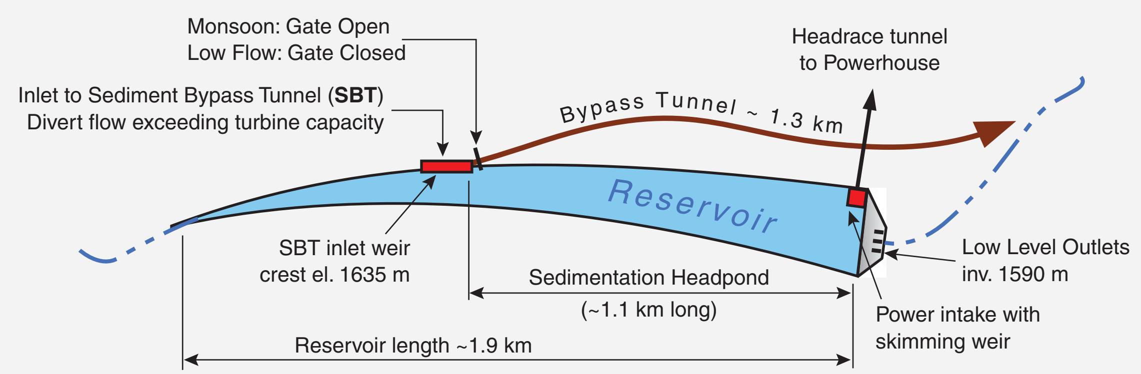
Source: Extracted, in parts verbatim, from Wasti & Ray (2019).

Four ways of releasing flows are typically available at hydropower projects of this type:

- through the turbines
- through the main gates of the dam
- through the sediment bypass tunnel (SBT), into which flows are diverted before they get into the reservoirs
- low-level outlets

The operating rule determines how this mix of flow releases are managed. How these interact at the UAHEP is shown in **Figure 6.5**.

FIGURE 6.4: THE UPPER ARUN HYDROELECTRIC PROJECT



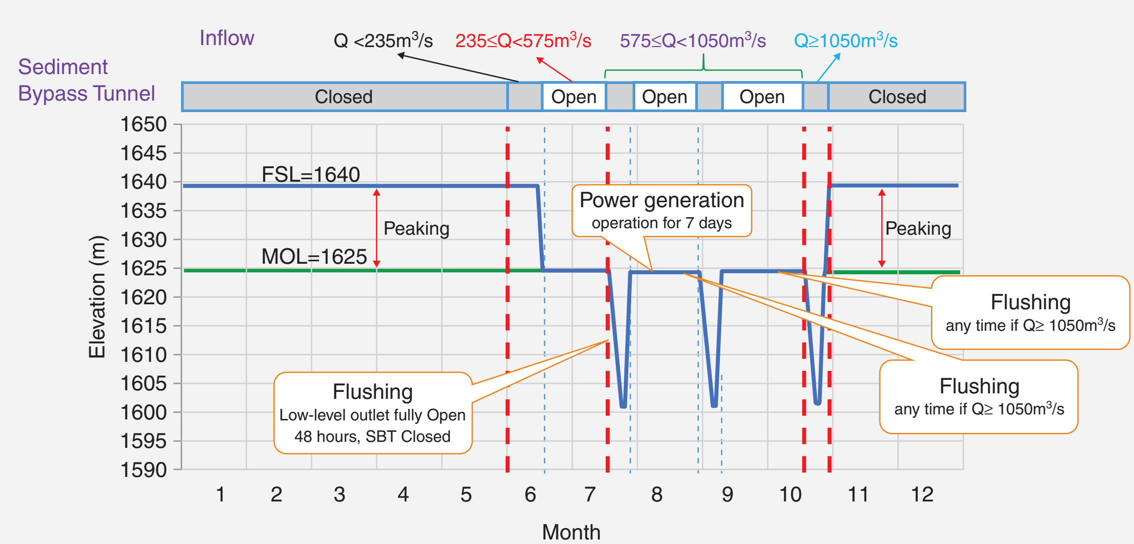
Source: CSPDR 2020, Volume II Main Report, Figure 11-4Volume IV, Annex H-1, Figure 1.2-1.

The operating rule proposed in the FS is as follows:

- **Peaking Operation Mode**: Q_{IN} < 235 cumecs. The reservoir is filled every day to elevation 1640 masl, and emptied during the peak hours, drawn down to elevation 1625 masl by the end of the day. The reservoir operation simulation model calculations for such a day appears as shown in **Table 6.3**. The sediment bypass tunnel is not used. There is no spill across the main gates of the dam.

- **Normal Wet Season**: 234 < Q < 575 cumecs: The sediment bypass tunnel discharges excess flow. All units running 24h/day (**Table 6.4**).

FIGURE 6.5: OPERATING RULE AT THE UPPER ARUN HYDROELECTRIC PROJECT



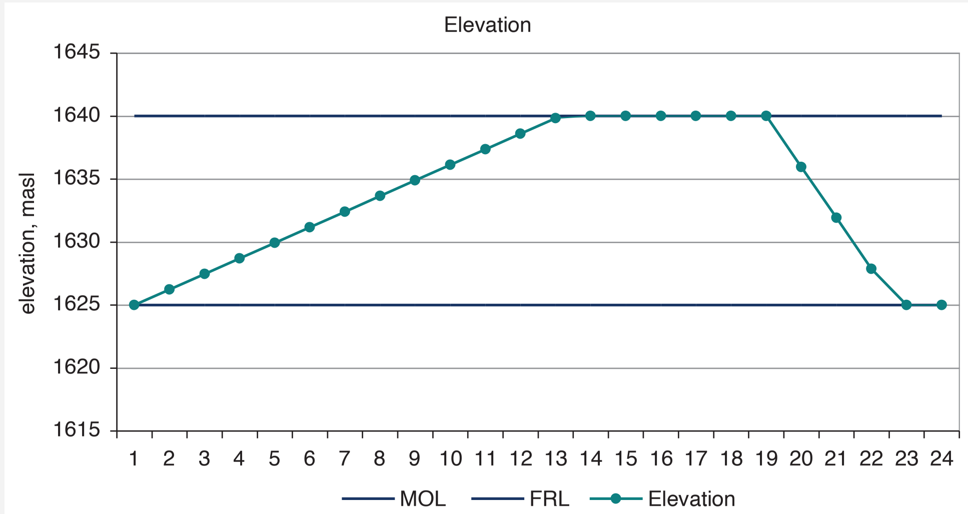
Source: CSPDR 2020, Volume II Main Report, Figure 11-13.

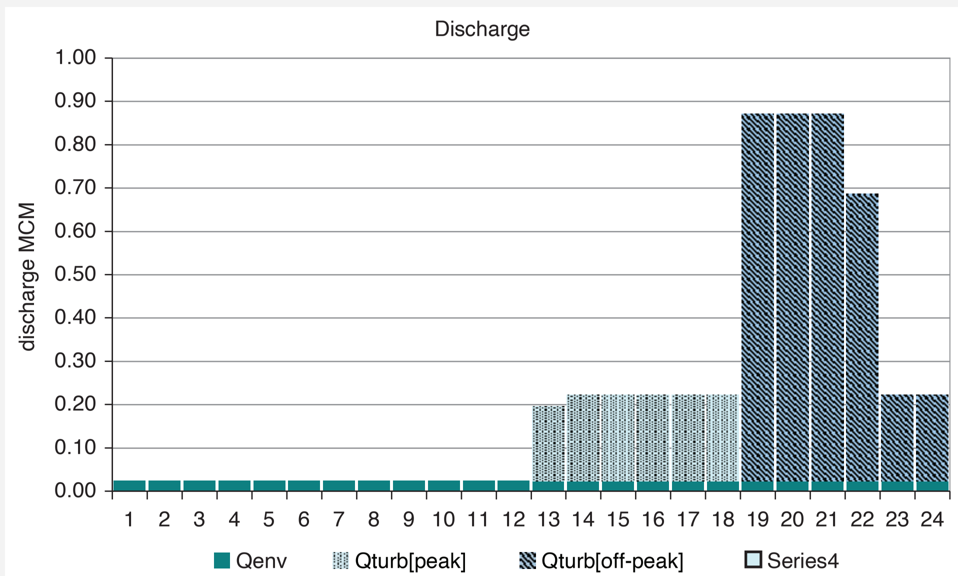
TABLE 6.3: PEAKING OPERATION: DAILY INFLOW JAN 1 2004 Q_{IN} = 61.8 CUMECS

		OFFPEAK																		PEAK					
HOUR		23	24	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
1 **Water balance**																									
2 in storage at start	[MCM]	0.000	0.199	0.397	0.596	0.794	0.993	1.192	1.390	1.589	1.788	1.986	2.185	2.383	2.410	2.410	2.410	2.410	2.410	2.410	1.761	1.112	0.463	0.000	0.000
3 inflow	[MCM]	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223
4 Qenv	[MCM]	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024
5 end storage before Qturb	[MCM]	*0.119*	*0.397*	*0.596*	*0.794*	*0.993*	*1.192*	*1.390*	*1.589*	*1.788*	*1.986*	*2.185*	*2.383*	*2.582*	*2.609*	*2.609*	*2.609*	*2.609*	*2.609*	*2.609*	*1.960*	*1.311*	*0.662*	*0.199*	*0.199*
6 minimim discharge	[MCM]	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.172*	*0.199*	*0.199*	*0.199*	*0.199*	*0.199*	*0.199*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
7 Qturb[off-peak]	[MCM]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	−0.172	−0.199	−0.199	−0.199	−0.199	−0.199						
8 Qturb[peak]	[MCM]																			−0.848	−0.848	−0.848	−0.662	−0.199	−0.199
9 spill	[MCM]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10 in storage at end	[MCM]	0.199	0.397	0.596	0.794	0.993	1.192	1.390	1.589	1.788	1.986	2.185	2.383	2.410	2.410	2.410	2.410	2.410	2.410	1.761	1.112	0.463	0.000	0.000	0.000
11 **Energy generation**																									
12 Qturb	[cumec]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47.8	55.2	55.2	55.2	55.2	55.2	235.4	235.4	235.4	183.8	55.2	55.2
13 Units in operation	[ ]	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	6	6	6	5	2	2
14 Head losses	[metres]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−9.5	−9.5	−9.5	−9.5	−9.5	−9.5	−21.7	−21.7	−21.7	−17.6	−9.5	−9.5
15 Elevation head	[metres]	530.6	531.9	533.1	534.3	535.6	536.8	538.0	539.3	540.5	541.7	543.0	544.2	544.9	545.0	545.0	545.0	545.0	545.0	543.0	538.9	534.9	531.4	530.0	530.0
16 net head	[metres]	530.6	531.9	533.1	534.3	535.6	536.8	538.0	539.3	540.5	541.7	543.0	544.2	554.4	554.5	554.5	554.5	554.5	554.5	564.7	560.7	556.6	549.0	539.5	539.5
17 generation	[MW]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	230.6	266.2	266.2	266.2	266.2	266.2	1086.0	1086.0	1086.0	878.1	259.0	259.0
19 **Elevation**																									
20 Start elevation	[metres]	1625.0	1626.2	1627.5	1628.7	1629.9	1631.2	1632.4	1633.7	1634.9	1636.1	1637.4	1638.6	1639.8	1640.0	1640.0	1640.0	1640.0	1640.0	1640.0	1636.0	1631.9	1627.9	1625.0	1625.0
21 End elevation	[metres]	1626.2	1627.5	1628.7	1629.9	1631.2	1632.4	1633.7	1634.9	1636.1	1637.4	1638.6	1639.8	1640.0	1640.0	1640.0	1640.0	1640.0	1640.0	1636.0	1631.9	1627.9	1625.0	1625.0	1625.0
22 Average elevation	[metres]	1625.6	1626.9	1628.1	1629.3	1630.6	1631.8	1633.0	1634.3	1635.5	1636.7	1638.0	1639.2	1639.9	1640.0	1640.0	1640.0	1640.0	1640.0	1638.0	1633.9	1629.9	1626.4	1625.0	1625.0

(*continues*)

TABLE 6.3: PEAKING OPERATION: DAILY INFLOW JAN 1 2004 Q_{IN} = 61.8 CUMECS (*Continued*)





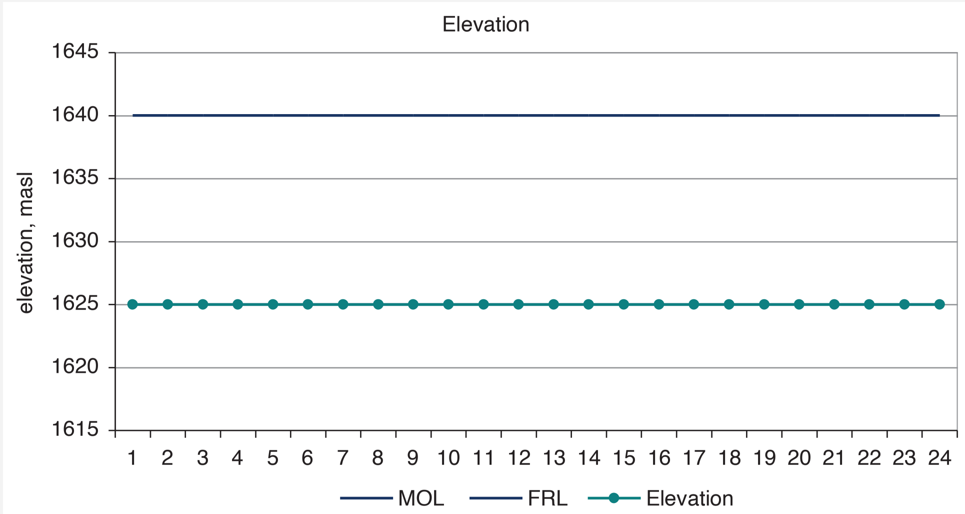
Source: Original calculations.

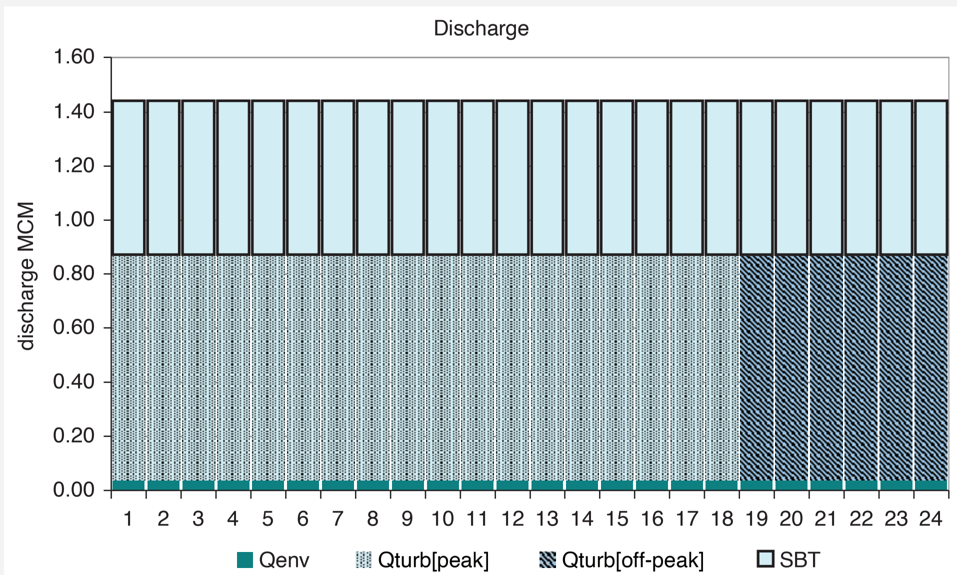
TABLE 6.4: WET SEASON FLOW, Q_{IN} = 400 CUMECS

			OFFPEAK																		PEAK					
	HOUR		23	24	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
1	**Water balance**																									
2	in storage at start	[MCM]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	inflow	[MCM]	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440
4	Qenv	[MCM]	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024	−0.024
5	end storage before Qturb	[MCM]	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*
6	minimim discharge	[MCM]	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*	*1.416*
7	Qturb[off-peak]	[MCM]	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848	−0.848						
8	Qturb[peak]	[MCM]																			−0.848	−0.848	−0.848	−0.848	−0.848	−0.848
9	spill	[MCM]	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568	−0.568
10	in storage at end	[MCM]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	**Energy generation**																									
12	Qturb	[cumec]	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4
13	Units in operation	[ ]	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
14	Head losses	[metres]	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7	−21.7
15	Elevation head	[metres]	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0	530.0
16	net head	[metres]	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7	551.7
17	generation	[MW]	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0	1086.0
19	**Elevation**																									
20	Start elevation	[metres]	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625
21	End elevation	[metres]	1625.0	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625
22	Average elevation	[metres]	1625.0	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625	1625
23	change in elevation	[m / hour]		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(continues)

TABLE 6.4: WET SEASON FLOW, Q_{IN} = 400 CUMECS (*Continued*)





Source: Original calculations.

- **Partial Flushing Mode**: 575 < Q < 1050 cumecs. Gates fully open for 48 hours, during which time no power generation occurs. Thereafter, units resume power generation for 7 days. If the flow is still above 575 cumecs at the end of the 7 days, the cycle is repeated.
- **Full Flushing Mode**: Q > 1050 cumecs. No power generation. SBT closed. Low-level outlet fully open (1590 masl). Dam gates fully open for flushing.

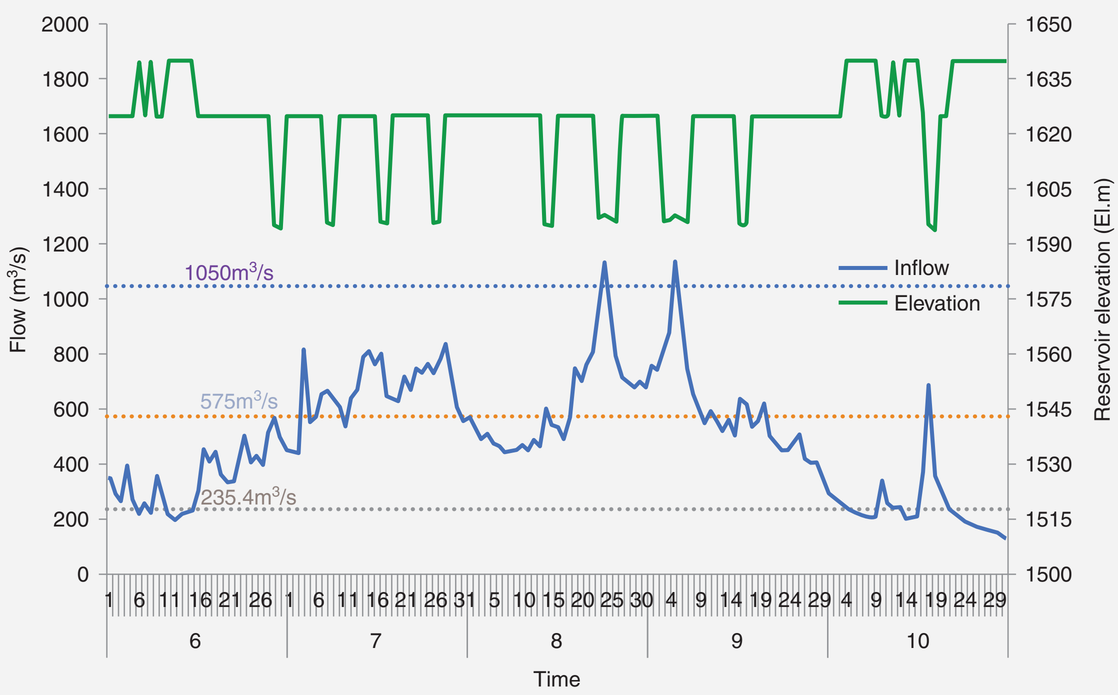
Figure 6.6 shows the resulting simulation of reservoir operations for the wet months in a typical year.

Climate Change Simulations

To assess the impact of long-term climate change requires at its heart a synthetic hydrology model that converts temperature and precipitation patterns in the watershed of the Arun River into runoff and inflow series at the dam site. Temperature and precipitation are stochastic processes and the actually observed historical inflow series is just one manifestation of a very large number of possible outcomes of the underlying drivers. **Figure 6.7** shows the output of such a hydrological model—here, 15 stream-flow traces for 2004, with the average superimposed. The model, developed by the UC, generates at each iteration daily inflows from 2004 to 2050.

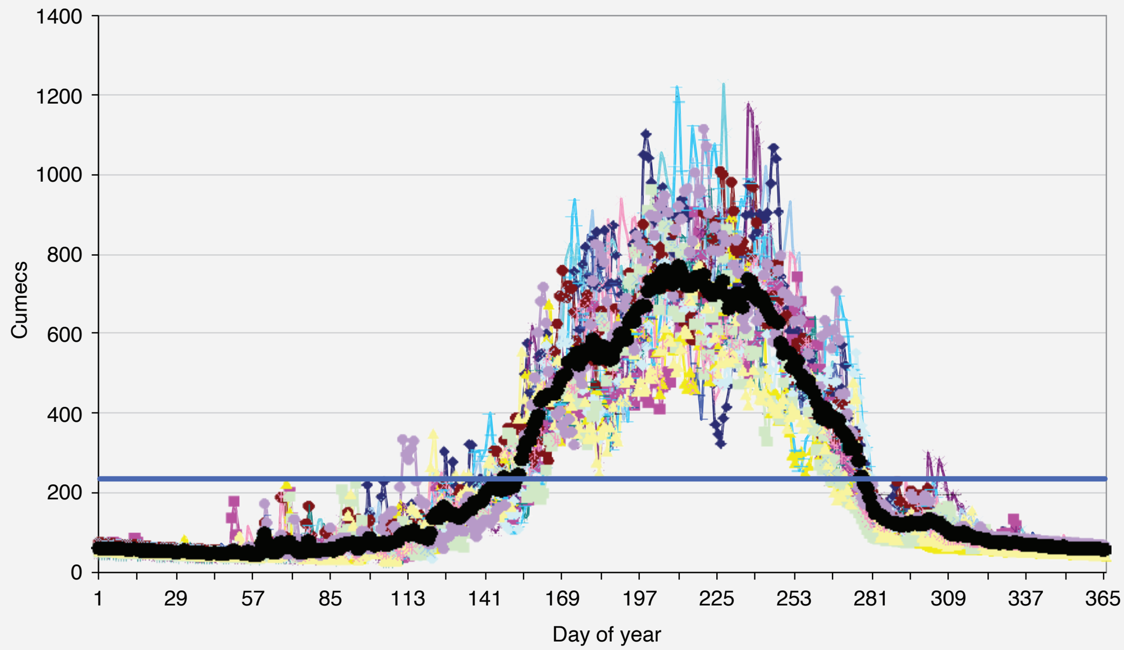
Figure 6.8 shows a typical set of 45-year stream flow traces of annual averages under no climate change, which shows the extent of variation between years. The long-term annual average is what is typically used as the basis for the energy balances, which in terms defines the benefits in the table of economic flows.

FIGURE 6.6: SIMULATION OF RESERVOIR OPERATIONS, 1985



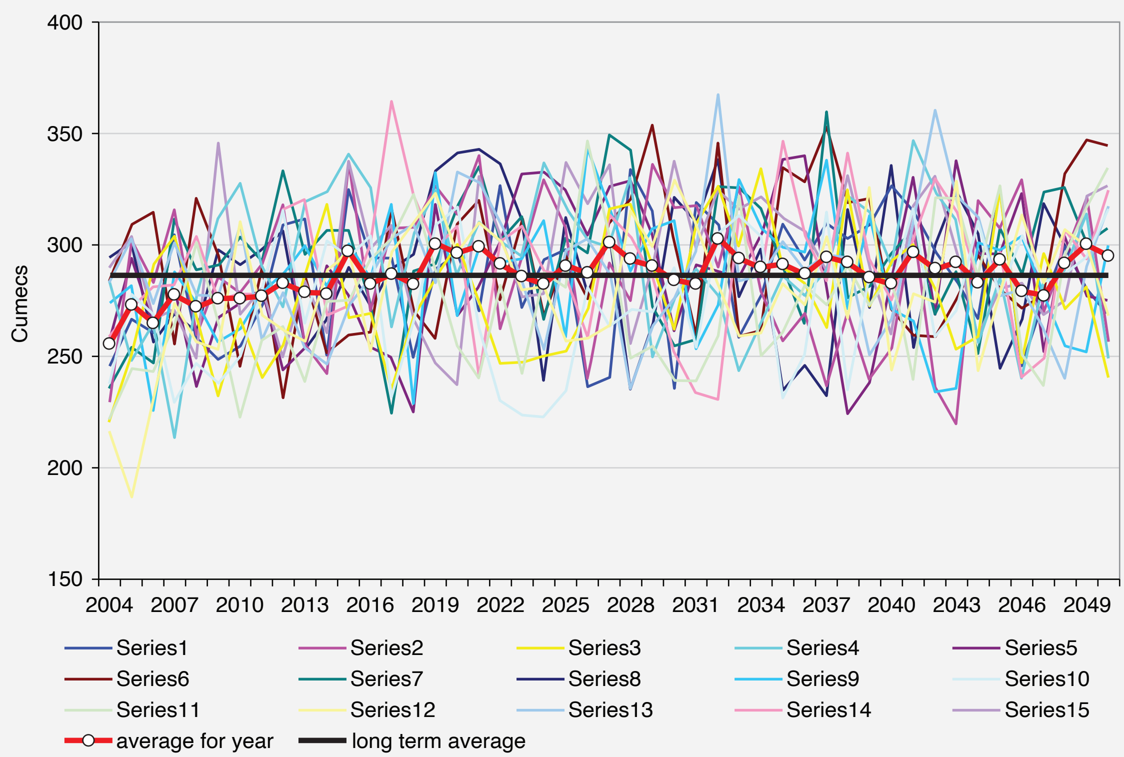
Source: CSPDR 2020.

FIGURE 6.7: SIMULATIONS OF 2004 FLOWS, NO CLIMATE CHANGE



Source: Generated from raw data used in University of Cincinnati (2021).

FIGURE 6.8: STREAM FLOW SIMULATION RESULTS: ANNUAL AVERAGES FOR 15 TRIALS, NO CLIMATE CHANGE



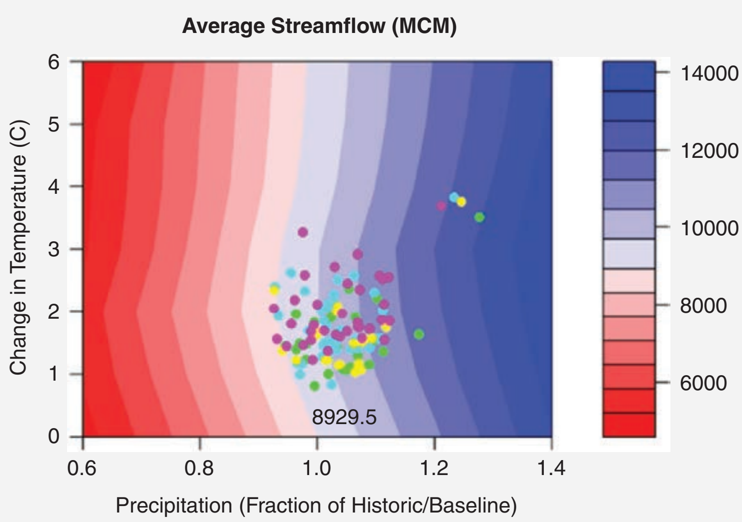
Source: Generated from raw data used in University of Cincinnati (2021).

The information from these traces can be aggregated in many different ways. In the UC model, they are aggregated into response surfaces, as shown in **Figure 6.9**. A response surface is a data visualization technique that demonstrates the sensitivity of a dependent variable based on the changes in two independent variables. In this case, the dependent variable is the annual stream flow in million cubic meters (MCM), the independent variables are (a) mean changes in precipitation (represented as a faction of the historical observations) along the horizontal axis, and (b) uniform increase in temperature (with respect to the historical observation) along the vertical axis. Each dot represents a particular forecast of annual stream flow based on different climate change model forecasts of precipitation and temperature increase (and alternative concentration pathways). The blue sections of the response surface represent increases in stream low—most of the scenarios are seen to forecast an *increase* in total annual stream flow, not a decrease. Under the most severe climate change conditions of a >3°C temperature increase, total inflow is 30 percent greater than the baseline inflow. The point at precipitation=1, and temperature increase=0 represents the present average annual stream flow of 8,929 MCM. Note that these temperature changes are as forecasted for the watershed, and not global averages.

The historical average annual flow in UAHEP is summarized as a single coordinate (1,0) at the bottom center of the figure. This observation of 8,930 MCM is sensitive to changes in climate (precipitation and temperature) and ranges between 5,000–14,000 MCM, which is indicated by the color bar on the right side of the figure. The increase in the stream flow values (in reference to the historical observation) is represented by blue and the decrease is represented by red. The response surface helps us to understand the behavior of the hydrology to changes in precipitation, changes in temperature or a combination of both. Each dot on the response surface represents the outcome of a particular

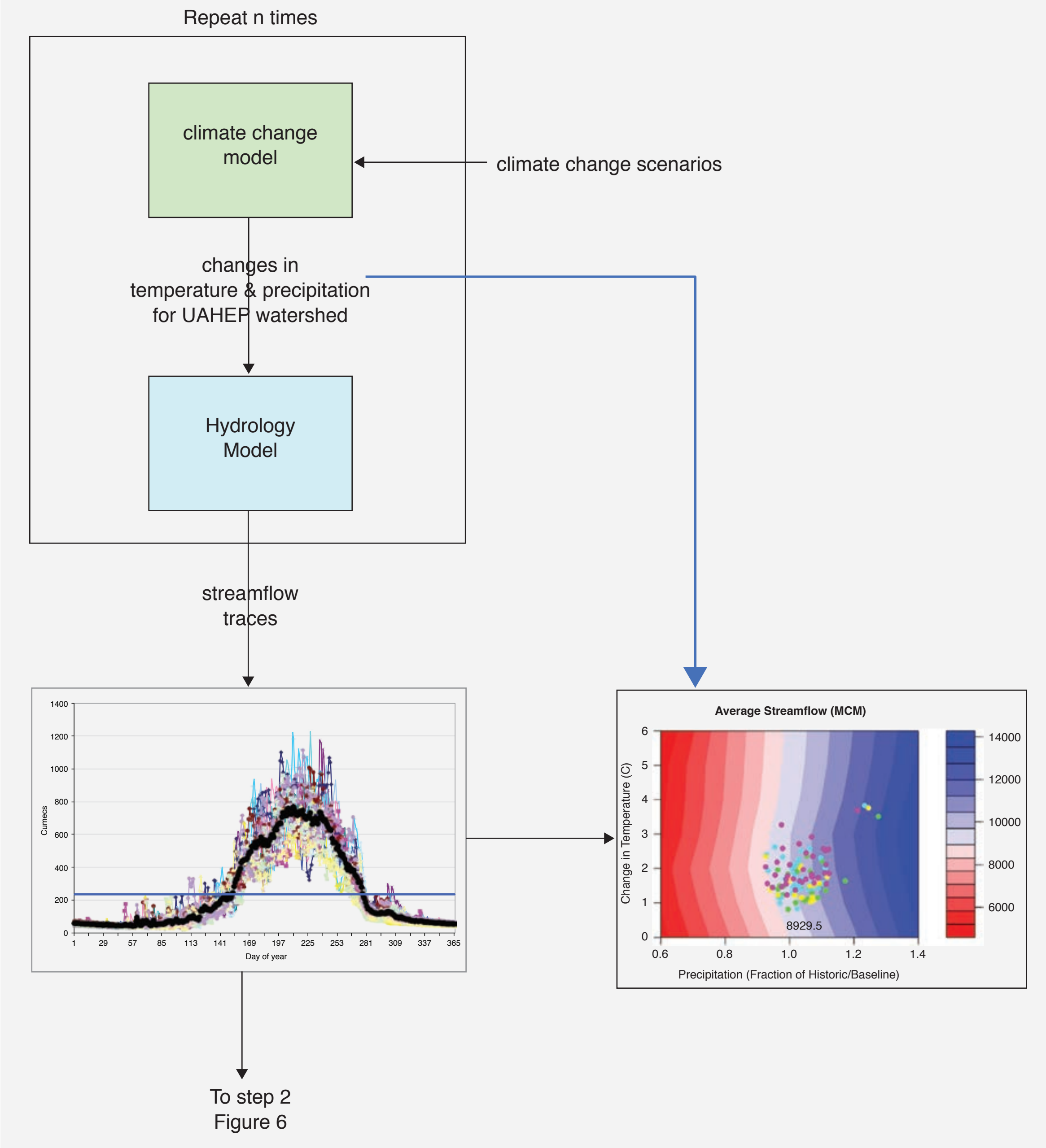
These steps in the climate change assessment of a hydropower project are illustrated in **Figure 6.10**. Each stream flow trace for each trial and climate change future is then run through the reservoir operation simulation model (as described above) to calculate the impact on average annual generation. We have noted above that the sediment management strategy is quite complex and requires a shut-down of generation during days of high inflows.

FIGURE 6.9: CLIMATE CHANGE RESPONSE SURFACE



Source: University of Cincinnati, 2021. Climate change risk assessment (CCRA) of the Upper Arun Hydropower Project in Nepal. Report to the World Bank,15 February 2021.

FIGURE 6.10: THE STEPS OF THE CLIMATE CHANGE ASSESSMENT MODEL



Source: Original calculations.

Table 6.5 shows the results of this assessment for 12 different futures represented by the rows of the table. Each future is some combination of rainfall change and temperature increase: the generation shown is the average of 15 trials in the basin hydrology simulator. In the most severe cases, generation falls by 13 percent, or *increases* by 13 percent in the very wettest, and hottest future. The impact on NPV changes accordingly. We note that even in the most severe case of a drop in rainfall, the NPV remains substantially above the hurdle rate in all cases examined (NPV > 0 at the relevant discount rate).

The difficulty with this analysis (and other similar assessments) is that the NPVs are calculated for each steady state future—in other words, if the entire project, including construction, were implemented in that future. But these changes do not apply to a project where CAPEX is expended *today*. Achieving these futures may take several years. Even under catastrophic climate change (say, with a 5°C temperature increase), the corresponding changes in stream flows will not be instantaneous.

Sedimentation Impacts

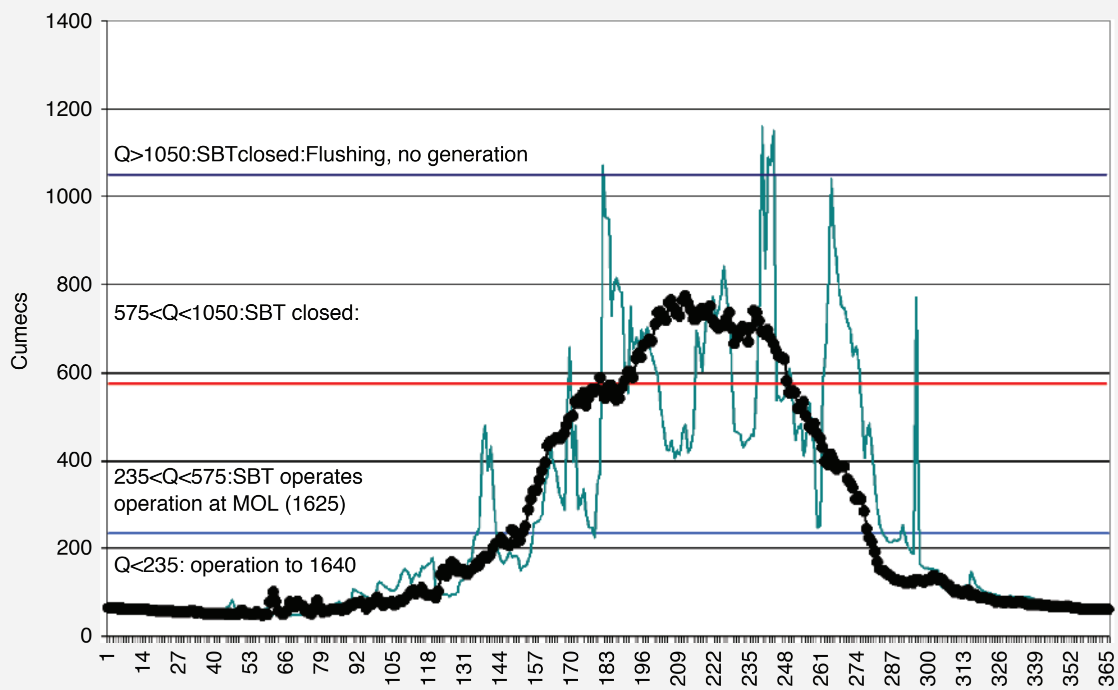
As noted above, abrasive sediment loads pose a major problem in the design of hydropower projects in many parts of the world, and the UAHEP is no exception. Given that most of the sediment loads are carried during wet season storm events, how these loads are managed is a crucial design and operational decision. With climate change often comes an intensification of storms, which changes the frequency and duration of wet season flushing days when there will be loss of generation. Therefore, it is necessary for the climate change assessment not to examine *average* generation, but to identify for each trace the number and duration of flushing days, since these imply loss of benefits.

TABLE 6.5: RESULTS OF THE CLIMATE CHANGE ASSESSMENT

RAINFALL	TEMP INCREASE	ANNUAL GENERATION	IMPACT	IMPACT AS % BASELINE	NPV	CHANGE IN NPV
%BASELINE	°C	GWh	GWh	GWh	[MILLION $US]	[MILLION $US]
baseline	0	4,504			580	
0.7	1	3,915	–589	–13.1%	433	–147
0.7	3	4,005	–499	–11.1%	455	–125
0.7	5	4,058	–446	–9.9%	471	–109
1.0	1	4,407	−97	–2.2%	551	–29
1.0	3	4,520	16	0.4%	575	–5
1.0	5	4,778	274	6.1%	630	50
1.1	1	4,514	10	0.2%	575	–5
1.1	3	4,637	133	3.0%	601	21
1.1	5	4,893	389	8.6%	655	75
1.4	1	4,601	97	2.2%	596	16
1.4	3	4,821	317	7.0%	642	62
1.4	5	5,112	608	13.5%	702	122

Source: University of Cincinnati, 2021.

FIGURE 6.11: THE OPERATING RULE



Source: Original calculations.

For example, in **Figure 6.11**, where we have selected one of the 2004 traces (the green line), we see that only on three occasions is the 1050 cumec threshold reached, but that there are also six sequences of days with flows between 575 and 1050 cumecs, when flushing would be triggered and all turbines shut down.

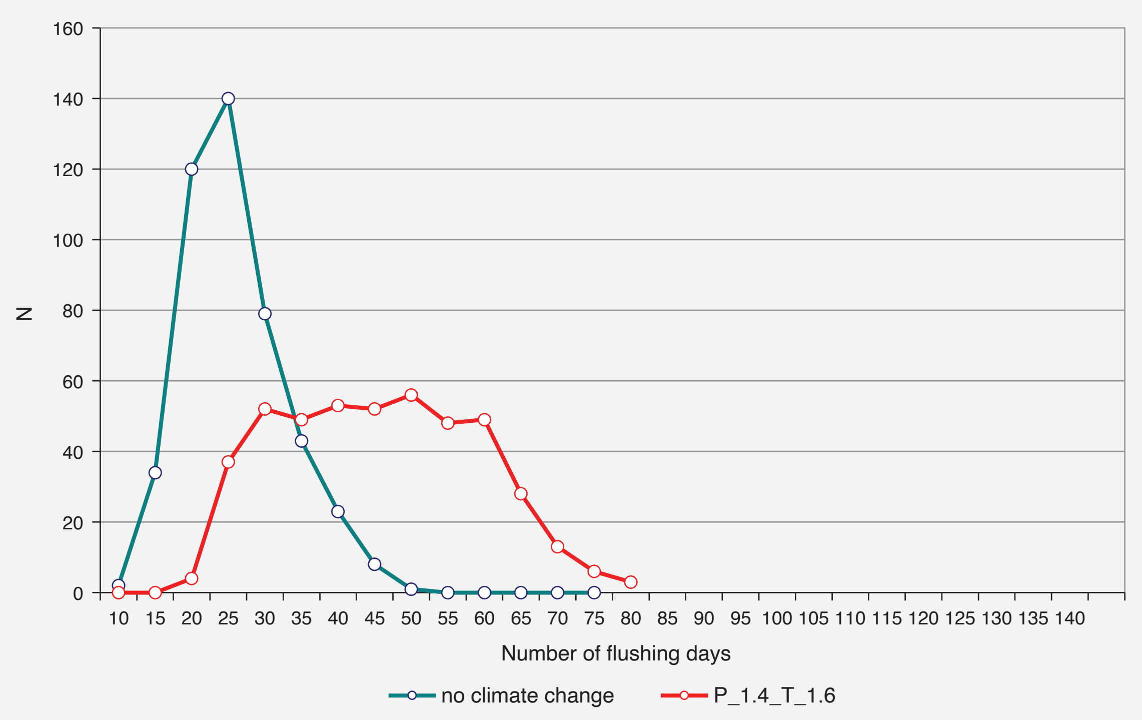
Figure 6.12 shows the frequency distribution of the number of lost days of generation due to sediment management flushing. Under no climate change (green curve), the average number of days lost to flushing per year is 20; under the climate change scenario (1.4 precipitation increase and 3°C temperature increase), the average days of flushing increases to 44.

6.3 ECONOMIC ANALYSIS

The first change is a modification of the underlying energy balances, as shown in **Table 6.6**, which makes the following assumptions for a worst-case climate change impacts as follows:

- Rapid climate change starts in 2030, so already in the first year of operation energy is 1 percent less, but declines to –13 percent by 2040, in both day and wet seasons (the extreme cases in Table 6.6); and
- By 2040, the average number of flushing days increases from 20 to 40.

FIGURE 6.12: FREQUENCY DISTRIBUTION OF FLUSHING DAYS



Source: Original calculations.

These parameters are changed in Model section 11, and then transferred into rows [11]-[16] of the project energy balances (section 12). The combined impact of lower inflows, but significant intensification of storms, is to cause a 24 percent decrease in generation by 2040, over the no climate change scenario. This is indeed a worst case, that may be considered quite unlikely—but that is precisely the point: what is the impact of the worst case, were it to occur? This is the lesson drawn from the 2007–2008 financial crash: the focus was on expected values, not on the resilience of the banking system to a series of frauds and miscalculations outside the grasp of regulators.

In the absence of climate change, the ERR for the UAHEP is 14.5 percent, increasing to 23 percent when GHG emission benefits are included. However, given the asymmetry of input assumption probability distributions, the expected value of economic returns in the Monte Carlo simulation fall to 11.1 percent, and 18.6 percent when GHG emission benefits are included (Figure 6.12).

The distribution of returns shifts to the right when GHG emission reduction benefits are included: The risk of not meeting the hurdle rate of 8 percent reduces from 18 percent to close to 0 percent (**Figure 6.13**).

How do these assessments of economic returns change under a scenario of worst-case climate change impacts—taken here as flushing days increasing to 40 per year, and a 24 percent decrease in inflows by 2040)? The ERR declines, but only by a small decrement—from 14.5 percent to 13.1 percent (**Table 6.7**).

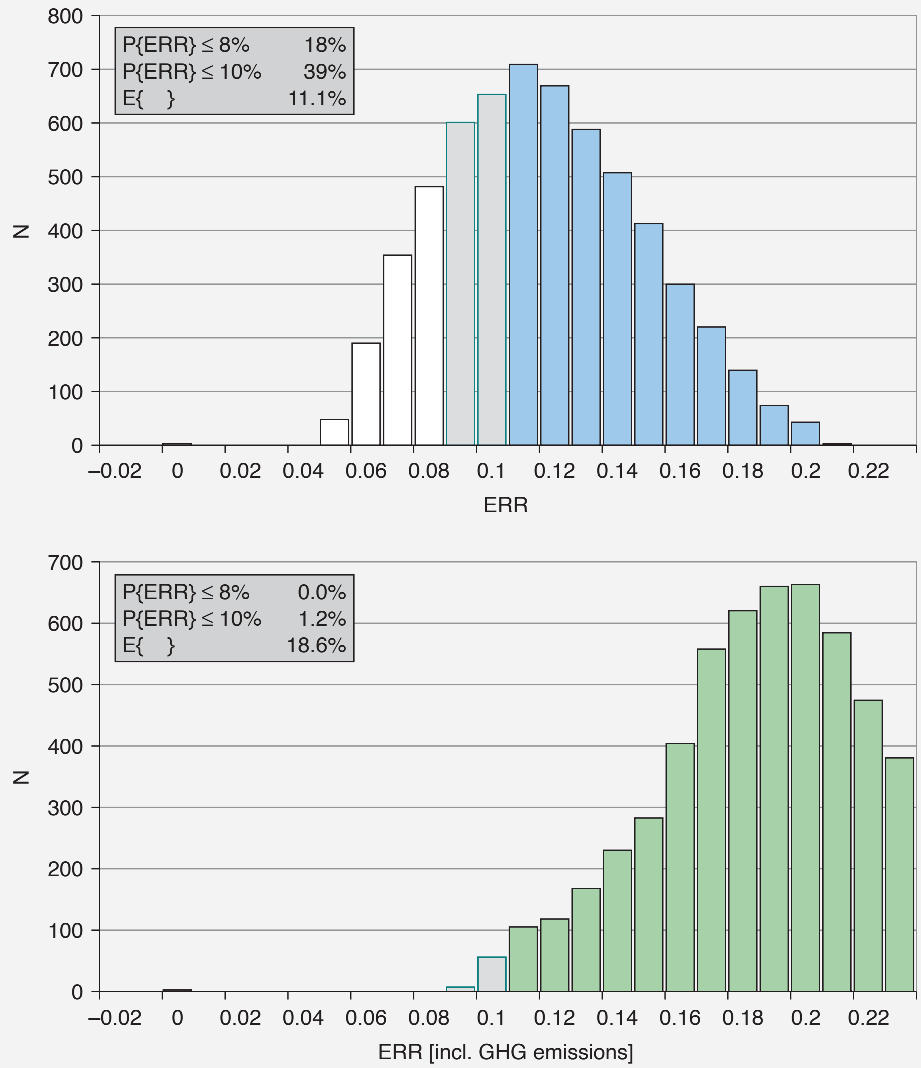
TABLE 6.6: UPDATED ENERGY BALANCES

	11 CLIMATE CHANGE IMPACTS		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
		TOTAL DELTA	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
[1]	change in dry GWh	**−0.13**	−0.01	−0.03	−0.04	−0.05	−0.07	−0.08	−0.09	−0.10	−0.12	−0.13	−0.13	−0.13
[2]	change in wet GWh	**−0.13**	−0.01	−0.03	−0.04	−0.05	−0.07	−0.08	−0.09	−0.10	−0.12	−0.13	−0.13	−0.13
[3]	additional flushing day	**20**	2	4	6	8	10	12	14	16	18	20	20	20
[4]	flushday GWh peak		−12	−25	−37	−50	−62	−75	−87	−100	−112	−125	−125	−125
[5]	flushday GWh offpeak		−37	−75	−112	−150	−187	−225	−262	−300	−337	−374	−374	−374
[6]														
[7]														
[8]	*Notes*													
[9]	***Flushing day fractions:*** GWh/day													
[10]	peak	6.24												
[11]	off-peak	18.72												

12 Project Energy balance		Resiliance Study: Worst Case climate change												
			2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
			1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
[1]	**Gross generation**													
[2]	Dry season peak	[GWh]	**836**	835	834	833	833	832	831	830	829	829	828	827
[3]	Dry season-offpeak	[GWh]	**424**	424	423	423	422	422	421	421	421	420	420	419
[4]	Wet season peak	[GWh]	**959**	958	957	956	955	954	953	952	951	950	949	949
[5]	Wet season off-peak	[GWh]	**2313**	2311	2308	2306	2304	2301	2299	2297	2295	2292	2290	2288
[6]	**total gross generation**	**[GWh]**	**4532**	**4527**	**4523**	**4518**	**4514**	**4509**	**4505**	**4500**	**4496**	**4491**	**4487**	**4482**
[7]	**Adjustments**													
[8]	own use	[ ]	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
[9]	outages	[ ]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
[10]	**Climate change impacts**													
[11]	Dry season peak	[GWh]	−11	−22	−33	−43	−54	−65	−76	−86	−97	−108	−108	−107
[12]	Dry season-offpeak	[GWh]	−6	−11	−17	−22	−27	−33	−38	−44	−49	−55	−55	−55
[13]	Wet season peak	[GWh]	−25	−50	−75	−100	−124	−149	−174	−199	−224	−248	−248	−248
[14]	Wet season off-peak	[GWh]	−68	−135	−202	−270	−337	−404	−471	−538	−605	−672	−672	−672
[15]	total adjustment	[GWh]	−109	−218	−326	−435	−543	−651	−759	−867	−975	−1083	−1082	−1082
[16]		[%]	−2%	−5%	−7%	−10%	−12%	−14%	−17%	−19%	−22%	−24%	−24%	−24%
[17]	**energy at meter**													
[18]	Dry season peak	[GWh]	821	809	798	786	774	763	751	740	728	717	716	715
[19]	Dry season-offpeak	[GWh]	416	410	405	399	393	387	381	375	369	363	363	363
[20]	Wet season peak	[GWh]	929	903	878	852	826	800	774	749	723	697	696	696
[21]	Wet season off-peak	[GWh]	2234	2164	2094	2025	1955	1886	1816	1747	1678	1608	1606	1604
[22]	**total energy sold**	**[GWh]**	**4401**	**4287**	**4174**	**4061**	**3948**	**3836**	**3723**	**3610**	**3498**	**3386**	**3382**	**3378**

Source: Original calculations.

FIGURE 6.13: BASELINE ECONOMIC RETURNS, NO CLIMATE CHANGE



Source: Original calculations.

TABLE 6.7: IMPACT OF CLIMATE CHANGE ON BASELINE ECONOMIC RETURNS

	BASELINE	WORST CASE CLIMATE CHANGE
ERR	14.5	13.1 percent
ERR incl. GHG	22.3 percent	20.6 percent
NPV (8 percent)	$673 million	$486 million
NPV incl GHG	$2,101 million	$1,646 million

Source: Original calculations.

This result is for the worst-case climate change scenario—at its worst plausible outcome. However as noted, both the timing and magnitude of the climate change are subject to uncertainty, captured in the quantitative risk assessment by including *all* futures in the plausible range. In such a simulation one would look at drier futures as well as wetter futures—so a 13 percent decrease in flows as well as a 13 percent increase in flows (and related impact of flushing days), and on timing, reaching each climate change future not in 2040 (the worst case) but as far out as 2070.

The result is shown in **Figure 6.14**. We note:

- A flattening of the distribution—a consequence of the wider range of futures considered
- Expected values are only slightly lower than the no climate change value—10.9 percent as against 11.1 percent (in Figure 6.13). And when GHG benefits are included, 18.3 percent rather than 18.6 percent

However, the risk of not meeting the hurdle rate has increased by a somewhat greater extent. With climate change impacts included, the risk of not meeting the 8 percent hurdle rate has increased from 18 percent to 21 percent.

One may conclude that the inclusion of *chronic* climate change impacts (insufficiency of flow, increase in the number of flushing days), has only a small impact on economic returns. The analysis of the Trung Son hydropower project in Vietnam showed a similar decline of just a few percent in the ERR. In any event, there is little one can do to mitigate insufficiency of flow at the *project* design level, and an increase in flushing days has a relatively modest impact because the economic value of wet season energy (particularly in an all-hydropower system such as Nepal) is much lower than dry season energy. Compared to the construction risk (CAPEX increases and delays) chronic climate change impacts have little impact. Headline rates of ERR and NPV are little threatened by climate change risks for the UAHEP. It also follows that the magnitude of the impact of asymmetric risks in the main assumptions—CAPEX, duration of construction time, and benefit estimation—is similar to that of *worst-case* climate change. But the former risks are much more likely than the latter for a project built today.

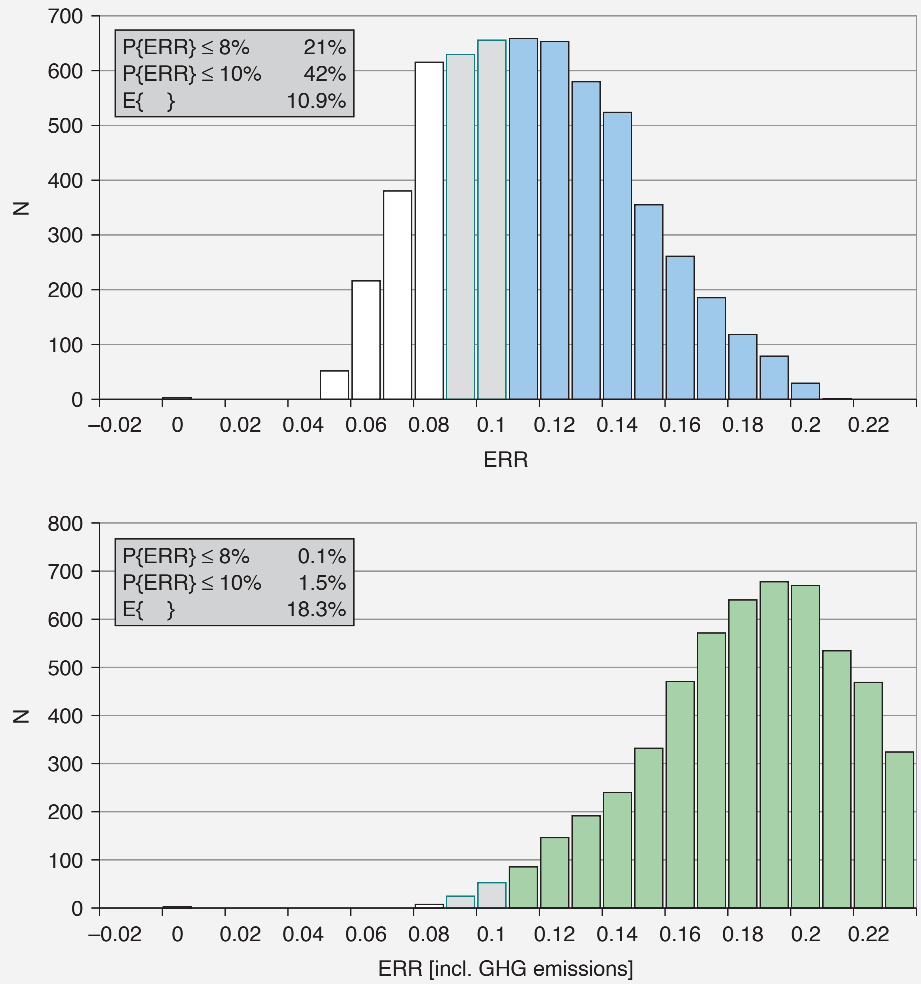
Hazard Assessment

The recent experiences in Nepal and Vietnam illustrate well the most likely acute hazard events, which include:

- Severe storms during construction when structures not yet fully protected; and
- Landslides, both upstream and downstream of projects, that result in powerhouse flooding (overtopping as a consequence of a slide into a reservoir or flooding by water backing up into the tail water and powerhouse as a consequence of a landslide immediately downstream of a project).

To assess the impact of such events requires expansion of the traditional table of economic flows. **Table 6.8** shows the baseline estimate of returns, with an ERR of 14.3 percent and NPV of $673 million (before inclusion of GHG emission benefits). This estimate is somewhat lower than that reported in the FS because it assesses benefits at Arun Hub a few kilometers from the project, rather than at the location where benefits are received (for domestic sales in the major load center at Kathmandu, and for exports in India, thereby including additional T&D losses). Rows have been added for hazard damage costs, insurance, and adaptation costs (with entries to be described below).

FIGURE 6.14: PROBABILITY DISTRIBUTION OF ECONOMIC RATE OF RETURN, INCLUDING CLIMATE CHANGE



Source: Original calculations.

Table 6.9 shows the impact of a powerhouse flooding in year 3, with a 9-month repair time and a repair cost of 15 percent of the original CAPEX. The returns fall from 14.5 percent to 12.8 percent, with the loss of $154 million in NPV, under the assumption that such flooding occurs just once in the life of the project.

Obviously, the more often such an event occurs, the greater the impact—something that would be tested in a switching value analysis. In this case, it would have to occur every two years—an exceptionally unlikely event—for the ERR to fall to the 8 percent hurdle rate. One may conclude that plausible worst-case events of this kind have only a small impact on economic returns—understandable, given economic lives of 50 years and more.

TABLE 6.8: BASELINE ECONOMIC RETURNS

				2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
			NPV	**-8**	**-7**	**-6**	**-5**	**-4**	**-3**	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**
[22]	**total benefits**	**[$USm]**	*1571*	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**347**	**347**	**346**	**346**	**346**	**215**
[23]	**Costs**																	
[24]	**CAPEX**																	
[25]	Disbursement	[ ]		0.005	0.019	0.024	0.045	0.116	0.187	0.265	0.197	0.141						
[26]	Investment	[$USm]	*0*															
[27]	SCF adjustment	[$USm]	*0*															
[28]	CAPEX, shadow priced	[$USm]	*−762*	−6	−24	−31	−57	−147	−237	−335	−249	−179						
[29]	**Life extension**																	
[30]	E&M	[$USm]	*−20*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[31]	Civil	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[32]	**Hazard damage costs**																	
[33]	repair costs	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[39]	Lost revenue	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[40]	**Adaptation costs**	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[41]	**OPEX**																	
[42]	Insurance	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[43]	Fixed O&M	[$USm]	*−116*	0	0	0	0	0	0	0	0	0	−19	−19	−19	−19	−19	−19
[44]	Sediment abraison repair	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[45]	**total costs**		*−899*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**−19**	**−19**	**−19**	**−19**	**−19**	**−19**
[46]	levelized economic cost	[USc/k]	−3.28															
[47]	**Net economic flows**	**[$USm]**	*673*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**328**	**328**	**327**	**327**	**327**	**196**
[48]	**ERR**	[ ]	***14.5%***													0.007	0.049	0.068
[49]	Local externalities	[$USm]		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[50]	**Net economic flows**	**[$USm]**	*673*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**328**	**328**	**327**	**327**	**327**	**196**
[51]	ERR(+Local ENV)	[ ]	***14.5%***															
[52]	GHG emissions	[$USm]		0	0	0	0	0	0	0	0	0	177.2	181.0	186.8	190.5	194.3	198.1
[53]	**Net economic flows**	**[$USm]**	*2,101*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**505**	**509**	**514**	**518**	**521**	**394**
[54]	ERR(+Local+Global)	[ ]	***22.3%***												0.044	0.103	0.141	0.160

Note: some rows are hidden for the sake of legibility.

Source: Original calculations.

TABLE 6.9: ECONOMIC RETURNS WITH A POWERHOUSE FLOODING IN YEAR 3

				2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
			NPV	-8	-7	-6	-5	-4	-3	-2	-1	0	1	2	3	4	5	6
[22]	**total benefits**	**[$USm]**	*1571*	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**347**	**347**	**346**	**346**	**346**	**215**
[23]	**Costs**																	
[24]	**CAPEX**																	
[25]	Disbursement	[ ]		0.005	0.019	0.024	0.045	0.116	0.187	0.265	0.197	0.141						
[26]	Investment	[$USm]	*0*															
[27]	SCF adjustment	[$USm]	*0*															
[28]	CAPEX, shadow priced	[$USm]	*−762*	−6	−24	−31	−57	−147	−237	−335	−249	−179						
[29]	**Life extension**																	
[30]	E&M	[$USm]	*−20*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[31]	Civil	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[32]	**Hazard damage costs**																	
[33]	repair costs	[$USm]	*−50*	0	0	0	0	0	0	0	0	0	0	0	−127	0	0	0
[39]	Lost revenue	[$USm]	*−103*	0	0	0	0	0	0	0	0	0	0	0	−260	0	0	0
[40]	**Adaptation costs**	[$USm]	*0*	0	0	0	0	0	0									
[41]	**OPEX**																	
[42]	Insurance	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[43]	Fixed O&M	[$USm]	*−116*	0	0	0	0	0	0	0	0	0	−19	−19	−19	−19	−19	−19
[44]	Sediment abraison repair	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[45]	**total costs**		*−1052*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**−19**	**−19**	**−406**	**−19**	**−19**	**−19**
[46]	levelized economic cost	[USc/k]	−3.84															
[47]	**Net economic flows**	**[$USm]**	*519*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**328**	**328**	**−60**	**327**	**327**	**196**
[48]	**ERR**	[ ]	***12.8%***														−0.002	0.024
[49]	Local externalties	[$USm]		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[50]	**Net economic flows**	**[$USm]**	*519*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**328**	**328**	**−60**	**327**	**327**	**196**
[51]	ERR(+Local ENV)	[ ]	***12.8%***															
[52]	GHG emissions	[$USm]		0	0	0	0	0	0	0	0	0	177.2	181.0	186.8	190.5	194.3	198.1
[53]	**Net economic flows**	**[$USm]**	*1,947*	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**505**	**509**	**127**	**518**	**521**	**394**
[54]	ERR(+Local+GLobal)	[ ]	***20.8%***														0.107	0.131

Source: Original calculations.

Financial Impacts

The same thing, however, is not true of financial returns. The UAHEP will be implemented by a SPV, the Upper Arun Hydropower Power Company, in which the Nepal Electricity Authority will have majority ownership—but if it is to attract other investors, the SPV will need to be run along commercial lines with an adequate equity return. Loss of revenue over 9 months following a powerhouse flooding during the early years of highest debt service obligations would have serious financial consequences for the UAHPC.

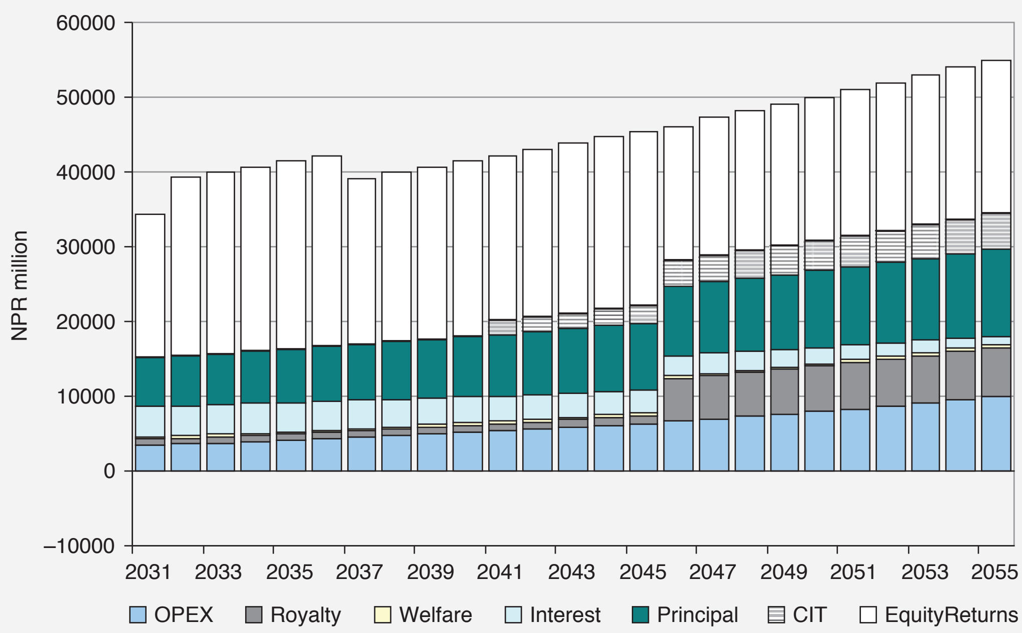
The baseline tariff assumes:

- 12 percent return on equity
- 30:70 equity-to-debt ratio
- $600 million concessionary finance (IDA and regional IDA) 38 years at 2.24 percent interest rate (and service charge), with the balance funded at 20 years at 5 percent

These assumptions lead to NPR 9.9/kWh (5.13 USc/kWh) in the first year of operation (nominal) and escalated thereafter at the US$ CPI. The first-year debt service cover ratio (DSCR) is a healthy 2.5. The revenue requirement—*excluding* equity returns—in year 3 is some NPR 16 billion ($83 million) (Figure 6.15).

It follows that in a serious hazard incidence year, with so high a debt service coverage ratio, the loss of revenue associated with six-month generation outage, could easily be absorbed by cutting the dividend—albeit at a hit to the equity return. But under the same scenario as in the economic analysis, namely a 9-month loss of generation *and* a 15 percent CAPEX repair bill, there is NPR 33.5 billion loss in 2033, rather than the expected NPR 12.2 billion profit.

FIGURE 6.15: UPPER ARUN HYDROELECTRIC PROJECT REVENUE REQUIREMENTS



Source: Original calculations.

But as shown in **Table 6.10**, even with a two-year dividend cut, the cash balance would still be negative.

Obviously, some additional measure would be required. **Table 6.11** shows the impact of a NPR33 billion short-term recovery loan from the Government of Nepal, repayable over three years at 8 percent interest, and with a one-year suspension of dividends. This results in zero dividend payment in year 3, and reduced payouts in years 4, 5, and 6. With this gap in dividend payments, the FIRR falls to 10.5 percent. Under such financial assistance, the project remains financially viable.

In Section 1.3, we noted resilience described in terms of the ability to recovery from shocks and stresses, which is the point of this illustrative assessment of the impacts on the UAHEP financials.

This hazard event may be viewed as excessively severe, and/or highly unlikely. That may be so, but the point here is one of methodology: it is not sufficient to merely examine the impact of hazard events on the economic returns. Plausible worst-case hazard and acute climate change impacts also need to be tested in the financial analysis of a project appraisal.

Insurance

If indeed the incidence of catastrophic storms and related flood events increases over time, insurance premiums will increase. It seems likely that insurance companies will set premiums based on recent experience—in India, insurance for power projects is renegotiated annually, so the focus will be on the year (or two) ahead, not 10 or 20 years ahead.

An annual insurance premium of 5 percent of project cost at UAHEP—some $63 million a year—reduces the economic returns at UAHEP from 14.5 percent to 11.1 percent (**Table 6.12**). In NPV terms, that is 50 percent of the CAPEX (at 8 percent discount rate), **which suggests that up-front resilience investments have very high returns.**

This is illustrated in **Table 6.13**, where we assume that $100 million in additional CAPEX for upfront adaptation costs reduce the insurance premium from 5 percent to 1.5 percent. The impact on economic return is now much smaller, reducing to just 12.7 percent.

One may note that the UAHEP FS is completely silent on the question of insurance, whether as an incremental cost during construction, or as part of operation and maintenance (O&M) costs once in operation. Such an assessment should surely be part of any economic analysis for climate risk assessment.

6.4 CONCLUSIONS AND LESSONS

Main Findings

This case study illustrates several important points:

- **Risks around engineer's estimates of the most likely assumptions on key parameters are rarely symmetric**, even when generous allowances are made for physical contingencies: construction times and construction costs are more likely to be higher than lower. The result is that the baseline estimate under expected "most likely" assumptions tend to be overestimated, and the expected value of economic returns, emerging from a Monte Carlo simulation using asymmetric risks, will be lower.

TABLE 6.10: EXTRACT FROM THE BALANCE SHEET, YEAR 3 HAZARD EVENT

			2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
			1	2	3	4	5	6	7	8	9	10
[1]	**ASSETS**											
[2]	Cash	[NPRm]	748	797	−19,069	238	898	935	973	1,013	1,054	1,097
[3]	Accounts receivable	[NPRm]	4,383	4,466	4,550	4,637	4,725	4,815	4,906	4,999	5,094	5,191
[4]	DSRA balance	[NPRm]	0	0	0	0	0	0	0	0	0	0
[5]	Major Maintenance escrow	[NPRm]	0	0	0	0	0	0	0	0	0	0
[6]	Fixed assets at cost	[NPRm]	209,834	209,834	209,834	209,834	209,834	209,834	209,834	209,834	209,834	209,834
[7]	VAT refunds due	[NPRm]	18,411	14,838	11,198	7,489	3,709	0	0	0	0	0
[8]	CWIP	[NPRm]										
[9]	Life extension asset	[NPRm]	0	0	0	0	0	0	0	0	0	0
[10]	less cummulative depreciation	[NPRm]	−8,393	−16,787	−25,180	−33,573	−41,967	−50,360	−58,754	−67,147	−75,540	−83,934
[11]	**total assets**	[NPRm]	**224,982**	**213,149**	**181,333**	**188,624**	**177,199**	**165,223**	**156,959**	**148,699**	**140,442**	**132,188**
[12]	**LIABILITIES&EQUITY**											
[13]	short term liabilities A/P	[NPRm]	374	399	4,240	392	449	467	487	506	527	549
[14]	short term loan	[NPRm]	0	0	0	0	0	0	0	0	0	0
[15]	***long term liabilities***											
[16]	IDA	[NPRm]	30,166	29,802	29,402	28,964	28,487	27,969	27,408	26,804	26,153	25,454
[17]	Regional IDA	[NPRm]	30,166	29,802	29,402	28,964	28,487	27,969	27,408	26,804	26,153	25,454
[18]	IBRD/IFI	[NPRm]	100,098	98,889	97,561	96,108	94,525	92,806	90,947	88,941	86,782	84,463
[19]	NPR loan	[NPRm]	0	0	0	0	0	0	0	0	0	0
[20]	GoN loan	[NPRm]	0	0	0	0	0	0	0	0	0	0
[21]	total	[NPRm]	160,805	158,892	160,604	154,427	151,947	149,211	146,250	143,055	139,615	135,921
[22]	Paid-in equity	[NPRm]	69,965	69,965	69,965	69,965	69,965	69,965	69,965	69,965	69,965	69,965
[23]	retained earnings	[NPRm]	−5,788	−15,708	−49,236	−35,768	−44,713	−53,953	−59,256	−64,321	−69,139	−73,698
[24]	total equity	[NPRm]	64,177	54,257	20,729	34,197	25,252	16,012	10,709	5,644	827	−3,733
[25]	**Total liabilities and equity**	[NPRm]	**224,982**	**213,149**	**182,333**	**188,624**	**177,199**	**165,223**	**156,959**	**148,699**	**140,442**	**132,188**

Source: Original calculations.

TABLE 6.11: FINANCIAL RECOVERY LOAN

24 BALANCE SHEET

			2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
			1	2	3	4	5	6	7	8	9	10
[1]	**ASSETS**											
[2]	Cash	[NPRm]	748	797	800	782	895	934	973	1,013	1,054	1,097
[3]	Accounts receivable	[NPRm]	4,383	4,466	4,550	4,637	4,725	4,815	4,906	4,999	5,094	5,191
[4]	DSRA balance	[NPRm]	0	0	0	0	0	0	0	0	0	0
[5]	Major Maintenance escrow	[NPRm]	0	0	0	0	0	0	0	0	0	0
[6]	Fixed assets at cost	[NPRm]	209,834	209,834	209,834	209,834	209,834	209,834	209,834	209,834	209,834	209,834
[7]	VAT refunds due	[NPRm]	18,411	14,838	11,198	7,489	3,709	0	0	0	0	0
[8]	CWIP	[NPRm]										
[9]	Life extension asset	[NPRm]	0	0	0	0	0	0	0	0	0	0
[10]	less cummulative depreciation	[NPRm]	−8,393	−16,787	−25,180	−33,573	−41,967	−50,360	−58,754	−67,147	−75,540	−83,934
[11]	**total assets**	[NPRm]	**224,982**	**213,149**	**201,202**	**189,168**	**177,196**	**165,222**	**156,959**	**148,699**	**140,442**	**132,188**
[12]	**LIABILITIES&EQUITY**											
[13]	short term liabilities A/P	[NPRm]	374	399	4,239	391	448	467	487	506	527	549
[14]	short term loan	[NPRm]	0	0	22,000	14,667	7,333	0	0	0	0	0
[15]	***long term liabilities***											
[16]	IDA	[NPRm]	30,166	29,802	29,402	28,964	28,487	27,969	27,408	26,804	26,153	25,454
[17]	Regional IDA	[NPRm]	30,166	29,802	29,402	28,964	28,487	27,969	27,408	26,804	26,153	25,454
[18]	IBRD/IFI	[NPRm]	100,098	98,889	97,561	96,108	94,525	92,806	90,947	88,941	86,782	84,463
[19]	NPR loan	[NPRm]	0	0	0	0	0	0	0	0	0	0
[20]	GoN loan	[NPRm]	0	0	0	0	0	0	0	0	0	0
[21]	total	[NPRm]	160,805	158,892	182,603	169,092	159,279	149,211	146,250	143,055	139,615	135,921
[22]	Paid-in equity	[NPRm]	69,965	69,965	69,965	69,965	69,965	69,965	69,965	69,965	69,965	69,965
[23]	retained earnings	[NPRm]	−5,788	−15,708	−51,366	−49,890	−52,048	−53,954	−59,256	−64,321	−69,139	−73,698
[24]	total equity	[NPRm]	64,177	54,257	18,600	20,075	17,917	16,012	10,709	5,644	827	−3,733
[25]	**Total liabilities and equity**	[NPRm]	**224,982**	**213,149**	**201,202**	**189,168**	**177,196**	**165,222**	**156,959**	**148,699**	**140,442**	**132,188**

Source: Original calculations.

TABLE 6.12: IMPACT OF INSURANCE PREMIUMS ON ECONOMIC RETURNS

				2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
			NPV	-8	-7	-6	-5	-4	-3	-2	-1	0	1	2	3	4	5
[1]	**total benefits**	**[$USm]**	*1571*	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**347**	**347**	**346**	**346**	**346**
[2]	**Costs**																
[3]	**CAPEX**																
[4]	Disbursement	[ ]		0.005	0.019	0.024	0.045	0.116	0.187	0.265	0.197	0.141					
[5]	Investment	[$USm]	*0*														
[6]	SCF adjustment	[$USm]	*0*														
[7]	CAPEX, shadow priced	[$USm]	*−762*	−6	−24	−31	−57	−147	−237	−335	−249	−179					
[8]	**Life extension**																
[9]	E&M	[$USm]	*−20*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[10]	Civil	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[11]	**Hazard damage costs**																
[12]	Lost revenue	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[13]	**Adaptation costs**	[$USm]	*0*	0	0	0	0	0	0	0							
[14]	**OPEX**																
[15]	Insurance	[$USm]	*−387*	0	0	0	0	0	0	0	0	0	−63	−63	−63	−63	−63
[16]	Fixed O&M	[$USm]	*−116*	0	0	0	0	0	0	0	0	0	−19	−19	−19	−19	−19
[17]	Sediment abraison repair	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[18]	**total costs**		***−1285***	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**−82**	**−82**	**−82**	**−82**	**−82**
[19]	levelized economic cost	[USc/ kWh]	−4.70														
[20]	**Net economic flows**	[$USm]	***285***	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**265**	**264**	**264**	**264**	**263**
[21]	**ERR**	[ ]	***11.1%***														0.008
[22]	Local externalities	[$USm]		0	0	0	0	0	0	0	0	0	0	0	0	0	0
[23]	**Net economic flows**	**[$USm]**	***285***	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**265**	**264**	**264**	**264**	**263**
[24]	ERR(+Local+ENV)	[ ]	***11.1%***														
[25]	GHG emissions	[$USm]		0	0	0	0	0	0	0	0	0	177.2	181.0	186.8	190.5	194.3
[26]	**Net economic flows**	[$USm]	***1,713***	**−6**	**−24**	**−31**	**−57**	**−147**	**−237**	**−335**	**−249**	**−179**	**442**	**445**	**451**	**454**	**458**
[27]	ERR(+Local+Global)	[ ]	***20.2%***														0.113

Source: Original calculations.

TABLE 6.13: ADAPTATION VS. COMMERCIAL INSURANCE COST

				2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
			NPV	**-8**	**-7**	**-6**	**-5**	**-4**	**-3**	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**
[1]	**total benefits**	**[$USm]**	*1571*	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**347**	**347**	**346**	**346**	**346**
[2]	**Costs**																
[3]	**CAPEX**																
[4]	Disbursement	[ ]		0.005	0.019	0.024	0.045	0.116	0.187	0.265	0.197	0.141					
[5]	Investment	[$USm]	*0*														
[6]	SCF adjustment	[$USm]	*0*														
[7]	CAPEX, shadow priced	[$USm]	*−762*	−6	−24	−31	−57	−147	−237	−335	−249	−179					
[8]	**Life extension**																
[9]	E&M	[$USm]	*−20*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[10]	Civil	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[11]	**Hazard damage costs**																
[12]	Lost revenue	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[13]	**Adaptation costs**	[$USm]	*−61*	0	0	0	0	0	−50	−50							
[14]	**OPEX**																
[15]	Insurance	[$USm]	*−116*	0	0	0	0	0	0	0	0	0	−19	−19	−19	−19	−19
[16]	Fixed O&M	[$USm]	*−116*	0	0	0	0	0	0	0	0	0	−19	−19	−19	−19	−19
[17]	Sediment abraison repair	[$USm]	*0*	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[18]	**total costs**		*−1076*	**−6**	**−24**	**−31**	**−57**	**−147**	**−287**	**−385**	**−249**	**−179**	**−38**	**−38**	**−38**	**−38**	**−38**
[19]	levelized economic cost	[USc/kWh]	−3.93														
[20]	**Net economic flows**	[$USm]	*496*	**−6**	**−24**	**−31**	**−57**	**−147**	**−287**	**−385**	**−249**	**−179**	**309**	**309**	**308**	**308**	**308**
[21]	**ERR**	[ ]	*12.7%*														0.023
[22]	Local externalities	[$USm]		0	0	0	0	0	0	0	0	0	0	0	0	0	0
[23]	**Net economic flows**	**[$USm]**	*496*	**−6**	**−24**	**−31**	**−57**	**−147**	**−287**	**−385**	**−249**	**−179**	**309**	**309**	**308**	**308**	**308**
[24]	ERR(+Local+ENV)	[ ]	*12.7%*														
[25]	GHG emissions	[$USm]		0	0	0	0	0	0	0	0	0	177.2	181.0	186.8	190.5	194.3
[26]	**Net economic flows**	**[$USm]**	*1,924*	**−6**	**−24**	**−31**	**−57**	**−147**	**−287**	**−385**	**−249**	**−179**	**486**	**490**	**495**	**499**	**502**
[27]	ERR(+Local+Global)	[ ]	*20.6%*														0.117

Source: Original calculations.

- Under the worst-case climate change scenario that even climate scientists might see as pessimistic, both with respect to the rate at which the unfavorable future is reached, and the magnitude of its impact**, the expected value of economic returns falls relatively little as a consequence of the risk of insufficiency of flow or increasing flushing days**. The UAHEP assessment presented here thus differs little from earlier assessments of other large hydropower projects.

- In many cases encountered in the literature, **the calculations of the impact of climate change impacts on NPV assume that the project experiences the climate changed future already in the first year of its operation** (i.e., without any judgment as to when it might occur) and based on the premise that the task of a climate change assessment is simply to identify the outcome if it occurs, and to define the outcome of that plausible worst case.

- As noted in the example of recommendations for coated turbines, **there arises the difficulty in distinguishing between what is a standard practice and what could be classified as an adaptation measure**. This goes beyond mere semantic differentiation, but is relevant to the ability to access new concessionary financing sources earmarked for meeting the costs of adaptation.

- **The experience in Nepal suggests that the combined impact of seismic events and landscapes already destabilized by intense storms is an increased material risk the Himalayas**. The serious 2015 earthquake in Nepal did little direct damage to dams and powerhouses, but triggered landslides that resulted in powerhouse flooding. This suggests that the costs of valley slope stability enhancement measures need more attention. Such expenditures can reasonably be claimed as an adaptation cost incremental to established practice, which has tended to focus on the reservoir valley slopes upstream of the dam rather than in the valley slopes immediately downstream of the project. The consequences of such events were also illustrated clearly at the Trung Son hydropower project in Vietnam.

- **The impact of serious hazard events on financial returns may be greater than on the economic returns**, particularly in the early years of debt service repayment obligations. The severity of impact will be highly specific to the financing and ownership structure, as well as the tariff and PPA; while the impact of disasters on financial returns may be mitigated if IFI assistance is forthcoming, such assistance should not be taken for granted.

- Insurance is now a routine provision in IPP hydropower projects. However, in projects undertaken by traditional state-owned utilities, this appears to largely ignored at the FS stage. **The trade-off between what will almost certainly be higher flood insurance costs consequent to climate change, and upfront adaptation costs needs to be assessed for all hydropower projects**.

Recommendations

The following steps should be adopted as a standard practice:

- The table of economic flows should be extended in the manner shown in this Annex, to make transparent the impacts of specific hazard events and additional adaptation costs.

- In consultation with the engineers, plausible worst cases should be defined (e.g., for a major powerhouse flooding, duration, and cost of repairs); the magnitude and frequency of occurrence should be included as variables subject to a sensitivity analysis (switching value calculation).

- Chronic climate change impacts such as insufficiency of flows and increased number of flushing days (where high sediment loads are an issue) should be included in the risk assessment and presented along the lines suggested here—for example, showing the probability distribution of flushing days (Figure 6.13).
- Both chronic and acute hazards should be included in any quantitative risk assessment. This will likely broaden the probability distributions of economic returns and increase the risk of not attaining the hurdle rate.
- The summary presentation of the economic analysis should include the results of the quantitative risk assessment (and in particular, the risk of not attaining the hurdle rate, and the impact of asymmetric risks).
- The hazard assessment is particularly important for the financial analysis and should be undertaken as soon as the financing package and likely PPA and tariff arrangements are under discussion.

7. CASE STUDY: PHOTOVOLTAIC HYBRIDIZATION IN SOMALIA

7.1 CONTEXT

This background is extracted from the PAD for the Somali Electricity Recovery Project (P173088).

Somalia bears the development burden of three decades of conflict, fragility, and state fragmentation following the collapse of the Siad Barre government in January 1991 and the ethnic and border disputes in the Horn of Africa. Concentrated mainly in Southern Somalia, the protracted conflict and fragility led to the collapse of rule of law, institutions, basic public services, and the social contract, resulting in the impoverishment of millions. It also destroyed much of the country's governance and economic infrastructure—undermining legitimate institutions and creating widespread vulnerability.

Somalia's current political structure broadly consists of three self-administered and self-governed regions: Somaliland, Puntland, and Southern Somalia, whose main cities are Hargeisa, Bossaso, and Mogadishu, respectively. Somaliland is an autonomous region that declared its independence in 1991 and has since maintained a separate government. Puntland is a semi-autonomous region that declared autonomy in 1998 and has its own constitution and hybrid political system, while Southern Somalia is the remaining territory consisting of Galmudug, Jubaland, South West, and Hirshabelle states.

Pre-conflict, the Somalia National Electric Corporation (ENEE) was the single public utility in operation, supplying Mogadishu and the main regional centers of Hargeisa, Berbera, Burao, Baidoa, and Kismayo through distributed diesel generators and localized distribution grids with a combined total installed capacity of about 70 MW and annual energy production of about 250 GWh (1987). However, public electricity infrastructure was destroyed during the conflict and the associated public institutional frameworks are almost completely defunct at present. ENEE currently only operates 12 MW installed capacity in Boossaso and Qardho in the northeast part of the country.

Private sector entities are the main electricity services providers in Somalia using local diesel-based mini grids. The system of delivering electrical energy to users comprises a network of isolated distribution grids with isolated generation providers. These island networks are owned and operated by private Electricity Service Providers (ESPs), each of whom owns and operates their complete generation-distribution-customer revenue chain. The ESPs supply more than 90 percent of the power in the country, and it is estimated that there are at least 55 operators in the large cities and towns. Some NGOs also contribute to Somalia's power supply but at a smaller scale.

The supply is dominated by high-speed diesels (HSD), though some ESPs have begun adding PV, wind, and small battery energy storage systems (BESS). As shown in **Table 7.1**, ESP tariffs are high, as are losses.

The reasons for the poor performance and high costs are many and are a direct consequence of the dependence of the sector on the high cost of diesel. As shown in **Table 7.2**, these are subject to wide variation across the country, and averages are in the range of $0.6 to $1.1/liter. These prices will have increased substantially in 2022, given the sharp increase in global oil prices following the start of the war in Ukraine (see World Bank 2022).

TABLE 7.1: ENERGY SERVICE PROVIDER TARIFFS AND LOSSES

URBAN CENTER	POP	ESP	INSTALLED CAPACITY	GENERATION TYPE	POP SERVED	TARIFF (USD/KWH)	LOSSES	DISTRIBUTION TYPE	SYNCHRO
Mogadishu	3,000,000	BECO	65MW	HSGD, SPV	230,000	0.36	18%	Radial 11KV	No
		Blue Sky	8MW	HSDG	40,000	0.36	20%	Radial 11KV	No
		Mogadishu Power Supply	11MW	HSDG	70,000	0.35	32%	Radial LV	No
Boossaso	627,399	ENEE		HSDG		0.8	35%	Radial 16KV, 15KV	No
		Golis		HSDG			30%	Radial LV	No
		Sometel		HSDG			30%	Radial LV	No
Qardho	89,176	ENEE		HSDG		0.8	35%	Radial 15KV	No
Garoowe	131,577	NESCOM	10MW	HSDG, Wind, SPV, Battery	17,000	0.79	25%	Radial 11KV	Yes
Baidoa	355,800	BECO	5MW	HSDG	52,300	0.9	40%	Radial LV	
Marka	301,400	Marka Electric	1100KVA	HSDG	2000	0.7		Radial LV	No
Afgooye	210,900	Hisra Electric	300KW	HSDG	75,000	0.5	40%	Radial LV	No
Berdaale	152,600	Faraj Electric Company		HSDG	3,000				
Barawe	74,400	BECO	500KW	HSDG	4,200	0.5	20.0%	Radial LV	
Hudur	145,400	Afar Indhud Electric Company	500KVA	HSDG	600	0.8	20.0%		
Abuduwak	64,200	Elays Electric Company	915KVA	HSDG	2,150	1	19.5%	Radial LV	No
		DAYAH	1500KVA	HSDG	2500	1	20%	Radial LV	No
Balcad	188,200	BECO	1000KVA	HSDG	1,450	0.6	20%	Radial LV	No
		MPS	800KVA	HSDG	750	0.45	20%	Radial LV	
Buurhakaba	255,234	Jinaw Electric	500KVA	HSDG	800	1.2	40%	Radial LV	
Baletweyne	225,500	DAYAH Electric Company	1MW	HSDG	8,000	0.7	20%	Radial LV	No
Buule Butre	139,200	DAYAH Electric Company	6500KVA	HSDG	5,200	0.7	25.0%	Radial LV	No
Jalalaqsi	80,724	DAYAH Electric Company	5000KVA	HSDG	4000	0.7	20%	Radial LV	No
Hawadley	122,000	Llyas electric		HSDG	13,400		7.3%		
Jowhar	340,600	BECO	2010KVA	HSDG	3,800	0.6	20%	Radial LV	No
		MPS	1200KVA	HSDG	950	0.45	20%	RADIAL LV	NO

Source: Original calculations.

TABLE 7.2: RETAIL DIESEL PRICES

	DIESEL PRICE SOS/ LITER	EXCHANGE RATE SOS:USD	DIESEL PRICE $/ LITER
January 2021			
Bay, Bakool, Gedo, Hirar	29,333	26,958	1.09
Juba	22,344	22,644	0.99
Shabelle [Mogadishu]	17,667	25,842	0.68
Banadir	13,433	25,175	0.53
Central	17,550	29,563	0.59
Northeast	21,250	38,321	0.55
Northwest [Somaliland]	5,377	8,533	0.63
5 year average (2016–2020)			
Bay, Bakool, Gedo, Hirar	25,630	24,056	1.07
Juba	26,200	23,798	1.10
Shabelle [Mogadishu]	19,391	24,007	0.81
Banadir	15,126	23,600	0.64
Central	20,810	25,070	0.83
North east	21,196	27,319	0.78
Northwest [Somaliland]	6,308	8,650	0.73

Source: FAO Market Update, January 2021

The Proposed Project and Its Interventions

The Somalia Electricity Sector Recovery Project (SESRP) has four main components:

1. Generator synchronization and automation
2. Sub-transmission and distribution network integration in the major load centers
3. Renewable energy generation optimization
4. Electrification of public facilities (health and education)

Synchronization and automation: Rarely encountered in ESPs. As a consequence, separate generator units are connected to exclusive feeder lines and therefore, many generators operate below their expected optimal performance criteria. Further, the absence of automation and synchronization prevents the ESPs from utilizing parallel generation to assure optimal generator performance and dynamic reactivity to electricity load variations. This results in significant amounts of “wet stacking” (diesel fuel waste, extra pollution, and performance degradation), which combine to reduce power output, reduce life spans of the generator engines, and elevate maintenance costs and unscheduled generation downtime. Automation and synchronization of the numerous generators will permit the optimization of electricity generation as the synchronization will enable the parallel operation of the generation so that each generator is operating in its optimal performance zone and the automation would makes it easy for a particular generator to be brought online or offline easily and smoothly.

Sub-transmission and distribution network integration: In the major load centers, all of the ESPs operate independently; as a consequence, there is significant infrastructure duplication. This component will provide comprehensive rehabilitation including (i) adding bus-bars to permit generation synchronization; (ii) interconnection of distribution facilities of individual ESPs with their neighbors; (iii) sub-transmission and distribution network reinforcement to increase power transfer capacity and reduce technical losses. The intention to focus on establishment of an integrated sub-transmission and distribution network is deliberate considering the need to consolidate the currently existing investments in infrastructure and concretize the building blocks to meet increasing electricity demand.

Renewable energy generation optimization: This aims at increasing the efficiency of the existing mini grids by adding PV and BESS. Hybrid opportunities offer significant improvements in fuel efficiency, fuel consumption, extended generator life spans, reducing GHG emissions and combustion pollution. Some ESPs report significant tariff reductions in consequence.

Some ESPs have already begun converting their generation systems into hybrid electricity generation, mostly via solar PV; six ESPs have been hybridized with support from the UK-funded Energy Security and Resource Efficiency in Somaliland (ESRES) program. In Puntland, NECSOM installed 1-MW solar PV and 900 kW of wind generation. In the South-Central region, the Benadir Electric Company (BECO) has implemented a 2.5 MW solar farm with Chinese collaboration. Leading Energy Solutions (LESCO) of Somaliland has implemented a solar PV-Battery-HSDG hybrid generation system comprising 500 kW of solar PV, 1,300 kW of battery storage, and 1,900 kVA of diesel generation, which has enabled a diesel savings of about 53%. Unfortunately, information available to the Bank at appraisal is purely anecdotal; no pre-feasibility study, feasibility study, or economic analyses of these projects is available, and actual costs of batteries and PV systems are unknown.

PV solar systems for schools and health centers: This aims to install over 1,000 stand-alone PV systems in presently unelectrified rural and peri-urban areas to electrify schools and health facilities (**Table 7.3**).

7.2 METHODOLOGY

Standard cost-benefit analysis for project appraisal encounters many problems in a post-conflict country such as Somalia:

- **Lack of pre-feasibility studies**: There is no pipeline of investment-ready projects that provide sufficient detail on assumptions to be able to make reliable assessments.
- **Unreliability of previous studies**: A power sector master plan for Somalia (PSMP) was prepared in 2017. While much survey data was collected, it contains no economic analysis of specific projects, and many of its assumptions are not credible. A good example is the cost assumption for diesel, for which the PSMP used $800/kW. A quick telephone survey of Mogadishu importers by the PAD preparation team revealed that the export price of the most expensive diesel in the size of most ESPs (200 kVA–2,000 kVA) was around $235/kW.
- **Lack of basic data:** Optimization of a multi-unit ESP, and its hybridization, depends crucially on the daily load curve. While the PSMP hypothesized an hourly load curve for illustrative calculation of the benefits of synchronization, whether this bears any resemblance to that of actual ESPs is unknown.

TABLE 7.3: PV SYSTEMS FOR SCHOOLS AND HEALTH CENTERS

TYPE	NUMBER	SYSTEM SIZE KW	TOTAL PEOPLE SERVED	UNIT CONSUMPTION (KWH/YR)	UNIT CAPEX ($)	TOTAL CAPEX (M$)	YEARLY OPEX ($)
Health facilities							
Health Center	187	10	935,000	35,040	59,800	11.2	223,652
Referral Health Centre	3	10	15,000	35,040	59,800	0.2	3,588
IDP Health Center	3	10	15,000	35,040	59,800	0.2	3,588
IDP Primary Health Unit	1	10	5,000	35,040	59,800	0.1	1,196
Maternal Health Clinic	25	20	125,000	70,080	119,600	3.0	59,800
Primary Health Unit	121	10	605,000	35,040	59,800	7.2	144,716
Subtotal	***340***		***1,700,000***			***21.8***	***436,540***
Educational facilities							
Primary	376	2	2,595,000	1,328	12,930	4.9	97,235
Secondary	376	4	931,000	2,458	23,920	9.0	179,878
Subtotal	***752***		***3,526,000***			***13.9***	***277,113***
TOTALS	**1092**				23,920	**35.7**	**713,653**

Source: World Bank calculations.

- **Paucity of relevant literature:** While the benefits of synchronization and automation are well understood, there are very few cost-benefit analysis of a specific synchronization at the scale of Somalia's ESPs. Although the cost of the synchronization hardware and software is small (and almost trivial compared to the benefits), additional investments for bus-bar connection, cabling, or modifications to the 11-kV feeders necessary to realize the benefits are highly site-specific. The PMP estimates to the upfront cost for a three-generator synchronization at around $5,000.

However, the electricity sector in Somalia runs at such low levels of efficiency and high levels of dilapidation and losses that almost any technical intervention will bring substantial economic benefits when coupled with the very high diesel prices encountered in most locations. This is true even if prices for modern power sector equipment (solar panels, BESS, control software) are much greater than general international price levels; the default assumption of the PAD is that PV system costs and BESS are priced at multipliers of between 2.0 and 2.25 over general international price levels. Thus, economic returns will be very high under a wide range of uncertainties of input assumptions.

Moreover, under the new Bank guidance for discount rates, the applicable hurdle rate is somewhere between zero and 4 percent, which means that fine tuning of input assumptions when one is in the range of 20 to 50 percent for ERR carries the danger of spurious accuracy. With population growth in Somalia still around 3 percent, and with gross domestic product (GDP) growth since 2015 in the 1 to 3 percent range, and with even pre-pandemic forecasts of near to medium term growth of around 3 percent, the future per-capita GDP growth rate will struggle to be above 2 percent.

The same applies to any attempt at capturing resilience and hazard adaptation costs into such an economic analysis. Unlike in the case of hydropower projects, for which there is reasonably reliable data on the probability of powerhouse flooding and its related damage costs (as discussed in Annex I), at the time of PAD preparation there was no data on how many ESPs have experienced flood damages in the past—all we know is that urban areas, where ESPs are likely to have their generators, are regularly flooded.

This leads to a situation where it is easier to hypothesize repair costs of a worst-case situation than to estimate the damage costs if the hazard is encountered. This is a dilemma similar to that faced in the early days of monetization of air pollution damage costs, in which one assumed that the cost of (the then still largely unknown) damages would be at least as high as the pollution control equipment in place to reduce emissions—an approach that has little merit among economists. However, the worst-case assumption that flooding of an ESP generation site will lead to replacement of HSD diesels is suitably conservative as an estimate of consequences of worst-case climate change. Indeed, one may well argue that an even greater uncertainty governs the rate at which this worst-case climate scenario would be reached. The interventions proposed for the SESRP are assumed to have 15-year lives (corresponding to the warranty periods offered by PV panel manufacturers), so whether the worst-case outcomes are reached by 2050 is subject to further uncertainty.

In this situation, the best that can be expected is a determination of the *sign* of the change in economic returns, and the order of magnitude of that change: one can do no better than be roughly right. At the same time, once the project is in the disbursement phase, the issues raised in this discussion need case-specific re-examination to assess the extent to which the measures enumerated below are worthwhile.

The economic analysis prepared for the PAD is based on a CBA for a representative sample of projects for each of the four major categories, then aggregated over an assumed 5-year implementation period.

Synchronization and Optimization of Diesels

The costs of diesel generation are strongly dependent upon the loading (**Figure 7.1**). At full load, efficiency is around 30 percent; and at partial loads below 50 percent this falls rapidly. One of the main problems in Somalia's ESP operation is that much of the generation is at low loading (in addition to lack of synchronization).

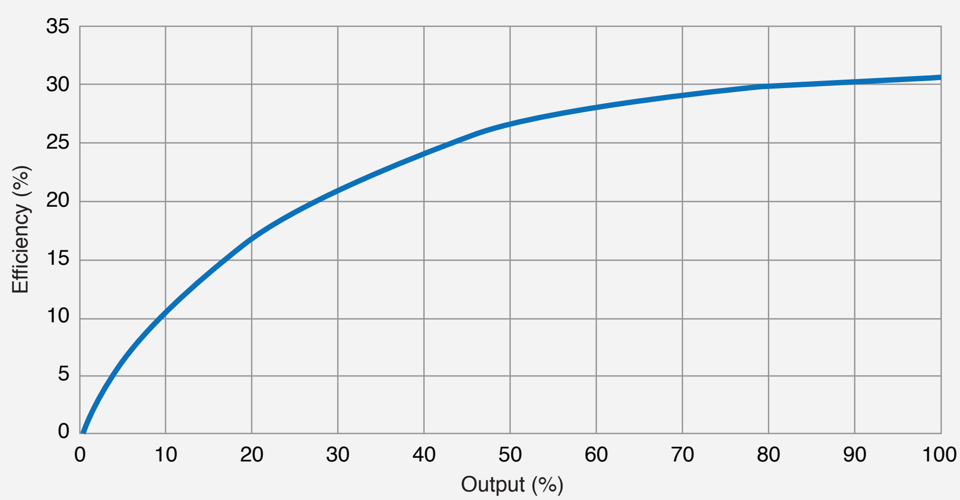
To illustrate the methodology, consider the daily load curve of **Figure 7.2**, taken from the PSMP served by a 2 MW diesel.

For much of the day this diesel runs at part load, with efficiencies at just 18 percent during low-load night-time hours. The annual cost is $2.99 million, consuming 4.273 million liters per year (**Table 7.4**).

Now, suppose one added to the system a 0.5-MW unit that runs just during nighttime hours. That unit will run at very near-best efficiency at night, and the 2 MW unit now only has only a few hours at which it runs below 27 percent efficiency (**Table 7.5**).

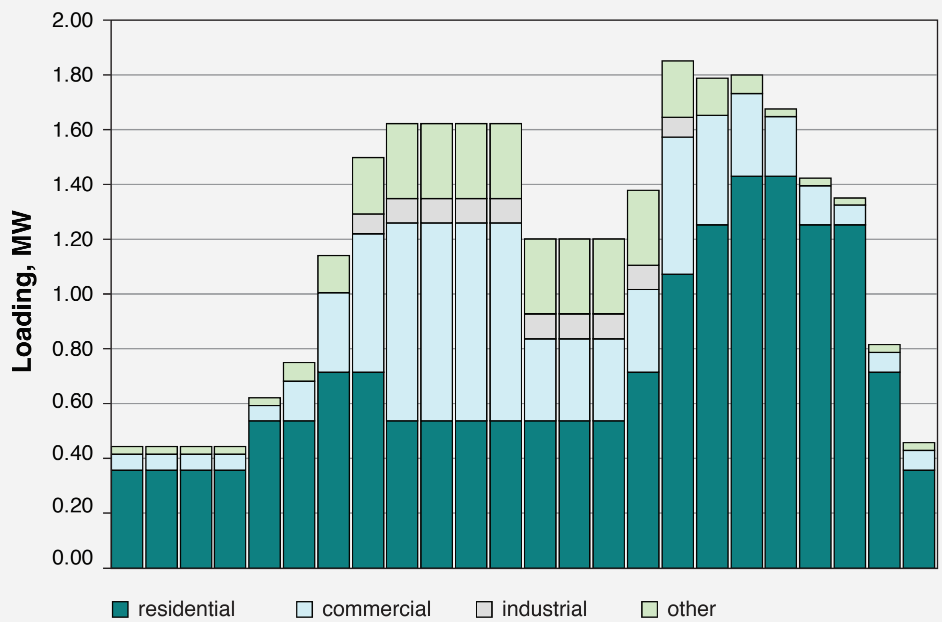
This results in a diesel cost saving of $140,000 per year. But since a 500-kV diesel generator, delivered to Mogadishu, costs just $76,000 (including 18 percent import duty) and would thus installed surely cost not much more than $100,000; and assuming a 4-year life, the (undiscounted) net saving of adding an additional small diesel for meeting the low nighttime load is 4 × $140,000 – $100,000 = $460,000. In fact, this underestimates the saving because the avoidance of running at low load reduces wear and tear on the machine, and likely extends machine life by many months.

FIGURE 7.1: EFFICIENCY OF HIGH-SPEED DIESELS



Source: Unicon 2018.

FIGURE 7.2: THE LOAD CURVE



Source: Original calculations.

Hybridization

The hybridization component of the project assumes not only the addition of a PV field (and possibly a BESS as well) but also synchronization and optimization of the diesel operation itself. The PAD assesses such a project for the 1-MW Beledweyne ESP, assumed to have 2 × 500 kW diesel generators, the operation of which defines the project counterfactual (**Table 7.6**).

Into this operation we add a 400-kW solar PV field, and a 125 kWp/250 kWh BESS, with dispatch loading curves as shown in **Figure 7.3** and **Figure 7.4**.

Baseline Returns

The baseline calculation of economic returns is as shown in **Table 7.7**. The return is a high 46 percent—largely a consequence of the high diesel prices faced by inland towns in Somalia—here the assumed price is $0.875/liter (a 25 percent increase over the assumed coastal price of $0.7/liter).

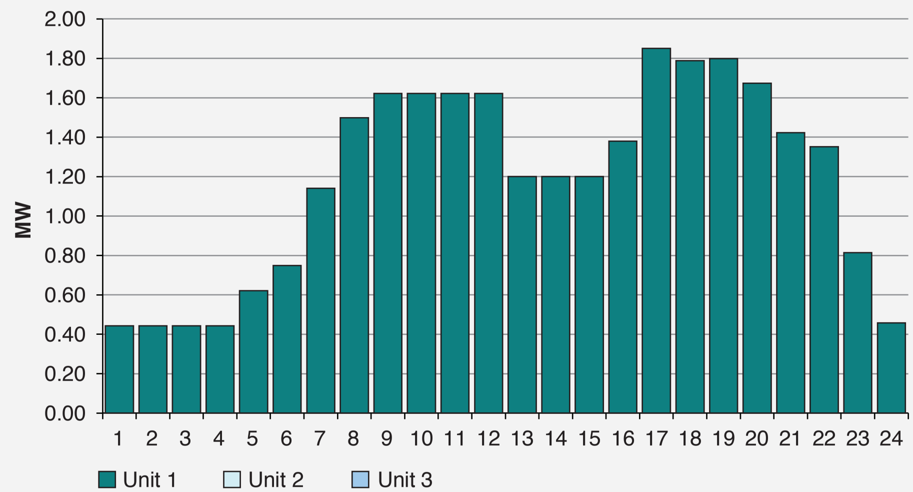
We are now ready to assess the impact of climate change and the improving the resilience of the system.

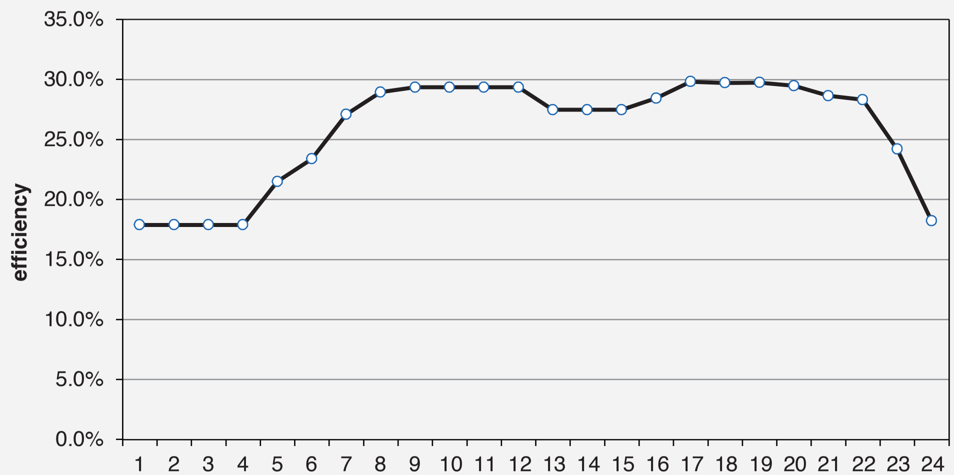
TABLE 7.4: DISPATCH OF A SINGLE 2 MW DIESEL

	UNIT 1	2[MW]							
TOTAL LOAD [MW]	HOUR	LOAD [MW]	LOADING [%]	EFFICIENCY [ ]	HEAT RATE TU/KWH]	FUEL COST [$/KWH]	FUEL CONSUMP [LITRES]	KWH/LITRE]	HOURLY COST [$]
0.44	1:00 AM	0.44	22%	17.9%	19091	0.44	276	1.60	193
0.44	2:00 AM	0.44	22%	17.9%	19091	0.44	276	1.60	193
0.44	3:00 AM	0.44	22%	17.9%	19091	0.44	276	1.60	193
0.44	4:00 AM	0.44	22%	17.9%	19091	0.44	276	1.60	193
0.62	5:00 AM	0.62	31%	21.5%	15878	0.36	322	1.93	226
0.75	6:00 AM	0.75	37%	23.4%	14595	0.33	357	2.10	250
1.14	7:00 AM	1.14	57%	27.1%	12599	0.29	470	2.43	329
1.50	8:00 AM	1.50	75%	28.9%	11794	0.27	577	2.60	404
1.62	9:00 AM	1.62	81%	29.3%	11631	0.27	616	2.63	431
1.62	10:00 AM	1.62	81%	29.3%	11631	0.27	616	2.63	431
1.62	11:00 AM	1.62	81%	29.3%	11631	0.27	616	2.63	431
1.62	12:00 PM	1.62	81%	29.3%	11631	0.27	616	2.63	431
1.20	1:00 PM	1.20	60%	27.5%	12422	0.28	487	2.46	341
1.20	2:00 PM	1.20	60%	27.5%	12422	0.28	487	2.46	341
1.20	3:00 PM	1.20	60%	27.5%	12422	0.28	487	2.46	341
1.38	4:00 PM	1.38	69%	28.4%	12000	0.27	541	2.55	378
1.85	5:00 PM	1.85	93%	29.8%	11445	0.26	692	2.68	484
1.79	6:00 PM	1.79	89%	29.7%	11483	0.26	671	2.67	470
1.80	7:00 PM	1.80	90%	29.7%	11476	0.26	674	2.67	472
1.67	8:00 PM	1.67	84%	29.5%	11577	0.26	633	2.64	443
1.42	9:00 PM	1.42	71%	28.6%	11917	0.27	554	2.57	388
1.35	10:00 PM	1.35	68%	28.3%	12057	0.28	532	2.54	372
0.81	11:00 PM	0.81	41%	24.1%	14142	0.32	374	2.16	262
0.46	12:00 AM	0.46	23%	18.2%	18730	0.43	280	1.63	196
28.41	total	28.41				0.31	11708	**2.31**	8195
	cost/year								2.99
	diesel comsumption [10^3 litres/year]						4273		

(continues)

TABLE 7.4: DISPATCH OF A SINGLE 2 MW DIESEL (*Continued*)





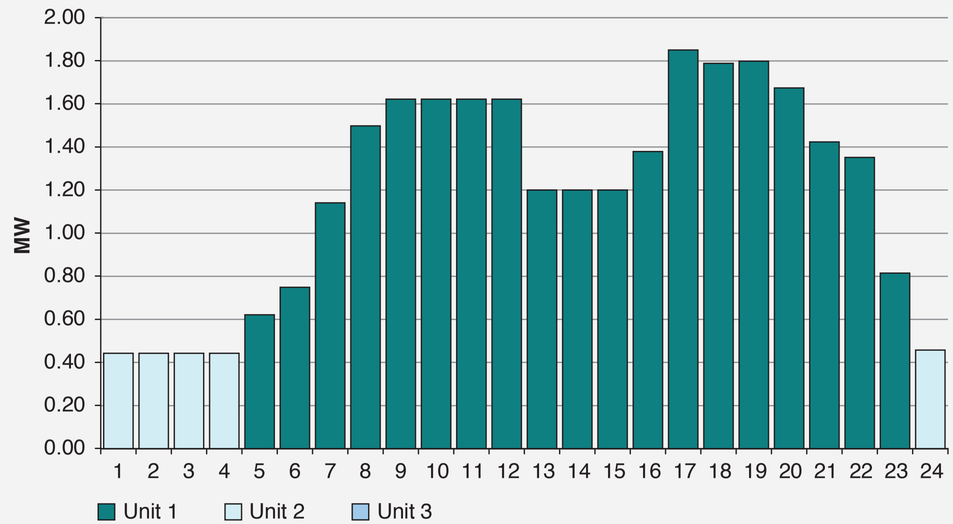
Source: Original calculations.

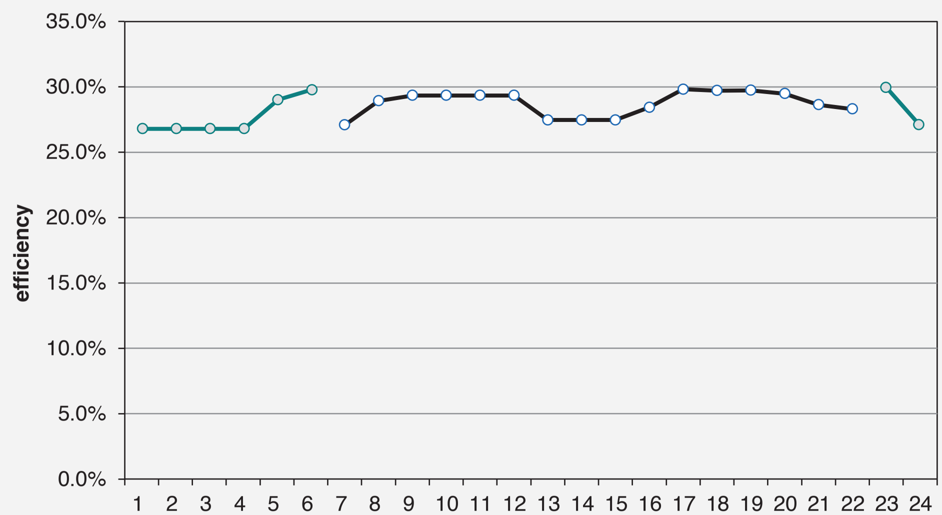
TABLE 7.5: ADDITION OF A SMALL DIESEL FOR NIGHTTIME OPERATION

	UNIT 1	2[MW]								UNIT 2	0.5 [MW]						
TOTAL LOAD	HOUR	LOAD	LOADING	EFFICIENCY	HEAT RATE	FUEL COST	FUEL CONSUMP		HOURLY COST	LOAD	LOADING	EFFICIENCY	HEAT RATE	FUEL COST	FUEL CONSUMP		HOURLY COST
[MW]		[MW]	[%]	[ ]	TU/ KWH]	[$/ KWH]	[LITRES]	KWH/ LITRE]	[$]	[MW]	[%]	[ ]	TU/ KWH]	[$/ KWH]	[LITRES]	KWH/ LITRE]	[$]
0.44	1:00 AM	0.00	0%	0.0%	0	0.00	0	0.00	0	0.44	89%	29.7%	11496	0.26	166	2.66	116.38
0.44	2:00 AM	0.00	0%	0.0%	0	0.00	0	0.00	0	0.44	89%	29.7%	11496	0.26	166	2.66	116.38
0.44	3:00 AM	0.00	0%	0.0%	0	0.00	0	0.00	0	0.44	89%	29.7%	11496	0.26	166	2.66	116.38
0.44	4:00 AM	0.00	0%	0.0%	0	0.00	0	0.00	0	0.44	89%	29.7%	11496	0.26	166	2.66	116.38
0.62	5:00 AM	0.62	31%	21.5%	15878	0.36	322	1.93	226		0%				0	0.00	0.00
0.75	6:00 AM	0.75	37%	23.4%	14595	0.33	357	2.10	250		0%				0	0.00	0.00
1.14	7:00 AM	1.14	57%	27.1%	12599	0.29	470	2.43	329		0%				0	0.00	0.00
1.50	8:00 AM	1.50	75%	28.9%	11794	0.27	577	2.60	404		0%				0	0.00	0.00
1.62	9:00 AM	1.62	81%	29.3%	11631	0.27	616	2.63	431		0%				0	0.00	0.00
1.62	10:00 AM	1.62	81%	29.3%	11631	0.27	616	2.63	431		0%				0	0.00	0.00
1.62	11:00 AM	1.62	81%	29.3%	11631	0.27	616	2.63	431		0%				0	0.00	0.00
1.62	12:00 PM	1.62	81%	29.3%	11631	0.27	616	2.63	431		0%				0	0.00	0.00
1.20	1:00 PM	1.20	60%	27.5%	12422	0.28	487	2.46	341		0%				0	0.00	0.00
1.20	2:00 PM	1.20	60%	27.5%	12422	0.28	487	2.46	341		0%				0	0.00	0.00
1.20	3:00 PM	1.20	60%	27.5%	12422	0.28	487	2.46	341		0%				0	0.00	0.00
1.38	4:00 PM	1.38	69%	28.4%	12000	0.27	541	2.55	378		0%				0	0.00	0.00
1.85	5:00 PM	1.85	93%	29.8%	11445	0.26	692	2.68	484		0%				0	0.00	0.00
1.79	6:00 PM	1.79	89%	29.7%	11483	0.26	671	2.67	470		0%				0	0.00	0.00
1.80	7:00 PM	1.80	90%	29.7%	11476	0.26	674	2.67	472		0%				0	0.00	0.00
1.67	8:00 PM	1.67	84%	29.5%	11577	0.26	633	2.64	443		0%				0	0.00	0.00
1.42	9:00 PM	1.42	71%	28.6%	11917	0.27	554	2.57	388		0%				0	0.00	0.00
1.35	10:00 PM	1.35	68%	28.3%	12057	0.28	532	2.54	372		0%				0	0.00	0.00
0.81	11:00 PM	0.81	41%	24.1%	14142	0.32	374	2.16	262		0%				0	0.00	0.00
0.46	12:00 AM	0.00	0%	0.0%	0	0.00	0	0.00	0	0.46	91%	29.8%	11458	0.26	171	2.67	119.77
28.41	total	26.18				0.22	10324	**1.98**	7226	2.23				0.26	836	**0.56**	585.28
	cost/year																0.21
	diesel comsumption [10^3 litres/year]						3768		2.64								
			totals	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**	**Baseline**	**delta**								
	diesel consumption		4073	3768	305			4273	−200								
	cost		2.85	2.64	0.21			2.99	−0.14								

(continues)

TABLE 7.5: ADDITION OF A SMALL DIESEL FOR NIGHTTIME OPERATION (*CONTINUED*)





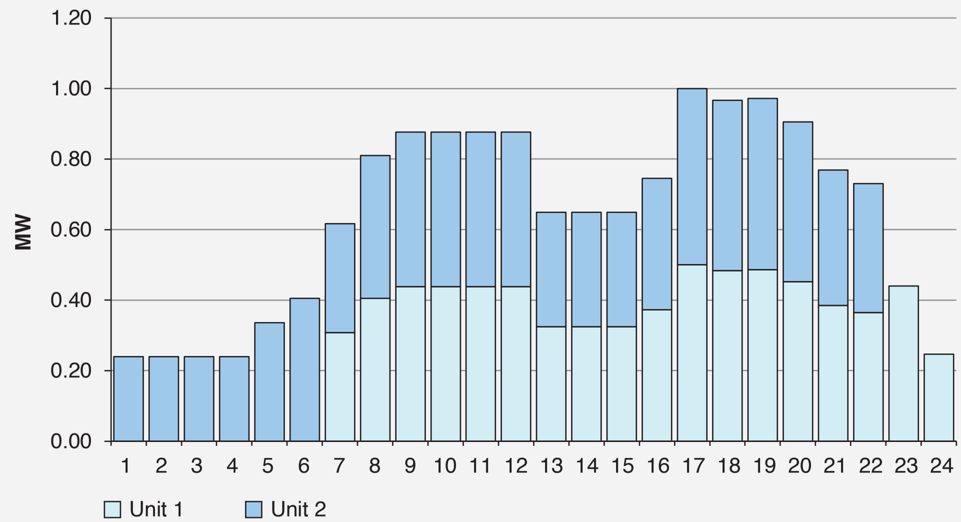
Source: Original calculations.

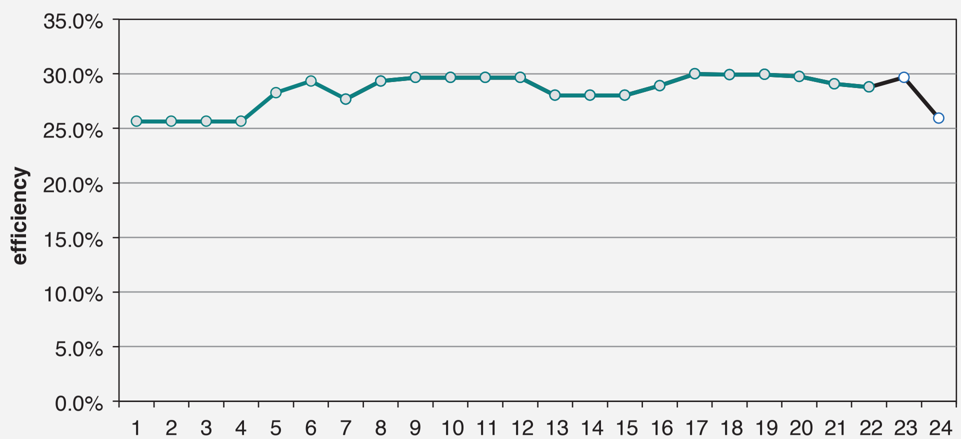
TABLE 7.6: HYBRIDIZATION COUNTERFACTUAL

	UNIT 1 0.50 [MW]								UNIT 2 0.50 [MW]							
HOUR	LOAD	LOADING	EFFICIENCY	HEAT RATE	FUEL COST	FUEL CONSUMPTION		HOURLY COST	LOAD	LOADING	EFFICIENCY	HEAT RATE	FUEL COST	FUEL CONSUMPTION		HOURLY COST
	[MW]	[%]	[ ]	TU/ KWH]	[$/KWH]	[LITRES]	[KWH/ LITRE]	[$]	[MW]	[%]	[ ]	TU/ KWH]	[$/KWH]	[LITRES]	[KWH/ LITRE]	[$]
1	-	0%	0.0%	0	0.00	0	0.00	0	0.24	48%	25.6%	13307	0.38	104	2.30	91
2	-	0%	0.0%	0	0.00	0	0.00	0	0.24	48%	25.6%	13307	0.38	104	2.30	91
3	-	0%	0.0%	0	0.00	0	0.00	0	0.24	48%	25.6%	13307	0.38	104	2.30	91
4	-	0%	0.0%	0	0.00	0	0.00	0	0.24	48%	25.6%	13307	0.38	104	2.30	91
5	-	0%	0.0%	0	0.00	0	0.00	0	0.34	67%	28.3%	12072	0.35	132	2.54	116
6	-	0%	0.0%	0	0.00	0	0.00	0	0.40	81%	29.3%	11634	0.33	154	2.63	135
7	0.31	62%	27.7%	12333	0.35	124	2.48	109	0.31	62%	27.7%	12333	0.35	124	2.48	109
8	0.40	81%	29.3%	11635	0.33	154	2.63	135	0.40	81%	29.3%	11635	0.33	154	2.63	135
9	0.44	88%	29.6%	11509	0.33	165	2.66	144	0.44	88%	29.6%	11509	0.33	165	2.66	144
10	0.44	88%	29.6%	11509	0.33	165	2.66	144	0.44	88%	29.6%	11509	0.33	165	2.66	144
11	0.44	88%	29.6%	11509	0.33	165	2.66	144	0.44	88%	29.6%	11509	0.33	165	2.66	144
12	0.44	88%	29.6%	11509	0.33	165	2.66	144	0.44	88%	29.6%	11509	0.33	165	2.66	144
13	0.32	65%	28.0%	12175	0.35	129	2.51	113	0.32	65%	28.0%	12175	0.35	129	2.51	113
14	0.32	65%	28.0%	12175	0.35	129	2.51	113	0.32	65%	28.0%	12175	0.35	129	2.51	113
15	0.32	65%	28.0%	12175	0.35	129	2.51	113	0.32	65%	28.0%	12175	0.35	129	2.51	113
16	0.37	75%	28.9%	11805	0.34	144	2.59	126	0.37	75%	28.9%	11805	0.34	144	2.59	126
17	0.50	100%	30.0%	11377	0.33	186	2.69	163	0.50	100%	30.0%	11377	0.33	186	2.69	163
18	0.48	97%	29.9%	11404	0.33	180	2.68	158	0.48	97%	29.9%	11404	0.33	180	2.68	158
19	0.49	97%	29.9%	11400	0.33	181	2.69	158	0.49	97%	29.9%	11400	0.33	181	2.69	158
20	0.45	90%	29.7%	11469	0.33	170	2.67	148	0.45	90%	29.7%	11469	0.33	170	2.67	148
21	0.38	77%	29.1%	11736	0.34	147	2.61	129	0.38	77%	29.1%	11736	0.34	147	2.61	129
22	0.37	73%	28.8%	11854	0.34	141	2.58	124	0.37	73%	28.8%	11854	0.34	141	2.58	124
23	0.44	88%	29.7%	11503	0.33	165	2.66	145		0%	0.0%	0	0.00	0	0.00	0
24	0.25	49%	25.9%	13166	0.38	106	2.33	93		0%	0.0%	0	0.00	0	0.00	0
total	7.17				0.25	2745	**1.95**	2402	8.18				0.31	3175	**2.34**	2778
cost/year								0.88								1.01
diesel comsumption [10^3 litres/year]						1002								1159		

(continues)

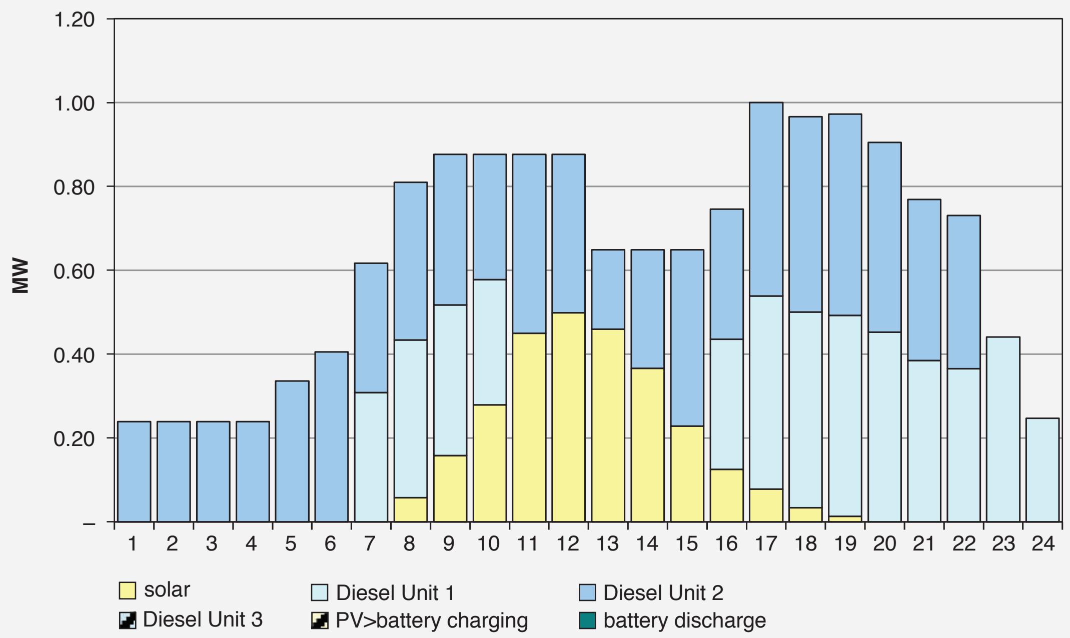
TABLE 7.6: HYBRIDIZATION COUNTERFACTUAL (*Continued*)





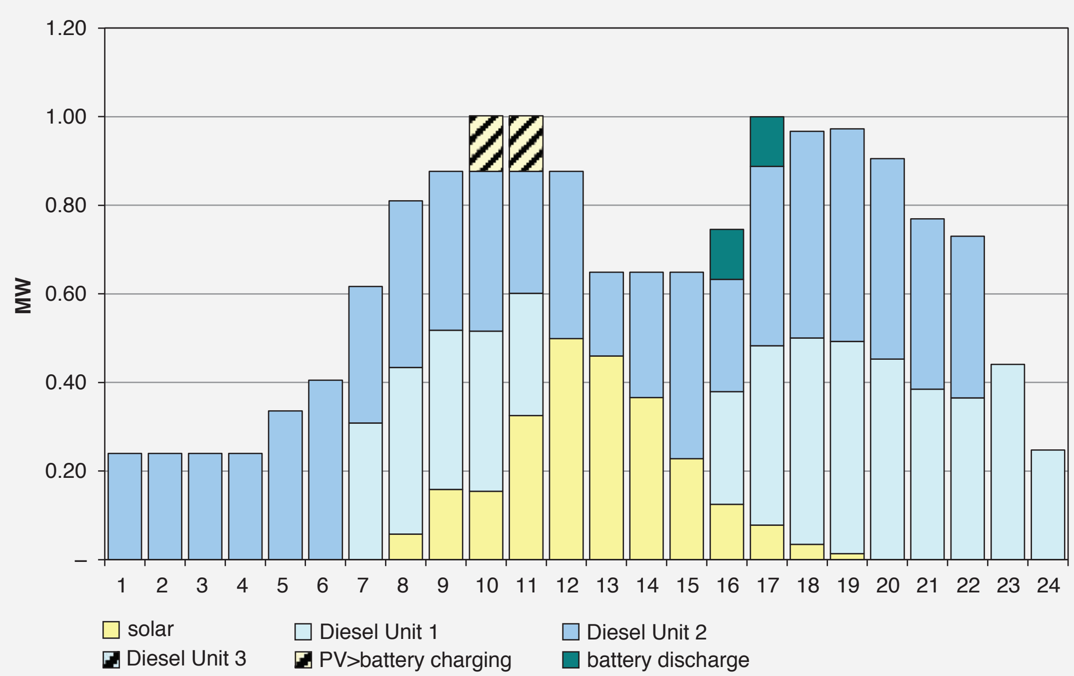
Source: Original calculations.

FIGURE 7.3: LOADING WITH 400 KW PV



Source: Original calculations.

FIGURE 7.4: 400 KW PV + BATTERY ENERGY STORAGE SYSTEM



Source: Original calculations.

TABLE 7.7: ECONOMIC RETURNS FOR THE HYBRIDIZED SYSTEM

					2023	2024	2025	2026	2027	2028	2029	2030	2031
					0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
[1]	**Baseline system**												
[2]	CAPEX	477	[$/kW]										
[3]	installed capacity	1000	[kVA]										
[4]	CAPEX	3	[$USm]	*1.8*	0.477	0.00	0.00	0.48	0.00	0.00	0.48	0.00	0.00
[5]	annual generation		[GWh]			5.61	5.61	5.61	5.61	5.61	5.61	5.61	5.61
[6]	Fuel costs	0.875	[$USm]	*21.0*		1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
[14]	**total costs**		[US$m]	*22*	**0.5**	**1.89**	**1.99**	**2.37**	**1.89**	**1.89**	**2.37**	**1.89**	**1.89**
[15]	**Modified system:PV+BESS**												
[16]	***diesels***												
[17]	capital cost	477	[$/kW]										
[18]	installed capacity	1	[MW]										
[19]	capital cost	0.477	[$USm]	*1.5*	0.477	0.00	0.00	0.00	0.48	0.00	0.00	0.00	0.48
[20]	Synchromization		[$USm]	*0.0*	0.02								
[21]	additional CAPEX		[$USm]	*0.0*	0								
[22]	***Solar***												
[23]	capital cost	**1000**	[$/kW]										
[24]	PV installed kWp	**500**	[kW]										
[25]	PV CAPEX	0.5	[$USm]	*0.5*	0.5								
[26]	PV OPEX	0.05	[$USm]	*0.3*	0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[27]	BESS capacity	250	[kWh]										
[28]	BESS CAPEX	750	[$USm]		0.188								
[29]	BESS OPEX	0.1	[$USm]			0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
[30]	Fuel costs unit 1		[$USm]	*6.9*	0	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
[31]	Fuel costs unit 2		[$USm]	*10.1*	0	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
[32]	Fuel costs unit 3		[$USm]	*0.0*	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[46]	**total cost**		[$USm]	*19.55*	**1.18**	**1.63**	**1.63**	**1.63**	**2.10**	**1.63**	**1.63**	**1.63**	**2.10**
[47]	**Net economic flows**		[$USm]	*2.59*	**−0.71**	**0.26**	**0.36**	**0.74**	**−0.21**	**0.26**	**0.74**	**0.26**	**−0.21**
[48]	ERR			46%									

Source: Original calculations.

Acute Hazards

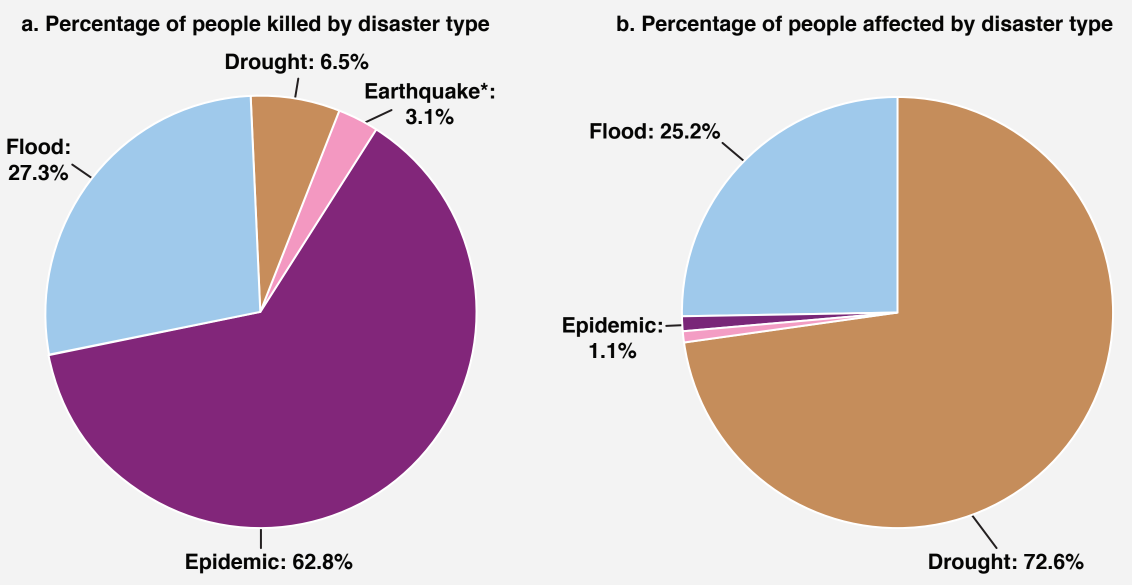
Although even prior to the COVID-19 pandemic, epidemics accounted for the majority of deaths in Somalia, as noted in Somalia's 2015 INDC report (FRS 2015), Somalia is particularly affected by floods and droughts, the frequency and intensity of which are likely to increase as a consequence of further global warming (**Figure 7.5**). At the time of writing in April 2021, severe drought affected some 2.1 million people in the Dawa, Liban, Afdher, and Shabel regions.

However, none of the project components involve any consumptive water use (no hydropower or evaporative cooling for thermal generation, or water-cooled low-speed diesels). The prolonged absence of rain associated with drought implies cloudless conditions that can only benefit the predictability of solar PV.

The main acute hazard is exposure to floods, which are strongly dependent on location: southern locations are potentially the most severely affected by flooding from severe storms even at some distance from the coast. Almost 1 million people were affected by floods in 2020, with 400,000 displaced. Beledweyne district was the worst affected, with flooding impacting 25 villages and 80 percent of the town of Beledweyne—the location of the sample PV hybridization project (though at the time of PAD preparation, there was no information of the extent to which ESPs were affected).

The distinction between acute and chronic impacts has its problems. If flooding becomes increasingly frequent and regular, describing this as an acute impact is problematic. However, the narrow footpath of tropical cycle paths imply that *for a particular area*, severe flooding may not occur every year, even though from the national perspective, there is a major flood every year. In the counterfactual, the worst-case flood damage would be the need for completely new diesel generators and replacement of control equipment. However, given that diesel generator CAPEX is small compared to running costs, even if diesels were added or replaced as part of the project modernization, the impacts can be expected to be small.

FIGURE 7.5: IMPACT OF NATURAL DISASTERS



Source: FRS 2015.

Other consequences that may need consideration:

- Increased sand and dust from sandstorms in the northern areas of Somalia may necessitate additional annual cleaning (the Good Practice Guide suggests costs of $1.30/kW-year, so $2.90/kW with the Somalia Multiplier).
- Diesel generators may need the protection of physical structures or higher elevations against flood damage. This will be highly location specific (and may not be needed at all): we assume here a one-time cost of 20 percent of CAPEX.
- PV sensitivity to high winds, mitigated by stronger support platforms: more robust design leads to a 15 percent higher balance of system CAPEX, using the value suggested by the Good Practice Guide.
- Distribution rehabilitation and rationalization: increase CAPEX by 10 percent for more robust design against wind and flood (though again strongly dependent on location but applied to all for sake of conservative calculation).

Chronic Impacts

The main chronic impact is the gradual increase in temperature. The Somali National Adaptation Program of Action on Climate Change (NAPA), issued in 2013, suggested that mean average temperatures in Somalia would rise by 3.2°C in 2080 (**Table 7.8**; FRS 2013). The World Bank Climate Change Knowledge Portal predicts a mean annual temperature rise of 1.6°C by 2040–2059, and by 3°C across all areas of Somalia by the end of the century.

Temperature increases will have two main consequences for the SESRP:

- PV output decreases with increasing temperature, so to maintain a given level of kWh implies larger panel area, modeled as an increase in CAPEX. However, there is considerable variation in the temperature coefficients depending on the type of PV cells. A worst-case temperature gradient of 0.5 percent power drop per degree C is assumed in a review of the literature by Kaldellis et al. (2014). They report a temperature gradient of 0.40–0.45 for c-Si modules, down to 0.2 percent for amorphous Si modules.

TABLE 7.8: EXPECTED TEMPERATURE IMPACTS

	MEAN PROJECTED CHANGES (°C) FOR SOMALIA		
PERIOD AVERAGE	**2030**	**2050**	**2080**
Annual	**+0.8**	**+2.5**	**+3.2**
December to February (DJF)	+0.7	+2.4	+3.2
March to May (MAM)	+0.8	+2.5	+3.5
June to August (JJA)	+0.7	+2.8	+3.8
September to November (SON)	+0.9	+2.1	+3.1

Source: FRS 2013.

- Diesel power output also decreases with increases in ambient temperature, that can be similarly modeled as an increase in CAPEX. Manufacturers' specifications sometimes provide for running at up to 50°C (see, e.g., Cummins n.d.), but in general, the literature suggests thermal gradients of between 0.3 to 0.5 percent loss per degree C. For example, the Egyptian code specifies de-rating factor around a 40°C baseline of 1.053 for 50°C and 0.952 for 30 °C (Esebaay et al. 2017).

A further peculiarity of the diesel systems operated by ESPs is their short lives. A diesel operated in wet-stacking conditions will need to be replaced every 3 to 4 years anyway, so the impact of a total loss caused by urban flooding in, say, year 2 of its life makes the need for major adaptation investments less compelling.

7.3 ECONOMIC ANALYSIS

The procedure for assessing the impact of climate change and disaster resilience has the following four steps

1. Calculation of economic returns under baseline conditions (as described above).
2. Definition of a plausible scenario for chronic impacts of severe climate change (such as higher ambient temperatures) combined with a disaster occurring in the early years of a project—in our case, for example, a flooding event that requires replacement of the diesels, control equipment and transformers in year 2 of operation—in both the with and without project cases.
3. For the with project case, add the adaptation costs that would avoid the impact of the disaster, and mitigate the chronic impacts.
4. Assume that the adaptation costs are also implemented in the counterfactual.

The result of Step 2 assessment is shown in **Table 7.9**. The green-tabbed rows record the chronic damage costs, the acute hazards, and adaptation costs for both the counterfactual and the hybridization project. The ERR decreases from 46 percent to 33 percent. This is a consequence of the assumed flood disaster in year 2, as well the chronic impacts of ambient temperature increases that de-rate the capacity of diesels and the efficiency of PV output.

Table 7.10 shows the results of step 2. We make no change to the damage or adaptation costs in the counterfactual. In the hybridization project we reduce the potential damage to PV structures and site flooding by an up-front adaptation cost. The result is an *increase* in the ERR (relative to the unadapted counterfactual) to 56 percent. It stands to reason that a resilient hybridization project will perform better than the vulnerable counterfactual.

When the resilience adaptation measures also included in the counterfactual—flood protection (row [12] in **Table 7.11**)—the advantage of the hybridization investment falls somewhat from 56 percent to 43 percent. However, there is no evidence to suggest that under the current conditions in Somalia such measures would actually be taken by the private mini-grid operators in the absence of the Bank-financed project.

TABLE 7.9: STEP 2 CLIMATE CHANGE: FLOOD DISASTER IN YEAR 2

					2023	2024	2025	2026	2027	2028	2029	2030	2031
					0	1	2	3	4	5	6	7	8
[1]	**Baseline system**												
[2]	CAPEX	477	[$/kW]										
[3]	installed capacity	1000	[kVA]										
[4]	CAPEX	3	[$USm]	*1.8*	0.477	0.00	0.00	0.48	0.00	0.00	0.48	0.00	0.00
[5]	annual generation		[GWh]			5.61	5.61	5.61	5.61	5.61	5.61	5.61	5.61
[6]	Fuel costs	0.875	[$USm]	*21.0*		1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
[7]	**chronic damage costs**	1											
[8]	diesel derating	0.05	[$USm]	*0.1*	0.024	0.00	0.00	0.02	0.00	0.00	0.02	0.00	0.00
[9]	**acute hazards**	1											
[10]	site flooding		[$USm]	*0.4*	0.00	0.00	0.48						
[11]	**adaptation cost**	0											
[12]	flood protection	0.2	[$USm]	*0.0*	0	0.00	0.00						
[13]	**total cost**		[US$m]	$\boxed{23}$	**0.5**	**1.89**	**2.37**	**2.39**	**1.89**	**1.89**	**2.39**	**1.89**	**1.89**
[14]	**Modified system:PV+BESS**												
[15]	*diesels*												
[16]	capital cost	477	[$/kW]										
[17]	installed capacity	1	[MW]										
[18]	capital cost	0.477	[$USm]	*1.5*	0.477	0.00	0.00	0.00	0.48	0.00	0.00	0.00	0.48
[19]	Synchronisation		[$USm]	*0.0*	0.02								
[20]	additional CAPEX		[$USm]	*0.0*	0								
[21]	*Solar*												
[22]	capital cost	1000	[$/kW]										

[23]	PV installed kWp	**500**	[kW]										
[24]	PV CAPEX	0.5	[$USm]	*0.5*	0.5								
[25]	PV OPEX	0.05	[$USm]	*0.3*	0	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[26]	BESS capacity	250	[kWh]										
[27]	BESS CAPEX	750	[$USm]		0.188								
[28]	BESS OPEX	0.1	[$USm]			0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
[29]	Fuel costs unit 1		[$USm]	*6.9*	0	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
[30]	Fuel costs unit 2		[$USm]	*10.1*	0	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
[31]	Fuel costs unit 3		[$USm]	*0.0*	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[33]	**chronic damage costs**												
[34]	diesel derating	0.05	[$USm]	*0.07*	0.02	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00
[35]	PV degradation—dust&dirt	0.01	[$USm]	*0.17*	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
[36]	PV degradation—temperature	0.02	[$USm]	*0.34*	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[37]	**acute hazards**												
[38]	Damage to PV structure	0.3	[$USm]	*0.13*	0	0	0.15						
[39]	diesel site flooding		[$USm]	*0.42*	0	0	0.48						
[40]	**adaptation cost**												
[41]	PV O&M cleaning	2.9	[$USm]	*0.00*	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
[42]	upgrade PV supports	0.15	[$USm]	*0.00*	0								
[43]	site flood protection	0.2	[$USm]	*0.00*	0								
[45]	**total cost**		[$USm]	*20.67*	**1.18**	**1.67**	**2.30**	**1.67**	**2.18**	**1.67**	**1.67**	**1.67**	**2.18**
[46]	**Net economic flows**		[$USm]	***1.90***	**–0.68**	**0.22**	**0.07**	**0.72**	**–0.28**	**0.22**	**0.72**	**0.22**	**–0.28**
[47]	ERR			**33%**									

Source: Original calculations.

TABLE 7.10: REVISED TABLE OF ECONOMIC COSTS, INCLUDING ADAPTATION COSTS

					2023	2024	2025	2026	2027	2028	2029	2030
					0	**1**	**2**	**3**	**4**	**5**	**6**	**7**
[1]	**Baseline system**											
[2]	CAPEX	477	[$/kW]									
[3]	installed capacity	1000	[kVA]									
[4]	CAPEX	3	[$USm]	*1.8*	0.477	0.00	0.00	0.48	0.00	0.00	0.48	0.00
[5]	annual generation		[GWh]			5.61	5.61	5.61	5.61	5.61	5.61	5.61
[6]	Fuel costs	0.875	[$USm]	*21.0*		1.89	1.89	1.89	1.89	1.89	1.89	1.89
[7]	**chronic damage costs**	1										
[8]	diesel derating	0.05	[$USm]	*0.1*	0.024	0.00	0.00	0.02	0.00	0.00	0.02	0.00
[9]	**acute hazards**	1										
[10]	site flooding		[$USm]	*0.4*	0.00	0.00	0.48					
[11]	**adaptation cost**	0										
[12]	flood protection	0.2	[$USm]	*0.0*	0	0.00	0.00					
[13]	**total cost**		[US$m]	*23*	**0.5**	**1.89**	**2.37**	**2.39**	**1.89**	**1.89**	**2.39**	**1.89**
[14]	**Modified system:PV+BESS**											
[15]	*diesels*											
[16]	capital cost	477	[$/kW]									
[17]	installed capacity	1	[MW]									
[18]	capital cost	0.477	[$USm]	*1.5*	0.477	0.00	0.00	0.00	0.48	0.00	0.00	0.00
[19]	Synchronisation		[$USm]	*0.0*	0.02							
[20]	additional CAPEX		[$USm]	*0.0*	0							
[21]	*Solar*											
[22]	capital cost	1000	[$/kW]									

[23]	PV installed kWp	**500**	[kW]									
[24]	PV CAPEX	0.5	[$USm]	*0.5*	0.5							
[25]	PV OPEX	0.05	[$USm]	*0.3*	0	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[26]	BESS capacity	250	[kWh]									
[27]	BESS CAPEX	750	[$USm]		0.188							
[28]	BESS OPEX	0.1	[$USm]			0.02	0.02	0.02	0.02	0.02	0.02	0.02
[29]	Fuel costs unit 1		[$USm]	*6.9*	0	0.64	0.64	0.64	0.64	0.64	0.64	0.64
[30]	Fuel costs unit 2		[$USm]	*10.1*	0	0.94	0.94	0.94	0.94	0.94	0.94	0.94
[31]	Fuel costs unit 3		[$USm]	*0.0*	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[33]	**chronic damage costs**											
[34]	diesel derating	0.05	[$USm]	*0.07*	0.02	0.00	0.00	0.00	0.02	0.00	0.00	0.00
[35]	PV degradation— dust&dirt	0.01	[$USm]	*0.00*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[36]	PV degradation—temperature	0.02	[$USm]	*0.34*	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[37]	**acute hazards**											
[38]	Damage to PV structure	0.3	[$USm]	*0.00*	0	0	0.00					
[39]	diesel site flooding		[$USm]	*0.00*	0	0	0.00					
[40]	**adaptation cost**											
[41]	PV O&M cleaning	2.9	[$USm]	*0.02*	0	0.001	0.001	0.001	0.001	0.001	0.001	0.001
[42]	upgrade PV supports	0.15	[$USm]	*0.07*	0.075							
[43]	site flood protection	0.2	[$USm]	*0.09*	0.095							
[45]	**total cost**		[$USm]	*19.95*	**1.18**	**1.66**	**1.66**	**1.66**	**2.16**	**1.66**	**1.66**	**1.66**
[46]	**Net economic flows**		[$USm]	***2.61***	**–0.68**	**0.23**	**0.71**	**0.73**	**–0.27**	**0.23**	**0.73**	**0.23**
[47]	ERR			56%								

Source: Original calculations.

TABLE 7.11: STEP 4: ECONOMIC RETURNS AGAINST A MORE RESILIENT COUNTERFACTUAL

					2023	2024	2025	2026	2027	2028	2029	2030
					0	1	2	3	4	5	6	7
[1]	**Baseline system**											
[2]	CAPEX	477	[$/kW]									
[3]	installed capacity	1000	[kVA]									
[4]	CAPEX	3	[$USm]	*1.8*	0.477	0.00	0.00	0.48	0.00	0.00	0.48	0.00
[5]	annual generation		[GWh]			5.61	5.61	5.61	5.61	5.61	5.61	5.61
[6]	Fuel costs	0.875	[$USm]	*21.0*		1.89	1.89	1.89	1.89	1.89	1.89	1.89
[7]	**chronic damage costs**	1										
[8]	diesel derating	0.05	[$USm]	*0.1*	0.024	0.00	0.00	0.02	0.00	0.00	0.02	0.00
[9]	**acute hazards**	0										
[10]	site flooding		[$USm]	*0.0*	0.00	0.00	0.00					
[11]	**adaptation cost**	1										
[12]	flood protection	0.2	[$USm]	*0.1*	0	0.00	0.10					
[13]	**total cost**		[US$m]	*22*	**0.5**	**1.89**	**1.99**	**2.39**	**1.89**	**1.89**	**2.39**	**1.89**
[14]	**Modified system:PV+BESS**											
[15]	*diesels*											
[16]	capital cost	477	[$/kW]									
[17]	installed capacity	1	[MW]									
[18]	capital cost	0.477	[$USm]	*1.5*	0.477	0.00	0.00	0.00	0.48	0.00	0.00	0.00
[19]	Synchronisation		[$USm]	*0.0*	0.02							
[20]	additional CAPEX		[$USm]	*0.0*	0							
[21]	*Solar*											
[22]	capital cost	1000	[$/kW]									

[23]	PV installed kWp	**500**	[kW]										
[24]	PV CAPEX	0.5	[$USm]	*0.5*	0.5								
[25]	PV OPEX	0.05	[$USm]	*0.3*	0	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[26]	BESS capacity	250	[kWh]										
[27]	BESS CAPEX	750	[$USm]		0.188								
[28]	BESS OPEX	0.1	[$USm]			0.02	0.02	0.02	0.02	0.02	0.02	0.02
[29]	Fuel costs unit 1		[$USm]	*6.9*	0	0.64	0.64	0.64	0.64	0.64	0.64	0.64
[30]	Fuel costs unit 2		[$USm]	*10.1*	0	0.94	0.94	0.94	0.94	0.94	0.94	0.94
[31]	Fuel costs unit 3		[$USm]	*0.0*	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[33]	**chronic damage costs**												
[34]	diesel derating	0.05	[$USm]	*0.07*	0.02	0.00	0.00	0.00	0.02	0.00	0.00	0.00
[35]	PV degradation—dust&dirt	0.01	[$USm]	*0.00*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[36]	PV degradation—temperature	0.02	[$USm]	*0.34*	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03
[37]	**acute hazards**												
[38]	Damage to PV structure	0.3	[$USm]	*0.00*	0	0	0.00						
[39]	diesel site flooding		[$USm]	*0.00*	0	0	0.00						
[40]	**adaptation cost**												
[41]	PV O&M cleaning	2.9	[$USm]	*0.02*	0	0.001	0.001	0.001	0.001	0.001	0.001	0.001
[42]	upgrade PV supports	0.15	[$USm]	*0.07*	0.075								
[43]	site flood protection	0.2	[$USm]	*0.09*	0.095								
[45]	**total cost**		[$USm]	*19.95*	**1.18**	**1.66**	**1.66**	**1.66**	**2.16**	**1.66**	**1.66**	**1.66**
[46]	**Net economic flows**		[$USm]	*2.27*	**−0.68**	**0.23**	**0.33**	**0.73**	**−0.27**	**0.23**	**0.73**	**0.23**
[47]	ERR			43%									

Source: Original calculations.

7.4 CONCLUSIONS AND RECOMMENDATIONS

Table 7.12 summarizes the results of the resilience assessment. The main limitation of this analysis is the absence of the sort of detailed technical climate change assessment as was available for the case study described in Chapter 6. The "worst-case" hypotheses were chosen by the study team based on discussions of with Bank staff who had worked on other East African projects of a similar kind, without the assistance of any formal climate change modeling. In part, this was also a consequence of the security situation that placed limitations on local data collection, and the uncertainty over the precise location of project interventions.

Even under the pessimistic scenario utilized, the resilience of the hybridization investment to severe climate change is high. The worst-case climate change scenario does not threaten the economic viability of the proposed project investments.

Nevertheless, with given the limited information available at the time this appraisal was presented, these calculations would need to be repeated once all the necessary information that applies to a specific site is identified, and the details of the equipment in place into which the PV energy is injected are known more precisely. For example, only once a site has been identified, and the historical flood events assessed, is it possible to assess flooding risk and the cost of flood protection measures. However, this annex does serve as a guidance on how the table of economic flows should be modified to allow a transparent assessment of potential damage and adaptation costs.

TABLE 7.12: SUMMARY OF RESILIENCE ASSESSMENT

	STEP 1	STEP 2	STEP 3	STEP 4
	BASELINE	BASELINE + DAMAGE COSTS	+ ADAPTATION COSTS	+ ADAPTATION COSTS + COUNTERFACTUAL MITIGATION
	NO CLIMATE CHANGE	WITH CLIMATE CHANGE	WITH CLIMATE CHANGE	WITH CLIMATE CHANGE
ERR	46%	33%	56%	43%
NPV, $US million (4% discount rate)	2.59	1.90	2.61	2.27

Source: Original calculations.

8. CASE STUDY: DISTRIBUTION SYSTEM UPGRADES IN BANGLADESH

8.1 CONTEXT

Few countries are likely to experience the severity of climate change impacts as Bangladesh, which already today faces regular disasters from tropical cyclones due to flooding in coastal areas and high winds everywhere along the storm tracks (**Table 8.1**). Maximum storm speeds are increasing, creating widespread damage to power distribution systems and regularly flooding power generation plants in the low-lying areas. The probability of occurrence of such impacts can only increase with sea-level rise.

Bangladesh has a highly variable wind regime in that for most of the year, winds are quite calm with average wind speeds on the order of 4 or 5 m/s. The 50-year mean recurrence winds used for designing of buildings are very high, on the order of 60 to 80 m/s depending on location within the country (NRECA International 2020). The highest winds are along the Bay of Bengal and result from cyclonic storms coming off the bay, which tend to lose strength as they move north.

This case describes a recent study for the Bangladesh Rural Electrification Board (BREB) to review its approach to climate resilience planning (Deloitte 2020). This included a study to determine whether more robust distribution systems design would reduce the number of distribution system outages caused by high wind events.

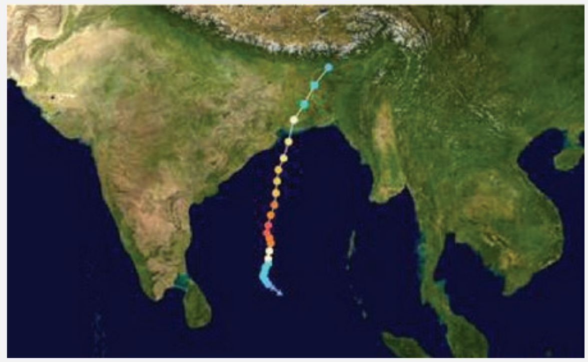
The study took advantage of a database that assembled outage and wind speed data for 45 rural electrification systems (PBS) from 2000 to 2015. The available data for the Jessore-I PBS—selected for detailed study— is shown in **Table 8.2**. Unfortunately, this database does not extend to more recent years during which the intensity of storms has increased.

The amount of energy unserved is increasing over time, as shown in **Figure 8.1**. Unfortunately, the database does not contain information on the number of customers served, or the growth of total energy sales over time. However, it is clear that the rate of growth in unserved energy—six-fold over 15 years—is unlikely to be explained by growth in electricity demand or in the number of connections.

The salient features of the Jessore system are shown in **Table 8.3**. Based on a load factor of 53 percent (NRECA International 2020, Table 5) and a peak load of 109.2 MW, the total energy delivered is some 506 GWh, so unserved energy of 160 MWh (in 2015) constitutes just 0.03 percent of the total. The presumption of the study is that that greater resilience of the feeder network designed on the basis of avoiding wind damage would also reduce the outage rate attributable to other causes.

TABLE 8.1: STORM SPEED MAXIMA IN BANGLADESH

YEAR	STORM NAME	STORM SPEED MAX(KM/HR)
2020	Amphan	240
2019	Bulbul	140
2019	Fani	215
2017	Mora	110
2016	Dianmu	75
2016	Roanu	85
2015	Komen	75
2013	Viaru	85
2009	Aila	110
2009	Bijli	75
2008	Rashmi	85
2007	Sidr	215
2007	Akash	85



Storm track Amphan (2020)

Storm track Bulbul (2019)

Source: Deloite 2020.

8.2 TECHNICAL MODELING

Figure 8.2 shows the present configuration of the 33-kV system. This represents the baseline against which four different upgrade options are measured.

Option 1: Undergrounding

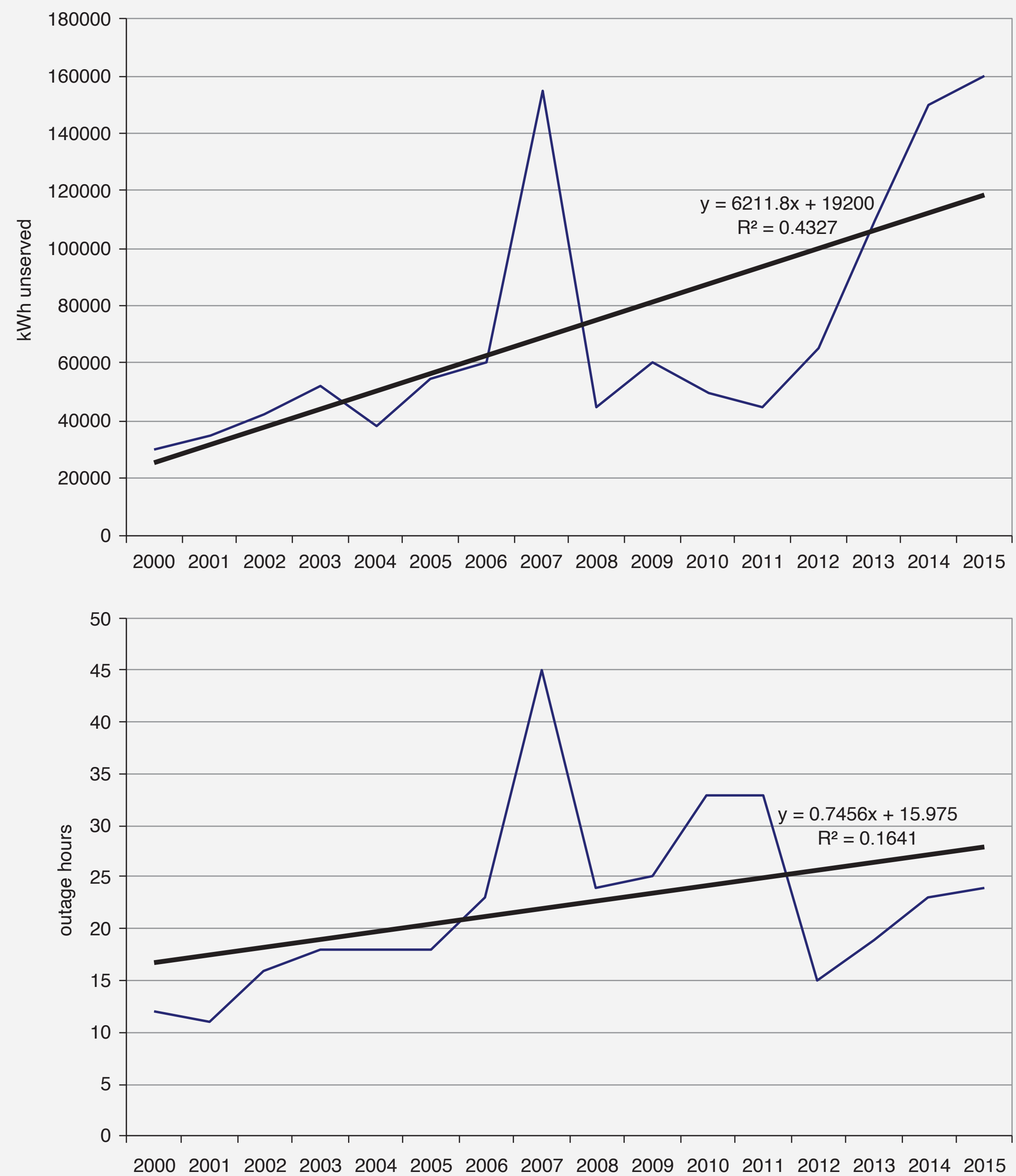
Replacement of overhead feeder with underground cables has maximum impact on network resilience as such an arrangement reduces the probability of feeder outage due to high wind speeds almost to zero. However, the underground cable system entails the highest upfront investment ($6.7 million) among the options considered. This converts the primary 33-kV sections emanating from the 132/33 kV substation as shown in **Figure 8.3**.

TABLE 8.2: OUTAGE DATA FOR THE JESSORE 11 KV SYSTEM

	OUTAGE DURATION	OUTAGES	CONSUMERS AFFECTED	ENERGY NOT SERVED	RESTORATION COSTS	MAX. WIND SPEED	MEAN WIND SPEED	DAYS WITH SEVERE WIND SPEED	CONSECUTIVE DAYS OF SEVERE WIND SPEED
	HOURS	NUMBER	NUMBER	KWH	TAKA, LAKHS	M/SEC	M/SEC	DAYS	DAYS
YEAR	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
2000	12	5	15,000	30,000	6	50	11	3	1
2001	11	3	16,000	35,000	8	43	11	5	1
2002	16	2	15,000	42,000	11	48	11	3	1
2003	18	3	17,000	52,000	11	58	11	12	4
2004	18	4	16,000	38,000	13	58	12	10	3
2005	18	2	18,000	55,000	15	56	11	8	2
2006	23	3	20,000	60,000	25	49	11	5	2
2007	45	5	60,000	155,000	39	57	11	8	3
2008	24	4	20,000	45,000	24	53	11	8	2
2009	25	3	19,000	60,000	36	95	11	5	2
2010	33	2	16,000	50,000	13	54	12	5	2
2011	33	4	20,000	45,000	17	56	11	4	2
2012	15	3	25,000	65,000	18	43	12	5	2
2013	19	2	35,000	110,000	23	52	12	7	3
2014	23	4	45,000	150,000	32	42	11	3	2
2015	24	4	40,000	160,000	39	46	11	5	1

Source: Original calculations.

FIGURE 8.1: OBSERVED TRENDS



Source: Original calculations.

TABLE 8.3: SALIENT FEATURES OF JESSORE-I

PBS ZONE	PARAMETERS	DETAILS
	Area (sq. km)	1590
	No. of Connected Substation (33/11 kV)	13
Jessore-1	No. of Interconnecting Feeders (33 kV)	13
	Total Line Length (km)	7497.129
	No. of Consumer Connected	4,44,866

SUB-STATION	SUB-STATION CAPACITY (MVA)	CONNECTED LOAD (MW)
Bag12	10	8.8
Bag21	3.1	2.59
Ben19	15	8.03
Ben27	10	8.7
Ben28	10	6.5
Nav139	10	7.5
Nav126	15	10.9
Sat110	15	9.5
Top143	15	8.8
Top145	15	9.5
Top144	10	6.5
Top146	20	14.5
Sat 115	10	7.2

Source: Original calculations.

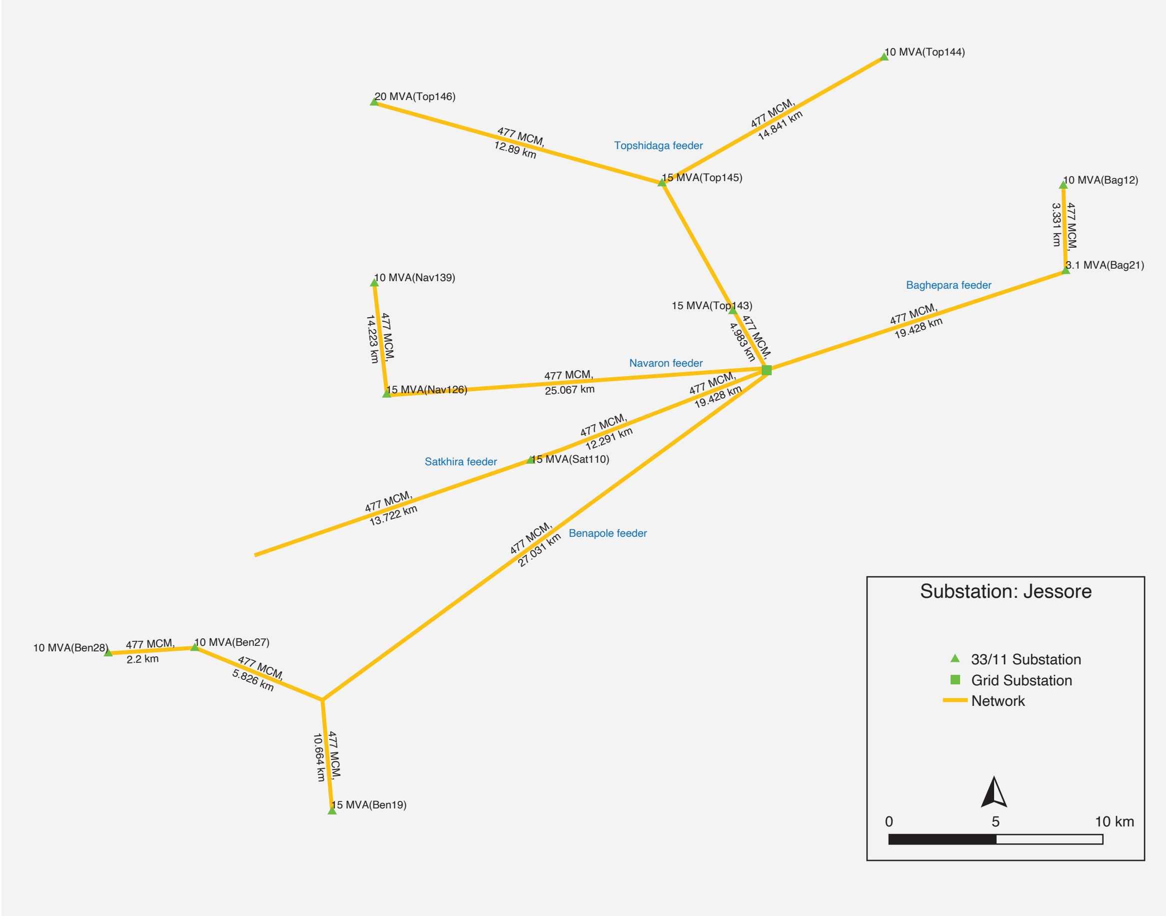
Option 2: Feeder Augmentation

This encompasses a package of measures on the primary 33-kV feeders that includes shortening of the span length of poles, mending of tilted/partially uprooted poles, tree trimming and tightening of loose cross-arms and insulators (**Figure 8.4**), with a cost estimated at $1.6 million.

Option 3: Ring Main System

A ring main system provides secondary input connection to the 33/11 kV substation, thereby mitigating chances of complete outage; in case of outage in one of the incoming feeders, the load can be shifted to the other feeder or at least partial load 33/11 kV substation and still be served (Figure 8.5). The cost estimate of $1.16 million is a function of the length of new feeder erected, circuit type (single or double circuit, depending upon the load of the interconnected substations), upgrading of transformers, and change in bus arrangement at receiving 33/11 kV substation (dual incoming supply will mandate a bus coupler arrangement).

FIGURE 8.2: PRESENT CONFIGURATION



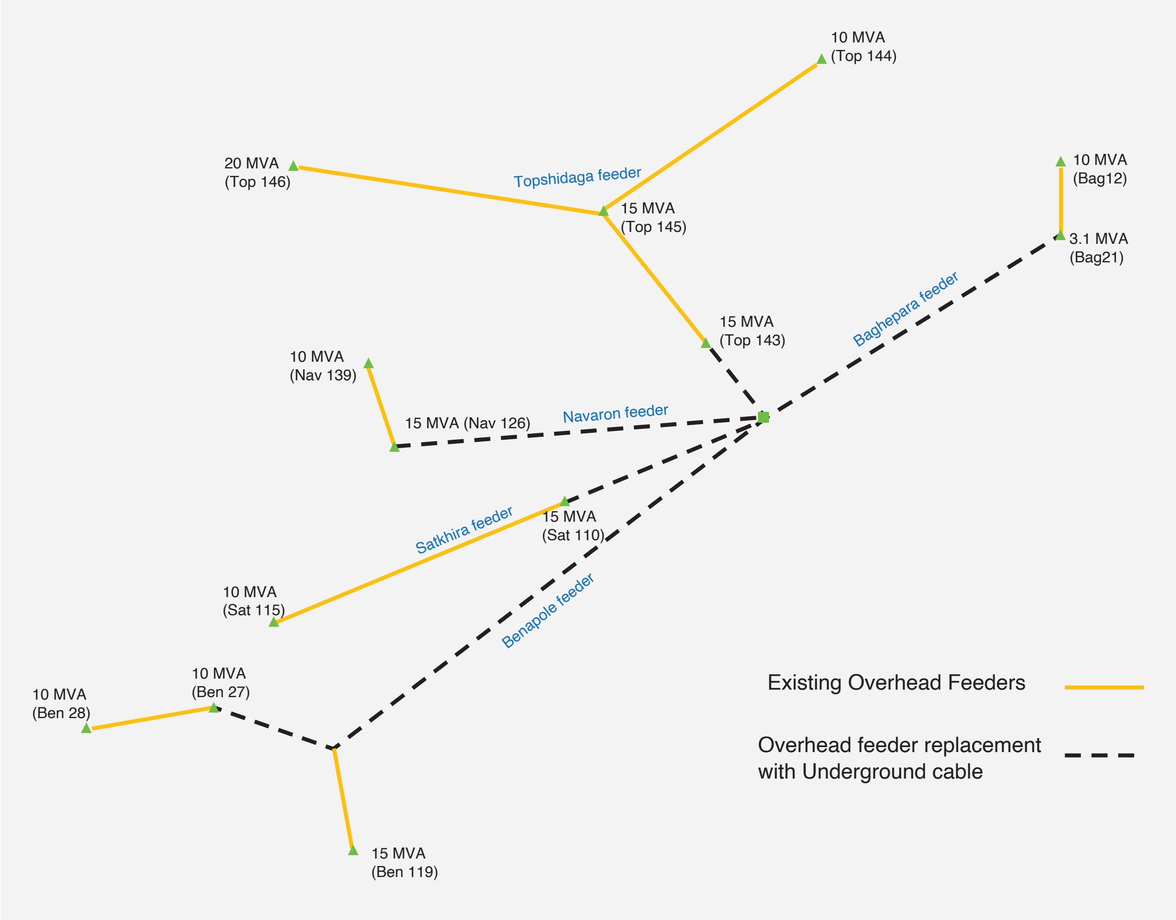
Source: Deloitte 2020.

Option 4: Optimized Composite

The last option is defined in such a way as to combine the maximum benefits of the three conventional alternatives, illustrated in **Figure 8.6**:

- Use of underground cables, which requires the maximum capital expenditure out of the three conventional options, has been restricted to the section that caters to substantial load portion of the network (approximately 21 km of underground cable directly impacts 30 MVA substation capacity and indirectly supports another 30 MVA substation capacity).
- Development of alternate feeding arrangement for tail-end sub stations (Ben 28 Sat 115 Nav 139 with the help of an approximately 20 km connection between NAV 139 substation and Ben 28 substation along with a tapping connection on this new feeder to Sat 115 SS will further improve network resilience).
- Augmentation of exiting feeders catering to high-capacity substation.

FIGURE 8.3: UNDERGROUNDING



Source: Deloitte 2020.

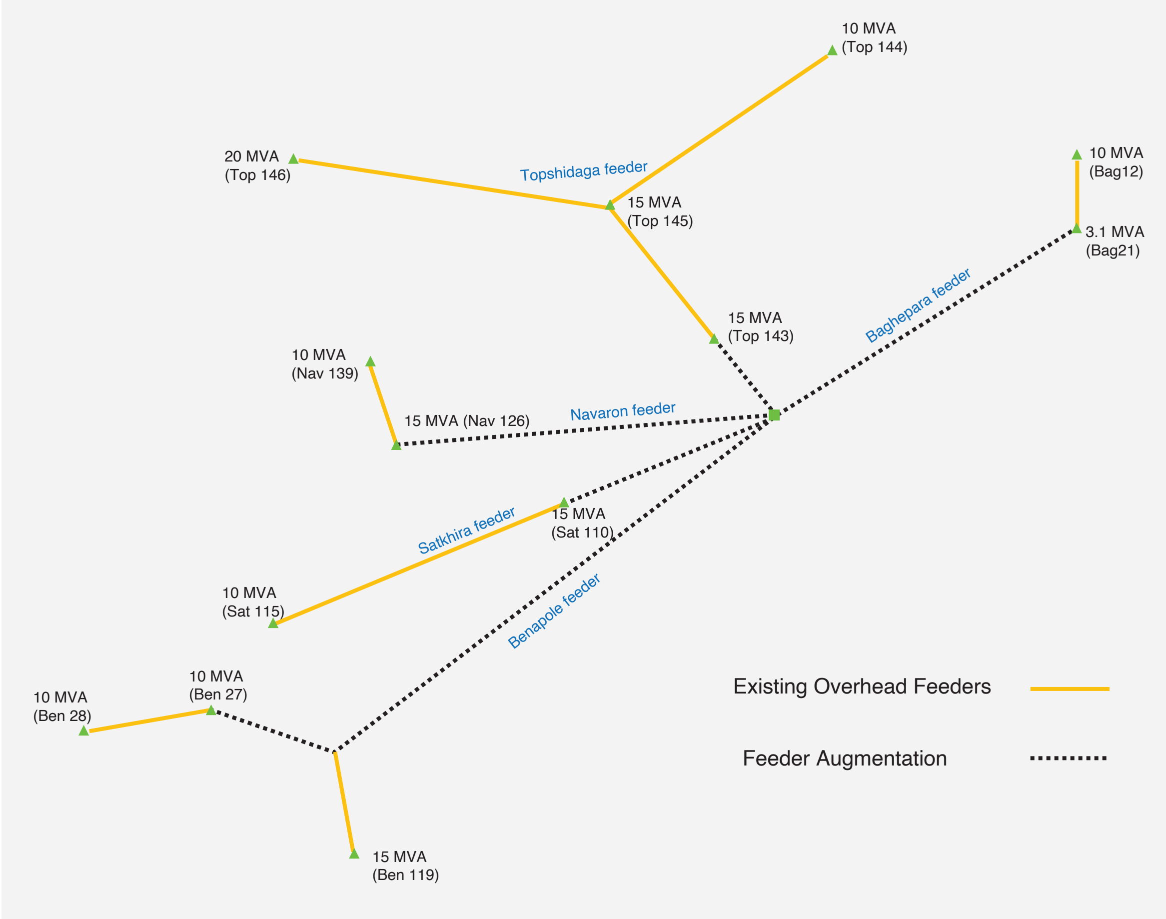
8.3 METHODOLOGY

These various configurations are modeled in PSSE load flow analysis, the single line diagram for which is shown in **Figure 8.7**. This is then mapped onto blocks in the 12.5 km^2 grid for which corresponding wind speed data is available.

The next step is to calculate the failure probability (Pf) at different wind speeds, by using the Weibull statistic that generates the failure probability function shown in **Figure 8.8**.

In a given extreme event such as a storm, not all the network components will face damage—it depends on local conditions and wind speeds together to make an impact. For example, feeder in zone 7 may face damage while feeder in zone 13 may remain intact. However, given the variable nature of maximum wind speeds across a PBS zone, all such possible combinations must be explored (10,000 simulations were required to reach convergence). **Table 8.4** shows the output of the PSSE simulation for one such trial for a wind speed of 65 km/h with standard deviation of 8 km/hour. Based on a literature review, the study assumes that an outage will occur at Pf > 0.9. For this trial, the total energy loss is 82 MWh. An important assumption appears to be that the outage occurs at the time of day during which the maximum load on feeders is observed.

FIGURE 8.4: FEEDER AUGMENTATION



Source: Deloitte 2020.

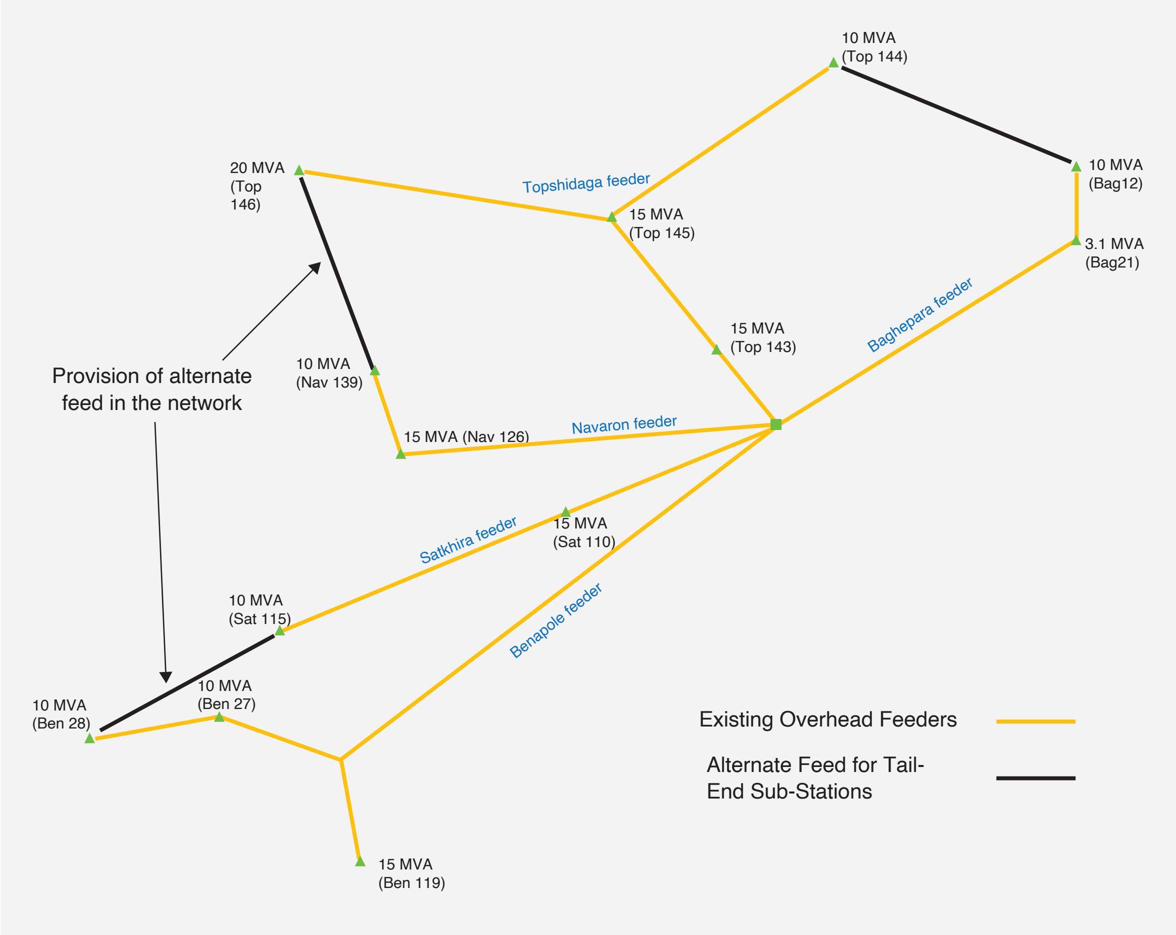
The Monte Carlo simulation then allows insights into the reduction of ENS for different wind speeds and the various feeder enhancement options (**Figure 8.9**).

With this information, one can compare the different options under alternative scenarios of the frequency and intensity of storms. This was done under the assumption that each year would see three wind events with speeds of 50, 60, and 70 km/h. This results in a BAU ENS of 469.5 MWh, with reductions in ENS as shown in **Figure 8.10**. Note that the BAU ENS is almost three times the ENS of the highest ENS in the 2000–2015 period of 160 MWh.

8.4 ECONOMIC ANALYSIS

Two benefits of a more resilient system were assessed: lower repair and recovery costs and lower unserved energy. In a financial analysis, the benefit to the PBS is the additional revenue, assessed at the average tariff (which is the metric used by Deloitte). However, in an economic analysis, the benefit is likely much higher, since the actual tariff (taken in the study as 7.4 USc/kWh) is only the lower bound of the

FIGURE 8.5: RING MAIN SYSTEM



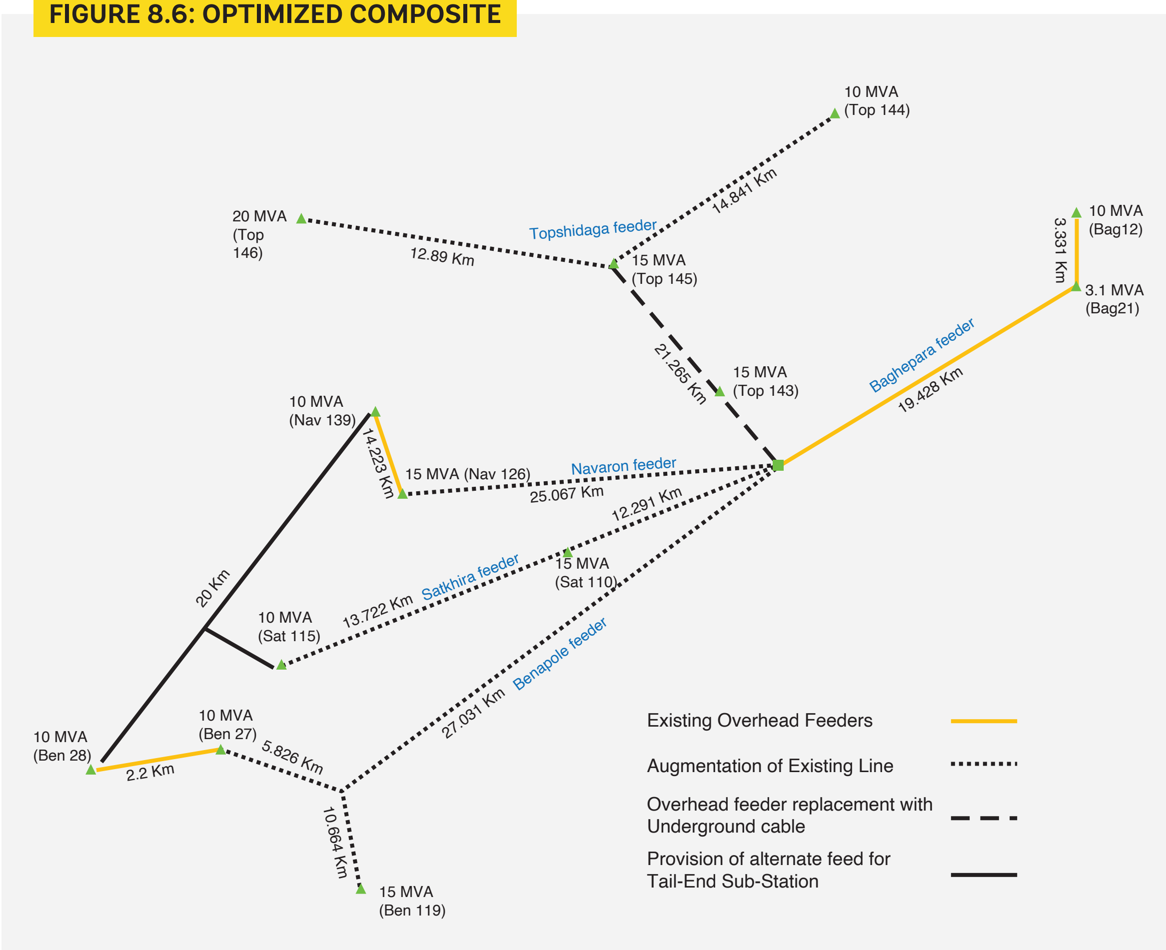
Source: Deloitte 2020.

willingness to pay. In the absence of a survey, the approach taken in this Annex is calculate the shadow price for unserved energy (i.e., the value of unserved energy that make the investment in adaptation expenditure worthwhile). **Figure 8.11** shows the trend in repair and recovery costs (converted to constant 2020 prices).

Table 8.5 sets out the economic analysis for the four options. In row 6 of each sub-table is the calculation of the value that ENS must have to be equal to the net costs of the upgrade. The values lie between $1.02/kWh to $4.33/kWh—clearly above any reasonable valuation for ENS. Feeder augmentation is seen to be by far the most cost-effective intervention and undergrounding the least cost-effective.

The discount rate matters at 10 percent the value of ENS increases to $1.38/kWh. Moreover, this valuation is equivalent to the tariff necessary to make the investment financially sustainable: clearly, $1.02/kWh is not close to the revenue collected by the PBS (7.4 USc/kWh).

FIGURE 8.6: OPTIMIZED COMPOSITE



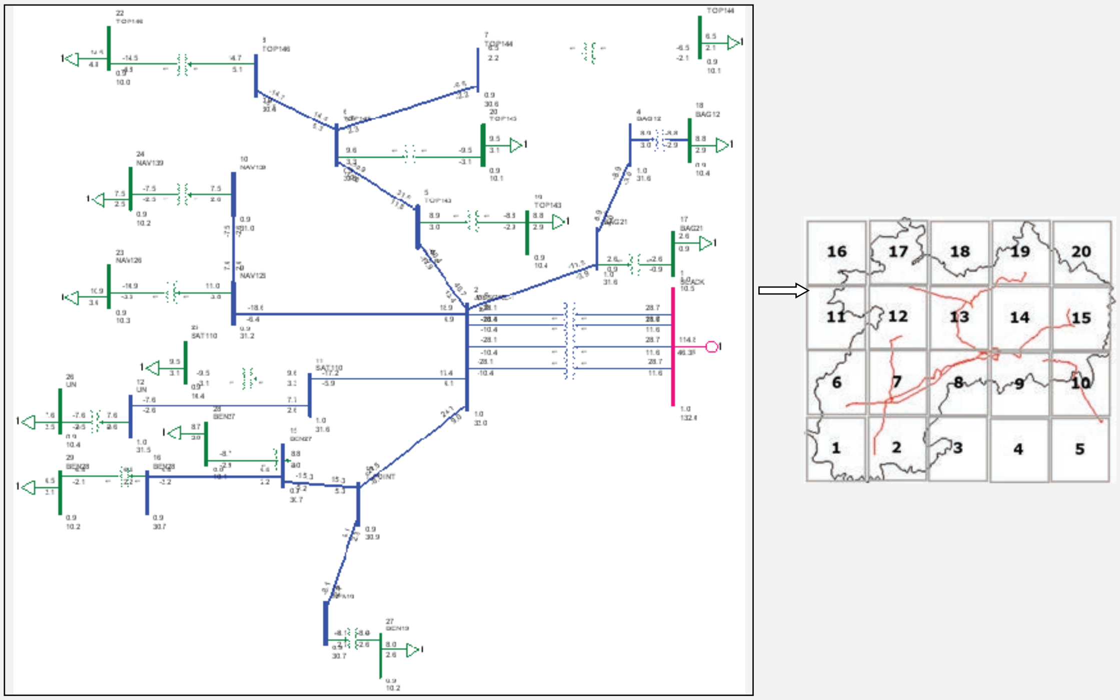
Source: Deloitte 2020.

8.5 CONCLUSIONS AND LESSONS

The Deloitte (2020) analysis shows that in the case of the Jessore PBS, which lies some way inland, none of interventions are cost effective even when the amount of ENS under business-as-usual is three times higher than what was observed in 2000–2015. It does, however, make the convincing case that feeder augmentation is by far the most effective way to improve resilience, and that undergrounding by far the most expensive. A case for undergrounding will be difficult in most cases unless there is a risk of losing a feeder every 2 to 3 years.

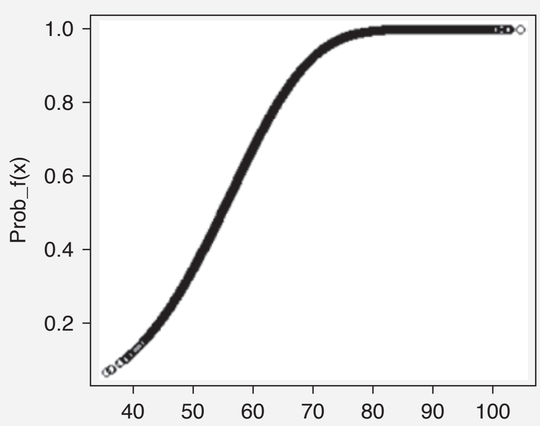
This technical assessment may also not capture other mitigation measures. Once the poles and lines are knocked down by a storm, they are often fully replaced, when a guy wire or cutting the trees before storm season would do the job; better regular preventative maintenance is often the best mitigant against storm damage (as is widely practiced, for example, by most American utilities that lie in the hurricane pathways regularly encountered in the Southeastern states). A good example is the experience of the Long Island Lighting Company (LILCO), in financial difficulties in wake of an imprudent expenditure on the Shoreham Nuclear power project (that cost $4.5 billion but never received an operating license). In consequence it neglected its summer tree pruning program, with catastrophic impact when Hurricane Gloria hit in October 1985. Repairs cost $30 million. Emergency repair crews brought in from neighboring utilities expressed shock at the condition of poles and wiring, and the evident neglect of normal tree maintenance (see, e.g., McQuiston 1985).

FIGURE 8.7: LOAD FLOW MODELING FOR JESSORE-I



Source: Deloitte 2020.

FIGURE 8.8: FAILURE PROBABILITY FUNCTION FOR JESSORE-1



Source: Deloitte 2020.

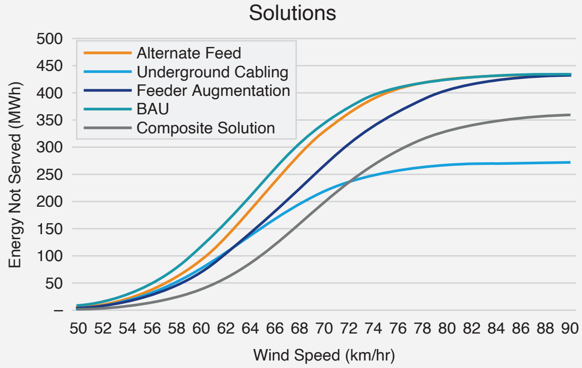
TABLE 8.4: PSSE TRIAL SIMULATION

NAME	LOAD_MVA	WIND_SPEED	PF	OUTAGE	ENERGY_LOSS
Top143	8.80	62.13320	0.7428494	FALSE	0
Top145	9.50	62.13320	0.7428494	FALSE	0
Top144	6.50	62.13320	0.7428494	FALSE	0
Top146	14.50	71.26536	0.9405944	TRUE	29000
Bag21	2.59	82.01081	0.9974564	TRUE	5180
Bag12	8.80	69.41927	0.9974564	TRUE	17600
Nav126	10.90	59.13807	0.6477173	FALSE	0
Nav139	7.50	71.26536	0.9405944	TRUE	15000
Sat110	9.50	59.13807	0.6477173	FALSE	0
Ben27	8.70	62.55306	0.7553175	FALSE	0
Ben28	6.50	62.55306	0.7553175	FALSE	0
Ben19	8.03	81.80739	0.9972483	TRUE	16060

Source: Deloitte 2020.

FIGURE 8.9: COMPARISON OF ENERGY NOT SERVED

Comparison of Energy Not Served using Conventional Solutions

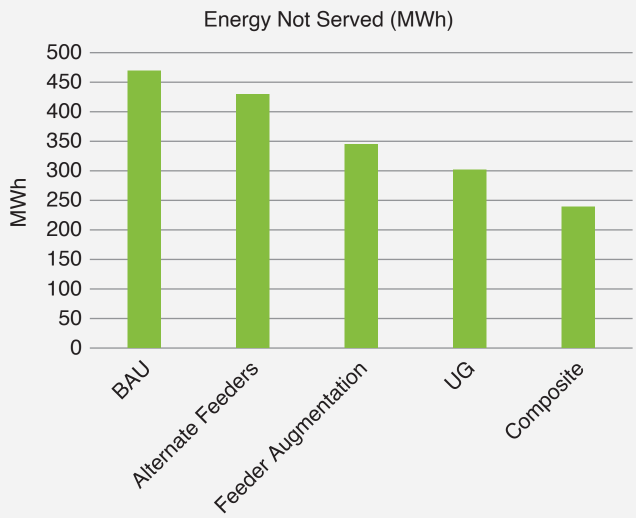


Comparison of energy not served (kWh)

Wind (km/hr)	BAU Loss	Alternate Feed	UG Cable	Feeder Augmentation	Composite Solution
50	8,878	6,466	6,131	4,962	2,319
55	38,739	29,837	25,974	22,779	11,141
60	1,18,363	93,713	77,907	74,307	38,687
65	2,34,219	2,09,593	1,52,795	1,62,806	1,02,906
70	3,42,297	3,29,934	2,18,408	2,67,260	1,98,335
80	4,24,370	4,23,911	2,65,999	4,03,222	3,29,299
90	4,32,828	4,32,893	2,71,037	4,30,948	3,58,104

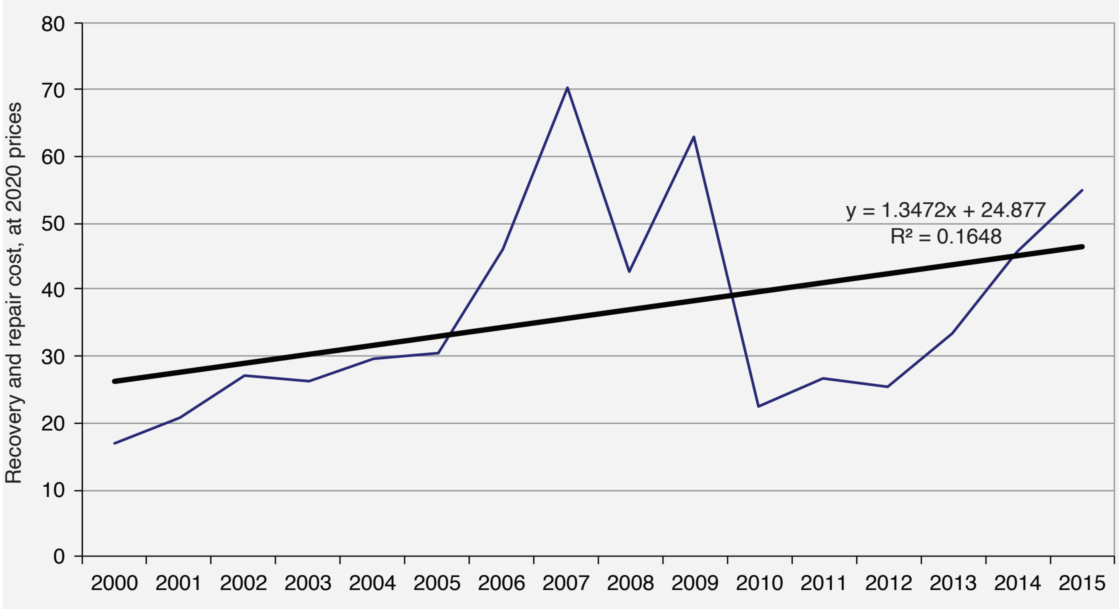
Source: Deloitte 2020.

FIGURE 8.10: ENERGY NOT SERVED REDUCTION COMPARISONS



Source: Original calculations.

FIGURE 8.11: REPAIR AND RECOVERY COSTS



Source: Original calculations.

TABLE 8.5: ECONOMIC ANALYSIS

	UNDERSGROUND CABLE			**NPV**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	Reduction in ENS		[MWh]	*1,162*	0	**168**	168	168	168	168	168	168	168	168	168	168	168	168	168	168
2	CAPEX		[$USm]	*−6.09*	−6.7															
3	OPEX	0.02	[$USm]	*−0.93*	0	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13	−0.13
4	Repair cost savings		[$USm]	*0.66*	0	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
5	total cost		[$USm]	*−6.36*	−6.7	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04	−0.04
6	value ENS		[$US/kWh]	5.47																
	FEEDER AUGMENTATION			**NPV**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	Reduction in ENS		[MWh]	*857*	0	**124**	124	124	124	124	124	124	124	124	124	124	124	124	124	124
2	CAPEX		[$USm]	*−1.45*	−1.6															
3	OPEX	0.02	[$USm]	*−0.22*	0	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03	−0.03
4	Repair cost savings		[$USm]	*0.49*	0	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
5	total cost		[$USm]	*−1.19*	−1.6	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
6	value ENS		[$US/kWh]	1.38																
	RING MAIN/ALTERNATE FEEDERS			**NPV**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	Reduction in ENS		[MWh]	*277*	0	**40**	40	40	40	40	40	40	40	40	40	40	40	40	40	40
2	CAPEX		[$USm]	*−1.05*	−1.16															
3	OPEX	0.02	[$USm]	*−0.16*	0	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02	−0.02
4	Repair cost savings		[$USm]	*0.16*	0	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
5	total cost		[$USm]	*−1.06*	−1.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	value ENS		[$US/kWh]	3.82																
	COMPOSITE			**NPV**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	Reduction in ENS		[MWh]	*1,597*	0	**231**	231	231	231	231	231	231	231	231	231	231	231	231	231	231
2	CAPEX		[$USm]	*−4.12*	−4.53															
3	OPEX	0.02	[$USm]	*−0.63*	0	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09	−0.09
4	Repair cost savings		[$USm]	*1.91*	0	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
5	total cost		[$USm]	*−3.83*	−4.53	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
6	value ENS		[$US/kWh]	2.40																

Note: (1) snapshot only: calculations are for 15-year time horizon; (2) Discount rate 6%

Source: Original calculations.

This is confirmed by the more rigorous (and reliable) economic analysis presented in this Annex. The economic analysis in the Deloitte (2020) report has numerous problems. First, the restoration cost calculation does not adjust the historical values for inflation, and simply averages the annual repair costs and divides by the 2020 exchange rate, resulting in an average annual restoration cost of $26,325. This calculation is unreliable. Second, this same repair cost saving is used for all four scenarios. The rationale for this is unclear. Third, there appears to be no inclusion of incremental OPEX. Finally, the total benefits are given as the undiscounted total over 15 years. Regardless of whether the analysis is at constant or nominal prices, the justification for zero discount rate needs to be given. In a financial analysis, weighted average cost of capital (WACC) would be a more appropriate discount rate than zero. To reach a value of unserved energy comparable to the cost of self-generation—$0.22/kWh would require a business-as-usual ENS of 940 MWh, which would require a six-fold increase in storm outage days.

However, the underlying methodology is sound, and whether the same conclusion would be drawn in a PBS closer to the coast, where wind speeds are much higher, and liable to cause much greater damage, needs further assessment.

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