Economic Analysis of Battery Energy Storage Systems

Clean Energy Global Solutions Group
Energy & Extractives Global Practice

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CONTENTS

Abbreviations

AC	Alternating current
ADB	Asian Development Bank
BESS	Battery energy storage system (see Glossary)
BMS	Battery management system (see Glossary)
BoS	Balance of System (see Glossary)
BTU	British Thermal Unit
CAES	Compressed air energy storage
CAPEX	Capital investment expenditure
CAR	Central African Republic
CBA	Cost/benefit analysis
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CEA	Central Electricity Authority (India)
CEB	Ceylon Electricity Board (Sri Lanka)
CERC	Central Electricity Regulatory Authority (India)
CSP	Concentrated solar power
CoUE	Cost of unserved energy
CT	Combustion turbine
DC	Direct current
DL	Distribution licensee
DoD	Depth of discharge (for a battery (see Glossary))
DR	Demand response
DSM	Demand side management
EMS	Energy management system (see Glossary)
ENTSO-E	European Network of transmission System Operators
EOCK	Economic opportunity cost of capital
EPC	Engineering, procurement and construction
EPRI	Electric Power Research Institute (US)
ERR	Economic rate of return
ESS	Energy storage system (see Glossary)
EV	Electric vehicle
FCAS	Frequency control ancillary services
FFR	Fast frequency response
FIRR	Financial internal rate of return
FIT	Feed-in tariff
FS	Feasibility study
GDP	Gross domestic product
GHG	Greenhouse gas
HFO	Heavy fuel oil
HVDC	High voltage direct current(transmission)
IEA	International Energy Agency
IEG	Independent Evaluation Group (of the World Bank)
IEX	Indian Electricity Exchange
IPP	Independent power producer
IRp	Indian Rupee
ITC	Investment tax credit
IWGSCC	Interagency Working Group on the Social Cost of Carbon (US)
LBNL	Lawrence Berkeley National Laboratory
LCoE	Levelized cost of electricity
LCoS	Levelized cost of storage
LDC	Load duration curve
LFP	Lithium iron phosphate (see Glossary)

LECO	Lanka Electricity Company
Li-ion	Lithium ion metal oxide (as in battery, see Glossary)
LOLP	Loss of load probability
MAC	Marginal abatement cost
MADA	Multi-attribute decision analysis
MATA	Multi-attribute trade-off analysis
mbd	million barrels per day
MC	Marginal cost
MENA	Middle East and North Africa (Region), World Bank
mmBTU	million British Thermal Units
mtpy	million tons per year
MW	Megawatts (equal to million joules per second)
NCA	(Lithium) nickel cobalt aluminum (oxide) (see Glossary)
NG	Natural gas
NLDC	Net load duration curve; net of renewable energy
NMC	(Lithium) nickel manganese cobalt (oxide) (see Glossary)
NPV	Net present value
NREL	National Renewable Energy Laboratory (US)
O&M	Operating and maintenance costs (may be variable, fixed or both)
OPEX	Operating cost expenditure
OPSPQ	Operations Policy and Quality Department (World Bank)
PAD	Project Appraisal Document (World Bank)
PCM	Production cost model
PCN	Project Concept Note
PCS	Power conversion system
PG&E	Pacific Gas and Electric
PHS	Pumped hydroelectric storage
PJM	Pennsylvania-Jersey-Maryland Power Pool (USA)
PPA	Power purchase agreement
PPP	Public-Private-Partnership
PSG	Power Sector Guidelines (Guidelines for Economic Analysis of Power Sector Investment Projects, World Bank)
PV	Photovoltaic
RE	Renewable energy
RMI	Rocky Mountain Institute
RT	Round trip efficiency (of a BESS)
RTO	Regional transmission organization
SAIFI	system average interruption frequency index
SCC	Social cost of carbon
SLDC	Storage load duration curve
SLPUC	Sri Lanka Public Utilities Commission
SNL	Sandia National Laboratory
SoC	State of charge (for a battery)
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SVC	Social value of carbon
T&D	transmission and distribution
ToU	Time of use
TSO	Transmission system operator
TTL	Task Team Leader (World Bank)
UCTE	Union for the Coordination of Transmission of Electricity (EU)
UPS	Uninterruptible power supply
US	United States

USAID	United States Agency for International Development
USC	ultra super-critical
USEIA	United States Energy Information Administration
VOLL	Value of lost load
VRE	Variable renewable energy
VRFB	Vanadium redox flow battery (see Glossary)
VRLA	Valve regulated lead acid (battery)
WACC	Weighted average cost of capital
WDI	World Development Indicators (World Bank database)
WEO	World Energy Outlook (IEA)
WTP	Willingness-to-pay
ZBFB	Zinc bromine flow battery (see Glossary)

UNITS AND CONVERSION FACTORS

cst	Centistokes (a measure of viscosity)
BCM	billion cubic meters
BTU	British thermal unit
cumec	cubic meters per second
m/s	meters/second
GW	Gigawatt = 1,000 MW
MW	Megawatt = 1,000 kW
KW	Kilowatt
bbl	barrel
kWh	kilowatthour=3,412 BTU
TCM	thousand cubic meters
mtpy	million tons per year

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ACKNOWLEDGEMENTS

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PREFACE

The recent advances in battery technology and reductions in battery costs have brought battery energy storage systems (BESS) to the point of becoming increasingly cost-effective projects to serve a range of power sector interventions, especially when combined with PV and where diesel is the alternative, or where subsidies or incentives are used. However, such projects bring new challenges to economic and financial analysis: because BESS can deliver a range of grid energy management and power services (such as peak load shifting, renewable integration and , ancillary services), that are not always easy to quantify, or even possible to value and monetize.

Quantifying the economic impact of BESS requires a high level of temporal granularity in the analysis, because the time-steps required for a reliable assessment of costs and benefits are much shorter than the usual annual time steps of many power sector investment projects. Of course that is also true of variable renewable energy (VRE) such as solar and wind, but the combination of VRE and BESS brings additional analytical challenges.

The institutional and regulatory framework is critical, in particular for the provision and monetization of many of these services. But absent markets for these services - which is the case in most World Bank client countries - the extent to which these potential economic benefits can be harnessed in practice is unclear.

In short, there is as yet still limited experience in the economic and financial analysis of BESS investment projects particularly, in developing countries, and one cannot yet set out with clarity what constitutes best international practice. The literature is growing fast, but much of it reflects the unique regulatory, taxation and institutional environment of the USA and of the EU. ADB, IRENA, and IFC have all issued guidance documents and handbooks on BESS, but the case material for economic and financial analysis is limited, again draws mostly in practice in the market-based systems of the developed countries or focuses on estimating the levelized cost of energy storage.

This report sets out the principles and practices of BESS economic analysis as required for the World Bank's appraisal of investment projects - that cover the range of BESS projects likely to be encountered by the Bank over the next few years.

The economist faced with the task of preparing the economic analysis of a BESS at appraisal faces two main challenges. The first, as always, is to position the analysis along a scale that runs from rules of thumb to complex systems modeling. Of course this is influenced by the scale of the investment project under appraisal and the size the system considered, but the report is intended to set out what is minimally required for data and modeling even for a small VRE+BESS system serving a mini-grid, or a BESS at the distribution level, where complex production cost models or capacity expansion optimization models would not substantially improve the appraisal (even assuming the necessary resources were at hand).

The second is technical. The presumption of this report is that the project appraisal team will include a technical specialist to provide guidance on technical aspects of battery design, performance and sizing, just as a hydro engineer will be part of an appraisal for a hydro scheme. Nevertheless, the economist needs a sufficient understanding of the unique technical aspects of BESS.

The extent to which this report succeeds in meeting these challenges only its practical application will tell. This report must therefore be seen as preliminary, and will necessarily need updating within a year or two, once the lessons learned from the practical application of its methodology can be assessed, where gaps are identified that need to be filled, and the document improved accordingly. Feedback from its readers is encouraged.

HOW TO USE THIS REPORT

To the extent practical, this report is designed as a "stand-alone" document. However, a number of important topics in economic analysis are already covered extensively in the Guidelines for Economic Analysis of Power Sector Investment Projects (PSG), and are not therefore repeated here (such as the impact of discount rates, estimates of willingness-to-pay, and the general principles of sensitivity analysis and risk assessment).

Those experienced in preparing economic analysis for power sector project appraisal should start with the checklist of Table 1, in which the special problems associated with battery systems are set out at each step of the procedure set out in the PSG. The section on key questions (Section 3) then provides recommendation on the decisions to be made as work on detailed project design and appraisal begins.

For first encounters with a BESS project, a quick read of the Introduction (Section 1) and the relevant economic principles (Section 2) should be the starting point, again followed by Section 3.

Once the range of potential benefits are identified, the relevant issues of costs and benefit valuation are provided in Section 4 and 5.

Projects involving batteries span a wide range, for which case material is provided for each, and presented in Section 6.

Summary of case material[1]

BESS application	Country	Main questions and issues	Report reference
Utility scale BESS	Jordan	• Design of a study to examine the role of storage • scenario design in a systems planning model	Box 2
BESS for spinning reserve	India	• BESS compared to flexible operation of coal projects	Section 6.4
BESS for VRE integration	Central African Republic	• Time shifting into peak hours	Section 6.2
BESS for VRE integration	Vietnam	• Avoidance of curtailment at wind farms • importance of tariffs	Section 6.5
Price arbitrage at distribution licensee level	Sri Lanka	• Difference between economic and financial analysis	Section 6.1
Price arbitrage at large consumer level	Philippines	• Avoidance of capacity charges • battery sizing	Box 3
Ancillary services	India	• benefit stacking	Section 6.3

[1] As new projects emerge, this case material will be extended to provide examples of battery projects in all regions.

BESS application	Country	Main questions and issues	Report reference
Power smoothing	Cambodia	• Reduce ramp rates at floating PV systems	Box 4

The spreadsheet templates that can be downloaded may be used as a starting point for establishing the appraisal economic and financial analysis. Final versions of these spreadsheets will be issued (and available from the Practice website) once comment and feedback from users is received.

1 Introduction

1.1 Objectives and Scope

1. Although the Bank's Guidelines for economic analysis of power sector investment projects[2] need to be followed in all power sector investment project appraisals, a number of special issues arise in the appraisal of Battery Energy Storage Systems (BESS) that are not covered in the Power Sector Guidelines or the supporting Technical Notes. **This Report on the economic and financial analysis of BESS is designed to assist the project economist in the preparation of a project appraisal.**

2. This report is in support of **the World Bank Group's $1 billion global battery storage program**, announced in 2018. This aims to raise a further $4 billion in **private and public funds to create markets and help drive down prices for batteries**, so it can be deployed as an affordable and at-scale solution in middle-income and developing countries.

3. **There exists a very large and growing literature** on the technical aspects of BESS, the details and mastery of which - in most cases - will go beyond the qualifications and experience of economists, even in cases where the economist has much experience in the economic analysis of power sector projects, including variable renewable energy (VRE) projects. The presumption of this report is that a suitable technical specialist - who does possess the detailed technical and engineering knowledge to make informed decisions about the technical design and performance of a BESS - is part of the project preparation team.

4. **The main challenge is the estimation of the *benefits***. What is important is that the economist asks of the technical specialist the right set of questions about the operation and performance of the proposed system to enable the costs and benefits to be properly quantified and monetized, and compared to a credible counter-factual. Performance would include round trip efficiency and degradation; operation refers to how the BESS is used or operated e.g. for load shifting or spinning reserve.

Reading List 1: Relevant World Bank Guidelines

The following guidance documents are relevant to all economic analysis of investment projects:

- Investment Project Financing Economic Analysis Guidance Note, OPSPQ, 2014
- Guidelines for Economic Analysis of Power Sector Investment Projects, 2017 (**hereinafter cited as Power Sector Guidelines, PSG**)
- Technical Notes Power Sector Policy and Investment Projects: Guidelines for Economic Analysis 2016
- Guidance Note on Shadow Price of Carbon in Economic Analysis, 2017
- Discounting Costs and Benefits in Economic Analysis of World Bank Projects, OPSPQ 2016

2 Hereinafter cited simply as PSG, Power Sector Guidance

1.2 THE KEY DECISIONS

5. The principal objective of this report is to assist the economist in making (or contributing to) the key questions at the beginning of the project preparation cycle:

- To what extent would a BESS be an alternative to meet the critical needs of a country power system. This lies at the heart of any economic analysis: what is the counter-factual for a proposed investment project.
- Given the proposed primary application or applications, **where is the BESS best located**? For example, co-located as part of hybrid VRE + BESS , or as a stand-alone project elsewhere in the system, which may be grid connected or off-grid
- Given the proposed primary application and location, **what is the** appropriate **technology.**
- What should be the optimal **size** of the project; the size for BESS has a power (kW) and the energy (kWh) component. For hybrid VRE + BESS projects the ratio of the nameplate VRE to BESS power capacity also needs to be chosen.

6. There then follows the question of **what analytical tools are required to answer these questions, and the extent of data that is required**. The task is to position the analysis along a scale that runs from the use of relatively simple rules of thumb to more complex systems modeling. Of course this is influenced by the scale of the investment project under appraisal, and the extent to which the necessary data is available, as well as the uncertainty of that data, including how it may change over the life of the investment. The practical question is often whether the application of complex production cost models or capacity expansion optimization models would substantially improve the reliability of the appraisal, even assuming the necessary resources and data were at hand. This may be particularly true in some developing countries that are experiencing rapid growth in demand and/or electricity access, and where the resource mix may change significantly over the next decade.

7. As noted, the main challenge for economic analysis is the estimation of benefits. **But is it always necessary to quantify all benefits**? If some of the more easily quantifiable benefits of time shifting for VRE integration already deliver robust economic returns, to what extent is it necessary to attempt to quantify other ancillary services benefits particularly in cases where there are no established markets).

8. **However desirable, simplification, back of the envelope calculations, and use of assumptions taken from other countries rarely suffice and require caution**. For example

- Credible estimates of the GHG emissions that conform to official Bank Guidance on carbon accounting require careful attention to detailed energy balance calculations that properly account for degradation of battery performance over time, and to properly capture the emission of the counter-factual.
- Where markets for ancillary services do not yet exist, valuations taken from other countries (and from countries very different in size and stage of development) carry high levels of uncertainty.

1.3 CANDIDATE ENERGY STORAGE SYSTEMS

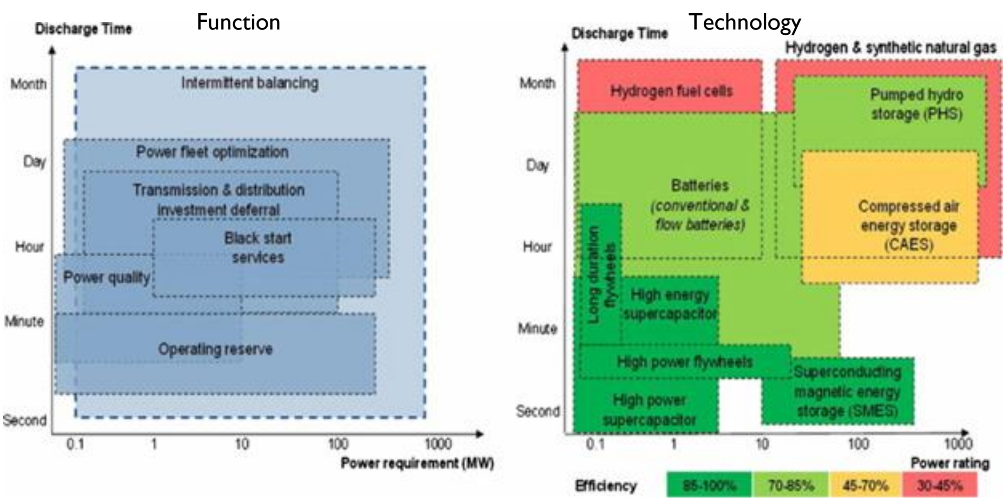
9. Although the focus of this Report is on batteries, BESS is not the only technology that can provide energy storage, some of which have long been part of power systems and familiar to economists:

- Conventional storage hydro (other than pure run-of-river projects) adequately covered in the PSG. No other energy storage technology for the electric sector has the potential for monthly and seasonal time scales.
- Pumped hydroelectric storage (PHS) (covered to some extent in the PSG)
- Thermal storage as used in concentrated solar power (CSP) projects.[3]
- Flywheels (see Glossary).
- Compressed air energy storage (CAES), including adiabatic-CAES that does not require fossil fuel (early stage)
- Hydrogen storage (still at a nascent stage globally, in part due to significant new infrastructure requirements)

10. Hybrid energy storage systems may also be possible, such as those that combine with BESS with different chemistries, or even different technologies e.g. a hybrid BESS and flywheel system to serve both energy management and power applications.

11. Energy storage technologies span a wide range of time scales and requirements for flexible operation. This means some energy storage technologies are better suited to provide certain services than others. Figure 1 shows the relationship between application, power size, duration and different energy storage technologies. BESS is becoming increasingly attractive – in part – because its modular nature means that it can be deployed across a wide range of sizes for power (a few kW or less to 100MW or more) and energy (from minutes to hours, or more). The choice of battery technology and electrochemistry will unlikely fall on the project economist, but on the technical specialist.

Figure 1: Growing needs and range of options for flexibility



Source: M. Aneke and M. Wang. *Energy Storage Technologies and Real-life Applications–A State of the Art Review*. Applied Energy 179 (2016): 350-377

3 The *methodology* for optimizing the amount of storage for CSP is similar to that for storage at solar PV projects .CSP may become comparatively more cost effective for high duration compared to BESS because the cost of thermal storage (typically molten salts) is much lower than electrochemical storage even after adjusting for efficiency losses, and the need for a larger solar field. The cost of CSP has been falling rapidly in recent years though installed costs vary widely by project even when normalized for hours of thermal storage (see e.g. Lilliestam and Pitz-Paal 2018 and IRENA 2017). Best practice in World Bank financed CSP projects can be found in the PADs for the Morocco CSP projects (see e.g. PAD 1007, Noor-Ouarzazate CSP project, Sept 2014)

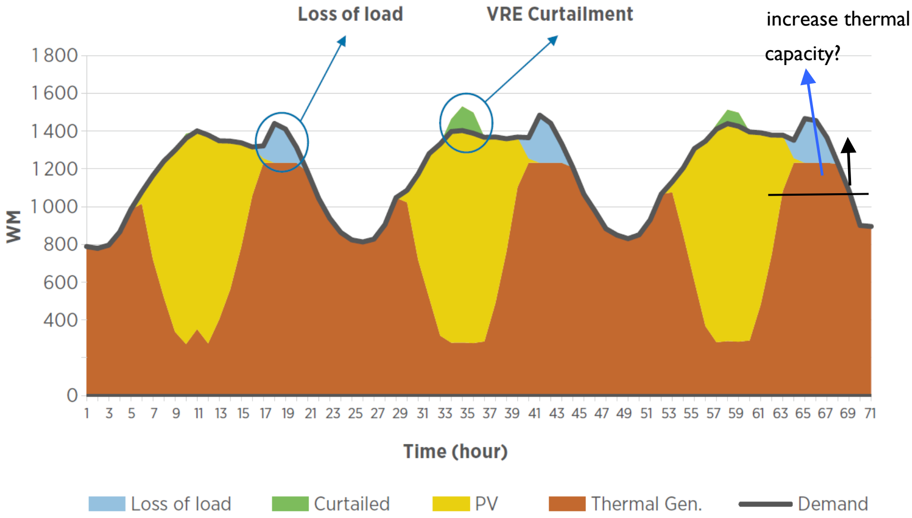
1.4 THE OBJECTIVES AND FUNCTIONS OF A BATTERY ENERGY STORAGE SYSTEM[4]

12. One of the main traditional roles of utility scale energy storage systems is to absorb energy during periods of low prices (low economic value) in order to release it back to the electricity system in times of scarcity or high prices (higher economic value) - in other words **to time shift the use of energy and provide firm capacity to meet the objective of minimizing overall system cost for some stated level of reliability.** Until the recent dramatic cost reductions in battery energy storage based on lithium chemistries (of over 80% over the last decade]), two technologies provided this ability at grid scale. The first is conventional storage hydro with reservoirs to permit daily peaking, monthly or even annual balancing. The second is pumped hydroelectric storage (PHS), which may also have significant energy storage, with durations of 20 hours or more not being uncommon. Hydro and PHS projects can also meet other objectives such as grid reliability though the provision of ancillary services, that include frequency regulation, operating reserves (spinning and non-spinning), reactive power and voltage support, inertial response, and black start capability.

13. **Over the past decade there has emerged another potential role for energy storage, namely the integration of variable renewable energy (VRE)** whose deployment has been driven by the need to reduce global carbon emissions, and the dramatic cost reductions in some renewable technologies, especially solar PV and wind.

14. The potential for BESS to facilitate integration of VRE is illustrated in Figure 2, which depicts a thermal system with high penetration of solar PV. If some part of the solar output could be stored by a BESS two beneficial consequences follow (as shown in the figure): one avoids the curtailment during peak solar output hours (when the thermal load can be reduced no further), and one avoids loss of load (or the investment associated with adding additional thermal units to provide peaking power for a few hours in the evening).

Figure 2: Issues in a system of high solar PV penetration



Source: IRENA, *Power System Flexibility for the Energy Transition: Part I: Overview for Policy Makers*. November 2018.

15. The functions of a BESS can be summarized as follows:[5]

4 This summary draws on D. Chattopadhyay, N. Fridas, T. Kramskaya & E Tavoulereas, *Battery Storage in Developing Countries: Key Issues to Consider*, https://www.researchgate.net/publication/330116801

- **Price arbitrage and peak load shifting -** storing electricity at times when it has lower value, and discharging when it has higher economic value. This can be at grid, transmission, distribution or consumer levels, with typical time frames of several hours or more each day. It is increasingly deployed at VRE projects, where it may also serve to reduce curtailment, and offer firmer energy contracts. In the typical application, there is often one charging and one discharging cycle per day.

- **Smoothing and ramping** – both use the same principle as load shifting, but for smoothing is at much shorter time intervals (typically seconds to minutes) due variations in output of wind (due wind speed variations on these timescales) or PV (e.g. due to cloud cover or rain) . For this application BESS may undergo perhaps hundreds of partial cycles a day - and consequently may requires different battery performance (or possibly technology). In contrast, ramping services that might be provided to support the system as PV declines toward the evening may have multi-hour time horizons similar to traditional peak load shifting.

- **As a source of peaking or firm capacity -** where a BESS is installed expressly for the purpose of avoiding conventional thermal peaking capacity that is used only for a few hours of system peak every day. More broadly BESS may provide significant capacity when used for peak load shifting on a stand-alone basis or as part of a PV + BESS project, though it depends on duration and the rest of the system

- **Congestion management and deferral of network investments:** Batteries located near VRE resources can be useful in managing the loading of transmission lines by storing energy including surplus renewable energy, that cannot be otherwise transferred due to inadequate transfer capability, and releasing them at a later period when the line is not fully loaded. Alternatively, batteries located near load centers may reduce the peak demand on transmission or distribution lines and may be useful in deferring network upgrades including both transformer and line upgrades that would otherwise be needed.

- **Provision of ancillary services,** which include frequency control, and the provision of operating reserves (spinning and non-spinning). Note: some newer service like ramping discussed above may be classified as ancillary services.

16. The realization of the potential benefits of BESS depends critically on the regulatory and institutional environment. Thus for example, for the ancillary services function of batteries to be realized in practice ideally requires a market for these services - but these still exist only in a few World Bank country clients. The financial incentives need care: in cost of service regimes, whether or not energy storage assets can be included in the rate base is critical. Box 1 reviews some recent developments in the regulation of storage projects in developing countries.

[5] see also, e.g., IFC/World Bank Group, *Methodology for the applications of battery storage in power systems*, White Paper, October 2018.

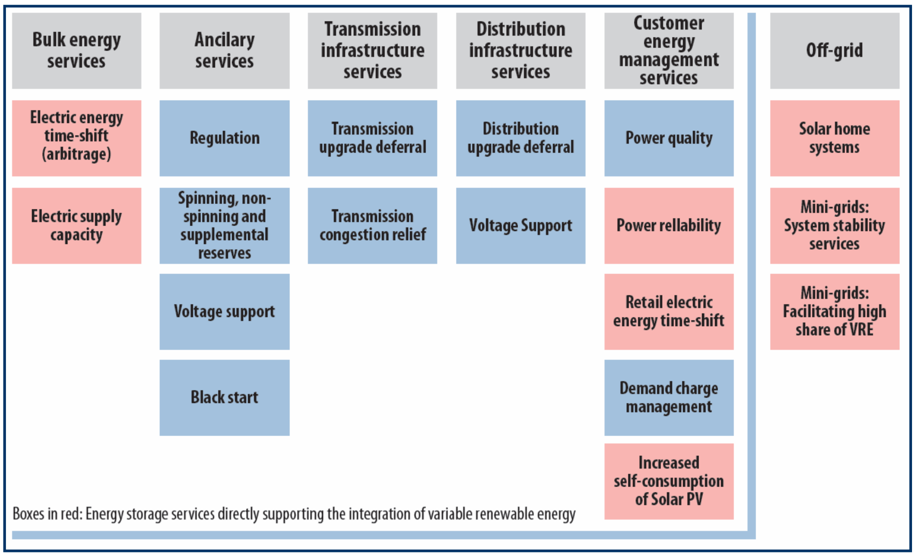
Box 1: Recent developments in storage regulation

The recent *2019 Bloomberg Energy Storage Market Outlook* reports several examples of new regulations that will encourage BESS in developing countries (but that also includes some unfavorable issuances)

- China, where several hundred MW of storage will be online by end of 2019. But a setback was suffered in May 2019 when the regulator ruled that T&D operators could not include storage assets in the rate base.
- Guangdong and West Inner Mongolia have launched frequency regulation markets
- China Southern Power and China State grids have issued their first ever guidance on energy storage business strategies.
- Chile has drafted a "Flexibility Law". The proposal considers storage as part of the strategy to increase the flexibility of its grid. A Technical Commission is developing proposals for alteration of current regulations by end 2019
- In Vietnam, 4.5GW of solar came on-line in the first half of 2019 to qualify for a generous FIT that expired mid-year, which is leading to significant levels of curtailment. Auctions rather than FIT is now planned for further PV additions. GE has been awarded a study to assess the deployment of storage to integrate a greater renewables share (In Vietnam the nuclear program has been cancelled, no more new coal plants are planned, and domestic gas resources are limited, making increased solar integration more urgent).
- In the Philippines, the Department of Energy has published a draft circular covering the regulation and operation of energy storage systems (which could encourage behind the meter rooftop+storage in the commercial and industrial applications).

17. Thus **BESS can provide a wide range of services to a power system**, as summarized in Figure 3. While BESS applications are sometimes presented as distinct and separate grid services, a BESS is often designed and configured with the capability of providing multiple services to the grid both within and across the different categories illustrated in the Figure - referred to in the literature as *benefit stacking*. How to optimize BESS to operate and capture multiple or "stacked" benefits is an active area of research. A related challenge is whether and how, in the frequent absence of energy, capacity and ancillary services markets in typical World Bank client countries, these benefits can be quantified and monetized.

Figure 3: Services provided by BESS



Source: IRENA *Electricity Storage and renewables: Costs and Markets to 2030*, October 2017.

18. **The technical literature is large and growing**. Reading List 2 lists some of the works that may be consulted for additional technical background. The technical aspects of some of the services noted in Figure 3 can be quite challenging and may be beyond the background and expertise of the project economist - who will need to engage with the relevant engineering experts in project design. The bibliography also contains a wide range of more detailed reports and papers on the technical, economic and market analysis of energy storage.

Reading List 2: Technical literature for the non-specialist

ADB *Handbook on Battery Energy Storage System*. Asian Development Bank, December 2018. An excellent starting point for those new to BESS, with well written introductions to the various BESS technologies. However, the guidance on economic analysis is limited, providing simple examples from the UK and Korea.

DOE/EPRI *Electricity Storage Handbook,* 2015. A detailed handbook that with appendices is over 300 pages long. Discusses energy storage technologies, applications and models.

IRENA *Electricity Storage and Renewables: Costs and Markets to 2030*, October 2017. The section on *Electricity storage systems characteristics and applications* is a good introduction to matching different technologies to their intended application.

19. **The need for, and application of BESS in developing countries may differ from developed countries in several ways:**[6] Some challenges facing developing countries may include or depend on:

- Insufficient capacities and skills to evaluate the possible role of energy storage to meet energy policy objectives. Assessing the possible role for energy storage often requires an informed approach to system planning that considers multiple options and relies on advanced modeling tools—both at the power system level as well as on the level of modeling

[6] Few, S., O. Schidt, and A. Gambhir. *Energy access through electricity storage: Insights from technology providers and market enablers*. Energy for Sustainable Development 48 (2019): 1-10.

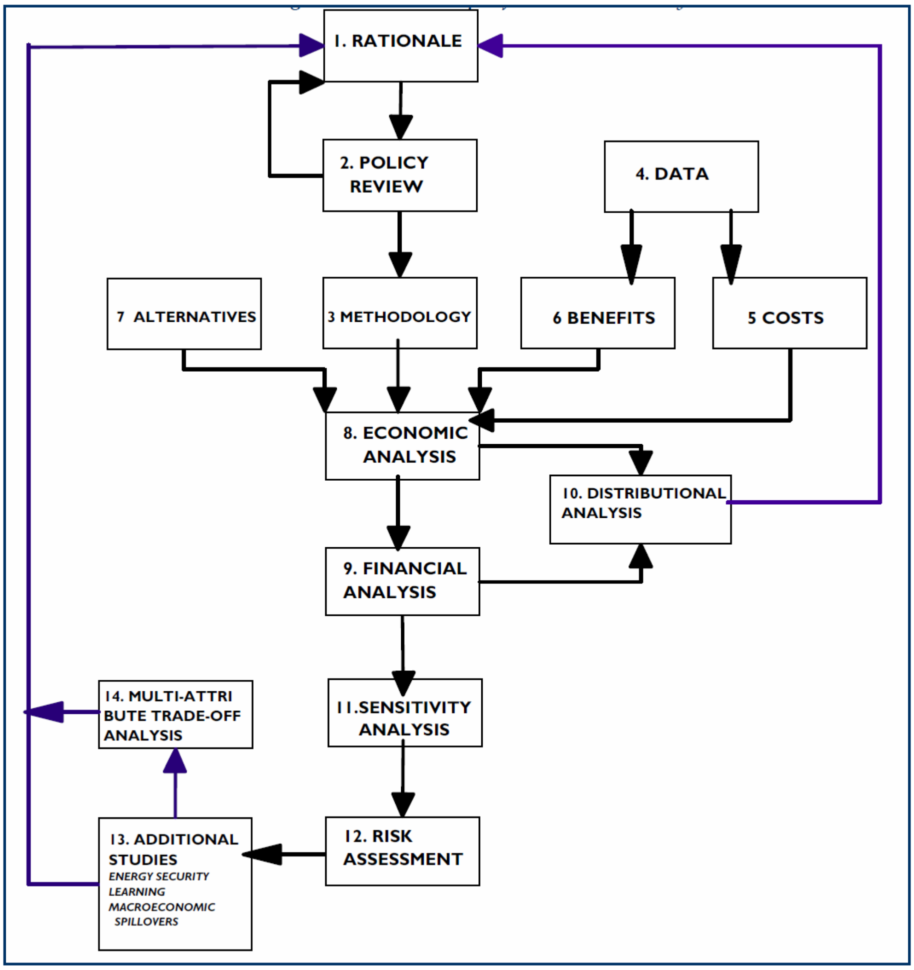
individual storage systems. Such tools are frequently not available in developing countries.[7] On the other hand for small projects where significant unmet demand simpler approaches may be more practical and appropriate.

- Relevant experience, human resources and local support infrastructure, including for maintenance and repair.
- Energy storage choices available locally, and the availability of cost-effective warranties to cover the battery pack and the system.
- The state of power sector and market reforms.
- Mechanisms to facilitate recycling of battery pack and other materials at end of system life.
- Deployment, transportation and installation challenges in remote regions given the temperature sensitivity and fragility of some battery chemistries and BESS systems.

1.5 PROCEDURE

20. Figure 4 shows the main steps in an economic analysis of power sector investments, taken from the PSG. The PSG requires elaboration to account for the unique aspects of BESS, notably that BESS time shifts, rather than produces, net electricity.

Figure 4: The main steps in economic analysis of investment projects



[7] de Sisternes, F. J., H. Worley, S. Mueller and T. Jenkin. *Scaling up Energy Storage in Developing Countries*, Journal of Sustainability Research, Nov 2019.

Source: PSG

21. The PSG provide a checklist for the adequacy of an economic analysis for an investment project appraisal. Table 1 lists for each step in Figure 6 the issues that arise for BESS - and points to the Section in this Report where the issues are discussed in more detail.

Table 1: Checklist for economic analysis

All power sector projects	Issues arising in the Application to BESS [**Reference to the Section of this report for further discussion**]
1. Rationale • What is the main rationale for the project?	• What are the primary applications for the BESS? **[1.4]** • What are the possible secondary applications? **[5]** • Is the battery intended for stand-alone use or to be integrated with PV and/or wind?**[5.3]**
2. Policy Review • What is the rationale for public sector and World Bank involvement? • Are the supporting policies adequate to ensure a sustainable project?	• Public sector and World Bank involvement may well be essential where BESS is unfamiliar to commercial lenders (much as was the case with renewable energy projects a decade ago) • For the value of BESS to ancillary services to be fully realized may require institutional and regulatory reforms **[5.5]**
3. Methodology • Does CBA provide a sufficient justification for the project?	• BESS typically has a shorter life than other projects in a power system (such as a PV or wind project with which it may be coupled. Economic analysis of options with different lives requires care **[4.4]**
4. Data • Are the sources of data credible, and adequately described and cited?	• While widely quoted sources for battery cost data (Bloombery New Energy Finance, Lazards) provide general guidance, Cost estimates for any specific application require the input of a battery engineering expert **[4.1], [Annex IV]**
5. Project costs • Are project costs estimated in the past brought to a common and clearly stated price level? • Are all relevant negative externalities identified? • Is the presentation of economic and financial costs clear?	• BESS costs are declining fast, , though the rate of decline over the next decade is uncertain **[4.1]** • Are end of life costs included (for example, these were a concern to Governments in the proposals for floating solar+BESS in the Mekong Basin)?**[Box 3]** • Have CAPEX costs been broken into fixed and variable so that CAPEX for different hour duration can be estimated?**[4.2]**
6. **Project Benefits** • Is the basis for benefit valuation (incremental, substitution) adequately justified? • Are all likely benefits considered?	• In the absence of a market for ancillaries, capacity, or flexibility, could one introduce specific (formal) policies and regulations to realize these benefits.**[5.5]** • Are claims for a "resilience benefit" justified - e.g., with the increase of wildfires in California and

All power sector projects	Issues arising in the Application to BESS **[Reference to the Section of this report for further discussion]**
• If energy security benefits are claimed, is their presentation consistent with the best practice recommendations?	Australia, consumers have rushed to install behind-the-meter generation (solar + gensets) and storage.[8] However quantifying such benefits in the economic analysis need to meet the test of plausibility, and need to be grounded in empirical evidence. • The valuation of reliability benefits of a BESS depend on credible estimates of the value of lost load/unserved energy [2.6] • In the case of a BESS integrated with a VRE project, does the project level optimization involve any trade-offs with benefits at the system level?[5.3]
• If incremental benefits are based on estimates of willingness-to-pay, is the methodology credible?	• Where WTP estimates are unavailable, the cost of self-generation can be used to value peak power in small systems [6.2]
• Are all positive externalities identified? • Are the costs of fossil fuels properly valued as *economic* prices? • Is the valuation of avoided GHG emissions consistent with the Guidance Note on the value of the social cost of carbon?	• Energy balances need special care in GHG accounting due to battery degradation.[2.3]
7. Definition of alternatives • Are the alternatives to the proposed project adequately justified?	• Several small PV and Wind projects that include BESS have not presented the no-BESS option in the PAD, making it difficult to assess the *incremental* economic benefits of BESS [6.2] • For BESS that connect to the high-medium voltage grid for the delivery of ancillary or flexibility services, are all potential alternatives for delivering these services considered? [5.5]
8. Baseline calculations of economic returns • Are the macroeconomic assumptions (GDP growth, inflation, international fuel prices) clearly stated? • Has the choice of numeraire ($US or local currency) been explained • Is the presentation of the economic flows and the calculations consistent with the recommended format? • Is the choice of baseline discount rate consistent with the recommendation of the Bank's Guidance	• is the capacity value of the BESS based on a credible methodology**?** [2.4] • Are other potential benefits, such as transmission upgrade deferral, considered? [5.1] [6.5] • BESS typically has a much shorter lifetime than other components of the power grid or VRE project: the treatment of unequal lives requires care [4.4]
9 Financial Analysis • Is the economic analysis accompanied by a financial analysis with a consistent set of assumptions?	• Economic and financial analyses need to be based on a common set of assumptions. What is financially feasible may not be economically attractive, and vice versa. [6.1]

[8] In Sri Lanka in the 1990s, many rural households who were connected to the grid, elected to install solar home, simply because grid supply was often of such bad quality, if available at all, that households were willing to acquire a PV system just to ensure reliable supply.

All power sector projects	Issues arising in the Application to BESS **[Reference to the Section of this report for further discussion]**
	• There often arise significant differences between economic and financial benefits for VRE projects that merit consideration for a BESS (e.g., a time of day - undifferentiated Feed-in tariff does not properly reflect the difference in benefit of peak and off peak hour proeduction **[6.5]**
10. Distributional analysis • Is a distributional analysis presented, and the stakeholders identified? • Are the impacts of the project on the poor identified? • Are any unusual or counter-intuitive results of the distributional analysis properly explained?	• Any distribution-level financial analysis also needs a financial analysis of the grid operator whose peak hour revenue may be eroded **[6.1]**
11 Sensitivity analysis • Have the switching values been calculated for all important variables? • Is a sensitivity analysis to discount rate presented? • Where switching values indicate a significant risk to the realization of economic returns, are mitigating measures discussed in other sections of the PAD?	• To what extent do other sources of revenue, based on "stacking" of the various benefits of storage to the system, add to the economic returns. **[5.7]** • Where BESS appears uneconomic, switching values should also be presented with respect to the no BESS option, rather than just to the hurdle rate.**[6.2]**
12. Risk assessment • Are all the main risks identified in the PAD risk matrix included in the economic analysis risk assessment? • Are the probability distributions proposed for key input assumptions credible? • Is the probability of *not* meeting the hurdle rate provided?	• Have methods and costs of mitigating some risks through the use of warranties been identified? **[4.3]**
13. Scenario and trade-off analysis • Is the sensitivity analysis (one variable at a time) accompanied by a scenario analysis that identifies plausible worst cases (many variables at unfavorable outcomes)?	• plausible worst cases in BESS projects will include much shorter intervals between battery replacements: this interval should always be one of the assumptions tested in a sensitivity analysis of economic and financial returns **[4.6]**
14. Need for additional studies • If employment creation is noted, do these show *net* employment (i.e. offset by job losses associated with thermal fuel generation, say in coal mining?) • If macroeconomic impacts are included in the analysis, are the arguments for the establishment of local manufacturing, and the assignments of economic benefit, plausible for the project under appraisal	Unlikely to be a material issue for BESS *per se*, though to the extent BESS enables large scale VRE generation suitable for local manufacture and local job creation, can be mentioned in the text (if there is credible evidence/studies to support such a claim) Unlike CSP and PV local manufacture and associated local employment (as in the case of the solar program in Morocco) are unlikely to be of sufficient magnitude in the case of BESS to warrant inclusion of such macroeconomic spillover effects in the benefit cost analysis.

2. Relevant Principles of Economic Analysis

2.1 The Table of Economic Flows

22. **The basic principle of an economic analysis of an investment project is straightforward: the net economic flow is the difference between the economic flows of the proposed project (i.e., in our case with the BESS) and those of the counterfactual (i.e., without the BESS)**

23. **The recommended general layout for the table of economic flows is shown in Table 2:** this Report is designed to assist in its construction across the various BESS applications. This general format will be used throughout this Report, and will be available as an EXCEL template with the worked examples of Chapter 6 (which can be downloaded from the EEX Global Practice website, GSG Clean Energy page).

Table 2: The table of economic flows

Table [ ] Economic flows														
			NPV	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
				0	1	2	3	4	5	6	7	8	9	10
1	**Counterfactual: no BESS**													
2	*Costs*	[$USm]												
3	...	[$USm]												
4	...	[$USm]												
5	Benefits	[$USm]												
6	...	[$USm]												
7	Economic flows, no project	[$USm]	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Project: With BESS**													
9	Costs	[$USm]												
10	...	[$USm]												
11	...	[$USm]												
12	Benefits	[$USm]												
13	...	[$USm]												
14	Economic flows, with project	[$USm]	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Net economic flows**	**[$USm]**	**0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
16	ERR	[ ]	0%											

Source: BESS Spreadsheet Library {General Template.xls}

2.2 Energy Balances

24. **The PSG make mandatory as the first step in any economic analysis the preparation of a detailed energy balance** - which for sake of transparency must be set out in the same format as the table of economic flows: the energy balance must be set out *with* and *without* the project variant that includes a BESS.

25. **A basic characteristic for any energy storage system is that the amount of energy that is discharged will be smaller than the amount of energy needed for charging, a ratio that defines the so-called round-tip efficiency (RTE).**[9] Table 3 shows typical values for RTE for some different battery or flow battery energy storage systems. The table shows the RTE may vary significantly by technology and/or electrochemistry, with much less variation with overall system size.

9 Round trip efficiency losses occur for any energy storage devices. For example, at a pumped storage project there are efficiency losses associated with pumping water to the upper reservoir entails a first efficiency loss, and later discharging water to generate electric energy,. Round-trip efficiencies for PHS are typically around 80%

Table 3: Round-trip efficiencies

	Size	Duration	RT efficiency	
	MW	hours	low	high
Lithium	100	4	0.87	0.90
Flow battery -Vanadium	100	4	0.74	0.77
Flow battery Zinc bromide	100	4	0.67	0.70
Lithium	10	4	0.86	0.90
Flow battery -Vanadium	10	4	0.74	0.77
Flow battery Zinc bromide	10	4	0.69	0.76
Lithium	1	2	0.91	0.94
Flow battery -Vanadium	1	2	0.72	0.72
Flow battery Zinc bromide	1	2	0.82	0.82

Source: Lazard, *Lazard's Levelised Cost of Storage -Version 4,* 2018

26. Table 4 shows the revised pro forma for analysis, with the energy balances displayed in rows [1]-[8]. The energy balance format (and the economic analysis) will of course vary according to the specific application (as illustrated in the case studies of Section 6), but the general layout and coverage should be used in all projects.

Table 4: Adding the energy balances

Table [ ] Economic flows														
			NPV	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
				0	1	2	3	4	5	6	7	8	9	10
1	**Energy balances**													
2	Generation for charging	[GWh]												
3	transmission loss	[GWh]												
4	charging energy into BESS	[GWh]												
5	BESS RT efficiency	[ ]												
6	BESS discharge	[GWh]												
7	transmission loss	[GWh]												
8	displaced generation	[GWh]												
10	**Economic flows**													
11	**Counterfactual: no BESS**													
12	*Costs*	[$USm]												
13	. . .	[$USm]												
14	. . .	[$USm]												
15	Benefits	[$USm]												
16	. . .	[$USm]												
17	Economic flows, no project	[$USm]	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**Project: With BESS**													
19	Costs	[$USm]												
20	...	[$USm]												
21	...	[$USm]												
22	Benefits	[$USm]												
23	. . .	[$USm]												
24	Economic flows, with project	[$USm]	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**Net economic flows**	**[$USm]**	0	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
26	ERR	[ ]	0%											

Source: BESS Spreadsheet Library {General Template.xls}

27. In a typical BESS assessment, the basic energy balance must be prepared at as short a time step as possible. In the table of economic flows, the energy balance for each year can be summarized, but the underlying balances of VRE production and battery operation for VRE integration typically involve many years of data for PV or wind production at time steps no greater than hourly – illustrated in the case studies of Section 6.2 (for PV) and 6.5 (for wind).

28. Battery packs degrade with use and over time, which has an important impact on energy balances over time (and carbon accounting). The annual **rate of degradation of energy storage capacity (kWh)** depends on usage and many other factors such as:

- Total delivered energy or cycles
- Rate of discharge
- Rate of charging
- Temperature
- Depth of discharge (DoD)

- State of charge (SoC)

29. The rate of degradation also depends markedly on chemistry: some Li-ion chemistries are much better suited to use on electric sector than others.[10]

30. A battery energy storage system (BESS) may have a warranty that **guarantees maximum rate of degradation of energy capacity under specified operating conditions** [e.g. an annual degradation might be specified for set fixed number of cycles per year or total usage]. Energy capacity degradation may be accompanied by power capacity degradation, and both of these may reduce the round-trip efficiency. However, the relationship between the three is complex - and difficult to predict.[11]

31. For this reason degradation might be reasonably modeled based on what is guaranteed in the system warranty e.g. energy capacity degradation of 2% per year (with 365 cycles) or modified if need be based on expected usage.

32. Table 5 shows the energy balance calculations for energy only degradation.

Table 5:Energy Only degradation

Original		
Energy capacity (MWh)	[1]: Input	30
Power capacity (MW)	[2]: Input	10
Round Trip Efficiency (RTE)	[3]: Input	0.850
Duration (hours)	[4] = [1]/[2]	3.0
Energy (for charging)	[5] = [1]/[3]	35.3
Duration (for charging)	[6]=[5]/[2]	3.53
Degradation		
Energy capacity	[7]: Input	2.0%
Power capacity	[8]: Input	0.0%
Round Trip Efficiency	[9]: Input	0.0%
Adjusted after degradation		
Energy capacity (MWh)	[10] = [1]x[1-[7]]	29.4
Power capacity (MW)	[11] = [2]x[1-[8]]	10
Round Trip Efficiency (RTE)	[12] = [3]x[1-[9]]	0.850
Duration (hours)	[13] = [10]/[11]	2.94
Energy (for charging) (MWh)	[14] = [10]/[12]	34.6
Duration (for charging) (hours)	[15] = [14]/[11]	3.46

Source: Spreadsheet {BESS_DegradationCalculations 20April2020.xls}

[10] ITP Renewable Lithium Ion Battery Test Center provides information of different use characteristics of various Li-ion chemistries. ITP also note that lithium iron phosphate (LFP) and lithium nickel manganese cobalt (NMC) are favored electrochemistries in the stationary electric sector due to their long cycle life. Note: the name of a Li-ion battery typically refers to metal elements used in the **lithium metal oxide** cathode. https://batterytestcentre.com.au/project/lithium-ion/

[11] Adding to the complexity is that the (i) energy capacity (kWh) for a new BESS will typically increase as the discharge rate is lowered (for a given load), while (ii) the power output (kW) may decline during discharge as the voltage falls as the state of charge is reduced. These issues are separate from degradation with use over time

33. When power and round-trip efficiency (RTE) also degrade, the corresponding calculations are as shown in Table 6.. However, energy only degradation may be more typical to estimate, unless the economist has reliable estimates for impact on power and RTE degradation over the life of the BESS.

Table 6: Energy, power and RTE degradation

Original		
Energy capacity (MWh)	[1]: Input	30
Power capacity (MW)	[2]: Input	10
Round Trip Efficiency (RTE)	[3]: Input	0.850
Duration (hours)	[4] = [1]/[2]	3.0
Energy (for charging)	[5] = [1]/[3]	35.3
Duration (for charging)	[6]=[5]/[2]	3.53
Degradation		
Energy capacity	[7]: Input	2.0%
Power capacity	[8]: Input	1.0%
Round Trip Efficiency	[9]: Input	0.5%
Adjusted after degradation		
Energy capacity (MWh)	[10] = [1]x[1-[7]]	29.4
Power capacity (MW)	[11] = [2]x[1-[8]]	9.9
Round Trip Efficiency (RTE)	[12] = [3]x[1-[9]]	0.846
Duration (hours)	[13] = [10]/[11]	2.97
Energy (for charging))MWh)	[14] = [10]/[12]	34.8
Duration (for charging) (hours)	[15] = [14]/[11]	3.51

Source: Spreadsheet {BESS_DegradationCalculations 20April2020.xls}

34. These calculations must be replicated in each year of the energy balance table.

35. In setting up the energy balances, the checklist of Table 7 may be consulted. Table 7 shows that degradation may be offset by periodic battery pack replacements. Augmentation refers to the process where the BESS is installed and maintained through a combination of planned over-sizing and periodic replacements so that the BESS can provide a constant minimum available energy over the life of the project or contract.

Table 7: Checklist for energy balances

Item	Issue
Interval for time period definition	• In VRE integration projects, time steps need to be as short as possible given the underlying solar or wind data, and cover multiple years. Similarly, the BESS scale of operation may be hourly (or less)
Rate of degradation of battery and self-discharge	• Over time and with use, the total energy storage capacity of the battery may degrade over time – and this will typically depend on usage. Power or RTE efficiency degradation may also be considered if relevant and data estimates available. • Does the O&M include provision for augmentation to reduce or offset the impact of energy degradation.
Definition of the system boundary	• The energy balance should capture not just the immediate project boundary, but should include the system balances as well (this is no different to load flow assessment for a transmission line investment, in which the impact of a single line is felt far outside the project boundary) It is the balance across at the system level that matters most to the economic analysis.

Item	Issue
Transmission and distribution losses	• In general, losses during peak hours will be higher than losses in off-peak hours.

2.3 CARBON ACCOUNTING

36. The **Bank now mandates calculation of NPVs with and without valuation of carbon emissions in project appraisals**. The template provided with this Report includes consideration of GHG emissions reductions. The social values of carbon (SVC) to be used are mandated in the World Bank Guidance document for SVC.[12]

37. **However, care must be taken to properly assess roundtrip efficiency impacts,** and to make credible assumptions about the carbon emissions associated with charging energy, and the carbon emissions associated with the energy displaced when discharging. Thus fundamental to a reliable assessment of GHG emission reductions is a careful energy balance of the BESS impact at the system level.

38. Table 8 shows the desired format: the carbon accounting rows draw on the energy balances (and multiplied by the relevant emission factors for charging energy and for avoided generation during battery discharge). In this particular example charging energy is coal, discharging energy displaces open cycle CT gas. Note that because the battery degrades, some (increasing) open cycle CT is still required during peak hours to deliver the same energy as the no project case (row[20]).

Table 8: Adding carbon accounting

Table 3: Carbon Emissions acc				GHG Guidelines, Section 8.			[Exhibit 3]				
				sum	2021	2022	2023	2024	2025	2026	2027
				0	1	2	3	4	5	6	7
[1]	**NO PROJECT**										
[2]	**off-peak**										
[3]	emission factors	[kg/kWh]									
[4]	OCCT	0.58	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[5]	CCGT	0.40	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[6]	coal	0.80	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[7]	total emissions		[1000tCO2e]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
[8]	**Peak**										
[9]	OCCT	0.58	[1000tCO2e]		7.8	7.8	7.8	7.8	7.8	7.8	7.8
[10]	CCGT	0.40	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[11]	coal	0.80	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[12]	total emissions	0.00	[1000tCO2e]	77.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
[13]	**WITH BESS**										
[14]	**off-Peak [battery charging]**										
[15]	OCCT	0.58	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[16]	CCGT	0.40	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[17]	coal	0.80	[1000tCO2e]		12.5	12.5	12.5	12.5	12.5	12.5	12.5
[18]	total emissions	0.00	[1000tCO2e]	124.7	12.5	12.5	12.5	12.5	12.5	12.5	12.5
[19]	**Peak [battery discharging]**										
[20]	OCCT	0.58	[1000tCO2e]		0.0	0.2	0.3	0.5	0.6	0.7	0.9
[21]	CCGT	0.40	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[22]	coal	0.80	[1000tCO2e]		0.0	0.0	0.0	0.0	0.0	0.0	0.0
[23]	total emissions		[1000tCO2e]	6.6	0.0	0.2	0.3	0.5	0.6	0.7	0.9
[24]	**Net impact**		[1000tCO2e]	53.5	4.7	4.8	5.0	5.1	5.3	5.4	5.6

Source: BESS Spreadsheet Library {GHG accounting 27 March 2020.XLS}

12 World Bank, *Guidance Note on Shadow Price of Carbon in Economic Analysis*, 2017.

Data issues

39. Ideally, the data for the composition of generation that makes up both charging energy and the avoided energy during discharge would come from a power systems or production cost model.

40. In cases where a battery is co-located with a VRE, the charging energy may well be provided by the VRE, in which case the emissions associated with charging (as shown in the above example) fall away. A careful energy balance (for example, where a battery reduces curtailment) should ensure a reliable carbon accounting.

2.4 CAPACITY CREDITS

41. The capacity credit refers to the ability of a generator to provide firm capacity and is the fraction of its nameplate capacity that contributes reliably meeting demand (Keane *et al* 2011). Of course "reliable" and "firm" are also flexible terms, and what is meant by "meeting demand" really translates in practice to whether a unit is available and able to provide power capacity at the time that the system load reaches its annual peak and during other peak periods. No type of generation has a 100% probability of being available on that day, though some dispatchable technologies with low forced outage rates – such hydro and aero-derivative combustion turbines - have availabilities that can reach 98%.

42. The terms "capacity credit" and "capacity value" are widely used but often defined or estimated in different ways, and, in the context of VRE, are often controversial. The literature is large, contentious and often confused, in part a consequence of the way in which the term is used for different purposes, and in entirely different institutional and market environments.

World Bank Practice

43. A review of past World Bank practice reveals that "capacity credit" often appears as a line item in the table of economic flows, where the benefits of a proposed investment are based on the avoided costs: a renewable energy project avoids the variable fuel costs of its thermal counter-factual, and also avoids capital costs. This is true not just of variable renewable energy projects, but of conventional hydro as well. The key point is that the "capacity credit" is defined as an ***input*** to the analysis: for example, a typical 600 MW hydro project may be said to have a 50% capacity credit based on its firm capacity contribution: if it displaces a CCGT, then the capacity credit appearing in the table of economic flows would record the CAPEX required for a 300 MW CCGT.

44. It is widely acknowledged that such an assumption is subject to some considerable uncertainty, and is therefore tested in the sensitivity analysis and risk assessment. The point is that that the "capacity credit" is taken as an *input* to the analysis.

45. This expedient is now increasingly uncommon. Most of the World Bank's larger clients now have sophisticated capacity expansion planning models that allow the impact of a proposed project to be examined more rigorously: in this case there is no need for an *input assumption* about capacity credit: the changes in capacity are revealed by a comparison of the capacity expansion plan with and without the proposed project (or between scenarios that have more or less renewable energy).

46. This is illustrated by the studies conducted in Vietnam for the 2016 review of the 7th Power Development Plan (PDP7) - in the high renewables scenario, some 14,650 MW more of mainly solar and wind was forced into solution, with the results shown in Table 9: this displaced

just 3,500 MW of coal capacity. In other words, the capacity credit of the portfolio of renewables tested, is just 23.9%. One MW of VRE installed capacity displaces only 0.239 MW of thermal capacity.

Table 9: Capacity credits of renewable energy in Vietnam, installed 2030 capacity in MW

	High renewables case	PDP7 Least Cost Plan	difference
Hydropower and pumped storage hydropower	21,871	21,871	0
Coal-fired thermal power	55,252	58,752	-3,500
Oil & gas thermal power	19,078	19,078	0
Small hydropower + wind power + new energy (solar and biomass)	27,199	12,549	14,650
Nuclear power	4,600	4,600	0
Imports	1,508	1,508	0
Total installed capacity	129,508	118,358	11,150

Source: Electricity of Vietnam (EVN)

47. The question of whether the addition of BESS would change this capacity balance can be tested in exactly the same way - always providing the model has the ability to adequately model BESS (a question that is discussed in Section 3.1).

48. In short, the question of what "capacity credit" should be applied, and how the capacity credit of a proposed VRE project would increase if it were combined with BESS, is completely avoided. The capacity credit emerges as an output of a rigorous analysis.

49. Moreover, it can also be said that a stand-alone BESS at the system level can only be reliably evaluated in the context of an appropriate systems planning model.

Capacity credit determination in the absence of a systems planning model

50. That leaves open the question of what to do where a systems planning model is ***not*** available. This may well be the case for a substantial share of World Bank projects for small countries or remote grids in large countries (and is no less true of a VRE project where a BESS is not under consideration).

51. What *actually* matters for such small VRE projects is not an abstract and necessarily *ad hoc* "capacity credit", but the ability of a BESS to shift variable energy production from hours when electricity has low economic value, to hours when it has high economic value. That of course requires that one has the ability to estimate what such relative values are.

52. The planned revision to the PSG (to appear later in 2020) will define best practice (and minimal data requirements) for the evaluation of small VRE projects, whether with or without a BESS, along the following lines:

- Small VRE projects for which a systems planning model is not available should be treated as additional, with energy valuations assessed on the basis of willingness-to-pay.

- The ability of a BESS to shift loads across different hours of the day should be assess on the basis of a detailed energy balance at time steps no longer than one hour, based on several years of resource data, and based on the expected daily (and seasonal) load curves (adjusted for presently unmet/curtailed demands) to a comparable time step.

The issues associated with estimating willingness-to-pay are discussed below in Section 2.5

53. It is not difficult to postulate simple rules that may have some support from engineering experience, or from international practice.[13] For example, if a 100 MW PV system were given a capacity credit of 20%, and the estimated capacity credit of a 25 MW BESS with 4-hour storage is 70%, then one might argue that the overall capacity credit is additive, i.e., 37.5 MW.[14]

54. But what is the basis for such capacity credit estimates of the VRE and the BESS? The capacity credit for the VRE itself is subject to all manner of qualifications (how much PV is there already in the system, the size of the system, and so forth). In the context of a specific project, much better to assess the economic valuebase the calculation on the basis of the load curve, VRE and battery configurations that actually apply in a given situation.

55. **One may conclude as follows**:
- *Ad hoc* methods that involve the calculation of "capacity credits" should be avoided.
- In the case of small VRE+BESS projects for which neither a full systems planning model, nor a model like HOMER, is available or appropriate, **best practice to evaluate the ability of a battery to shift load into the peak hours is the detailed hourly energy balance approach based on several years of VRE resource data. How this should be done in practice is set out in Section 6.2**

13 For example, there may be a temptation to use de-rating factors applied to VRE used in many market-based systems as a proxy for capacity credits - as set out, for example, in Mastropietro, P. Rodale and C. Battle, 2019. *De-rating of wind and solar resources in capacity mechanisms: A Review of International Experiences,* Renewable and Sustainable Energy Reviews, 112 , 253-262. But the very variation in de-rating factors points to the uniqueness of different systems, and the difficulties of using these estimates as guidance to define "capacity credits" in the calculation of economic returns. These have important regulatory significance, and may be useful as general indicators of capacity value, but they should not be used in the economic analysis for an investment project appraisal.

Wind and solar derating facts

System	Wind capacity [a]	Solar capacity [a]	Wind de-rating factor	Solar de-rating factor
PJM [b]	0,6%	0,4%	13%	38%
MISO	8%	0%	15,6%	50%
NYISO [c]	5%	1%	10%–30%	2%–46%
CAISO [d]	11%	7%	2%–33%	0%–80%
Chile [e]	5%	5%	20%	25%
Ireland	22%	0%	10,3%	5,5%

[a] Renewable capacity as a percentage of installed capacity in the generation mix; data from Refs. [63–70].
[b] Class average capacity factors; subclasses within a same technology have been proposed recently, with higher values for some subclass.
[c] Summer and winter capacity factors for on-shore wind and solar PV with tracking technology; factors for new power plants.
[d] Monthly capacity factors (maximum and minimum) for new power plants.
[e] Capacity factors used for the calculation of the initial firm capacity; average factor within each technology.

14 i.e., 100 MW x 20% + 25 MW x 70% = 37.5 MW.

- Postulates of *ad hoc* "capacity credits" thereby become unnecessary. The recommended methodology allows a rational determination of the ability of a BESS to contribute to peak loads, and is grounded in economic rationale specific to the project in question.
- This does require more effort to calculate than *ad hoc* rules of thumb, but is hardly onerous, and is certainly requires less effort that running a full systems planning model.

2.5 VALUATION OF ENERGY

56. Electricity has three main attributes: quantity (of energy, kWh); power (capacity, kW) and quality (reliability). Economic analysis requires for each a quantification, and then a monetization.

57. Traditionally, when the international financial institutions (IFIs) have estimated the economic returns of power sector investment projects that have as their principal objective the additional provision of energy (and capacity), whether by adding generation or increasing efficiency, there are two approaches to valuation.

58. The first approach is to treat the project as *incremental*, which assumes the additional energy is delivered to previously unserved customers or meeting increased demands of existing customers, for which the valuation is given by the area under the demand curve to estimate the consumer surplus (see PSG, Technical Note 23). As noted in Section 2.4 this method does *not* require any estimate of capacity credit – though the presumption is that these consumers are also able to pay for a *connection* to the grid.

59. The second is to treat the project as a substitution, that is to say its economic returns are defined by the next best project: this assumes that if the proposed project is not built, then the *next best* project would be built. In other words, for example, if the VRE project, whether with or without a BESS, substitutes for some other project (the so-called counterfactual). Note that capacity expansion planning models necessarily imply the substitution approach since they build the technology mix for a least cost system cost for a given level of reliability (perhaps specified by a required reserve margin). If a capacity expansion planning model is not available, then indeed this substitution approach requires an estimate of a capacity credit for the proposed project.

60. However that capacity credit is defined, the entry in the table of economic flows should never be an annualized value. Just as the CAPEX of a VRE or BESS is recorded in the years in which it is incurred, so should be recorded the avoided CAPEX of the thermal project alternative (with due attention given to the problem of unequal lives, see Section 4.4).

Valuation methodology for incremental projects

61. This is discussed in detail in the PSG, Technical Note 23, for which its application to a typical BESS+VRE project can be summarized as follows

- The economic benefit may be taken as the so-called willingness-to-pay (WTP) – which is the area under the demand curve.
- The demand curve required by economic theory requires considerable effort to establish, typically by energy surveys, the resources for which are unlikely to be available in a typical VRE+BESS project.
- A first point on the demand curve is given by the tariff. This may be taken as the willingness to pay for off-peak energy.
- Another point on the demand curve is the cost of self-generation, which in landlocked areas may be in excess of 30 USc/kWh. This may be taken as the WTP for peak hour generation.

62. Although this does capture the economic benefit to the consumer, care is needed in the matter of taxes. Electricity tariffs are generally stated before VAT, but retail prices for diesel (or gasoline) likely include tax, which needs to be subtracted.

2.6 VALUATION OF RELIABILITY (QUALITY)

63. Perez-Arriaga defines four attributes for reliability[15]

- ***Security***, which is the readiness of existing and functioning generation and network capacity to respond in real time when they are needed to meet the actual demand. This is a short-term issue. Caring for system security is the main function of the System Operator, who sets at every moment the reserve margins for generation and network operation.

- ***Firmness***, which is the provision of the generation and network availability that partly results from operation planning activities of the already installed capacity. This is a short to mid-term issue. Firmness depends on the short and medium term management of generator and network maintenance, fuel supply contracts, reservoir management, start-up schedules, etc. A flawed management of firmness may result in poor system security, even if there is adequate installed capacity of generation and network.

- ***Adequacy***, which means the existence of enough available capacity of generation and network, both installed and/or expected to be installed, to meet demand. This is a long-term issue.

- ***Strategic* energy policy**, which concerns the long-term availability of energy resources and infrastructures: long-term diversification of the fuel provision and the technology mix of generation, geopolitical considerations, future price evolution of fuels, potential environmental constraints, expected development of interconnections, etc. This is a long to very long term issue.

64. BESS potentially contribute to all of these attributes, including strategic energy policy because of its important role in large scale VRE integration.

65. But quantification and monetization of these attributes in a form useful for economic analysis is difficult - a challenge not just for BESS but for many other power system investments as well.

66. Consider, for example, a transmission line upgrade from 35kV to 110 kV. The 35 kV line is overloaded, so may not deliver the desired quantity. It has high losses. And in consequence consumers experience poor quality - brownouts and blackouts. The economic benefits of that upgrade will be lower losses, increased energy delivery and improved reliability. The first two benefits are easy to quantify, but the question is how to quantify the improved reliability attributable to a proposed project.

67. In World Bank T&D system investment projects, reliability impacts are often presented as forecasts of changes of hours of lost load and numbers of incidents. These are captured by the

15 I. Perez-Arriaga, 2007. *Security of Electricity Supply in Europe in a Short, Medium and Long-term Perspective*. European Review of Energy Markets, Volumne 2, Issue 2, December

System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).[16]

68. These are estimated by application of detailed load flow and reliability models familiar to transmission engineers in simulations with and without the proposed project. Table 10 shows a typical assessment of such reliability improvements. They are also accompanied by estimates of changes in various quantitative indexes such as SAIFI (system average interruption frequency index).[17]

Table 10: Reliability improvements in the Vietnam Smart Grid Transmission Project

	Without Project		With Project	
	Times/year	Duration/incident (hours)	Times/year	Duration/incident (hours)
500 kV level	0.8	8.0	0.2	3.0
220 kV level	1.6	16.0	0.2	3.0
110 kV level	4.0	40.0	0.5	5.0

69. Based on such calculations the kWh impacts follow. In the financial analysis, the benefit valuation is easy - it can be assessed as the increased financial revenue based on the tariff.

70. But for the economic analysis the impact of lost load on consumers is far greater, typically one or even two orders of magnitude greater than the tariff. But a determination of a credible value of Lost Load (VoLL) and the cost of unserved energy (CoUE) is itself difficult. Technical Note 2 of the PSG discusses the credibility of these estimates at some length - the problem being the paucity of empirical studies. VoLL in *developed* countries can be more than $10/kWh;[18] most valuations in World Bank client countries are in the range of 0.5 to 1.0 $/kWh.[19]

71. The difficulties of assessing the impacts of BESS on reliability should therefore be apparent. Even if a plausible value for VoLL (CoUE) can be stated, how one links given frequency control benefits of a battery to changes in the number and duration of system outages is unclear. We note below the big improvements of frequency control in India since the late 1990s, but linking these improvements to specific investments, and to estimates of economic benefits that have resulted from these improvements, is difficult. However, as discussed in Section 5.5, where there exist markets for ancillary services, market values can be used in the economic analysis as the relevant metric.

2.7 LEVELISED COST OF ENERGY AND STORAGE

72. PSG cautions against the misuse of levelized cost of energy (LCoE) as a metric for comparing costs of generation of different technologies and project sizes, and exactly the same thing is true of the levelized cost of storage (LCoS). Its use in project appraisal requires great caution. Levelised cost of any technology says nothing about its economic benefit.

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16 As a typical (albeit random) example, the website homepage of Electricte de Djibouti shows the SAIDI and SAIFI for the last three calendar years.

17 Calculated as the average number of interruptions divided by the total number of customers.

18 For example, the UK regulator OFGEN claimed domestic customers VoLL of $9.7-$16.5/kWh.

19 The more reliable the system, the less are consumers willing to invest in their own self-generation, and therefore the greater is the cost when the grid does fail. In chronically unreliable grids typical of many client countries, the cost of diesel self-generation is a credible and conservative valuation for the cost of unserved energy.

73. The main rule is simple: comparisons of different technologies using LCoE and of LCoS are valid only if the *benefits* are identical (or very similar)**.** The levelized cost of wind energy may well be 6 USc/kWh, and the levelized cost of gas CCGT may be 8 USc/kWh (ignoring for the moment any externalities not captured in these estimates) - but that does not mean that wind is to be preferred over coal - because the **benefits** are not the same - wind may have only a small impact on the system capacity expansion plan,[20] whereas gas CCGT as a dispatchable technology has a high capacity benefit. In other words, a wind project and a CCGT are not providing the same service, even if the wind project was sized to provides the same total annual energy on an expected basis. On the other hand, wind also provides GHG reduction benefits, which CCGT does not.

74. **However, it *would* be valid to compare the LCoE of geothermal with the LCoE of coal** if their intended use was to provide base load power and have comparable plant load factors": geothermal projects in Indonesia have plant load factors in excess of 90%.

75. **Estimates of the levelized cost of storage (LCoS) should not appear as an *input* in an economic analysis of BESS.** Comparisons of different BESS technologies and sizes always require explicit statement of the initial capital, and of any degradation and battery replacement. CAPEX is entered in the table of economic flows in the year in which it is expended; the cost of battery replacement likewise, entered in the year it is expected to occur, including estimate of how BESS battery pack and other component costs may have fallen. OPEX is again entered year by year.

76. **Widely quoted LCoS figures are those published by Lazard in their publication "*Lazard's Levelised cost of Storag*e", the most recent being version 6.0 of November 2019.** It is important to understand how these estimates are actually defined - they are calculated in a *financial* model as that levelized cost, which when multiplied by the total annual generation (discharge), provides sufficient revenue to achieve a stipulated equity return for investors. Annex IV provides further discussion of the Lazard analysis in more detail.

77. A number of other **free tools that can estimate the LCOE and other financial metrics such as NPV for wide range of grid-connected or distribution level projects.** For example, the System Adviser Model (SAM) from the US National Renewable Energy Lab simulates the performance of photovoltaic, batteries, concentrating solar power, wind, and other. The detailed financial cash flow models are for projects that either buy and sell electricity at retail rates (residential and commercial) or sell electricity at a price determined in a power purchase agreement (PPA).[21]

20 For example, in he PJM power pool, wind has a 13% capacity credit.

21 Freeman, J., N. DiOrio, N. Blair, T Neises, M. Wagner, P. Gilman, and S. Janzou. 2018. *System Advisor Model (SAM) General Description (Version 2017.9. 5)*. No. NREL/TP-6A20-70414. National Renewable Energy Lab.(NREL), Golden, CO (United States).

3. Key questions

78. In Section 1.2 we outlined the key questions to be faced in project preparation the require the attention of the economist on the appraisal team, once the potential need for a BESS been proposed

- Choice of analytical tools: what models to use and their data requirements
- Selection of the counterfactual
- Selection of location
- Selection of the technology
- Selection of the project size

3.1 Models and their data requirements

79. The modeling requirements depend in large measure on the main purpose of a BESS, and on the scale of projects. Where practical, the default should be the use of an appropriate system planning model that can establish the economic benefits by running with BESS and without BESS scenarios.

80. But not all system planning models are equally suited for this task: and many runs of a model may be required to identify the optimal size and hours of storage. And not all BESS applications are in situations where a system planning model is practical at all: there may be little point in trying to run a resource and data intensive production cost model such as PLEXOS for a small BESS+VRE projects serving mini-grids (typical of many likely World bank clients), where spreadsheet based approaches or least levelized system cost models, like HOMER may be more appropriate (see below).

81. Simple decision rules about what models to use in what situations are not yet possible in light of the still very limited experience with BESS projects in World Bank client countries. At this point one can only set out some general principles that require consideration for any particular project for which benefits needs to be established.

82. Firstly, the level of complexity of the analysis is related to the primary applications of the BESS and whether it is grid connected or off-grid . For any BESS where:

- **ancillary services** would provide the major benefit, a detailed production simulation model and/or engineering study will often be required.
- **deferral or upgrade of major transmission investments** are involved, appropriate electrical engineering models (such as PSSE) will be needed to establish reliability and stability consequences.
- **peaking capacity** to replace thermal generation is a major benefit a capacity expansion planning or production model will be required.

83. But even here judgment is needed. Does a BESS that will be added to a VRE project to eliminate curtailments due to transmission congestion require a detailed PSSE study to evaluate the counter-factual of a transmission upgrade?

84. That will be determined by a second question related to scale and relative size. One may say that a detailed power system and production cost models are ***not*** required if the BESS is

- of a ***small scale compared to the size of the grid into which its discharge is made***. A 50 MW PV +15 MW/60MWh BESS project is unlikely to have significant implications for a 5,000 MW grid.
- ***to be applied in a mini**-grid* (even though the size of the VRE may be a significant share of total installed capacity)

85. Finally, one may say that

- for any BESS being considered as part of, or related to, a VRE project, **the same model as is being used to evaluate the VRE and its impact on the grid, would (in general) also be suitable for use to evaluate the incremental costs and benefits of a BESS.**

86. For example, if the well-known HOMER model is judged useful for VRE design and sizing in a small grid or micro-grid, then that model would also be the model suitable for assessing the added value of a battery.[22]

87. For example, if the model does not have sufficient temporal resolution to model VRE it will unlikely be able to easily model how BESS and VRE may interact. If a model does not have sufficient temporal resolution to model VRE it will not be able to easily model how BESS and VRE may interact.

88. For example, in many of the Bank's client countries, the WASP model is still on widespread use - a model that is quite unsuited to capturing the benefits of VRE -and hence equally unsuitable for BESS. WASP could indeed be run with and without scenarios of additional VRE, but the impact on spinning reserve[23] necessary for VRE integration cannot be so determined, with the result that *ad hoc* estimates of the additional cost of spinning reserve are sometimes added exogenously.[24] Table 11 sets out some of the modeling requirements for different types of projects; lower temporal resolution may be possible for rough estimates of BESS on a stand-alone basis

Table 11: Modeling requirements of typical projects

Level of complexity	Typical BESS applications	Modeling approach
High	National or regional assessments of the role BESS, identification of BESS project opportunities	• Capacity expansion planning models with hourly time steps (such as the World Bank Electricity planning model, see text below) • Builds at least cost to meet future demand, and includes high VRE analysis
High	Standalone grid-scale BESS requiring benefit stacking for multiple services	• Detailed production cost modeling with and without the BESS. Such a modelling approach can estimate energy savings from peak load shifting and provision of ancillary services, and avoided curtailment of VRE. Capacity impacts must be made outside of the production cost model
High	Transmission system upgrades/deferrals	• Detailed production cost modeling with and without the BESS and load flow models (such as PSSE) to confirm stability and reliability

22 https://www.homerenergy.com/products/pro/docs/latest/index.html

23 See Annex I.5 for definitions of various kinds of reserves and their function.

24 A good example of which is Sri Lanka, where in recent years the system capacity expansion plan study of accelerated renewables made such *ad hoc* adjustments. But the basis of these estimates was unclear, the result of which was criticism from NGOs and the regulator - and which in turn resulted in the Ceylon Electricity Board requesting World Bank Assistance to acquire more modern software (OPTGEN).

Level of complexity	Typical BESS applications	Modeling approach
Low to moderate	BESS for time shifting in small VRE + BESS projects in small grids and microgrids	• Spreadsheet analysis driven by detailed wind&solar resource data (see e.g. case study 6.5) • Use of HOMER for microgrid analysis where appropriate

Note: Complexity refers to barriers that may inhibit using the model including but not limited to cost of acquiring and running model, training staff as necessary and obtaining data. Even then the uncertainty of load and resource mix data in the future may limit the benefit of carrying out more complex modeling

Minimum requirements

89. The minimum analytical requirement to evaluate the smallest BESS projects - likely to be for VRE integration in small systems - is the spreadsheet model described in more detail in the case studies of Section 6.2 (PV), and section 6.5 (wind). These provide for hourly energy balances of the VRE, with and with and without BESS, and in the context of the total hourly load curves in the grid; balances that ideally are driven by multi year solar and wind data, of sufficient length also to document seasonal variation of the VRE resource (and of the grid alternative that may be small hydro).

90. The key to such simulation models is also to provide the value of energy in each hour and season, so that different sizes and capacities can be evaluated in benefit terms. These short time-step results can then be aggregated to annual totals the represent the inputs to the economic analysis model. **The model described in the PV+BESS project in the Central African Republic (Section 6.2) represents best practice for small projects.**

The minimum system planning model requirement.

91. Numerous system planning models for both capacity expansion planning and least cost annual economic dispatch using production cost models are now available. Capacity expansion and production cost models differ in what they can do: production cost models often have more detailed resolution and operational constraints.

92. The newer production cost models such as *Plexos* or *Promod* do provide suitable models to assess VRE and their integration costs, though even here the capacity credit and capacity value will need to be estimated separately. However, such models are rarely available for the many smaller systems in Africa, the Caribbean and Pacific Islands for which VRE-BESS hybrids are likely to be proposed as part of World Bank projects. These commercially available models require extensive training, are very data intensive, and are often quite expensive (as much as $300,000 upfront costs and $40,000 per year maintenance fee).

93. On the other hand or large projects, for which consultants have prepared pre feasibility or feasibility studies, access to such models, and various in-house models, are now commonplace.. Such studies might be used, for example, to evaluate the economic impact for grid connected BESS systems in India.

94. What is needed is a combination of "capacity expansion" and "production cost" models. New software is starting to combine the two (such as WIS:DOM, PowerSimm, GridPath). NREL has also developed a "Linking Tool"[25]. An alternative approach is to run capacity expansion model followed by more detailed production cost modeling.

25 V. Diakov et al., 2015. *Improving Power System Modeling: A Tool to link Capacity Expansion and Production Cost Models*, NREL Technical report NREL/TP-6A20-649

95. For larger projects the World Bank's in-house Electricity Planning Model (EPM) is the most suitable tool as a starting point for any detailed BESS analysis for larger projects: the model has been applied in numerous countries as shown in Table 12.[26]

96. EPM has the capability of including BESS, and is based on hourly time steps. Written in GAMS, it is based on linear programming. Many of its applications are multi-country studies in which the model is used to assess the benefit of electricity trade. It has an EXCEL front-end that allows users to input data, run the model, and retrieve outputs (without any knowledge of GAMS *per se*). As it stands today, EPM has 80% of the modeling features of a high-end tool like PLEXOS but costs no more than $2,500 per year which is only 5% of the cost of the former. The remaining (20%) features are likely to be mostly superfluous to the needs of many developing countries and finding data even for the basic modules is onerous.. More broadly, the substantial uncertainty of the of future demand, generation mix and T&D investments for many developing countries cautions against overly detailed modeling and reinforces the importance of sensitivity analysis.

Table 12: Applications of the EPM within the Bank

Region	Model	Date	BESS	CSP	Pumped storage	Storage hydro
AFR	WAPP (14 countries)	2020	Y	Y		
	Nigeria	2020	Y			
	Sierra Leone	2020	Y			
	Burkina Faso	2020	Y			
	SAPP (12 countries)	2020	Y	Y	Y	
	Namibia	2020	Y	Y		
	Botswana	2020	Y	Y		
	EAPP (14 countries)	2020	Y	Y		
	Senegal	2020	Y			
	Mali	2020	Y			
	Djibouti	2019	Y			
	Madagascar	2018	Y			
MENA	Pan-Arab model (19)	2019	Y	Y		
	Jordan	2019	Y	Y		
	Tunisia	2019	Y	Y		
	Saudi Arabia	2018	Y	Y		
	Lebanon	2019	Y			
SAR	SAR regional model					
	Bangladesh	2018				
	Indian market design					
EAP	Myanmar	2019				
	Vietnam	2019				Y
	Papua New Guinea	2019				
	Mongolia	2019				
ECA	CASA (8 countries)	2018				Y
	Uzbekistan	2019				
	Turkey	2018	Y		Y	
	Kosovo	2017				
	Poland	2018				
	Ukraine	2018				

26 D. Chattopadhyay, F de Sisternes & S Oguah, *World Bank Electricity Planning Model (EPM):Mathematical Formulation*, ESMAP,

97. EPM has the capability of including BESS, and is based on hourly time steps. Written in GAMS, it is based on linear programming. Many of its applications are multi-country studies in which the model is used to assess the benefit of electricity trade. It has an EXCEL front-end that allows users to input data, run the model, and retrieve outputs (without any knowledge of GAMS *per se*). As it stands today, EPM has 80% of the modeling features of a high-end tool like PLEXOS but costs no more than $2,500 per year which is only 5% of the cost of the former. The remaining (20%) features are mostly superfluous to the needs of developing countries and finding data even for the basic modules is onerous.

3.2 THE COUNTERFACTUAL

98. In a number of recent World Bank appraisals for VRE projects, where a co-located BESS has been included in the VRE project, the counterfactual has been taken simply as "no project" whose costs and benefits are assessed in the usual way (often as the cost of diesel self-generation). Switching values are assessed against the hurdle rate, i.e. against the *no project* alternative.

99. But in such projects one should also test the proposed VRE+BESS against the "no *battery*" case, to be sure that the incremental costs of the BESS are assessed against the incremental benefits.

100. This may have important bearing also on carbon accounting, which will require an assessment of the generation mix of charging energy (if not self-charged, as this is possible even for a co-located BESS+VRE),

101. However, a formal BESS counterfactual is not always required. For example, batteries (or flywheels) as may be needed for VRE power smoothing (see Section 5.6) "with battery" and "without battery" scenarios may not need formal assessment: without such smoothing the VRE may simply not be acceptable to the grid operator. Box 6 illustrates such an example from Cambodia: without meeting the ramp rate control stipulated by the utility, the floating PV project would not be considered acceptable.

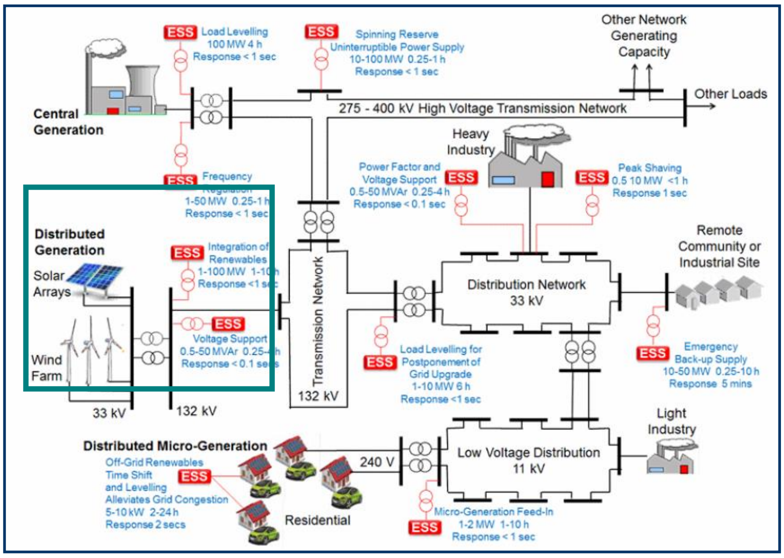
102. In such cases, the incremental cost of the battery must simply be added to the CAPEX of the proposed VRE project: there is no need for an analysis with and without the BESS.

3.3 SELECTION OF THE TECHNOLOGY AND LOCATION

103. Technology choice, size and location often go together. Figure 5 shows the range of primary applications, typical power and duration sizes, and response times, for different types of BESS as they might be applied at different points in a power system. The modular nature of BESS means that this technology can be used widely across the grid and off-grid with few geographic constraints.

104. This contrasts with other technologies like PHS which are typically only built for large utility applications and have severe siting constraints. It is probable that for the next 5 to 10 years (or more), the primary BESS applications most likely to be encountered in World Bank projects in developing countries are at solar PV and wind generation projects, at both grid scales and distributed level, including to better support weak grid and use in off-grid mini or micro grids.

Figure 5: ESS and applications



Source: https://www.mpoweruk.com/grid_storage.htm

3.4 BATTERY ENERGY STORAGE SYSTEM SIZING

105. The sizing optimization problem for a battery energy storage system is challenging, particularly when multiple applications are considered. In part this is because for energy storage (i) both power (kW) and duration (or energy (kWh) need to be selected for the primary application (ii) operational rules need to be developed to properly value multiple applications without double counting and to be operationally feasible. For example, a BESS cannot be fully discharging for peak load shifting and also provide spinning reserve at the same time. On the other hand a 4 hour grid connected BESS operating for peak load shifting will be typically providing significant capacity credit for avoided generation capacity.

106. For hybrid VRE + BESS projects there is an additional sizing consideration. Namely, what is the ratio of the power capacity of the PV system to the BESS (for any given duration). The optimal (PV(MW)/BESS(MW) ratio will depend on many factors including (i): how much of the PV output is intended to be shifted to later use (ii) whether or not the intention is for the PV to charge from the grid and/or whether that is even feasible.

107. When a suitable power system capacity expansion model is available, and the size of storage is one of the decision variables (as it is in the EPM), guidance on the optimal battery size (MW) and storage (MWh) will be provided by the model. But even so, it would be wise for the size and storage to be included as a variable in the in the economic analysis model, and the impact of one or two alternative battery sizes verified.

108. One reason for doing this that the approximate nature of modeling energy storage in some capacity expansion models means the sizing (MW) and (MW/MWh) sizing ratio may only be a rough cut. In large projects further refinement of sizing may be done in a production cost model that may be better at estimating the economic value of BESS particularly if being potentially used for multiple applications e.g. peak loading shifting, ramping and VRE integration and/or the provision of spinning reserves, say.

109. When grid connected capacity expansion models or off grid models like HOMER are not available or appropriate, then whether in a more complex production cost model, or a

spreadsheet energy balance model, the iterative procedure is the same: starting with zero storage, add storage in increments (of both power and energy) until an optimum has been found in terms of the lowest overall system cost (after adjusting for capacity credit of the BESS or VRE + BESS system).

110. This necessarily requires a higher value to peak hour energy than off-peak energy: as adding kWh of storage increases so will cost, which at some point will no longer be cost-effective. For example, for a 30 MW PV system intended to shift some PV output into the evening peak, the BESS sizing might start at 10 MW for capacity (for a 3:1 PV to BESS ratio) and 4 hours duration and then test impact of increases or decreases in power (MW) or energy in 1 MW or 1 hour steps respectively.

4. Technology Costs and Performance

111. **At the heart of the3f World Bank economic analysis for project appraisal is the so-called table of economic flows**. One section of that table needs to record the costs of the proposed investment which have two major components: capital expenditure (CAPEX) and operating costs (OPEX). In this section we set out how costs related to BESS are derived.

112. Two points need emphasis at the outset:

- Be clear about the distinction between the battery (or battery pack) and the BESS. Sometimes papers talk about battery cost when they mean BESS (and vice versa) or be ambiguous about what they are referring to.
- As noted, levelized costs of storage (such as the widely cited estimates by Lazard, see Annex IV) are not really relevant to the establishment of the table of economic flows in project appraisal. Levelized costs of a project do of course emerge naturally from the table of economic flows (as illustrated in the case studies of Section 6), but the basic requirement is that CAPEX and OPEX is captured in the table of economic flows in the year in which the expenditure is incurred. **LCoS will be an output of the analysis, not an input.**

4.1 THE COST OF STORAGE

113. **The $/kWh energy metric. or the $/kW power metric, when used alone, can be misleading because their value will depend on the number of hours of storage**. This is because as the hours of storage increases, the average cost of energy capacity ($/kWh) declines, while the cost of power capacity ($/kW) increases. The cost for BESS can be broadly divided into the cost of the battery pack, which will tend to scale with hours of storage, and the fixed costs for the balance of system (BoS) which depends on the power capacity ($kW). These (relatively) fixed costs include the inverter, energy management system, and may include EPC costs, and developer overhead costs and profits. [27]

114. For example, BNEF[28] estimates that the total system cost in 2017 for a utility scale Li-ion battery energy system with 4 hours storage is $421/kWh. These costs are split roughly 50:50 between the battery pack costs ($209/kWh) and rest of system (or non-battery pack) costs ($212/kWh). The total cost of the BESS on a power ($/kW) basis is given by

Total system costs($) = Capacity (kW)([Hours] x Battery pack cost ($/kWh) + Non-battery pack cost ($/kW))

Dividing the cost by the duration gives the total energy cost on a $/kWh basis. For this example, reducing the hours of storage, *for an otherwise identical system,* from 4 to 2 hours would increase the

27 For example, see Figure X in 2017 U.S. Battery storage market trends" U.S. Energy Information Administration, (2018) https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf. EPC, overhead costs and profit are treated as fixed here for simplicity but might scale with overall cost of project.

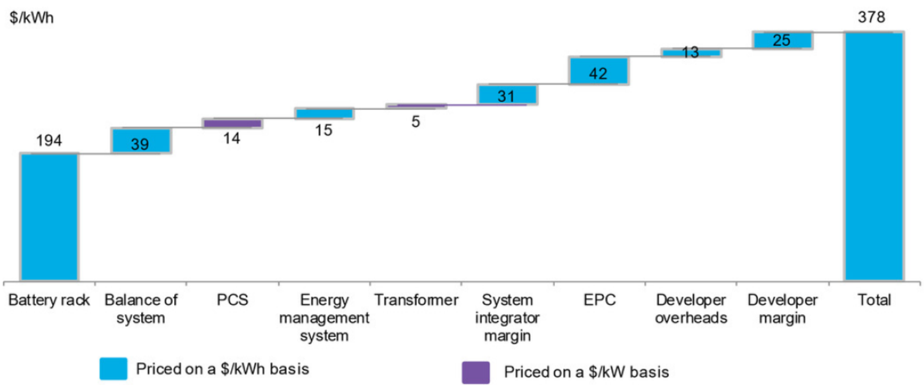
28 Bloomberg New Energy Finance, *Energy Storage System Costs Survey*, 2018

installed cost of energy storage by 50% from $421/kWh to $633/kWh, while decreasing the power related costs by 25% from $1,684/kW to $1,266/kW.

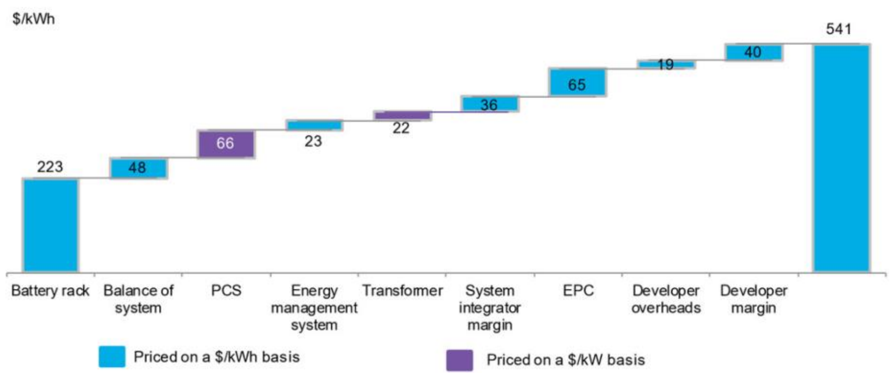
115. Figure 6 shows the composition of 2019 costs for utility scale BESS of 1 and 4-hour durations:

Figure 6: 2019 costs for a utility scale BESS

4-hour duration



1-hour duration



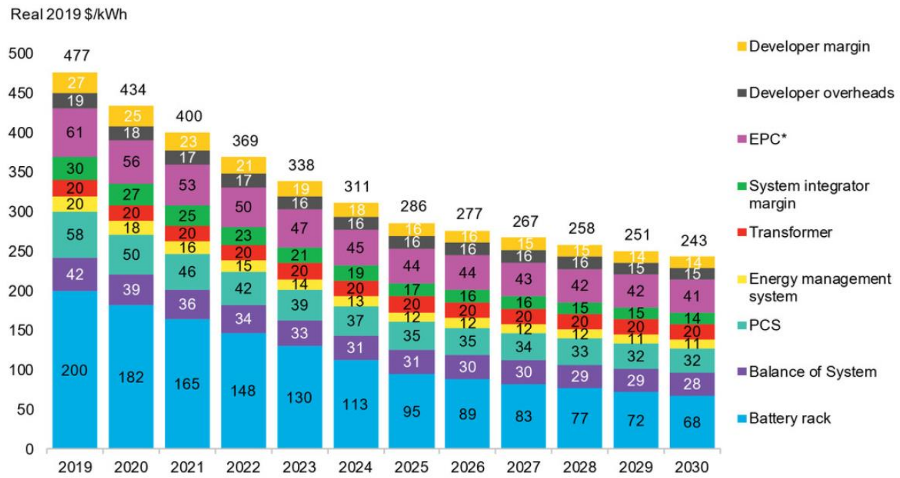
Source: Bloomberg NEF *Energy Storage System Costs Survey 2019*.

4.2 CAPEX ISSUES

116. Scale matters because it can impact both the choice of technology used and the LCoS. Costs per kW typically increase for smaller scale energy storage, but how costs scale to meet smaller loads depends on the technology. For example, Li-ion batteries and flow batteries are considered potential competitors at a utility scale. A Utility scale Li-ion battery system mighthave a CAPEX cost of between $400 and $500/kWh for 4 hours of storage, but the same technology at small residential scale may cost over $1,000/kWh.

117. Capital costs have indeed fallen over the past few years, as shown in Figure 7, and are expected to continue to decline substantively over the next decade. The anticipated continued reduction of the cost of BESS is important for the economic viability of many projects both in the future and the near term. This is because the falling cost should be considered explicitly in the analysis of BESS or hybrid VRE + BESS projects, where some battery packs will need to be replaced over the life of the project

Figure 7: Estimated capital costs, as $/kWh, for fully installed utility scale energy storage system for a 50MW/50MWh system



Source: Bloomberg NEF *Energy Storage System Costs Survey 2019*.

118. The gradual degradation of performance over time may require additional CAPEX for battery pack replacement at regular intervals: the batteries will have shorter lifetimes than the BESS system as a whole. In principle this is no different to CAPEX provision for regular turbine runner replacement and other life extension expenditures in an economic analysis of a hydro project.

119. Depending on technology, costs for end of life recycling or residual value may need to be included. While it varies by chemistry battery packs typically have significant amount of material that is toxic, harmful or valuable that should be recycled. While recycling is common for lead-acid batteries, it is currently much less common for Li-ion chemistries.

4.3 OPEX ISSUES

120. The OPEX of a BESS includes two main components: the O&M itself, including (i) an allowance for any incremental costs for performance warranties or maintenance service agreements, and (ii) where appropriate augmentation costs to maintain the energy capacity to the level of performance at some specified minimum level.

121. Warranties and insurance costs may be significant for BESS, and generally require explicit statement in the table of economic flows as a cost item, except when these costs are included in the CAPEX. In some cases, warranty costs (and warranty extensions) may be stated as an annual cost, though if the costs of the first warranty can be financed up front as part of the project cost it may be better to state these as part of CAPEX.[29]

[29] PSG discuss the question of whether insurance is an economic cost. Notwithstanding that some authorities (such as the USA OMB) state insurance is an *not* an economic cost, the PSEAG (and World Bank practice generally) holds that they should be included as an economic cost. The cost of warranties should be treated no differently.

122. Augmentation costs may be quite high, with Lazard (2019) estimating annual cost to be about 3% to 4.5%of the initial CAPEX per year depending on the size, technology and application. How to best enumerate these various categories of OPEX should be defined by the economist following the detailed advice of the technical expert on the project team - since these costs are very much a function of the technology and likely operating conditions.

4.4 UNEQUAL LIVES

123. One of the temptations to the problem of comparisons of unequal economic lives is to use annualized costs. But this is not acceptable practice for economic analysis: costs need to be booked in the year they are incurred.

124. Different parts of a BESS need replacement at different intervals – Battery packs perhaps every 5 or seven years, the entire system every 15 years; if part of a VRE project, PV panels may have a life of 20 years while its inverters need replacement at every 7 years. The thermal counterfactual may have a life of 25 years.

125. Recording the replacement CAPEX at appropriate intervals as required for the table of economic flows is straightforward. But what is more difficult is how far out into the future must one extend the Table itself. The classic procedure of engineering economics when comparing a project of life say 5 years, with one of life of say 7 years is to record all CAPEX and OPEX over 5 x 7 = 35 years – so 7 five-year machines with 5 seven-year machines. But with multiple lives this procedure is not practical.

126. One approach is to simply fix a life for the overall investment project in question (so for a VRE+BESS, for the VRE generation project), and then calculate for each investment tranche any salvage value at the end of the last year. At discount rates of 8-10% and typical lifetimes of 20-30 years, such salvage values will be of little importance and the benefits can safely be ignored. But at lower discount rates of 4-6% salvage values may well make a difference –though simply ignoring the salvage value (a benefit) will insure a conservative result.

127. What is important is that whatever economic life is chosen for the main investment, the various major lumpy replacement costs for battery packs or PV system inverters are properly recorded in the table of economic flows.

4.5 RELATED INVESTMENT COSTS

128. BESS may have a range of impacts on related investments. If expenditure on generation, or transmission and distribution infrastructure can be avoided, then that obviously counts as a benefit. If a related investment can be deferred, then there will arise both a benefit ***and*** a cost.

4.6 BESS COST CHECKLIST

129. Table 13 presents the checklist of entries that need to be reflected in the table of economic flows.

Table 13: BESS cost checklist

Item	Issue	Likely main sensitivity analysis variables
First cost	May need to separately itemize battery module, BoS and power conversion systems.	CAPEX
Major maintenance items		Annual OPEX
Battery replacements		Replacement interval, generally shorter than the BoS of the BESS, and maybe significantly shorter than life of hybrid VRE + BESS project Rate of CAPEX reduction important to estimate for battery pack replacements
salvage value	if any	
disposal costs	if any	
warranty and insurance	capitalized or annualized	

130. Working though the checklist would then typically lead to some set of entries in the table of economic flows that would appear as shown in Table 14. Here we assume the cost of the first warranty is part of the first cost; for subsequent battery replacements the cost for regular warranty extensions is recorded each year. The CAPEX for replacement batteries decreases over time. The presentation is assumed to be at constant prices: the numbers are purely illustrative in the interests of simplicity.

Table 14: Illustrative presentation of BESS costs (at constant prices)

			NPV	2020	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021
				-1	0	1	7	8	9	10	11	12	13	14	15	16	17	18	19
…..																			
[1]	**BESS**																		
[2]	**CAPEX**																		
[3]	First cost	[USm]	8.6		10.0														
[4]	Battery Replacements	[USm]					8.0									7.0			
[5]	Salvage value	[USm]					-1.0									-2.0			
[6]	Disposal costs	[USm]					0.5									0.5			
[7]	**OPEX**																		
[8]	warranty and insurance	[USm]			0.5														
[9]	[annualised]	[USm]						0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
[10]																			
…..																			
[20]	Total costs	[$USm	8.6	0.0	10.5	0.0	7.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	5.6	0.1	0.1	0.1

Note: for legibility, some columns have been hidden

Source: BESS Spreadsheet Library {GeneralTemplate.XLS}

131. Note that in the costs section one would record only and real increase in costs over time in the table of economic flows at constant prices – for example, the older the battery, the higher the maintenance burden. But this is separate to the deterioration of battery ***performance*** over time, whose effects are recorded in the ***energy balance***.[30]

30 See also the discussion on the Lazard LCoS (Annex IV)

Table 15: Checklist of questions for the energy balance and cost tables in the economic analysis.

System	Required information
BESS	• Maximum output MW • Duration (hours) • CAPEX Initial cost (see, e.g., Table 16) • Life, **n years** • degradation of performance over time (e.g. annual percentage or as a function of cycles) • Expected cost of replacement BESS **n** years hence • end-of-life recycling costs or salvage value benefits • OPEX • Any major maintenance outlays over time.
Transmission system	• impact on transmission capacity and transmission losses

5. Quantifying Benefits

132. Quantification of the economic and financial benefits of BESS spans a spectrum of difficulty, ranging from relative ease where the main impact is on *quantity*, to great difficulty where the main impact is on *quality and reliability*. This spectrum correlates well with the time scale: the benefits where a BESS operates over several hours (shifting PV output from mid-day to evening peak) is straightforward in principle, though the modeling and data requirements may make estimating the economic benefit in practice challenging. But where the benefits operate at time scales of seconds or less, estimating the economic benefits can be more difficult. This spectrum is illustrated in Table 16.

Table 16: The benefits of BESS

Benefit of BESS	Typical Time Scale	Difficulty of valuation for project appraisal	Main impacts	Reliability Attribute
Transmission upgrade deferrals	Hours to years	Straightforward.- but impact on VRE curtailment may require production cost model and shorter time steps	CAPEX Lower transmission losses> fuel costs	Adequacy
Provision of peaking capacity	Hours to years	needs system capacity expansion/production cost model for reliable assessment	CAPEX	Adequacy
Load shifting for VRE integration (BESS as part of a VRE generation project)	Hours	Straightforward [Case study Section 6.2, 6,5]	CAPEX Fuel costs	Firmness Adequacy
BESS at distribution or consumer level	Minutes to Hours	Straightforward [Case study Section 6.1]	CAPEX Fuel costs	Firmness
Ancillary services	Fractions of second to hours, depedning on the service	Increasing difficulty as the time scale shortens. Some services may require production cost models. [Case study, Section 6.3]	CAPEX Fuel costs	Security
VRE smoothing and ramping	Fraction of seconds to hours	Difficult, depending on scale, may simply need to be considered as part of VRE CAPEX [Case study 6.4]	Adds to VRE CAPEX Fuel costs	Security

(1) See Section 2.6 for elaboration of reliability attributes

133. This is not intended as a complete list of possible BESS provided services such as black start, reactive power and other system stability services (see also Figure 3). These services are not unimportant, but their valuation may be either (i) less important for the vast majority of World Bank funded projects or (ii) be an unavoidable cost but represent only a small fraction of the use of the project.

134. It should be emphasized that while a BESS project may be deployed with one of these primary applications in mind e.g. for peak load shifting or T&D deferral or integration with VRE, it is more usual that the BESS will provide multiple benefits. This can make the overall valuation more challenging. For example, the fuel saving benefits of peak load shifting, avoided curtailment and even spinning reserves can be estimated with production cost model. However, outside of that model it will be necessary to separately estimate the benefits or cost associated with avoided generation capacity, change in carbon emissions and possibly also T&D deferral.

135. All energy storage technologies, including batteries function in the same way - they shift electricity from one time to another. The actual operation of the varies markedly by services provided, technology and how the BESS is sized in terms of energy and capacity.

5.1 DEFERRAL OF TRANSMISSION & DISTRIBUTION UPGRADES

Concept

136. Many VRE projects added in the past few years have suffered curtailment because of transmission line capacity constraints. One option for easing curtailments is to invest in transmission upgrade. But another option is to install a battery to shift loads to hours when no transmission problem exists.

137. A distribution licensee BESS may have similar impacts - by charging at time of low load and discharging during peak hours, one may avoid peak hour transmission congestion that would require additional capital investment in the counter-factual. Indeed, such BESS-induced deferrals could also occur at various points in the transmission system

Modeling and data requirements

138. The information for a possible avoidance or change in design of a transmission line upgrade will be developed by the transmission engineer on the project appraisal team, who will specify changes in CAPEX amounts and timing, together with changes in losses and transmission capacity limits – for the with and without BESS alternatives. This may need to include PSSE modeling to confirm reliability and security impacts.

Valuation

139. There are no valuation issues involved, insofar as in this case, the economic benefits follow simply from the changes in CAPEX (and related OPEX). In the case of a deferral, there will be a *benefit* in the year that the line would have been built in the absence of the BESS, and a *cost* in the subsequent year in which it is built.

140. For example, if a planned transmission line expansion to accommodate a VRE project, say costing $10 million, otherwise planned in year 5, can be deferred by 3 years, then the table of economic flows requires three entries:

- In year 5, as CAPEX benefit of $10 million
- In year 8. a CAPEX cost of $10 million
- in years 6,7 and 8, the benefit of the avoided O&M of the transmission line

5.2 PEAKING CAPACITY

Concept

141. The role of thermal peaking units in merit order dispatch under spinning reserve constraints is discussed in detail in Annex I: because such units are often gas-fired combustion turbines (CT). CTs are often also used to provide peaking capacity, including capacity needed to meet the system reserve margin. While less efficient than combined cycle gas turbines, their lower capital cost means they may be the better option for thermal generation that is rarely run. . However, BESS *can* provide almost instantaneous capacity, and could be charged during off-peak hours, thereby potentially replacing peakers that may in any event only be needed a few hours a day, as well as being able to earn other revenue streams..

142. *Of course, i*n some regulatory environments, for a utility to consider a grid-connected battery as alternative peaking capacity requires that BESS be allowed into the rate base - the recent decision in China to not allow inclusion in the rate base (Box 1) is not helpful. Where a

BESS is allowed to replace peak capacity the duration of the BESS will need to be specified to ensure the BESS has sufficient energy to meet peak demand.

Modeling and data requirements

143. It is difficult to see how a stand-alone BESS to provide peaking capacity (and likely other ancillary services), to replace thermal peaker, can be justified in the absence of a capacity expansion planning or production cost model to ensure that the BESS has sufficient energy to provide firm capacity when needed). Experience with such models shows that the substitution will not necessarily be X MW of combustion turbine replaced by X MW of battery in the same identical year.

144. Rather it will depend on the BESS's hours of duration and the energy mix of the rest of the grid, and the hourly demand profile. The situation may be complicated further because as level of solar and wind penetration increases the storage may be also used for other energy services, such as ramping that could limits it ability to be relied on for capacity. Consequently substitution of one for the other in a simple spreadsheet model will not be reliable.

Valuation

145. Establishing the capacity value of BESS as stand-alone grid connected project is a largely uncharted area (see Box 3). Various studies in the literature provide some general conclusions, but the relevance of their conclusions to BESS project appraisal at the Bank is unclear. No rigorous project appraisal can be based on generalized conclusions from completely different applications.

146. In short, only proper capacity expansion/production cost modeling can provide a credible valuation of BESS as an alternative to thermal peaking capacity.

Box 2: BESS Capacity value studies

The study by Sioshansi *et al.*[31] estimated the credit for an energy storage device based on its ability to displace the top 100-hour highest net load hours with 2, 4 and 8-hours duration had average capacity values of 69%, 84% and 95% respectively.

An NREL study for the USA concludes that whether 4-hour energy storage can provide peak capacity as an alternative to gas thermal peakers depends largely on the shape of electricity demand – which in turn have also been changing as a consequence of renewable capacity additions.[32] The study finds that beyond 10% penetration of solar, the practical potential for 4-hour storage to provide peak capacity doubles. The impact of wind generation is less clear, in part because of the large-scale exchange of wind power across the multiple power pools of the US.

In California, the duration to qualify for a 100% capacity credit is 4 hours, though this is likely to be system mix dependent, and the BESS needs to be able reliably charge in advance of being used to provide capacity. In contrast, for PJM has suggested the "4-hour" rules is insufficient. An alternative might be a longer duration or a lower capacity credit (e.g. 80%).[33]

The capacity credit for BESS is dependent on many factors, including whether grid connected or not, and how the VRE mix might change over the life the project, the number of peak hours in day, and how it is operated. Hence without a detailed system study there is great uncertainty about any estimate.

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31 R. Sioshansi, S. Madaeni, and P. Denholm. *A dynamic programming approach to estimate the capacity value of energy storage*. IEEE Transactions on Power Systems 29, no. 1 (2013): 395-403.

32 P. Denholm, J. Nunemaker, P. Gagnon and W. Cole, 2019. *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States*, NREL, Teport NREL/TP-6A20-74184, June.

33 PJM has recently been considering alternatives to a 10 hour capacity rule for energy storage. https://insidelines.pjm.com/pjm-stakeholders-consider-alternatives-to-10-hour-capacity-rule-for-storage/

Box 3: Jordan Case Study using EPM

Jordan, as a net energy importer, is exposed to macro-economic stress and rising costs of electricity supply. The total installed capacity of Jordan reaches to 4,000MW and 85% of the electricity is produced by imported natural gas. Over the next two to three years, Jordan would experience a 75% increase in installed generation capacity from committed combined cycle, renewable energy and oil shale power plant projects.

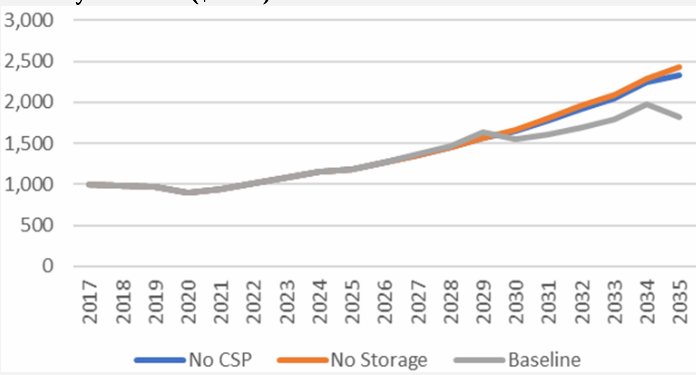
The Jordan Vision 2025 establishes a target of 39% of local energy resources in the energy mix by 2025, which are mainly renewable energy resources and oil shale. However, the intermittent renewable energy imposes the need for additional investments in auxiliary services including energy storage options. In the absence of clear policy, market and regulatory frameworks for these services, battery storage is being explored as an ad-hoc solution for providing primary response, address intermittency, and shift supply to match demand. Improving Jordan's power system flexibility by including different energy storage options will allow a greater share of VRE to be integrated and thus, improve Jordan's energy security.

The study ran the EPM model for 6 scenarios, that tested different combinations of technologies and storage options. The design started with all of the options made available in the least cost baseline, and then assessing the impact of removing individual technologies, ending with the no storage scenario. The table illustrates how one designs such a modeling study (which would apply regardless of the particular model used).

	RENEWABLES					CONVENTIONAL				
Scenario	Wind	PV Fixed	PV Tracked	CSP	Storage	CCGT	OCGT	Rec. Engines	Waste-to-Energy	Oil Shale
Baseline	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Reference (No CSP)	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes
Domestic resources only	Yes	Yes	Yes	Yes	Yes	No	No	No	Yes	Yes
RE only	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No
Solar Only	No	Yes	Yes	Yes	Yes	No	No	No	No	No
No Storage	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	Yes

As compared to baseline scenario system costs, no CSP and no storage options result in higher costs, especially after 2030. The total system costs for no CSP option reaches above $2,300 million by 2035, while system costs for no storage amount to$ 2,426 million..

Total system cost ($USm)



Source: World Bank (forthcoming 2020). *Modeling Utility-Scale Energy Storage: Database and Case Studies of Jordan and Tunisia*. Washington, DC: World Bank Group.

5.3 TIME SHIFTING FOR VRE INTEGRATION

Concepts

147. BESS can play a key role in facilitating the integration of VRE. As the share of VRE increases, a range of issues arise which may differ for grid connected versus off-grid/micro-grid applications.

- Particularly in the case of solar PV, the hours of maximum production do not match the peak load or net loads of the day, which might correspond to early evening or morning. Consequently the capacity value of renewable energy may be limited due to its relatively low value of its capacity credit.[34]
- The development of transmission systems often lags behind VRE additions. The result is transmission system congestion and curtailments, that decrease the load factors of VRE projects, and degrade economic and financial returns.
- The variability of VRE require more flexibility in the remaining generators in the system. As solar PV output rises, other plants must be backed down, and similarly as PV output falls toward the evening the output of dispatchable generators needs to be ramped up. The rate at which other plants can be backed down, or backed up again when VRE output increases or decreases, may exceed the ramping capacities of the remaining units in the system or increase system costs due to less economic generators with faster ramping capacities being dispatched..
- At shorter time scales, and in small systems, the variability of output may bring increased frequency regulation needs and system reliability concerns.

148. Each of these problems can be mitigated by various means, but these mitigation measures all involve additional costs, particularly in developing countries where load is growing:

- Lack of generation capacity for ramping may require additional CAPEX e.g. for thermal peakers or combined cycle gas turbines.
- Transmission congestion and curtailments can be mitigated by additional transmission system investment or system redispatch.
- To accommodate the variability of VRE generators the system may need to be redispatched to make generators available with faster ramp rates and additional regulation reserve must be provided[35]. More flexible capacity may also reduce curtailment when thermal generators have turndown limits.

149. As battery pack and BESS costs have declined and the technology developed, the question for an economic analysis is whether these conventional mitigation measures may sometimes be provided by BESS at lower cost, recognizing that different potential applications may require quite different battery performance characteristics. For example, a BESS intended primarily for power smoothing will need to have much smaller energy storage to power ratio storage requirement while accommodating many more storage-discharge cycles than a BESS

34 That is not always the case: in many countries with large and growing air conditioning loads, daily peaks have moved towards mid-day with a good match to peak PV output (or needing only short time shifts).

35 For example, an analysis of 30% VRE penetration in PJM found that an additional annual average of 1,000 MW to 1,500 MW of regulation reserves would be required to maintain system reliability; on the other hand, no additional spinning or non-spinning reserves would be required (https://www.sciencedirect.com/science/article/pii/S1364032119308755)

whose main purpose is multi-hour time shifting of energy to other hours of the day for peak load shifting or ramping.

150. As battery costs have declined and the technology developed, the question for an economic analysis is whether these conventional mitigation measures can be provided by BESS at lower cost. But these different potential applications may require quite different battery performance characteristics. For example, A BESS for power smoothing – (smoothing out high frequency variability) will need to have much smaller storage requirements and accommodate many more storage-discharge cycles than a BESS whose main purpose is time shifting of output to other hours of the day.

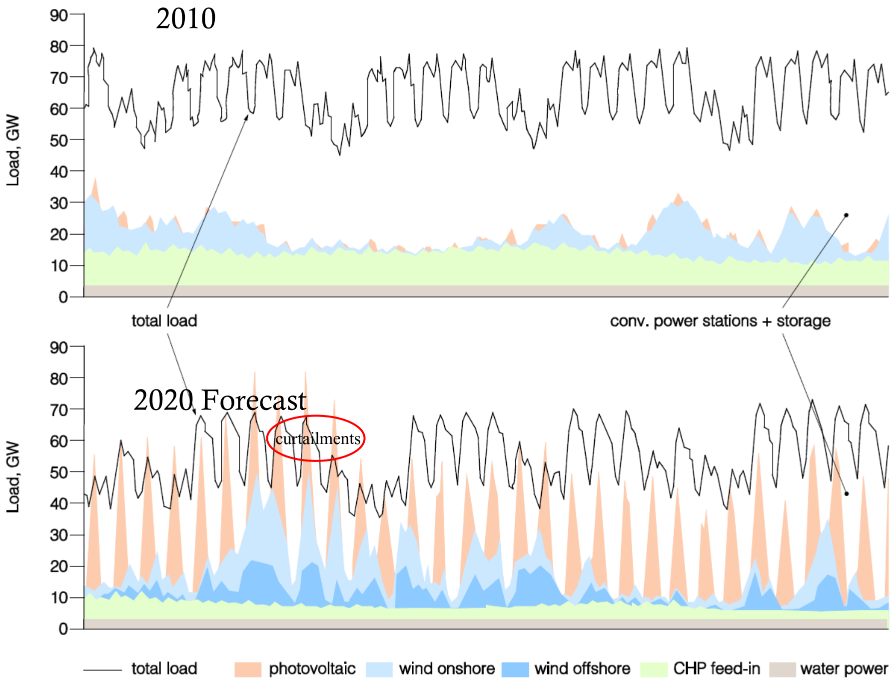
151. As battery pack and BESS costs have declined and the technology developed, the question for an economic analysis is whether these conventional mitigation measures may sometimes be provided by BESS at lower cost, recognizing that different potential applications may require quite different battery performance characteristics. For example, a BESS intended primarily for power smoothing will need to have much smaller energy storage to power ratio storage requirement while accommodating many more storage-discharge cycles than a BESS whose main purpose is multi-hour time shifting of energy to other hours of the day for peak load shifting or ramping.

152. There is a large and growing literature of the need for greater flexibility of system with higher VRE and mitigation methods. For example, Denholm et al (2016) identify six areas for greater system flexibility: changes to system operation, flexible generation, reserves and stability services from VRE, transmission and coordination, demand response and energy storage [36]

153. The challenge of VRE integration is particularly acute in countries that have the most ambitious renewables programs just because of their currently still high dependence on coal - most notably in India, Germany and China - but also in smaller countries that are still building new coal projects (as in Cambodia and Sri Lanka). Figure 8 shows for Germany a typical monthly generation and load pattern in 2010 and that forecast for 2020: with the solar peaks becoming larger, the thermal system and potential storage projects will need to operate ever more flexibly - and in the absence of adequate battery storage to time shift the PV peak, result in significant PV curtailments (as in the first week of the 2020 forecast). The challenge is how the benefits of BESS to system flexibility can be transparently presented in economic analysis.

[36] Denholm, Paul, Kara Clark, and Matt O'Connell. *On the Path to SunShot-Emerging Issues and Challenges in Integrating High Levels of Solar into the Electrical Generation and Transmission System.* No. NREL/TP-6A20-65800, 2016.

Figure 8 : Integration of VRE in Germany



Source: C. Henderson, *Increasing the Flexibility of Coal-fired Power Plants*, IEA Clean Coal Center, September 2014, Figure 1.

Modeling and data issues

154. In the absence of a system planning model that provides the necessary energy balances, one must still prepare a detailed energy balance, at time steps no less than hourly, in order to characterize the output of a VRE project with and without the battery. In the case study of Section 6.2, the energy balance spreadsheet has is based on 15-minute time steps. Any curtailments need careful documentation.

Valuation

155. For the financial analysis the tariff often does not reflect the time of day, or make a separate charge for fixed (capacity) costs. In the case study example of Section 6.2, there is a uniform tariff. If that is indeed the case, then the financial analysis will *never* show a net benefit (since all batteries are net consumers of energy) - except in the case where the is little or no demand during off-peak hours (which sometimes occurs in rural mini-grids where most of the electricity demand is residential with little productive use).

156. In a great many applications that involve small Pacific Island, Caribbean or African systems, the energy of VRE projects (or VRE+BESS) is reasonably taken as incremental - they are typically desperately short of power, particularly during peak hours, and cannot accept new customers or provide incremental power to existing consumers.

157. In most of these countries, the only plausible alternative to VRE or VRE + BESS diesel, whose avoided variable cost will be less than the cost of diesel self generation if heavy fuel oil (HFO) can be used; but in many small Island states or remote and landlocked areas, the infrastructure for heavy oil is not in place, and would involve major infrastructure cost.[37] If high speed diesels are used for grid generation (which require more expensive fuel), then the costs of

[37] A good example is the Tina River Hydro project in the Solomon Islands, where a very high cost hydro development was economic against a heavy oil, and against a PV+BESS system.

self generation may be comparable (and often it is taxes on auto diesel that make the difference, which are excluded from the economic cost). That is certainly true of the Central African Republic PV+BESS system examined in the case study of Section 6.2.

158. In short, such projects can be treated as incremental for which one may value off-peak hours for charging at the tariff (the lower bound for willingness to pay), and energy discharged in peak hours at the cost of diesel self-generation. A "capacity credit" assumption is not needed.

Reading List 3 : BESS for VRE integration

Hledik et al 2018, The economic potential for energy storage in Nevada, *The Brattle Group*, prepared for Public Utilities Commission of Nevada Governor's Office of Energy, October 1, 2018. A detailed and clear description of the use of a production cost model to estimate fuel cost savings due to BESS providing peak load shifting and spinning reserve services, and avoided curtailment

Denholm, Paul, Kara Clark, and Matt O'Connell. On the Path to SunShot-Emerging Issues and Challenges in Integrating High Levels of Solar into the Electrical Generation and Transmission System. No. NREL/TP-6A20-65800, 2016. Discusses six areas for greater system flexibility: changes to system operation, flexible generation, reserves and stability services from VRE, transmission and coordination, demand response and energy storage.

IRENA Source: IRENA Electricity Storage Valuation Framework: Assessing system value and ensuring project viability, March 2020. Presents a variety of case studies, including VRE integration in developing countries

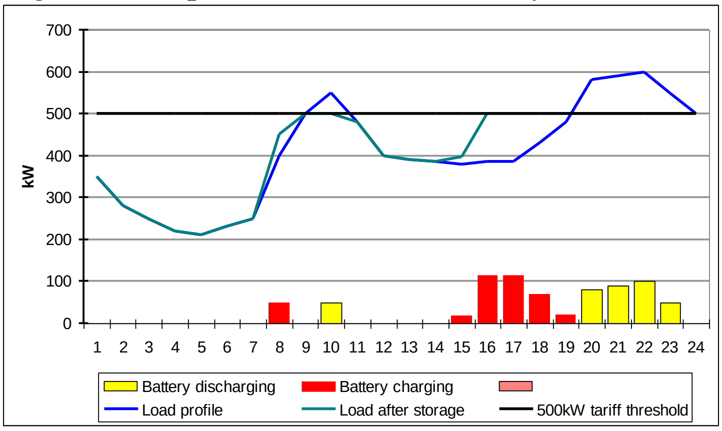
5.4 TIME SHIFTING FOR PRICE ARBITRAGE

Concept

159. The methodology of estimating the benefit of price arbitrage is straightforward, and similar in concept in some ways to in concept lit to VRE integration. It again requires a detailed energy balance (no less than hourly time steps), plus knowledge of the different value of energy and capacity at different times of the day (or different seasons). The power (kW) and energy (kWh) sizing of the battery will depend on the specific goals.

160. Consider the case of a BESS used for peak shaving - say a large commercial consumer who wishes to avoid high demand charges if his load exceeds 500 kW. By using a battery to shave the peak, this could be avoided. In addition, there may be energy price arbitrage benefits depending how the energy tariff is structured, though this is not the case for example below. The question for economic analysis is how big a battery is needed, and what would such a battery cost. Figure 9 shows the load profile with and without the battery. To determine the size and duration of storage, one needs an energy balance for each hour.

Figure 9: Load profile before and after battery installation



Source: BESS Spreadsheet Library

161. In hours 10, and 20-23 (peak hours) the load exceeds the 500 kW threshold, and therefore subject to the higher demand charge. This can be avoided by charging the battery in off-peak hours. To calculate the size and capacity of the battery, one asks first what energy output is required from the battery to meet the load in peak hours ***Eout*** (the yellow bars in Figure 9). In this case the battery energy capacity will be determined by the evening peak, not the morning peak. If the round-trip efficiency **e** is, say 85%, then the energy input ***Ein*** (the sum of the red bars) will be ***Eout/0.85. .***

162. The necessary calculations are shown in Table 17. It follows that one would need a BESS with a power capacity of 120 kW with a duration of 3.17 hours (or 380 kWh of storage), to avoid the 500 kW threshold. Obviously in practice one would need to look at more than one day of load, and in more than one season, which will likely increase both the power and duration requirements. The optimal kW and duration may be significantly different if the tariff depends on time of use.[38]

Table 17: Battery size calculation

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
load before storage		kW	380	280	270	240	242	255	260	400	500	550	480	400	395	380	380	380	400	420	500	580	590	620	570	495
threshold		kW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Battery discharge		kW										50										80	90	120	70	0
Potential battery contribtion		kW	120	220	230	260	258	245	240	100	0	0	20	100	105	120	120	120	100	80	0	0	0	0	0	5
Storage required	360	kWh																								
Efficiency	0.95	[ ]																								
Input required	379	[kWh]																								
Battery charging		kW								50							60	120	100	80						
Load after storage		kW	380	280	270	240	242	255	260	450	500	500	480	400	395	380	440	500	500	500	500	500	500	500	500	495

Source: BESS Spreadsheet Library {GeneralTemplate.XLS}

163. In Section 6.1 we assess the results of a study conducted by the Sri Lanka Public Utilities Commission on just such a potential peak shaving project: it concludes this is not *yet* financially feasible for this particular case, but would become so as battery costs decline. A recent assessment for peak shaving applications in the Philippines comes to the same general conclusion for this application (Box 3). The Vietnam wind power example of Section 6.5 provides a further example of battery size optimization.

38 A number of recent studies provide further insight on estimating the benefits of distribution level BESS including stacking considerations including those by the Rocky Mountain Institute (2015) and Sidhu et al (2018)

Valuation

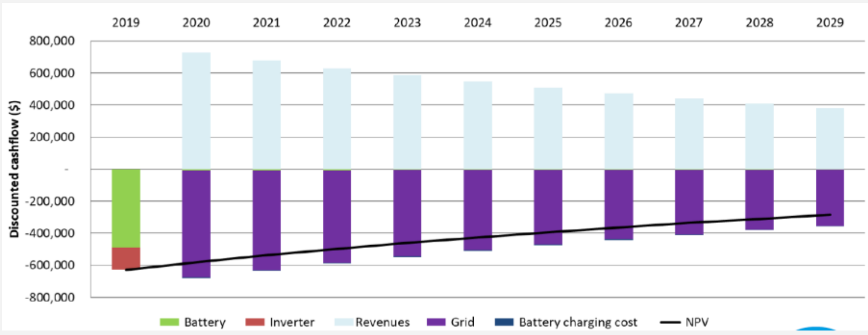
164. The valuation for financial analysis depends on the applicable tariffs for each if the hourly time-steps and is relatively straightforward, at whatever level the BESS is applied.

165. However, the valuation for an economic analysis is more difficult. Tariffs are merely transfer payments, which govern the distribution of net benefits among the stakeholders. However, in an economic analysis, the cost of energy is not that which the battery owner sees, but what the country sees. Thus the economic cost of charging energy is not the tariff, but the economic cost of the power generation (with costs of fossil fuels at *economic* costs), and including any appropriate capital recovery. Similarly the benefits are not the reduction in net costs valued at the tariff, but the avoided economic costs of generation during the discharge hours.

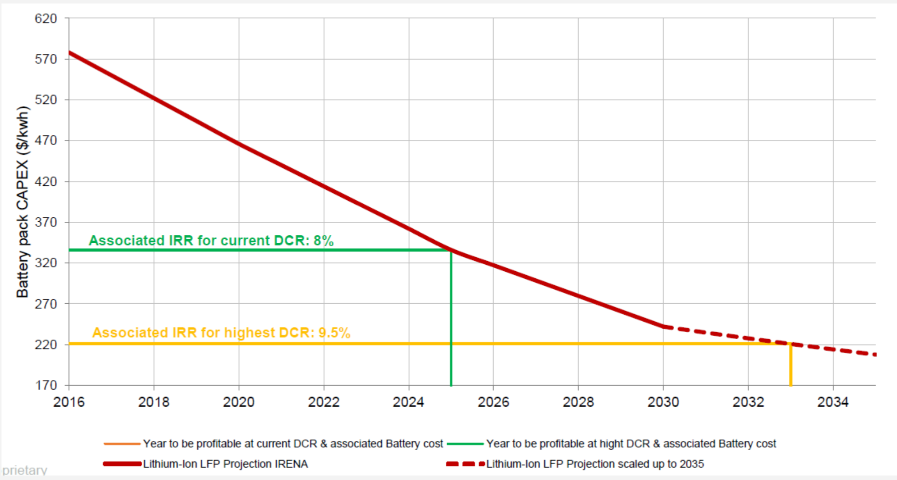
166. The differences in economic and financial analysis of price arbitrage is illustrated in the case study of Section 6.1

Box 4: Peak shaving in the Philippines

The study examined the business case for installing a BESS at a large shopping mall in Manila in order to flatten the power demand and avoid high peak hour demand charges. While the BESS would reduce peak demand by 19%, at 2018 Lithium-ion battery costs of 570 $/kWh the FIRR is minus 4%, with discounted cash flow loss of $285,000 over 10 years, compared to the no BESS case.[39]



BESS costs would need to fall to between 220 and 320 $/kWh for batteries at this scale for a positive business case to be made (in this case for a large shopping Mall).



Source: Tractebel, *IFC Battery testing for C&I applications in Southeast Asian Market,* World Bank, September 2019

39 Many papers often write battery cost when they mean *BESS* cost, and vice versa. One needs care in this matter, and hence the need for breaking down CAPEX by at least what is for batteries, and what is for everything else.

5.5 ANCILLARY SERVICES

Concept

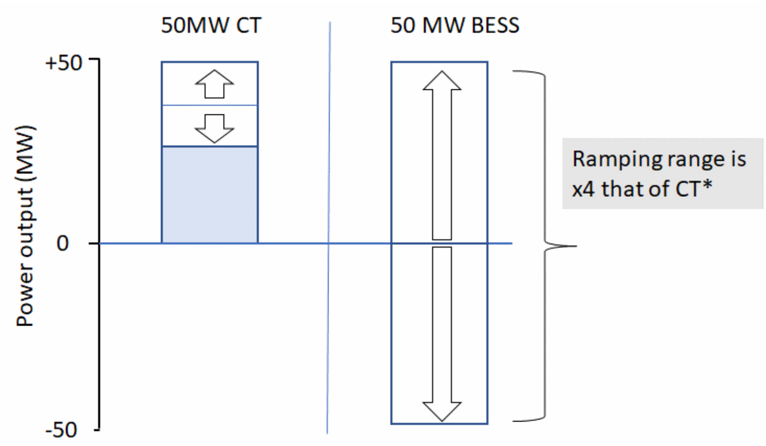
167. Ancillary services are those that provide support to the reliable operation of the grid. Ancillary services are typically divided into two broad classes depending on whether they support the operation of the grid under normal operating conditions (such as regulation) or are contingency services (such as spinning reserves, or black start capability). 167. The need for reliable operation is shaped by three requirements of grid operation:

- the ability to accommodate *emergency* events, such as a generator failure, or a lightning strike - events that may occur infrequently, but have potentially severe consequences when they do occur. Spinning reserves, followed by non-spinning reserves provide the quick response to such events.
- the need to adjust to everyday normal operational and expected and random fluctuations in *demand,* which is handled by regulation
- the need to adjust to changes in *supply* - particularly the output of variable renewable energy, which may require adjustments to the system on top of the normal ramping up and down requirements: thus VRE integration may require additional smoothing or ramping capacity .

168. These services can be provided with varying degrees of effective and cost by conventional generation resources, including hydro and pumped hydro. Where these services are provided by thermal generation, additional system costs arise for various reasons including the incremental cost of part load operation and because providing these service may require economic re-dispatch due to limits in ramping rates or plant load limits (see Annex I).

169. BESS can also provide these services. One advantage of a BESS over a conventional thermal unit is shown in Figure 10. A 50 MW CT operating for regulation or ramping will have some minimum operating limit, say 25MW. To be able to ramp 12.5MW up or down it would be operated around a center point of 37.5 MW - with a ramping range of 25 MW. But a 50 MW BESS providing equivalent ramping up or down would be operated at half charge, so it has ramping range of 50 MW and 50MW down, or 4x the range in this example. The range benefit is similar but less for spinning reserve. Here the CT might offer SR with a set point at 50% whereas BESS will have x2 (rather than x4) the range as it can move from idle to full output when needed.

Figure 10: CT v BESS for ramping



Source: Redrawn from Fluence (2019)

Modeling and data requirements

170. The benefits of BESS for spinning reserves have been examined in two recent World Bank projects: the China Renewable Energy and Battery Storage Promotion Project,[40] and the India Innovation in Solar Power and Hybrid Technologies Project.[41] In the former case, the benefit of BESS providing spinning reserve was simply taken from an earlier study of the value of ancillary service provided by pumped storage, estimated at $33.80/kW-year; in the latter case, BESS was not found to be economic. The assessment of BESS benefits to fast frequency control (and price arbitrage) in India is discussed in more detail in Section 6.4.

171. Fast frequency response, spinning reserve requirements, ramp rates and penalties for part load operation of thermal units can all be modeled in good system planning models: all of these potential benefits are captured in the Bank's Energy Planning Model.

172. However, where such a system planning model is not available, simple models to estimate heat rate penalties for part load operation in thermal projects require great caution, and are recommended only at the pre-feasibility study level. Box 3 reports on a preFS for a BESS for ramp rate control at a floating solar PV system in the Mekong Basin; the case study of Section 6.3 reports on an assessment of BESS to replace spinning reserves provided by flexible operation of Indian coal projects.

Valuation of ancillary services

173. Where markets for ancillary services are in place, valuation suitable for use in an economic analysis is readily provided by market prices. Such markets are in place in some larger developing countries of Latin America and China, but not yet in the bulk of World Bank country clients. However ,great caution needs to exercised in sensitivity analysis as the market prices may vary substantially over time, particularly for regions experiencing rapid growth and/or deployment of VRE.

174. But where such markets do *not* exist, how can one quantify the economic value potentially available? Utilities have long estimated and built the amount of regulation and spinning reserve that is required from an engineering standpoint, and their dispatch centers acting accordingly. That is true even of small Island systems running diesels and some VRE, where some fraction of the generator may be providing voltage support.

175. But reliable estimates of the *cost* of providing a given level of spinning reserve are rare. Utility managers in the typical state-owned, vertically integrated power sector entities will judge how much spinning reserve should be provided (through appropriate part-loading of units). And it is widely known that part-loading and flexible operation imposes costs. But that is a long way from *valuation* suitable for appraisal of a BESS (the difficulties of which are illustrated in Case Study 6.4).

40 World Bank, *China Renewable Energy and Battery Storage Promotion Project*, Project Appraisal Document, PAD 3258, April 2019.

41 World Bank, *India Innovation in Solar Power and Hybrid Technologies Project*, Project Appraisal Document, PAD 3258, April 2019.

Box 5: Battery assessment for floating solar PV-hydro in the Mekong Region

Studies of hydropower in the Mekong Basin examined the feasibility of floating PV at existing hydro projects (LSS2 in Cambodia, Xekamen 3 in Laos serving Vietnam) in place of building additional dams on the Mekong mainstream. The concept is to use the daily storage of the hydro project as shift solar production into the peak hours of the evening.

One of the challenges is to match expected ramp rates of the PV project with the ramp rate of the hydro turbines, for which purpose it was proposed to add a 25MWh BESS to the 100 MW scale floating PV system at the existing 400 MW Lower Sesan 2 hydro project in Cambodia. The cost analysis showed that at $500/kWh storage cost and 42MWh capacity, the BESS would add 20% to the cost of the PV system; at expected 2025 BESS prices of $300/MWh and a 25 MWh system the incremental cost of the battery would some 8% to CAPEX.

BESS system cost at LSS2

			La Ola	scaled to LSS2	scaled to LSS2 at 2020 prices	scaled to LSS2 at 2025 prices
			[1]	[2]	[3]	[4]
	PV system					
1	Installed capacity	kW	1200	100000	100000	100000
2	capacity factor	[ ]	0.18	0.18	0.18	0.18
3	annual PV energy	[MWh]	1,892	157,680	157,680	157,680
4	average daily generation	[MWh]	5	432	432	432
5	Cost of PV	[$/kW]	2000	2000	1000	900
6		[$USm]	2.4	200	100	90
7	**Battery**					
8	Battery capacity	[MWh]	0.5	41.7	41.7	25.0
9	Battery storage/daily output	[ ]	10%	10%	10%	6%
10	Cost of storage	[$/kWh]	1200	1200	500	300
11		[$USm]	0.6	50.0	20.8	7.5
12	battery cost increase	[ ]	25.0%	25.0%	20.8%	8.3%
13	**System Loads**					
14	peak load	[MW]	5	2552	2552	2552
14	PV peak output	[MW]	1.2	100.0	100.0	100.0
15	as fraction of peak load	[MW]	24%	4%	4%	4%
17	**Ramp rates**					
18	Natural	[kW/min	20	1667	1667	1667
19		[MW/min	0.02	1.67	1.67	1.67

The net economic benefits of floating PV+BESS at existing hydro projects significantly exceed that of new Mekong mainstream hydro projects when the environmental damage costs of these are properly costed - namely the dramatic reduction of the Mekong fishery, and loss of sediment deposition (as fertilizer and delta replenishment) in Vietnam's Mekong Delta region.

Source: Natural Heritage Institute, *Sustainable Hydropower Master Plan for the Xe Kong Basin*, Vol.3, January 2018

176. The question is often asked whether ancillary services could not also be provided even in the absence of a formal market and appropriate market signals? An example of this is provided by Vietnamese small hydro projects that were in operation before the introduction of time-of-day pricing in the avoided cost tariff introduced in 2009. It was observed that operators were happy to operate their projects as daily peaking whenever possible because of their desire for good relationships with the provincial power companies.

177. But there is a major difference between a hydro project and a battery: there may be no opportunity cost to an operator of a small hydro project operating during a peak hour rather than an off-peak hour. But battery lives and rate of degradation for most battery technologies is a function of the number of full cycles at which it operates, so there is a material cost to providing ancillary services such as ramp up and down, for which a private sector BESS owner-operator would need to be compensated.

178. The reason why ancillary services markets function well in the USA, the UK and Australia is that utilities are required by their regulators to meet given levels of reliability, and are subject to fines if these standards are not met. Utilities are therefore motivated to establish markets for ancillary services: they determine the quantity of service to be provided, and the market determines the price (whose costs can also be passed on to consumers).

179. It is also true that it is unlikely that one can develop a market for ancillary services before one can establish a competitive market for generation and capacity. Such ancillary services markets are highly complex, and certainly more challenging than markets for kWh and MW. India, Vietnam and the Philippines now have competitive generation markets, and are beginning to consider markets for ancillary services.

180. But for the smaller countries of Asia and Africa, and the small island countries of the Pacific and the Caribbean, the question would be whether ancillary services could be valued even in the absence of a market, and BESS investments made by state-owned utilities justified on the basis of analysis demonstrating these services can be provided by BESS at lower costs than traditional practices. It would be useful to explore various ownership and operational models to establish under what circumstances a utility owned BESS (or even a privately owned BESS) could be operated in the interest of least-cost system dispatch by the dispatch center?

181. These are some of the questions being taken up by the Bank's $1 billion program to support BESS globally. In theory, detailed power system modeling at suitable time steps with and without batteries serving ancillary service functions would reveal the economic benefits, but that modeling is time consuming and data intensive, and a strategy for operation of a BESS in non-market system. One could also simply use ancillary service market valuations from other countries, but applying these to other countries would unlikely have sufficient credibility to warrant a major BESS investment. It will take a pilot project to demonstrate the *realization* of the economic value of BESS ancillary services in a non-market environment.

Reading list 4: Ancillary services and flexible operation

Central Electricity Authority, Government of India: *Flexible Operation of thermal power plant for integration of renewable energy*, January 2019.

Central Electricity Regulatory Commission, New Delhi *Report of the Committee on Spinning Reserve,* Sept 17, 2015.

Henderson, C. *Increasing the flexibility of coal-fired power plants*, IEA Clean Coal Center, September 2014.

Hummon, M. *et al*. *Fundamental drivers of the cost and price of operating reserves*, National Renewable Energy Laboratory, July 2013

Rebours, Y., and D. Kirschen, *A survey of Definitions and Specifications of Reserve services*,2005. https://www.researchgate.net/publication/242170645

Rebours, Y and D. Kirschen, *What is spinning reserve*?, University of Manchester, Sept 2005. Mandatory reading for the economist who knows little or nothing about the subject.

Venkataraman et al., *Cost-Benefit Analysis of Flexibility retrofits for Coal and Gas-fueled Power Plants*, NREL, Report 60862, December 2013.

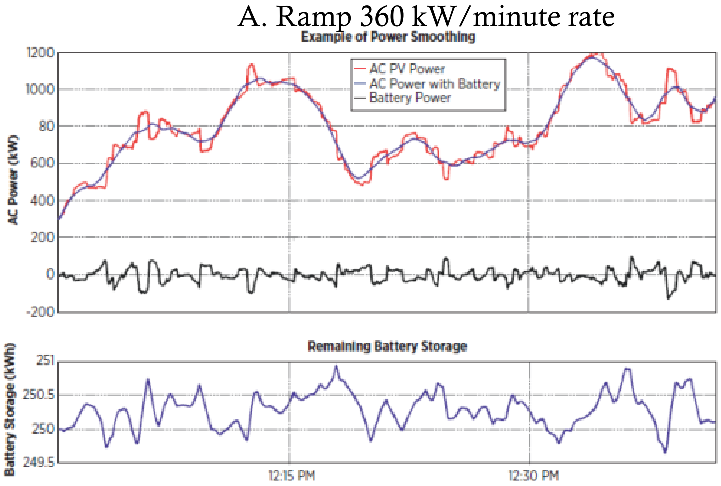
5.6 BESS FOR POWER SMOOTHING

Concept

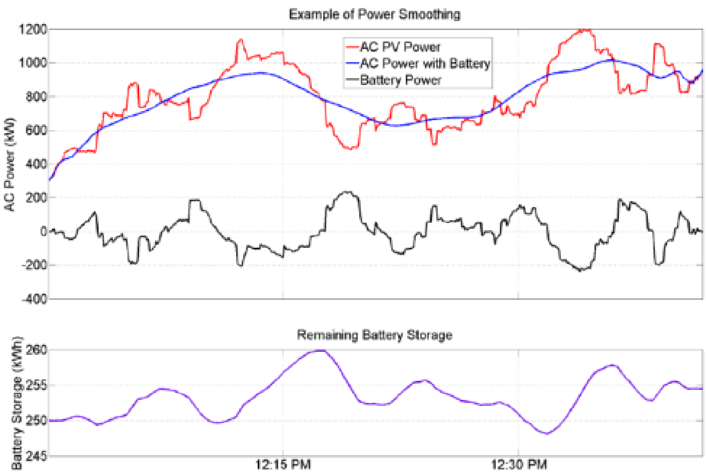
182. Figure 11 illustrates the principle by which fast acting storage fulfils the requirement for frequency control at small PV projects. This example is for a small 1.2 MW solar PV project in Hawaii (on the Island of Lanai).[42] The project provides about 10% of the Island's energy, with 10.4 MW of diesel generators providing the 5MW peak load. Typical (*un*smoothed) output ramp rates of the PV project (the red line in Figure 11A) were above 400 kW/minute, with a maximum observed rate of 760 kW/min. The project's battery storage system was designed to limit the ramp rate to 360 kW/minute. In the example of Figure 11A, during the first 15 minutes one observes that the *smoothed* output increased from 300 kW to 1,000 kW, equivalent to 47 kW/minute. The amounts of energy stored/discharged are very small - on the order of a few kWh (with a range of power absorbed at ± 75 kW).

Figure 11: Battery operation for power smoothing at La Ola Solar PV project, Hawaii

A. Ramp 360 kW/minute rate



B. Ramp rate 40kW/minute



Source: J. Johnson et al *Initial Operating Experience of the La Ola 1.2 MW Photovoltaic system*, Sandia National Laboratory. Report SAND2010-8848, October 2011.

[42] J. Johnson *et al.*, *Initial Operating Experience of the La Ola 1.2 MW Photovoltaic System*, Sandia National Laboratory. Report SANDIA-2010-8848, October 2011.

183. In Figure 11B, the battery is designed to control a much longer time scale than in Figure 11A. The cycles of battery charge and discharge are correspondingly longer. Now the charge/discharge range for the battery is ± 200 kW. The ramp rate (i.e. the rate of change in the smoothed, blue curve) in the first 15 minutes is 600 kW/15 minutes, or 40 kW/minute (0.04 MW/minute).[43]

Benefit valuation

This type of power smoothing will be dictated by engineering considerations: the technical design will have to meet the requirements of the buyer – which is often that without some minimum level of smoothing, a VRE project will not get to a signed PPA. The costs of such an application must be regarded as a cost of the VRE itself. Attempting to assess the incremental benefit of the smoothing battery is of little value if the counterfactual of no smoothing battery is not in fact a feasible option.[44]

5.7 BENEFIT STACKING

184. How to optimize BESS to operate and capture multiple or "stacked" benefits is an active area of research[45]

185. As noted, BESS may have a range of different kinds of benefits, particularly in the case of stand-alone systems to provide a range of ancillary services in addition to load shifting. The idea is illustrated in Figure 12, where the principal function is to charge the battery fully in hours 11 to 14 (say charging during hours of maximum PV output), and then discharging during the peak hours 18-21. But during the remaining hours a variety of other services can be provided, as shown.

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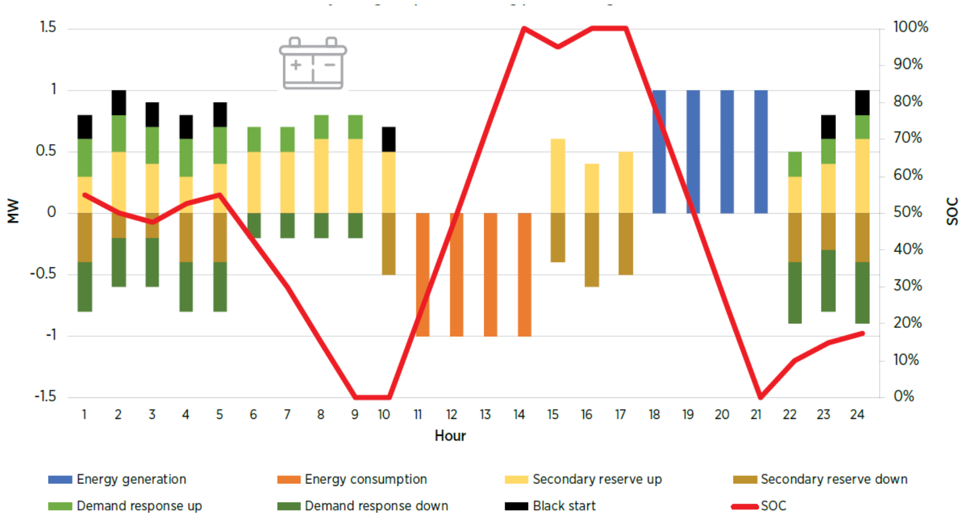
[43] It would seem that the battery system added to La Ola is oversized at 500kWh – 10% of the total daily output seems rather high: even when smoothing into longer cycles as shown in Figure 11B, the range of remaining battery storage varies only by some 15 kWh. This over-sizing was doubtless driven by the need to be very certain that the project would not disrupt the supply to the Island system

[44] In Cambodia, engineers at the State-owned utility stated things bluntly when presented with the concept of floating solar PV – only a showing that the technical design could meet the utility's ramp rate constraint would they consider such a large PV project.

[45] For more detailed discussion of stacking see for example, Hledik et al (2018) at a grid level and Fitzgerald et al (2015) and Sidhu et al (2018) (2018) which have strong distribution level focus.

Figure 12: Electricity storage dispatch including provision of grid services



Note: SOC = state of charge.

Source: IRENA *Electricity Storage Valuation Framework: Assessing System Value and Ensuring Project Viability*, March 2020.

186. It is hard to see how such a wide range of benefits can be quantified adequately and credibly (and also avoiding double counting), without the benefit of a production cost model to identify ancillary services benefits, and a capacity optimization model to identify associated capacity effects. The case study of Section 6.3 shows how FCAS and price arbitrage benefits would be combined in a standalone grid connected BESS.

187. In any event, in the absence of markets, hypothesizing valuations for many services, such as ancillary benefits, would require much speculation.

6 Case studies

188. The purpose of the case studies presented in this Section is not so much to highlight the findings of the studies - which the reader may in any event discover by reading the documents themselves, but to draw lessons from what has been done well and the shortcomings and issues of the economic and financial analysis methodologies applied.

Table 18: Focus of the case studies

	Case study	Focus
6.1	**Sri Lanka**: Distribution Licensee peak shaving	Difference between economic and financial analysis.
6.2	**Central African Republic**: BESS+PV for a small system	Use of BESS to shift some energy from peak hours of PV production to evening peak hours
6.3	**India**: Valuation of ancillary services and price arbitrage on the Indian energy exchange	Valuation of ancillary services
6.4	**India**: BESS+PV for a larger system	Valuation of ancillary services
6.5	**Vietnam:** Wind farm curtailment	BESS for reduction of VRE curtailment

6.1 DISTRIBUTION PEAK SHAVING (SRI LANKA)

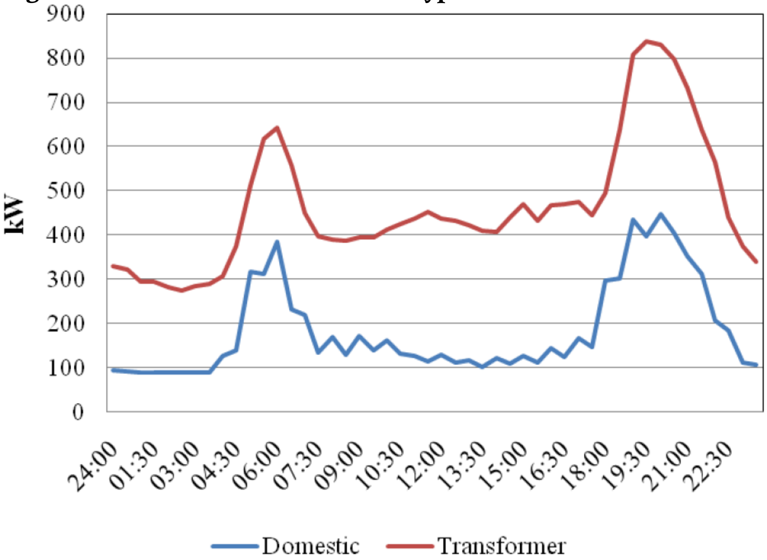
189. In 2015 the Sri Lanka Public Utilities Commission assessed the value of distribution-level BESS.[46] Although the study concluded that the costs of BESS (at that time) were still too high for investment into such system, **the study illustrates the difference between financial analysis of BESS (from the perspective of consumers and distribution companies), and the economic benefits of BESS (from the perspective of the country).**

Context

190. Sri Lanka's Sustainable Energy Authority had previously conducted a load research program for a sample of households connected to several distribution transformers. Figure 13 shows the typical load patterns observed: the evening peak is largely driven by lighting and TV loads.

[46] Sri Lanka Public Utilities Commission, *Use of Battery Energy Storage Systems for Peak Shaving during the time of National Night Peak*, Licensing Division, November 2015.

Figure 13: Load curves observed at typical distribution transformers



Source: SLPUC (2015)

191. The tariff to distribution licensees is shown in Table 19. There are 5 distribution Licensees in Sri Lanka, four that are business units of the Ceylon Electricity Board (CEB), and the separate Lanka Electricity Company (LECO). The rationale for a BESS is to avoid the higher energy tariff during peak hours, and to reduce the demand charge.

Table 19: Coincident demand charge and energy charge, 2014

	Energy Cost (LKR/kWh)						Capacity Cost (LKR/MW/Month)	
	1st Half			2nd Half			1st Half	2nd Half
	Day	Peak	Off-Peak	Day	Peak	Off-Peak		
CEB Reg 1	8.84	11.15	6.58	8.68	10.94	6.45	2,669,489.67	2,711,748.58
CEB Reg 2	5.68	7.16	4.22	5.57	7.03	4.14	2,669,489.67	2,711,748.58
CEB Reg 3	5.18	6.52	3.85	5.08	6.40	3.78	2,669,489.67	2,711,748.58
CEB Reg 4	6.31	7.95	4.69	6.19	7.80	4.60	2,669,489.67	2,711,748.58
LECO	10.41	13.12	7.74	10.22	12.88	7.59	2,669,489.67	2,711,748.58

source: SLPUC (2015)

192. From this one can calculate the energy charge benefit that can be obtained by each DL (Table 20)

Table 20: Price differences between peak and off-peak energy

	SLR/kWh	USc/kWh
CEB Reg1	3.61	2.78
CEB Reg2	2.32	1.78
CEB Reg3	2.11	1.62
CEB Reg4	2.57	1.98
LECO	4.24	3.26

Source: SLPUC (2015)

Methodology

193. Based on these cost assumptions, the financial analysis of a 25 kW/100 kWh BESS is presented as follows: the NPV at 10% is minus $78,200 (ERR minus 5%) (Table 21) - obviously not an attractive investment - though it noted that this excludes the indirect benefits from outage reduction, improved power quality, distribution investment deferral and the economic benefits of avoiding peaking plant capacity. Quantifying outage reductions and improved power quality are

indeed difficult to quantify and monetize, but some indicative estimates of potential avoided investment costs in distribution and generation capacity should not be too difficult to establish.

Table 21: Financial analysis, 25kW/100kWh rating

	Costs					Savings				
year	Investment (USD)	O&M Fixed (USD)	O&M Variable (USD)	Battery Replacement Cost (USD)	Total Cost (USD)	Reducing Coincident Peak Demand (USD)	Time shifting of Energy demand [Arbitrage] (USD)	Total Tangible Savings* (USD)	Net Savings (USD)	Present Value @ 10% discount rate (real)
0	(126,104)				(126,104)				(126,104)	
1		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
2		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
3		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
4		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
5		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
6		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
7		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
8		(1103.10)	(117.43)	(6250.00)	(7,471)	5,766	1,107	6,872	(598)	(78,211)
9		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
10		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
11		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
12		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
13		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
14		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	
15		(1103.10)	(117.43)		(1,221)	5,766	1,107	6,872	5,652	

Source: SLPUC (2015)

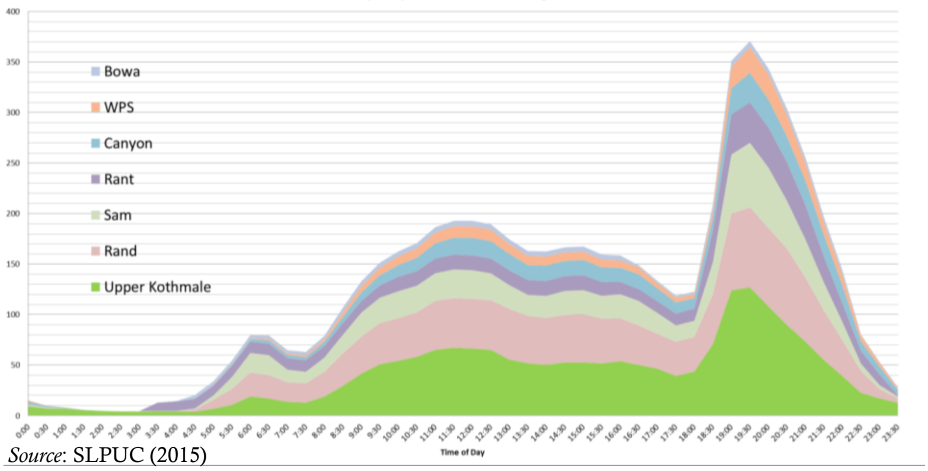
194. The analysis (prepared in 2015) assumed CAPEX of $5,044/kW for 25 kW BESS with 4 hours duration (or $1,261/kWh). The analysis then asked at what investment cost would the BESS be economic, and determined that the breakeven point (NPV=0 at 10% discount rate) was 1,602 $/kW for 4 hours duration ($401 kWh), a price at which, in 2015, it noted would be expected to be achieved by 2020.

195. Nevertheless, what the financial analysis did not address are the distributional impacts. The significant savings in the cost of electricity to the DLs are offset by a corresponding loss of revenue to the CEB.

Economic analysis

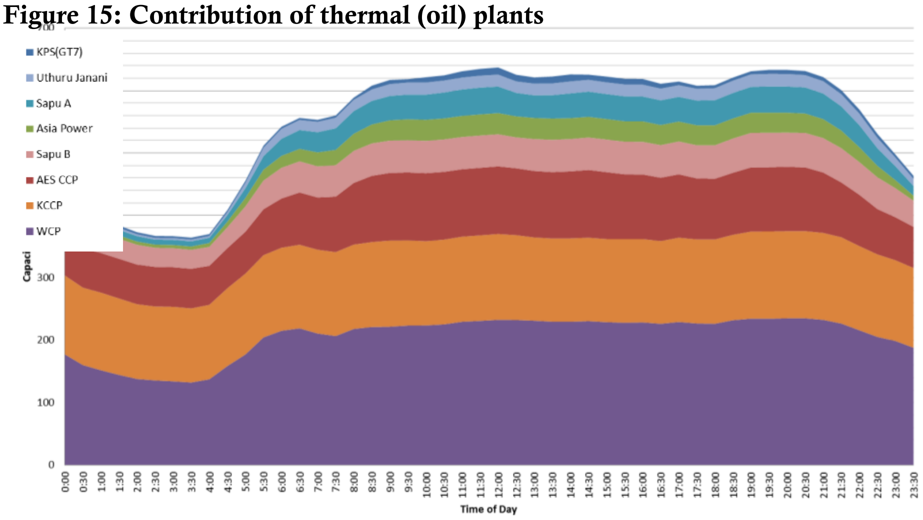
196. The case study then assesses the economic impacts (though no formal economic analysis is presented). It examines the contributions of different thermal and hydro generation to meeting the system load. It notes that hydro projects are used as peaking plants (Figure 14), whereas thermal projects are not (Figure 15).

Figure 14: Hydro plants ad peaking plants



Source: SLPUC (2015)

Figure 15: Contribution of thermal (oil) plants



source: SLPUC (2015)
[WCP=coal, the other thermal generators are all oil-fired combined cycle or open cycle]

197. From these observations, the report concludes that

> The value of an energy storage system is governed by the cost of the next best alternative means of providing the required service like peaking. In Sri Lanka the peaking power is provided by cheap hydro plants. Therefore direct benefit such as removing a portion of peak capacity required by expensive gas turbine cannot be considered in the prevailing situation.

198. Possible emission reductions are also noted:

> In case where BESS is charged with portion of energy produced from major hydro/renewables which are operating during the off peak hours (typically in rainy seasons), and BESS is discharged during peak hours where it avoids portion of peaking energy otherwise produced by GTs, then there is a case for possible emission reduction in [NOx, SO_2 and particulates][47]

199. We note as follows:

- The main conclusion of Figure 14 is not that hydro is used for peaking, but that there is substantial hydro storage in the system that allows dispatch during peak hours. In a sense, these hydro storage projects are themselves giant batteries that can discharge at any time of day (and some hydro projects have seasonal storage as well).
- Therefore, whatever hydro is not dispatched during the peak hours will be available for dispatch during the off-peak hours. However, because of roundtrip efficiency effects, more energy is needed in off-peak hours than is saved during peak hours, which means that additional thermal energy would be needed during these off-peak hours.
- While the SLPUC analysis does anticipate the need for replacement batteries after 7 years, the degradation of battery performance over time is not taken into account.

Study Conclusions

200. The study recommended that the SLPUC instruct its distribution licensees to initiate a pilot project to integrate several BESS systems at selected distribution transformers (out of some 26,000 distribution transformers) and evaluate/monitor the technical and economic

47 GHG emission reductions are not mentioned - their value likely exceeds the local environmental damage costs from GTs.

performance. This would "enable the licensees to jump start BESS projects when the storage costs are expected to be $500/kWh and reap the benefits identified in this report" (presumably for BESS with 4 hours of storage).

Reassessment

201. We have re-assessed this case study into the recommended format for economic analysis of power sector investment projects. Table 22 summarizes the assumptions, and Tables 23, 24, and 25 show the calculations. Note that the point here is not to debate the specific values of the assumptions chosen, but to present the *methodology* for analysis.

Table 22: Assumptions for distribution level peak shaving assessment

		units		source
[1]	**BESS**			
[2]	Battery size	[kW]	25	SLPUC
[3]	round trip efficiency	[ ]	0.88	SLPUC
[4]	annual battery degradation	[ ]	0.02	assumption
[5]	BESS cost	[$US]	40000	SLPUC study breakeven cost
[6]	Battery replacment cost	[US$]	6250	SLPUC
[7]	Fixed O&M/year	[$US]	1103	SLPUC
[8]	Variable O&M	[$/kWh]	0.00282	SLPUC
[10]	***DL***			
[11]	peak hour energy tariff	[$/kWh]	0.0656	SLPUC for LECO DL
[12]	off-peak energy tariff	[$/kWh]	0.033	SLPUC for LECO DL
[10]	***thermal generation***			
[11]	CT capacity cost	[$/kW]	900	CEB
[12]	variable generation cost	[$/kWh]	0.06	CEB
[13]	GHG emissions factor	[kg/kWh	0.55	Harmonised IFI emission factor
[15]	***Transmission***			
[16]	peak hour loss	[ ]	0.04	assumption (based on recent JICA study)
[17]	off-peak loss	[ ]	0.02	assumption (based on recent JICA study)
[14]	transmission LRMC	[$/kW]	200	assumption (based on recent JICA study)
[15]	**Economic analysis**			
[16]	Discount rate	[ ]	0.1	assumption

Source: BESS Spreadsheet Library {Distribution Level BESS.XLS}

Table 23: Financial analysis, perspective of the Distribution Licensee

				2020	2021	2022	2023	2024	2025	2026	2027	2028
				0	1	2	3	4	5	6	7	8
[1]	**Tariffs**											
[2]	Offpeak	[$/kWh]			0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033
[3]	Peak	[$/kWh]			0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066
[4]	Capacity tariff	[$/kW/month]										
[5]	**NO PROJECT**											
[6]	**energy purchased**											
[7]	Offpeak	[MWh]			0	0	0	0	0	0	0	0
[8]	Peak	[MWh]			38	38	38	38	38	38	38	38
[9]	Capacity charge	[MW]										
[10]	**energy costs**											
[11]	Offpeak	[$US 10^3]	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[12]	Peak	[$US 10^3]	22.9	0.0	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49
[13]	Capacity charge	[$US 10^3]	57.3	0.0	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25
[14]	total	[$US 10^3]	80.1	0.0	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
[15]	**WITH PROJECT**											
[16]	**energy purchased**											
[17]	Offpeak	[MWh]			41.48	40.65	39.83	39.04	38.26	37.49	36.74	36.01
[18]	Peak	[GWh]			0.00	0.73	1.45	2.15	2.83	3.51	4.17	4.81
[19]	capacity charge	[MW]										
[20]	**Energy cost**											
[21]	Offpeak	[$US 10^3]	11.2	0.0	1.37	1.34	1.31	1.29	1.26	1.24	1.21	1.19
[22]	Peak	[$US 10^3]	2.4	0.0	0.00	0.05	0.09	0.14	0.19	0.23	0.27	0.32
[23]	Capacity charge	[$US 10^3]		0.0								
[24]	total energy cost	[$US 10^3]	13.6	0.0	1.37	1.39	1.41	1.43	1.45	1.47	1.49	1.50
[25]	**BESS**											
[26]	CAPEX	[$US 10^3]	37.7	40.0								
[27]	Battery replaceme	[$US 10^3]	3.7	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.25
[28]	OPEX: Fixed	[$US 10^3]	10.1	0.0	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
[29]	OPEX: variable	[$US 10^3]	1.1	0.0	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
[30]	total costs	[$US 10^3]	66.2	40.0	2.59	2.61	2.63	2.65	2.67	2.69	2.71	8.97
[31]	Net cash flows	[$US 10^3]	13.9	-40.00	6.16	6.13	6.11	6.10	6.08	6.06	6.04	-0.23
[32]	FIRR, on BESS investment		11.4%									

Note: Spreadsheet is for 15 years; first 8 years shown here in the interest of legibility

Source: BESS Spreadsheet Library

Table 24: Financial analysis, Ceylon Electricity Board

Table 8: Financial analysis: Utility				Ceylon Electricity Board								
				2020	2021	2022	2023	2024	2025	2026	2027	2028
				0	1	2	3	4	5	6	7	8
[1]	**NO PROJECT**											
[2]	**revenue**											
[3]	peak Sales to DL	[$US 10^3]			2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
[4]	Capacity Charge t	[$US 10^3]			6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
[5]	**Costs**											
[6]	transmission CAF	[$US 10^3]		5.00								
[7]	generation CAPE	[$US 10^3]		22.50								
[8]	***generation cost***											
[9]	OCCT	[$US 10^3]										
[10]	CCCT	[$US 10^3]			-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1
[11]	coal	[$US 10^3]										
[12]	**Net revenue**	**[$US 10^3]**	***87.2***	**27.50**	**6.68**	**6.68**	**6.68**	**6.68**	**6.68**	**6.68**	**6.68**	**6.68**
[13]	**WITH PROJECT**											
[14]	**revenue**											
[15]	peak Sales to DL	[$US 10^3]		0.0	0.0	0.7	1.4	2.1	2.8	3.5	4.2	4.8
[16]	Capacity Charge t	[$US 10^3]										
[17]	incremental off-pe	[$US 10^3]		0.0	1.4	1.3	1.3	1.3	1.3	1.2	1.2	1.2
[18]	**generation cost**											
[19]	OCCT	[$US 10^3]										
[20]	CCCT	[$US 10^3]										
[21]	coal	[$US 10^3]										
[22]	**Net revenue**	**[$US 10^3]**	***47.8***	**0.00**	**1.37**	**2.07**	**2.76**	**3.43**	**4.10**	**4.74**	**5.38**	**6.00**
[23]	**Net cash flow**	**[$US 10^3]**	***-39.3***	**-27.50**	**-5.31**	**-4.61**	**-3.92**	**-3.25**	**-2.58**	**-1.94**	**-1.30**	**-0.68**
[24]	FIRR	[ ]	***negative***									

Source: BESS Spreadsheet Library {{Distribution Level BESS.XLS}

Table 25: Economic analysis

Table 7: Economic analysis				Sri Lanka								
				2020	2021	2022	2023	2024	2025	2026	2027	2028
			NPV	0	1	2	3	4	5	6	7	8
[1]	**Costs**											
[2]	BESS capex	[$US 10^3]	***-37.7***	-40.00								
[3]	Replacement batte	[$US 10^3]	***-3.7***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-6.25
[4]	incrmental genera	[$US 10^3]	***-2.0***	0.00	0.00	-0.04	-0.08	-0.12	-0.16	-0.19	-0.23	-0.27
[5]	**Benefits**	[$US 10^3]	***0.0***									
[6]	Avoided generati	[$US 10^3]	***21.2***	22.50								
[7]	Avoided transmis	[$US 10^3]	***4.7***	5.00								
[8]	**Net economic flo**	**[$US 10^3]**	***-17.5***	**-12.50**	**0.00**	**-0.04**	**-0.08**	**-0.12**	**-0.16**	**-0.19**	**-0.23**	**-6.52**
[9]	ERR		***negative***									
[10]	**GHG emissions valuation**											
[11]	Social value of car	[$/tonCO2e]			50	52.1	52.1	52.1	52.1	52.1	52.1	52.1
[12]	Change in emissio	[tons]			-12839	-12589	-12343	-12103	-11867	-11636	-11410	-11188
[13]		[$US 10^3]	***-0.5***	0	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05
[14]	**net flows incl.GF**	**[$US 10^3]**	***-18.0***	**-12.50**	**-0.05**	**-0.09**	**-0.13**	**-0.17**	**-0.21**	**-0.25**	**-0.28**	**-6.57**
[15]	ERR		***negative***									

Source: BESS Spreadsheet Library {Distribution Level BESS.XLS}

202. The following is to be noted:

- Hydro previously dispatched into the peak is simply kept in storage, and is now used for battery charging during the off-peak period. Since all available hydro is already used, the net impact of the BESS round-trip efficiency loss is to require some additional *off*-peak thermal generation for charging energy.
- The analysis takes into account that transmission losses during peak hours are greater than off-peak hours (but this is not nearly great enough to cancel the round-trip efficiency effect).
- The BESS may be financially efficient for the DLs, but their financial gain is the CEB's financial loss.
- GHG emissions increase
- Even if the project were financially feasible for the DL, the economic analysis shows a net *loss*.
- There are big differences across seasons: a more detailed study would need to look at this: a growing renewables share has raised curtailment issues particularly for wind, so it is possible that charging energy could be sourced by wind in the windy (monsoon) season. But this would simply mean that the additional thermal generation cost would be zero.
- As noted by SLPUC, there are other benefits (notably improvements to power quality and reliability) not reflected in the analysis. But it seems unlikely that these would be sufficient to offset the net costs.

Lessons of the case study

203. The lessons are several:

- the first requirement for reliable conclusions about the merit of BESS is a **detailed energy balance that extends to the entire system**, not just to the project area.
- **A detailed energy balance should be accompanied by a detailed cash flow balance for all the affected stakeholders**, since the financial gain to the DL (in this case) is offset by a loss to the Single Buyer (CEB): to the extent that these revenue losses to CEB are eventually offset by changes in the tariff structure, then that in turn changes the motivation for the BESS investment in the first place.[48]

- Even if the cost of BESS continues to fall, and distribution and consumer level BESS become attractive as a business proposition (for distribution licensees or consumers), **whether or not the *economic* benefits are also positive depends** on (1) the extent of hydro in the system, and especially on the extent of hydro storage projects (2) the mix of thermal generation, and (3) whether the deferral of distribution and transmission network CAPEX is actually achieved.

6.2 PV INTEGRATION INTO A SMALL MAINLY HYDRO SYSTEM (CENTRAL AFRICAN REPUBLIC)

Context

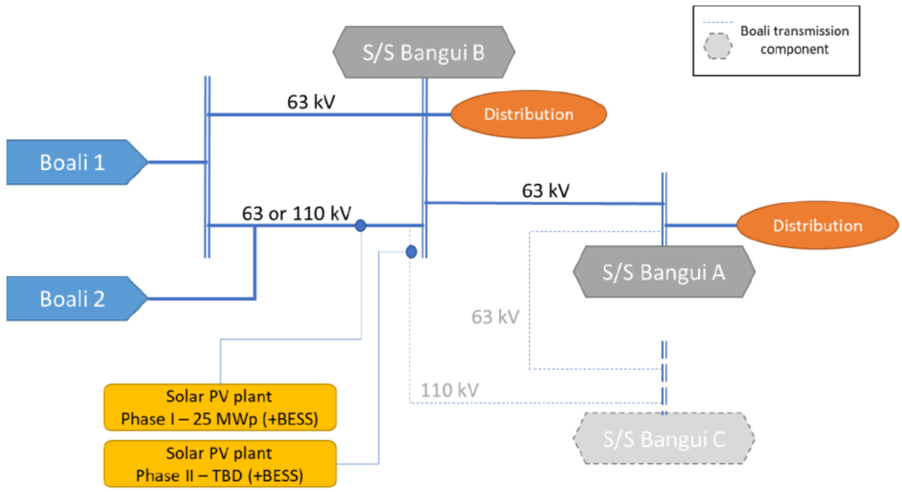
204. The city Bangui is the most populated city in the Central African Republic (CAR). With a total population of around 700,000 inhabitants, the capital city is the only one in the country connected to a relatively stable grid. Power is principally generated from hydro plants located in

48 On the other hand, if the utility simply increases tariff to offset revenue losses (the consequence in a regulated utility whose revenue requirements may fall more slowly than just the variable cost of generation), then the motivation for consumer-scale batteries increases, leading to a so-called "death spiral" for utilities. The literature on this is growing, in both academic and engineering circles. For a good article in the US, see, e.g., *T&D World* (https://www.tdworld.com/home/article/20969092/grid-death-spiral). This article also discusses new utility business models such as "Virtual Power Plants" - which are set up to manage networks of consumer scale distributed renewable energy production and storage, including any available vehicle-to- grid storage.

Boali, around 40 km, northwest of the city. The available capacity from hydro is just 18.4 MW (8.5 from Boali 1 and 9.9 MW from Boali 2). In addition, there is a small old diesel plant located in the center of the city that produces around 2.2 MW. As a result, the total generation is totally insufficient to cover a demand estimated in 2018 at 45 MW (Figure 16).

205. A pre-feasibility study examined the option of a PV project at Danzi, to be connected to the Bangui B S/S. The question posed was whether and how much battery storage should accompany the 25 MWp scale PV project.[49]

Figure 16: The Bangui network



Source: World Bank, 2018. *Pre-feasibility study for a PV+battery storage in the city of Bangui (Central African Republic).*

206. The grid in Bangui is composed of two 63 kV lines connecting the Boali system (Boali 1 and 2) with the substation Bangui B. One of these lines (from Boali 2) is being currently upgraded to 110 kV. In addition, there is an urban 63 kV line connecting Bangui B with the central substation Bangui A in the center of the city. From these two substations, there are several MV lines that supply to the distribution network and, therefore, the consumers.

207. This pre-feasibility study defined the size of the PV and BESS, with the annual generation then passed to the economic analysis model used for the PAD (with a CAPEX for the PV and BESS of $44,9million).[50] The project also included a component for rehabilitation of the distribution system to being down T&D losses from 33 to 25% (CAPEX $10.6 million).

Methodology

208. The starting point is to assess the solar resource, for which the SolarGIS database is used. This either makes use of ground based measurements at well controlled meteorological stations or uses processed satellite imagery. A minimum of 10 years of data is recommended to provide a representative value for the long-term average: for the CAR assessment 24 years of data (1994-2017) was used, providing data at 15-minute time intervals. This information is assembled in an

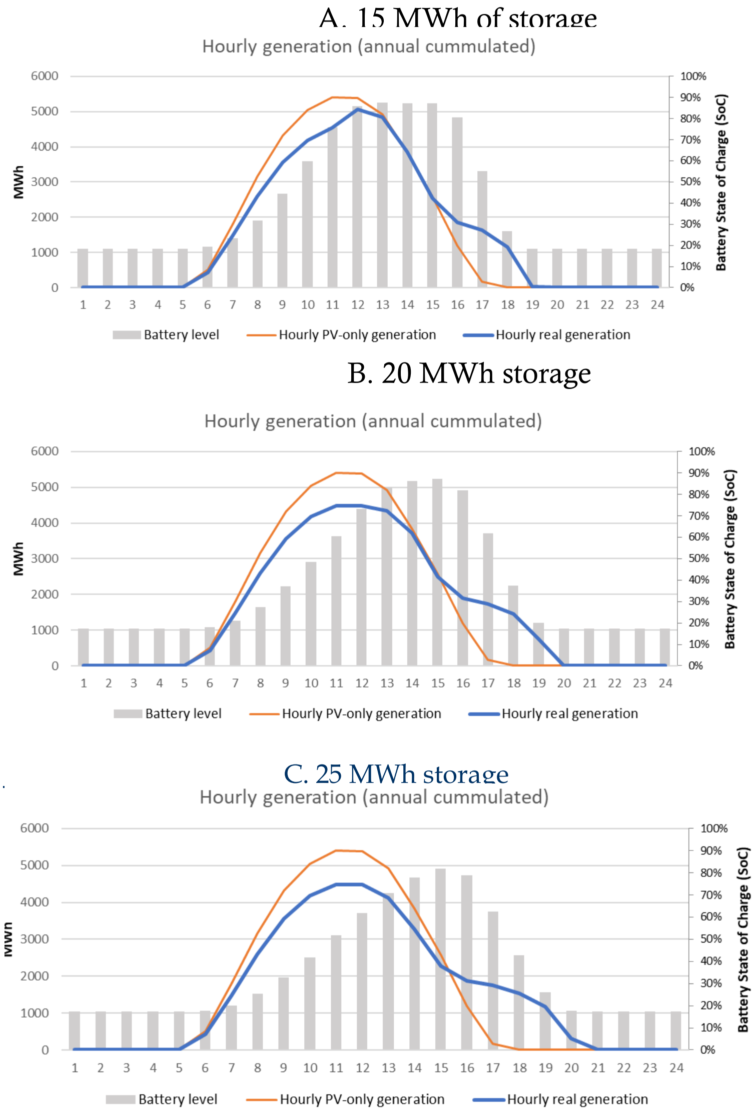
49 World Bank, 2018. *Pre-feasibility study for a PV+battery storage in the city of Bangui (Central African Republic).*

50 World Bank, 2019. *Emergency Electricity Supply and Access Project* (Puracell), Report PAD 2741, Feb14, 2019.

EXCEL database, which can be used to provide PV generation for systems of given size, for which 25 MW was selected for a first implementation phase.[51]

209. Onto this time series one then superimposes a BESS of given size and RT efficiency, simulating the performance of the BESS for each time step. Figure 17 shows the results for 15,20 and 25MWh storage - showing PV generation, net generation after charging and discharging, and battery system state of charge (cumulated over the year)

Figure 17: Generation profiles for 25MW PV

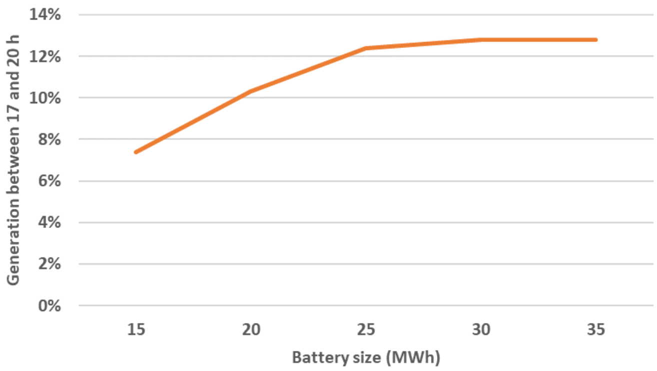


Source: World Bank, 2018. *Pre-feasibility study for a PV+battery storage in the city of Bangui (Central African Republic).*

210. A sensitivity analysis showed that beyond 25 MWh, the percentage of energy delivered to the grid between 17:00 and 20:00 does not increase significantly (Figure 18). Based on this assessment the project proposed for 25MWh of storage.

51 The spreadsheet is large: one year of data at 15-minute time steps has 35,040 rows.

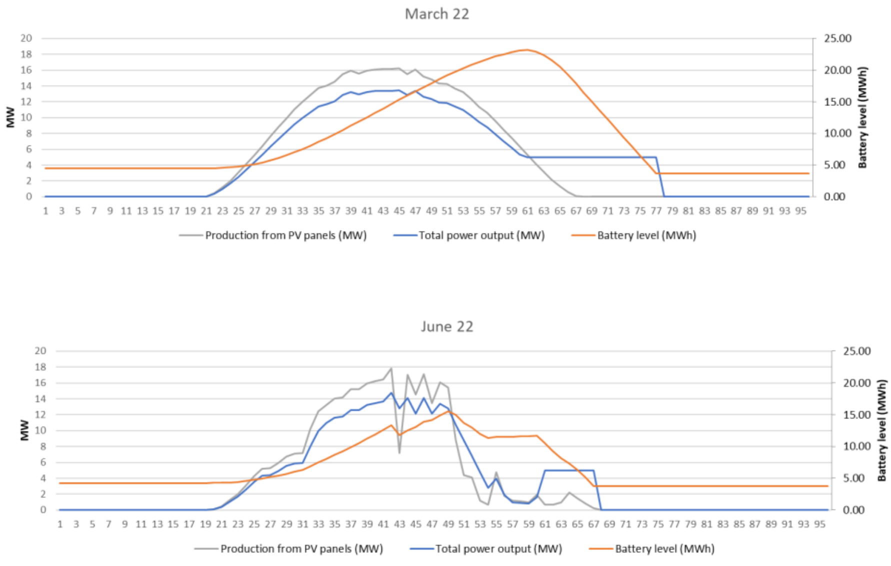
Figure 18: Percentage of generation delivered during peak hours



Source: World Bank, 2018. *Pre-feasibility study for a PV+battery storage in the city of Bangui (Central African Republic).*

211. The hourly generation profiles vary considerably across the seasons (Figure19): particularly in June (the wet season) there is high variation in solar radiation, which implies high utilization of battery storage for stability purposes, which in turn means the battery is practically exhausted at sunset - and hence allows little coverage of peak demand beyond 16:00. In the other three seasons there is little need for stabilization: the September and December 22 curves are similar to the for March 22, so allowing a fairly constant 5 MW output for a further four hours (between 16:00 and 20:00).

Figure 19: Hourly generation profiles by season



Source: World Bank, 2018. *Pre-feasibility study for a PV+battery storage in the city of Bangui (Central African Republic).*

212. The difficulty of this analysis is that while the choice of 25MWh storage is reasonable, may well be plausible, the differing value of energy in peak and off-peak hours is not incorporated into the decision: increasing storage implies increases in CAPEX and OPEX whose cost must be made up in the difference in value of peak and off-peak power.

213. Table 26 shows the annual generation balance for the 25MWh BESS. The highlighted values with the annual totals are passed to the economic analysis, as discussed below.

Table 26: Output of the detailed CAR model

	Hourly PV-only generation	Hourly real generation	Peak	Battery level	charging energy	energy discharged
	[1]	[2]	[3]	[4]	[5]	[6]
1	0	0	0	0.172		
2	0	0	0	0.172		
3	0	0	0	0.172		
4	0	0	0	0.172		
5	7	6	0	0.172		
6	516	427	0	0.177	88	
7	1788	1478	0	0.201	311	
8	3149	2591	0	0.252	558	
9	4318	3558	0	0.328	760	
10	5042	4176	0	0.419	866	
11	5406	4492	0	0.517	914	
12	5377	4480	0	0.617	897	
13	4914	4130	0	0.708	784	
14	3847	3288	0	0.777	559	
15	2572	2276	0	0.820	297	
16	1192	1871	0	0.787		-680
17	170	1752	1752	0.626		-1582
18	0	1529	1529	0.426		-1529
19	0	1178	1178	0.261		-1178
20	0	309	309	0.176		-309
21	0	0	0	0.172		0
22	0	0	0	0.172		0
23	0	0	0	0.172		0
24	0	0	0	0.172		0
total	38298	37540	4767		6034	-5277

source: BESS Spreadsheet Library {BESS+VRE.XLS}

PAD economic analysis

214. A snapshot of the economic analysis that is the basis for the PAD is shown in Table 27. The spreadsheet itself is exemplary and follows best practice as set out in the PSG.[52] Assumptions are clearly stated and documented. All of the supporting tables are well presented and easy to follow, and the model is available in the project files.

Table 27: PAD Economic analysis, CAR 26MW+25MWh BESS

Table 15 Economic analysis (at constant prices) CAR 25 MWp and 25 MWh BESS solar power plant													
	Treat as a incremental electrification project			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
		NPV											
[1]	**Costs**												
[2]	investment cost	(30,669)	[XAFm]	(5,968)	(18,081)	-	-	-	-	(4,140)	-	-	-
[3]	O&M Costs	(7,840)	[XAFm]	-	-	(436)	(441)	(445)	(449)	(454)	(458)	(463)	(467)
[4]	**total economic costs**		[XAFm]	(5,968)	(18,081)	(436)	(441)	(445)	(449)	(4,594)	(458)	(463)	(467)
[6]	**Benefits**												
[7]	**Economic Valuation of Incremental Ener**		[XAFm]	-	-	4,676	4,649	4,619	4,587	4,586	4,549	4,512	4,472
[8]	**Collection rate**		[ ]	0.67	1	0.71	0.74	0.77	0.80	0.80	0.80	0.80	0.80
[9]	**total benefits**		[XAFm]	-	-	3,320	3,440	3,556	3,669	3,669	3,640	3,609	3,578
[11]	**total economic flows**		[XAFm]	(5,968)	(18,081)	2,884	2,999	3,111	3,220	(925)	3,181	3,147	3,111
[12]	ERR		[ ]	9%									
[13]	local environmental impacts		[XAFm]	-	-	2,131	2,139	2,146	2,152	2,172	2,176	2,179	2,182
[14]	economic flows including local env.		[XAFm]	(5,968)	(18,081)	5,015	5,138	5,257	5,372	1,247	5,358	5,326	5,292
[15]	ERR including local env.		[ ]	19%									
[16]	avoided GHG emissions		[XAFm]	-	-	527	542	557	572	591	605	620	634
[17]	**econmic flows incl. global GHG benefits**		[XAFm]	(5,968)	(18,081)	5,541	5,680	5,814	5,944	1,838	5,963	5,946	5,926
[18]	ERR including global GHG		[ ]	21%									

`*Source*: BESS Spreadsheet Library {BESS+VRE.XLS}

215. The analysis as presented invites several comments:

- The ERR of the combined PV+25MWh BESS is plausible. The economic benefits are calculated by multiplying the annual energy delivered to consumer by the assumed willingness-to-pay, taken as the weighted average of the cost of self-generation and actual tariff.

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52 The only thing we have changed in this snapshot is the numeraire: kWh have been replaced with GWh, US$ by million US$, and XAF by million XAF - which makes the numbers much easier to read.

- The methodology used assumes that the economic benefit is reduced by the collection rate. But the collection rate is relevant only for the *financial* analysis (i.e. what proportion of billed energy is collected). This is energy that is consumed by consumers, and they therefore enjoy the economic benefit even if they do not pay for it (though their willingness to pay may also be lower).
- The sensitivity and switching value analysis is also well presented, including the sensitivity to battery replacement frequency and WTP.
- However, what the PAD economic analysis itself does *not* present is the more basic question of battery size, and what is the *incremental* benefit of the BESS. Since the RT efficiency of the battery is 88%, it necessarily follows that peak hour energy needs to be more valuable than off-peak energy, and therefore the incremental benefits of the BESS cannot be assessed using a constant WTP.

Reassessment

216. Table 28 shows the energy balance calculations, with a detailed breakdown of the various categories of losses.[53] Note the first-year entries for the PV+BESS system are taken directly from the summary table of the technical model (Table 26, above). Different BESS sizes and performance would require recalculation in the technical model, and then transferred to the this energy balance table.

Table 28: Reassessment, CAR Energy balance

				NPV	2020	2021	2022	2023	2024	2025	2026	2027
					-1	0	1	2	3	4	5	6
[1]	**Energy Balance**											
[2]	PV	0.005	[GWh]				38.30	38.11	37.92	37.73	37.54	37.35
[3]	-less input to battery		[GWh]				-6.03	-6.03	-6.03	-6.03	-6.03	-6.03
[4]	+battery output	0.002	[GWh]				5.30	5.29	5.28	5.27	5.26	5.25
[5]	-less curtailments, if any		[GWh]				0.00	0.00	0.00	0.00	0.00	0.00
[6]	Net output [at meter]		[GWh]	451.8	0.0	0.0	37.57	37.37	37.17	36.97	36.77	36.57
[8]	*technical T&D loss rate*	4	[ ]				0.22	0.22	0.22	0.22	0.22	0.22
[9]	-technical losses		[GWh]				-8.3	-8.2	-8.2	-8.1	-8.1	-8.0
[10]	=delivered (consumed)		[GWh]	381.1			29.3	29.1	29.0	28.8	28.7	28.5
[11]	*-non-technical losses*		[ ]				0.13	0.13	0.13	0.13	0.13	0.13
[12]	=billed energy		[GWh]				29.4	29.3	29.1	29.0	28.8	28.7
[13]	*collection loss rate*		[ ]				0.3	0.3	0.3	0.3	0.3	0.3
[14]	-collection losses		[GWh]				-8.8	-8.8	-8.7	-8.7	-8.6	-8.6
[15]	=total energy for revenue		[GWh]				20.6	20.5	20.4	20.3	20.2	20.1
[16]	energy in peak hours	0	[GWh]				0.0	0.0	0.0	0.0	0.0	0.0
[17]	energy in off-peak hours		[GWh]				20.6	20.5	20.4	20.3	20.2	20.1

Source: BESS Spreadsheet Library {BESS+VRE.XLS}

217. The table of economic flows is shown in Table 29 - here shown using US$ as the numeraire. The main difference to the presentation is that we make a distinction between the value of energy during peak hours and off-peak hours.

218. In the PAD analysis, a single value was used for all energy, taken as the average of 75% of the self-gen cost, and 25% of the tariff. In this presentation, we assume peak hour energy at the self-gen cost, and off-peak energy at the tariff. Under these more conservative assumptions, the ERR is somewhat lower than that presented in the PAD. However, the purpose here is not to disagree with the assumptions made by others, but to convey the importance of the methodology.

53 Many of the tables in this report's spreadsheet pro fromas are exactly (or mostly) the same as in the CAR PAD model, such as the tables for macroeconomic assumptions, fuel price build up, battery cost price degression, and the financial analysis.

Table 29: Economic flows, PV+BESS assessment

Table 4: Economic analysis: US$ [constant prices]				NPV	2020	2021	2022	2023	2024	2025	2026	2027
					-1	0	1	2	3	4	5	6
[1]	*Benefits*											
[2]	Peak hour benefit		[USc/kWh]		*0.0*	*0.0*	*44.5*	*44.0*	*43.8*	*43.3*	*42.8*	*42.3*
[3]			[$USm]	*18.8*	0.0	0.0	1.7	1.7	1.6	1.6	1.6	1.6
[4]	Off-peak benefit		[USc/kWh]		*0.0*	*0.0*	*15.4*	*15.2*	*15.1*	*14.9*	*14.8*	*14.6*
[5]			[$USm]	*43.6*	0.0	0.0	3.9	3.9	3.8	3.7	3.7	3.6
[6]	**total benefit**		[$USm]	*62.4*	0.0	0.0	5.6	5.5	5.4	5.4	5.3	5.2
[7]	Levelized benefit		[USc/kWh]	*13.8*								
[8]	**Costs**											
[9]	PV CAPEX		[$USm]	*-34.5*	-9.2	-27.7						
[10]	PV OPEX	0.18	[$USm]	*-2.2*	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
[11]	insurance	0.75%	[$USm]	*-3.5*	0.0	0.0	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
[12]	BESS CAPEX	10	[$USm]	*-9.3*	-2.5	-7.5						
[13]	Battery Replacement	5	[$USm]	*-11.4*	0.0	0.0	0.00	0.00	0.00	0.00	-7.35	0.00
[14]	BESS OPEX	0.25	[$USm]	*-3.1*	0.0	0.0	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
[15]	insurance	0.75%	[$USm]	*-0.9*	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
[16]	Total cost		[$USm]	*-65.0*	-11.7	-35.2	-0.8	-0.8	-0.8	-0.8	-8.1	-0.8
[17]	LCoE		[USc/kWh]	*14.4*								
[18]	**Net economic flows**		**[$USm]**	*-2.4*	**-11.7**	**-35.2**	**4.8**	**4.7**	**4.7**	**4.6**	**-2.8**	**4.4**
[19]	ERR		[ ]	3.3%								

Source: BESS Spreadsheet Library

Lessons of the case study

219. The lessons of the study are as follows:

- The very careful electricity balances presented in the pre-feasibility study are exemplary, and define best practice. **The procedure should be adopted as the basis for all projects of this type.**
- Good as is the energy balance work, the optimal battery size was not selected on the basis of a cost-benefit analysis, but based on a purely qualitative reasoning of maximizing generation during evening peak hours (a process that the preFS calls "technical optimization"). However plausible the recommended BESS size, it would be better to explicitly value the difference between peak and off-peak generation, to be balanced against the incremental storage cost, and present this analysis as part of the economic appraisal. One may also wish to look at a range of time shifts - for example 5 MW x 5 evening hours v, or 4 MW for 6.25 hours.
- It may be argued that there is no empirical basis for a time-of-use valuation in the CAR, and certainly in the absence a ToU *tariff,* the financial impact of BESS will always be negative (the more storage that is provided the greater the CAPEX, and the greater the kWh lost due to RT efficiency effects - neither of which is made up by greater peak period revenue).[54]
- But that does not apply to the economic analysis. With some cost of BESS storage defined, at the very least a back-calculation of the necessary tariff differential between off-peak and peak kWh should be presented.

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6.3 ECONOMICS OF BATTERY STORAGE FOR PRICE ARBITRAGE AND FREQUENCY RELATED ANCILLARY SERVICE IN INDIA[55]

Context

220. This case study examined how much a notional 1 MWh/2 MW BESS[56] would earn if the storage operator were a market participant and were able to charge buying electricity on the

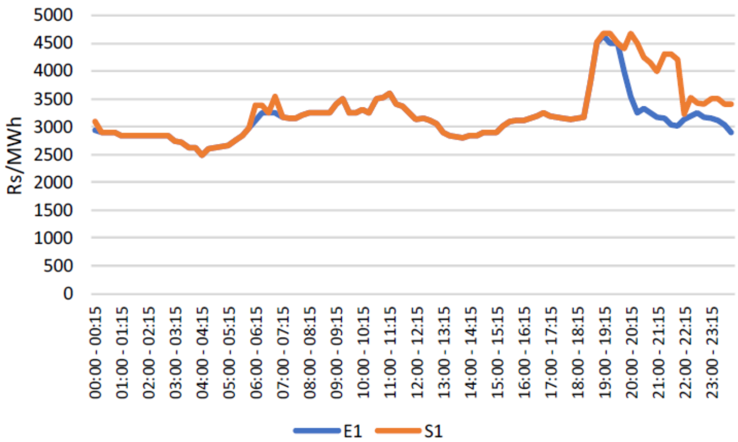
54 Except in the case where the battery also serves to eliminate or reduce curtailments - in which case batteries may well improve financial returns even without a ToU tariff.

55 D. Chattopadhyay. *The Economics of Battery Storage using IEX prices from 2012-2018.*

Indian Energy Exchange (IEX) during low price periods, and sell during high price periods (net of a 15% loss or 85% RT efficiency). [57]

221. On a typical day, prices across 96 15-minute periods and across the zones do not show significant variability – see for example prices from March 15, 2019 in Figure 20. Prices on average across 13 zones over the past 7 financial years have averaged around IRs 3,177/MWh (4.5 USc/kWh)

Figure 20: IEX prices for zones E1 and S1 on 15th March 2019



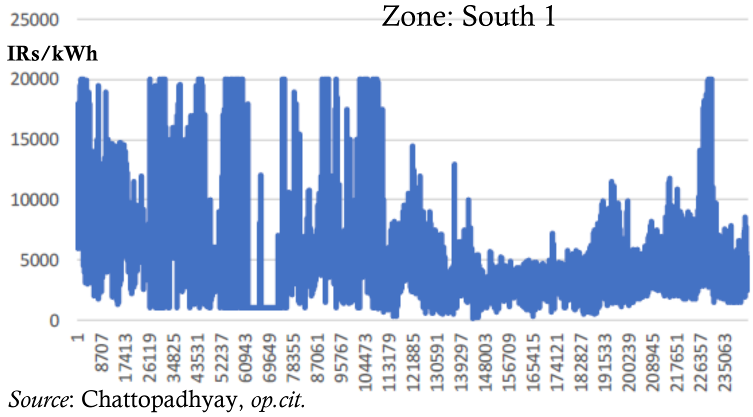
Source: Chattopadhyay, *op.cit.*

222. When one examines the full-time series prices within and across regions, one observes periods of extreme variability as demand exceeds supply and/or transmission constraints across zones bind. (Figure 21).

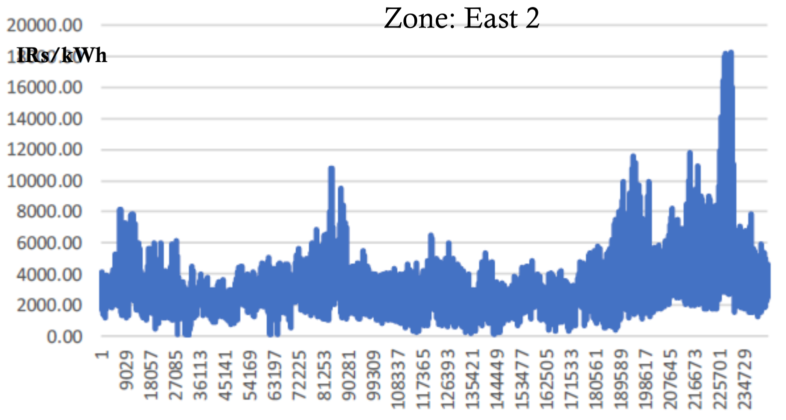
56 i.e., storage capacity is 1 MWh but the peak output for discharge could be 2 MW. An injection rate constraint that requires 1 MWh storage to be charged over a minimum 4-hour period was also used.

57 This is an unusual sizing for an energy management application like arbitrage. More typical would be 2 to 4 hours or more.

Figure 21: Prices in Zones E1 and S1 for all 15-minute periods from April 1, 2012 – March 15, 2019



Source: Chattopadhyay, *op.cit.*



Source: Chattopadhyay, *op.cit.*

223. On most days a battery or any other kind of storage would have very little arbitrage opportunity (for example in March when the price difference is below IRs 1,500 over the day or just over $20 USc/kWh. On other days revenue may be an order of magnitude higher.

224. In addition, stored energy on a battery can also provide frequency control ancillary services (FCAS). There is no formal market for FCAS in India at present although a proposal is currently under consideration by the regulator. Three cases are considered: (a) zero FCAS price (b) a low price of $2/MWh as observed internationally in markets with significant flexibility; and (c) double that price to $4/MWh that essentially allows for a premium for volatility in FCAS prices due to supply shortage during stressed conditions which can indeed be very significant. [58]

Modeling

225. The World Bank Electricity Planning model (EPM) was used to optimize the revenue from a combined FCAS and arbitrage over a seven year period for all 13 regions.[59] EPM decides when to fill the battery up by charging during low price periods taking into consideration the max injection rate (1 MW) and the ramp rate for injection (25% per hour). The cycle efficiency is

58 It is worth noting that the ADB BESS economic analysis example (see below) uses $16.7/MW-h, so four times higher!

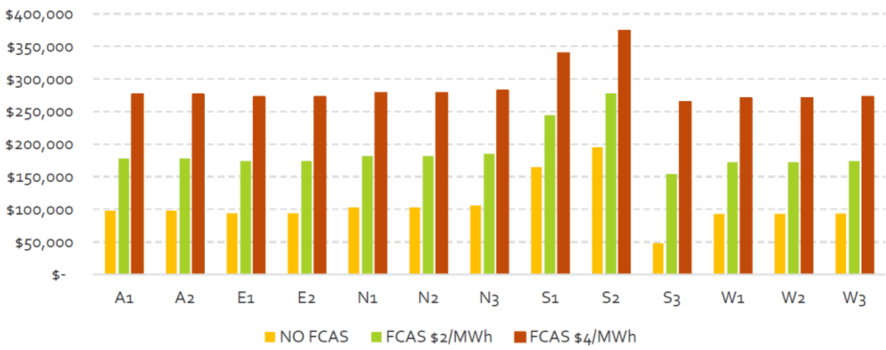
59 The model is an LP using the GAMS language. Although there are tens of millions of variables and constraints in the model (with 30+ million non-zeroes in the LP matrix), the model solves in approx. 20 minutes on a basic laptop. The relevant part of the GAMS code is in Chattopadhyay, *op.cit.* (2019).

considered in the storage balance. Discharge rate is 2 MW and the model will look for opportunity to generate during high price periods, but also has the advantage of perfect foresight in doing so - a limitation of such models (in general).

226. The other limitation of the model is that FCAS is allowed regardless of the level of charge. The overall effect is that the revenue estimates are optimistic in knowing the prices with perfection and allowing the entire MWh to be available for FCAS with a 100% charge[60] – both issues can be corrected using a more sophisticated model but goes beyond the scope of the immediate purpose of establishing a benchmark for revenue gap.

227. Figure 22 shows the total revenue estimates for the 13 regions of the IEX. Locating a BESS in a relatively constrained region (namely S2) makes sense over other regions as it can ease at least a small part of the congestion and offers a better energy arbitrage opportunity. One also observes that FCAS revenues are substantially greater than arbitrage and would likely be an important part of a business case.

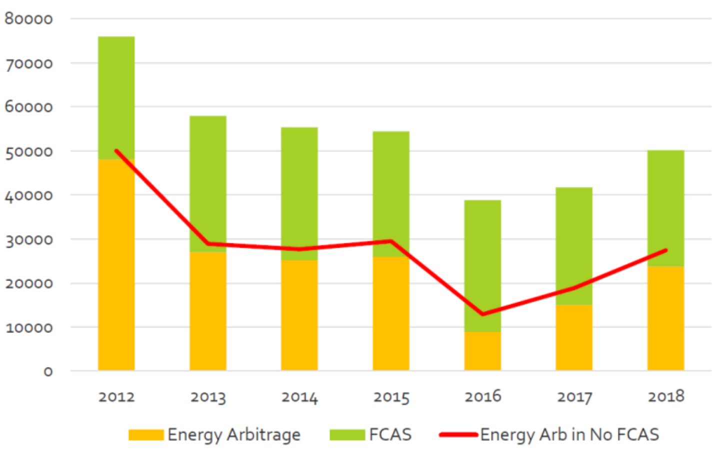
Figure 22: Revenue estimates for the 13-IEX regions of India, FY2012-2017



Source: Chattopadhyay, *op.cit.*

228. Figure 23 shows the decomposition of revenue in region S2 over the 7-year period, based on FCAS revenue of $4/MW, for a case of energy arbitrage only (red line), and a case of combined FCAS and energy arbitrage revenue.

Figure 23 : Revenue decomposition, Region S2



Source: Chattopadhyay, *op.cit.*

60 This can be adjusted: several studies suggest 80-90%.

229. Note than the revenue from energy arbitrage in the combined arbitrage + FCAS case is somewhat smaller than in the case of energy arbitrage alone. No formal economic analysis is presented, except to note that energy arbitrage alone would only recover 50% of the battery cost.

230. Indeed, the paper does not contain sufficient information to present our standard format economic analysis. However, the ADB BESS handbook contains as *its* sample financial and economic analysis a BESS designed for FCAS which does present at least some of the necessary detail - albeit limited to regulation.

The ADB FCAS economic analysis

231. The analysis is taken from a Korean source, which in turn is based on the enhanced frequency response (EFR) market prices in the United Kingdom, stated as £11.97/MW, or 16.725 US$/MW. This is four times higher than the high estimate of $4/MW in the above Indian example, so it is hardly surprising that it claims a high rate of financial return! The assumptions are shown in Table 30.

Table 30: ADB FCAS analysis assumptions

		units		source
[1]	**BESS**			ADB
[2]	Battery	[$USm]	2.00	5MWh@$0.4m per MWh
[3]	Power control system (PCS)	[$USm]	3.00	20MW@$0.15m per MW
[4]	HV tranformer	[$USm]	0.50	220kV/33kV, 30 MVA
[5]	MV transformer	[$USm]	0.48	33kV/0,44, 5MVA
[6]	storage containers	[$USm]	0.60	6 x 0.05 Battery, 6 x 0.05 PC
[7]	Installation	[$USm]	0.10	
[8]	total capital cost	[$USm]	6.68	
[9]	Battery replacement, year 5	[ ]	0.50	fraction of present price
[10]	**Energy balance**			
[11]	Cycles per day	[ ]	8	
[12]	depth of discharge	[ ]	0.8	
[13]	round trip efficiency	[ ]	0.85	
[14]	Power	[MW]	20	
[15]	Battery capacity	[MWh]	5	
[16]	Daily output energy	[MWh]	32	
[17]	Daily input energy	[MWh]	37.65	
[18]	GHG emissions factor	[kg/kWh	0.8	
[19]	**Financial analysis assumptions**			
[20]	cost of debt	[ ]	0.1	
[21]	cost of equity	[ ]	0.15	
[22]	debt ratio	[ ]	0.8	
[23]	**Economic analysis**			
[24]	Discount rate	[ ]	0.1	

Source: BESS Spreadsheet Library

232. The FCAS revenue is obtained by multiplying the $/MW assumed clearing price ($16.725/MW) by 8,760 hours. Thus for a 20 MW service available 8,760 hours per year the annual revenue is

$$16.725 \times 8760 \times 20 = \$2.93 \text{ million}$$

always assuming that the BESS is being used exclusively for FCAS.

233. The annual cost is based on purchase price of $80/MWh and usage is assumed to be 8 full charge discharge cycles at 80% capacity with 85% RTE. The 20 MW BESS has 0.25 hours duration (5MWh)

Daily output 32MWh = 20MWx0.25 hours x 8 x 0.8

For which it needs to charge 37.65MWh (=32MWh/0.85) so the annual charging cost is

37.65MWh x 365 x $8/MWh = $1.1 million

234. Table 31 shows the results, with the economic analysis showing an ERR of 16.2%, and an equity FIRR of 35.8% - which suggests that under the high FCAS price, the business case, and the economic returns of a BESS are substantial.[61]

Table 31: Pro forma economic analysis, ADB FCAS example

				NPV	2020	2021	2022	2023	2024	2025	2026	2030
				[1000$]	0	1	2	3	4	5	6	10
[1]	**Energy**											
[2]	power purchase cost		[US$/kWh]			0.08	0.1	0.1	0.1	0.1	0.1	0.1
[3]	input energy		[MWh]			13741	13741	13741	13741	13741	13741	13741
[4]	output energy		[MWh]			11680	11680	11680	11680	11680	11680	11680
[5]	energy lost		[MWh]			2061	2061	2061	2061	2061	2061	2061
[6]	**Economic analysis**											
[7]	Revenue	17	[$USm]	*16.4*	0.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9
[8]	BESS CAPEX		[$USm]	*-6.1*	-6.7							
[9]	Power purchase cost	0.08	[$USm]	*-6.1*	0.0	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1
[10]	Replacement Battery		[$USm]	*-0.6*	0.0	0.0	0.0	0.0	0.0	-1.0		
[11]	Insurance		[$USm]	*-0.4*	0.0	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07
[12]	O&M	0.04	[$USm]	*-1.5*	0.0	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27
[13]	**Net economic flows**		**[$USm]**	*1.7*	**-6.7**	**1.5**	**1.5**	**1.5**	**1.5**	**0.5**	**1.5**	**1.5**
[14]	ERR		[ ]	16.2%								
[15]	**Financial analysis:P/L**											
[16]	Revenue		[$USm]			2.9	2.9	2.9	2.9	2.9	2.9	2.9
[17]	Energy purchased		[$USm]			-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1
[18]	O&M		[$USm]			-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
[19]	Insurance		[$USm]			-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
[20]	***EBITDA***		[$USm]			1.5	1.5	1.5	1.5	1.5	1.5	1.5
[21]	Depreciation	5	[$USm]			-1.3	-1.3	-1.3	-1.3	-1.3		
[22]	***EBIT***		[$USm]			0.2	0.2	0.2	0.2	0.2	1.5	1.5
[23]	Interest expense		[$USm]			-0.5	-0.5	-0.4	-0.3	-0.3	-0.2	0.0
[24]	***Taxable income***		[$USm]			-0.4	-0.3	-0.2	-0.2	-0.1	1.3	1.5
[25]	corporate tax	0.3	[$USm]			0.0	0.0	0.0	0.0	0.0	-0.4	-0.4
[26]	**Net income**		**[$USm]**			**-0.4**	**-0.3**	**-0.2**	**-0.2**	**-0.1**	**0.9**	**1.0**
[27]	**cashflows**											
[28]	Net income		[$USm]			-0.35	-0.30	-0.25	-0.19	-0.14	0.88	1.03
[29]	depreciation		[$USm]			1.34	1.34	1.34	1.34	1.34	0.00	0.00
[30]	NICG		[$USm]			0.98	1.04	1.09	1.14	1.20	0.88	1.03
[31]	principal repayments		[$USm]			-0.53	-0.53	-0.53	-0.53	-0.53	-0.53	-0.53
[32]	**net cashflows**		**[$USm]**	*1.5*	**-1.3**	**0.4**	**0.5**	**0.6**	**0.6**	**0.7**	**0.3**	**0.5**
[33]	ERR		[ ]	35.8%								
[34]	**Loan**											
[35]	opening balance		[$USm]		0.00	5.34	4.81	4.28	3.74	3.21	2.67	0.53
[36]	disbursments		[$USm]		5.34							
[37]	principal repayments		[$USm]			-0.53	-0.53	-0.53	-0.53	-0.53	-0.53	-0.53
[38]	closing balance		[$USm]		5.34	4.81	4.28	3.74	3.21	2.67	2.14	0.00
[39]	Interest		[$USm]			0.51	0.45	0.40	0.35	0.29	0.24	0.03
[40]	**Carbon accounting**											
[41]	Emission factor	0.8	Kg/kWh]									
[42]	emissions		[tCO2]			1648.9	1648.9	1648.9	1648.9	1648.9	1648.9	1648.9
[43]	Social value carbon		[$/ton]			50.0	51.5	53.0	54.6	56.3	58.0	65.2
[44]	GHG emission reduction		[$USm]	*-0.5*	0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
[45]	**Economic flows with GHG emissio**		**[US$]**	*1.2*	**-6.7**	**1.4**	**1.4**	**1.4**	**1.4**	**0.4**	**1.4**	**1.4**
[46]	ERR including GHG		[ ]	14.4%								

Note: for sake of legibility, we show only years 7,8 and 9 from the above snapshot

Source: BESS Spreadsheet Library

61 We are unable to replicate the results shown in the ADB handbook. The table of cash flows shown in the Handbook (Table A.6),show substantial tax credits in the first five years (likely due to a formula error that shows a credit when pre-tax income is negative!) The total upfront CAPEX of $7.8million appears to include the cost of battery replacement - but this replacement costs is shown again in year 5. The footnote to Table A1 shows multiplication of BESS capacity (20 MW) in the calculation of daily energy which is not needed (though the actual daily energy of 36.75 MWh is correct).

235. The carbon accounting calculations need care. What is shown here is simply the impact of the BESS itself. But what is not shown here is the counterfactual - in the absence of BESS, FCAS will be provided by other providers, some of whom will be operating at part load to provide fast response time. Part load operation has its own GHG emission penalties, as will be discussed in the case studies of Section 6.4 and 6.5.

236. When assumptions that are more reasonable for India are applied, namely

- power purchase cost at 4.5 USc/kWh (rather than 8 USc/kWh)
- FCAS price of $4/MW (rather than the UK price of $16.725/MW)

then both the ERR and FIRR are negative. At the lower purchase price of 4.5USc/kWh, the switching value for the FCAS payment is $12.25/MW, as shown in Table 32.

Table 32: Switching value for FCAS value

				NPV	2020	2021	2022	2023	2024	2025	2026	2030
				[1000$]	0	1	2	3	4	5	6	10
[1]	**Energy**											
[2]	power purchase cost		[US$/kWh]			0.045	0.045	0.045	0.045	0.045	0.045	0.045
[3]	input energy		[MWh]			13741	13741	13741	13741	13741	13741	13741
[4]	output energy		[MWh]			11680	11680	11680	11680	11680	11680	11680
[5]	energy lost		[MWh]			2061	2061	2061	2061	2061	2061	2061
[6]	**Economic analysis**											
[7]	Revenue	12.25	[$USm]	*12.0*	0.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1
[8]	BESS CAPEX		[$USm]	*-6.1*	-6.7							
[9]	Power purchase cost		[$USm]	*-3.5*	0.0	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
[10]	Replacement Battery		[$USm]	*-0.6*	0.0	0.0	0.0	0.0	0.0	-1.0		
[11]	Insurance		[$USm]	*-0.4*	0.0	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07
[12]	O&M	0.04	[$USm]	*-1.5*	0.0	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27	-0.27
[13]	**Net economic flows**		**[$USm]**	***0.0***	**-6.7**	**1.2**	**1.2**	**1.2**	**1.2**	**0.2**	**1.2**	**1.2**
[14]	ERR		[ ]	10.0%								
[15]	**Financial analysis:P/L**											
[16]	Revenue		[$USm]			2.1	2.1	2.1	2.1	2.1	2.1	2.1
[17]	Energy purchased		[$USm]			-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
[18]	O&M		[$USm]			-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
[19]	Insurance		[$USm]			-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
[20]	***EBITDA***		[$USm]			1.2	1.2	1.2	1.2	1.2	1.2	1.2
[21]	Depreciation	5	[$USm]			-1.3	-1.3	-1.3	-1.3	-1.3		
[22]	***EBIT***		[$USm]			-0.1	-0.1	-0.1	-0.1	-0.1	1.2	1.2
[23]	Interest expense		[$USm]			-0.5	-0.5	-0.4	-0.3	-0.3	-0.2	0.0
[24]	***Taxable income***		[$USm]			-0.7	-0.6	-0.5	-0.5	-0.4	0.9	1.2
[25]	corporate tax	0.3	[$USm]			0.0	0.0	0.0	0.0	0.0	-0.3	-0.3
[26]	**Net income**		**[$USm]**			**-0.7**	**-0.6**	**-0.5**	**-0.5**	**-0.4**	**0.7**	**0.8**
[27]	**cashflows**											
[28]	Net income		[$USm]			-0.65	-0.60	-0.55	-0.49	-0.44	0.66	0.81
[29]	depreciation		[$USm]			1.34	1.34	1.34	1.34	1.34	0.00	0.00
[30]	NICG		[$USm]			0.68	0.73	0.79	0.84	0.89	0.66	0.81
[31]	principal repayments		[$USm]			-0.53	-0.53	-0.53	-0.53	-0.53	-0.53	-0.53
[32]	**net cashflows**		**[$USm]**	***0.0***	**-1.3**	**0.1**	**0.2**	**0.3**	**0.3**	**0.4**	**0.1**	**0.3**
[33]	FIRR		[ ]	10.9%								
[34]	**Loan**											
[35]	opening balance		[$USm]		0.00	5.34	4.81	4.28	3.74	3.21	2.67	0.53
[36]	disbursments		[$USm]		5.34							
[37]	principal repayments		[$USm]			-0.53	-0.53	-0.53	-0.53	-0.53	-0.53	-0.53
[38]	closing balance		[$USm]		5.34	4.81	4.28	3.74	3.21	2.67	2.14	0.00
[39]	Interest		[$USm]			0.51	0.45	0.40	0.35	0.29	0.24	0.03
[40]	**Carbon accounting**											
[41]	Emission factor	0.8	Kg/kWh]									
[42]	emissions		[tCO2]			1648.9	1648.9	1648.9	1648.9	1648.9	1648.9	1648.9
[43]	Social value carbon		[$/ton]			50.0	51.5	53.0	54.6	56.3	58.0	65.2
[44]	GHG emission reduction		[$USm]	*-0.5*	0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
[45]	**Economic flows with GHG emissio**		**[US$]**	***-0.5***	**-6.7**	**1.1**	**1.1**	**1.1**	**1.1**	**0.1**	**1.1**	**1.1**
[46]	ERR including GHG		[ ]	8.0%								

Source: BESS Spreadsheet Library

Lessons of the case study

237. The lessons of the India and ADB assessments are clear

- In the absence of an established market for ancillary services, extrapolations of FCAS benefits from other countries require great care.

- Where such markets do indeed exist, the economic benefits are likely to be significant, but to monetize such benefits in the economic analysis of BESS projects in World Bank appraisals is not advised in their absence.
- Whether the economic benefits can be realized in the absence of a market is unclear (i.e. if the BESS owner simply offers the services to the dispatch center, without financial compensation).
- As noted in Annex II, the UK system for FCAS compensation is the most transparent, and its component payments and energy flows would be easily recorded in the table of economic flows – with separate line items for the availability fee ($/hour) (i.e. the time actually available), for the nomination fee ($/h) for the hours actually dispatched, and the response energy payments ($/MWh) for the change in energy output while they are dispatched.

6.4 BESS AND SPINNING RESERVES IN INDIA

Context

238. A 160 MW solar PV-wind hybrid project at Ramagiri (in Andhra Pradesh, India) is one of the subprojects included in the World Bank financed *Innovation in Solar Power and Hybrid technologies* project.[62] As proposed this would provide 120 MW of solar PV, 40 MW of wind, and a 10 MW/20 MWh BESS. The project off-taker is the Andhra Pradesh Southern Power Distribution project. A range of alternative project configurations was examined against several counterfactuals for providing the generation profile with a mix of conventional coal and thermal generation.[63]

239. The economic analysis found that none of the various alternative project configurations were economic without the inclusion of GHG emission reduction benefits. Without BESS, the ERR of the wind-solar hybrid as proposed is 6.2%, increasing to 21,8% with GHG reduction benefits. At storage costs of $390/MWh, the addition of BESS the ERR with (GHG benefits) falls slightly to19.8% - so at any BESS cost lower than around $360/MWh, the BESS would be economic against a no BESS option.

240. The switching values presented in the PAD were calculated with respect to the overall hurdle rate, rather than the no BESS case (i.e. by how much would key assumptions need to change to reach the no BESS returns). However, it is fairly clear from the analysis that the storage price would not need to be very much lower for the PV-Wind hybrid to perform better if a BESS were installed.

241. The methodology of assessing the impact of a BESS to enhance the capacity value of the associated renewable energy is straightforward, and should follow the procedure in the CAR case study.

PAD economic analysis

242. However, of particular interest is the analysis of using BESS for replacing coal-based spinning reserve, the results of which are shown in Table 33 - presented in the PAD in the format suggested by the PSG. A BESS that serves solely to displace spinning reserve provided by coal

62 World Bank, *India Innovation in Solar Power and Hybrid Technologies Project*, Project Appraisal Document, PAD 3258, April 2019.

63 Alternatives included an all PV option (on the same site) replacing the wind component, and a comparison with floating solar PV

units was found not to be economic, even when GHG emission benefits are included (with a negative ERR and NPV).

Table 33: Economic Analysis BESS v Coal Spinning reserve: PAD summary

			Base Case
[1]	Discount rate		10.0%
[2]	**Economic rate of return**		
[3]	ERR	[ ]	-11.5%
[4]	ERR excluding GHG benefits	[ ]	-22.8%
[5]	ERR excluding GHG and local env. benefits	[ ]	-23.5%
[6]	Levelized cost of solar + wind hybrid	US$/Kwh	0.21
[7]	Levelized cost of counterfactual	US$/Kwh	0.08
[9]	**Composition of NPV**		
[10]	*Costs*		
[11]	Battery Capital Costs	[$USm]	7.3
[12]	Battery O&M	[$USm]	0.2
[13]	Associated Land & Infrastructure Costs	[$USm]	
[14]	Incremental Transmission O&M	[$USm]	
[15]	**total costs**	**[$USm]**	**7.5**
[16]	***Benefits[avoided thermal generation]***		
[17]	Avoided fuel costs:Coal	[$USm]	1.18
[18]	Avoided fuel costs: Gas	[$USm]	0.00
[19]	Capacity credit: Coal	[$USm]	0.33
[20]	Capacity credit: Gas	[$USm]	0.00
[21]	Capacity credit: Hydro	[$USm]	
[22]	Avoided O&M	[$USm]	0
[23]	**total benefits**	**[$USm]**	**2**
[24]	**NPV (before environmental benefits)**	**[$USm]**	**-6.0**
[25]	local environmental benefits: avoided grid gen	[$USm]	0.0
[26]	NPV (incl. Local environmental benefits)	[$USm]	**-5.9**
[27]	value of avoided GHG emissions	[$USm]	1.3
[28]	**NPV (including environment)**	**[$USm]**	**-4.6**
[29]	Lifetime GHG emissions, undiscounted	[mtons CO2	-0.06
[31]	Marginal abatement cost	$/ton	100.0

Source: World Bank, *Ramagiri Economic Analysis spreadsheet.XLSX*

243. The underlying table of economic flows is shown in Table 34.

Table 34: Table of economic flows, BESS v Coal spinning reserves to cover emergency events

				NPV	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**BESS Costs**																
2	BESS installed	25	[MWh]														
3	BESS investment cost	0.39	[$USm]	*7.3*	0.00	0.00	9.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	BESS O&M Costs		[$USm]	*0.2*	0.00	0.00	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
5	**total costs**		**[$USm]**	**7.5**	**0.00**	**0.00**	**9.79**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**
7	**Benefits**																
8	**grid(displaced coal)**																
9	avoided variable costs		[$USm]	*1.2*	0.00	0.00	0.26	0.25	0.24	0.23	0.22	0.21	0.20	0.19	0.18	0.18	0.17
10	avoided capacity costs	1.46	[$USm]	*0.3*		0.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	avoided O&M	0.01	[$USm]	*0.0*	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
12	**total benefits**		**[$USm]**	**1.5**	**0.00**	**0.00**	**0.66**	**0.26**	**0.24**	**0.23**	**0.22**	**0.21**	**0.21**	**0.20**	**0.19**	**0.18**	**0.17**
14	**total economic flows**		**[$USm]**	**-5.98**	**0.00**	**0.00**	**-9.12**	**0.22**	**0.21**	**0.20**	**0.19**	**0.18**	**0.17**	**0.16**	**0.15**	**0.14**	**0.14**
15	ERR		[ ]	-23.5%													
16	local environmental impacts																
17	avoided gas		[$USm]	*0.0*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	avoided coal		[$USm]	*0.0*	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
19	economic flows including local env.		[$USm]	-5.9	0.00	0.00	-9.12	0.23	0.22	0.21	0.20	0.19	0.18	0.17	0.16	0.16	0.15
20	ERR including local env.		[ ]	22.8%													
21	avoided GHG emissions		[$USm]	*1.3*	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22	**economic flows incl. global GHG benefi**		**[$USm]**	**-4.6**	**0.00**	**0.00**	**-8.87**	**0.48**	**0.47**	**0.46**	**0.45**	**0.44**	**0.43**	**0.42**	**0.41**	**0.40**	**0.40**
23	ERR including global GHG		[ ]	-11.5%													

For sake of clarity we have eliminated some of the rows that are zero throughout.

244. The analysis is based on the following general assumptions

- the Benefits consist of two components - a capacity credit, and an energy credit
- the capacity credit is based on the weighted average of PV and wind capacity factors divided by the assumed coal capacity factor - i.e. the capacity credit is based on the PSG rule of thumb for *VRE generation projects*. But this approach should not apply to a BESS, and especially not for an assessment of a BESS as a source of spinning reserve (the capital cost of coal itself is based on $1,460/kW for a new coal project).
- The energy benefit is based on 7.3 GWh per year provided by the battery on the basis of 1 cycle per day x 365 days a year x 20MWh per discharge (which reflects the energy loss due to the RT efficiency of 80%)

- the energy benefit then follows as 7.3 GWh x 3.58USc/kWh. In other words, the benefit is based on the *net* energy consumption of the battery.

245. Critical inspection of the calculation makes clear the difficulties of trying to force BESS evaluation into a template designed for VRE *generation* projects.

Reassessment

246. In the revised presentation following the spreadsheet template of this Report, the following assumptions are made:

- The calculation procedure draws on the results of the CERC report on flexible operation of coal projects.
- 25 MW, 4 hour battery as in the PAD. However for use solely to cover generating failures this may not in reality be the optimal size - a determination that would need to be made on a case-by-case basis.
- In the absence of BESS support, a 210 MW unit is backed down from 70% to 60% loading, with a penalty of 0.112 USc/kWh
- 12 events per year (i.e. the battery would be charged and discharged 12 times a year). RT efficiency at 0. 88.[64]
- Charging cost at 3USc/kWh (as per CERC report on flexible operation)
- Coal unit efficiency 34%, coal calorific value 5,000 KCal/kWh

247. The resulting calculations are shown in Table 35.

64 See Annex III, *Flexible Operation of Coal Projects*, Table 45

Table 35: BESS for spinning reserve

				NPV	2020	2021	2022	2023	2024	2025	2026
				[1000$]	0	1	2	3	4	5	6
[1]	Capacity of coal unit	200	[MW]								
[2]	Backing down ratio	0.125	[ ]								
[3]	**Energy and fuel balance**										
[4]	***at full load***	0.02									
[5]	Avoided capacity	25	[MW]			25.0	24.5	24.0	23.5	23.1	22.6
[6]	Generation at full load		[GWh]			219.0	214.6	210.3	206.1	202.0	198.0
[7]	Efficiency	0.34	[ ]								
[8]	Heat rate		[BTU/kWh]			10035	10035	10035	10035	10035	10035
[9]	calorific value	5000	[Kcal/kg]								
[10]		19828	[BTU/kg]								
[11]	coal consumption		[Kg/KWh]			0.51	0.51	0.51	0.51	0.51	0.51
[12]	coal quantity		[1000t]			110.8	108.6	106.5	104.3	102.2	100.2
[13]	***backed down as spinning reserve***										
[14]	coal quantity	1.092	[1000t]			121.0	118.6	116.2	113.9	111.6	109.4
[16]	***calls on spinning reserve***										
[17]	Events per year	12	[ ]								
[18]	RT efficiency	0.9	[ ]								
[19]	net consumption		[GWh/year]			0.03	0.03	0.03	0.03	0.03	0.03
[20]	Charging cost	0.03	[$USm]			0.0009	0.0009	0.0009	0.0009	0.0009	0.0009
[21]	**Economic analysis**										
[22]	Part load penalty	0.112	[USc/kWh]								
[23]	Avoided spinning reserve cost		[US$m]	*1.6*	0.0	0.2	0.2	0.2	0.2	0.2	0.2
[24]	BESS CAPEX	39	[US$m]	***-9.2***	-9.8						
[25]	charging cost		[US$m]	***0.0***		0.0	0.0	0.0	0.0	0.0	0.0
[26]	Replacement Battery		[US$m]	***0.0***							
[27]	O&M		[US$m]	***-0.3***		-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
[28]	**Net economic flows**		**[US$m]**	*-7.9*	**-9.8**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
[29]	ERR		[ ]	######							
[30]	**Local environmental impacts**										
[31]	Valuation per PAD		[US$m]	*0.1*		0.01	0.01	0.01	0.01	0.01	0.01
[32]	**Net economic flows incl. local ENV**		**[US$m]**	*-7.8*	**-9.8**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
[33]	ERR including GHG		[ ]	#NUM!							
[34]	**Carbon accounting**										
[35]	Increase in coal consumption		[1000t]			10.2	10.0	9.8	9.6	9.4	9.2
[36]			[mmBTU]			202191	198147	194184	190301	186495	182765
[37]	Emission factor	89.7	[Kg/mmBTU]								
[38]	emissions		[1000t CO2]			18.1	17.8	17.4	17.1	16.7	16.4
[39]	Social value carbon		[$/ton]			50.0	51.5	53.0	54.6	56.3	58.0
[40]	GHG emission reduction		[US$m]	*6.9*		0.9	0.9	0.9	0.9	0.9	1.0
[41]	**Economic flows with GHG emissio**		**[US$]**	*-1.3*	**-9.8**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
[42]	ERR including GHG		[ ]	2.9%							

Source: BESS Spreadsheet Library {BESS spinning Reserve Dec 16.XLS}

248. This revised presentation has several features:

- the explicit calculation of coal consumption when operated as spinning reserve at part load against large unit failure. This calculation is necessary to then make a reliable calculation of the additional benefit of GHG emissions reduction.
- The calculation of charging energy will depend on how many times a year the spinning reserve will be called on. These costs are seen to be trivial. (row[20])
- explicit calculation of local environmental impacts (associated with lower SOx, NOx and particulate emissions) - though for this illustration, we take the values as per the PAD).

249. The result is that BESS is not economic for this particular benefit alone. Additional benefits may accrue when used in conjunction with VRE or for additional ramping or frequency control purposes. When avoided GHG emissions are included, the economic returns are better, but remain substantially below plausible hurdle rates.[65]

250. However, the results are highly sensitive to the assumed battery capital cost - when reduced from $390/kWh to $300/kWh, the ERR including GHG benefit increases to 8,4%. The results are also very sensitive to the extent of part loading of the units being replaced: if the range of part load penalty were not 60-70%, but 30%-40%, the heat rate penalty increases to 0.17

65 However, ignored here are the embedded emissions (life cycle) of the BESS (i.e. the GHG emissions associated with the manufacture and delivery of the battery system, and subsequent safe disposal).

USc/kWh (Table 16), and the ERR including GHG emission reduction benefits increases from 2.9% to 4.9% (at the World Bank's low valuation scenario for SVC).

251. This calculation provides the same result as presented in the PAD - BESS replacement of part-loaded coal spinning reserve uneconomic - but the calculations are more transparent.

Lessons of the case study

252. These may be summarized as follows:

- The standard format for summary presentation of economic analysis of renewable energy generation, as set out in the PSG, is not really suited to the evaluation of BESS projects, particularly for the provision of ancillary services. Critical inspection of the calculations presented in the India solar project PAD makes clear the hazards of trying to force BESS evaluation into a template designed for VRE *generation* projects.
- The general format of the presentation in Table 37 is more suitable and should be adopted.
- Where spinning reserve is provided by coal (as in India), inclusion of avoided GHG emissions makes a significant difference to the economic returns.
- When evaluating the incremental benefit of adding BESS to a VRE, there should be included a switching value analysis relative to the *no battery* case.
- Numerous assumptions are necessary for a reliable calculation. But these are highly specific to the system into which the BESS is installed: generalizations are problematic.
- The presentation of Table 37 assesses only the benefit of BESS serving as a substitute for coal-based spinning reserve: it is only one of a range of benefits provided by a BESS.

6.5 WIND FARM OUTPUT CURTAILMENT IN VIETNAM[66]

Context

253. Vietnam has ambitious targets for renewable energy. An avoided cost tariff and a standardized PPA were introduced in 2009, which has been very successful in enabling small hydro (projects less than or equal to 30 MW): some 3,000 MW in over 250 projects have been implemented in the last decade under this scheme, and all at costs under 6 USc/kWh: the World Bank financed Renewable Energy Development Project (REDP) provided finance to developers through on-lending to domestic banks. The tariff provides recovery of avoided capacity costs by a capacity payment for peak hour generation in the dry season, which has encouraged SHPs with daily peaking, and thus of high capacity value.

254. This avoided cost tariff was technology neutral, and enabled neither wind nor solar PV. Subsequently, Vietnam introduced feed-in tariffs for both, with a view to moving to auctions for PV in the near future. But the first large wind farm has run into transmission congestion problems that are forcing curtailment, and developers are complaining that the wind PPA does not have adequate provisions for compensation for failure of the off-taker to compensate for curtailments.

255. The question for this case study is whether a BESS would mitigate the curtailment problem, and how would the economic case for a BESS for this purpose be presented against the counterfactual of investment in additional transmission lines to relieve the congestion.

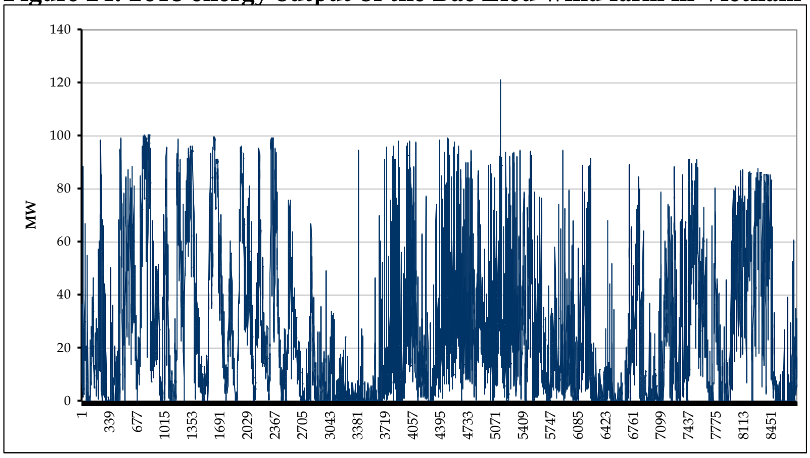
256. The Bac Lieu wind farm is Vietnam's first large wind project, a near-shore project with 62 x 1.6 MW turbines with an expected annual energy of 335 GWh/year. The first was connected to the grid in May 2013: the project became fully operational in 2016 - though actual output in the past three years has been significantly less - 196 GWh in 2017, 230 GWh in 2018.

Modeling

257. Figure 24 shows the 2015 hourly energy output of the Bac Lieu wind farm in Vietnam: one observes the typically high variability of output.

66 This case study was prepared as part of a 2019 review of the avoided cost tariff for renewable energy requested by the Electricity Regulatory Authority of Vietnam.

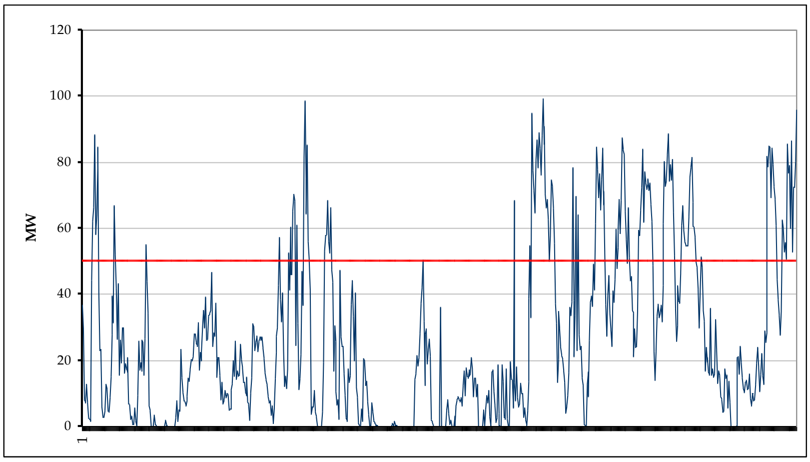
Figure 24: 2018 energy output of the Bac Lieu wind farm in Vietnam



Source: BESS Spreadsheet Library {Wind+BESS.XLS}

258. Figure 25 displays the output for the month of January, with a hypothetical 50 MW evacuation threshold - so any energy generation above the 50 MW is curtailed. Note (in this example) that the kWh curtailed varies substantially across each individual curtailment event.

Figure 25: Bac Lieu wind farm: January 2018 output.



Source: BESS Spreadsheet Library {Wind+BESS.XLS}

259. Table 36 shows an extract of the model required to optimize battery size and operating rule. The full model has 8,760 rows for each hourly time step - here we show just the first two days. This differentiates between production in peak and off-peak hours - though in this particular run the FIT is 8.5 USc/kWh throughout.

260. In this illustrative example, the battery operation decision rule is simply to avoid curtailments - by saving output that would otherwise be curtailed into the battery, and then subsequently discharging the battery such that the combined output in subsequent hours does not exceed the transmission capacity. Under typical FITs that have a constant unit price, there is no incentive for a developer to shift output from off-peak to peak hours.

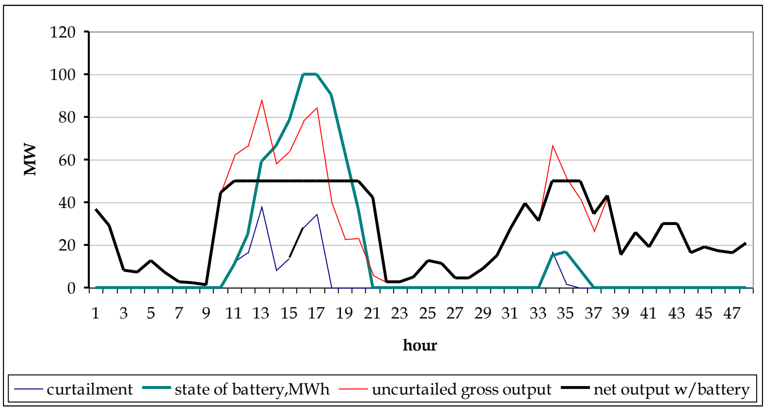
Table 36: Hourly wind farm output and curtailments

Power			Curtailment					Battery			Actual Output			Tariff		Revenue		
hour of day	tariff block	total	limit	curtial-ment	curtailed output	length	energy lost	charge	discharge	state of charge	output with battery	peak	off-peak	peak	off-peak	peak	off-peak	total
	Total>>	230		39	191		39	14	12	151	203	53	150			4.5	12.7	17.3
	Max>>					76	3			100								
	Count>>					365	365											
		[1]	]2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
[ ]		MW	MW	MW	MW	hours	MW	MW	MW	MW	MW	MW	MW	$/kWh	$/kWh	$000	$000	$000
01	offPeak	36.7	50.0		36.7						36.7		36.7		0.09	0.0	3.1	3.1
02	offPeak	29.2	50.0		29.2						29.2		29.2		0.09	0.0	2.5	2.5
03	offPeak	8.1	50.0		8.1						8.1		8.1		0.09	0.0	0.7	0.7
04	offPeak	7.1	50.0		7.1						7.1		7.1		0.09	0.0	0.6	0.6
05	offPeak	12.9	50.0		12.9						12.9		12.9		0.09	0.0	1.1	1.1
06	offPeak	7.2	50.0		7.2						7.2		7.2		0.09	0.0	0.6	0.6
07	offPeak	2.6	50.0		2.6						2.6		2.6		0.09	0.0	0.2	0.2
08	offPeak	2.1	50.0		2.1						2.1		2.1		0.09	0.0	0.2	0.2
09	offPeak	1.4	50.0		1.4						1.4		1.4		0.09	0.0	0.1	0.1
10	offPeak	44.6	50.0		44.6						44.6		44.6		0.09	0.0	3.8	3.8
11	offPeak	62.2	50.0	12.2	50.0			12.2		10.7	50.0		50.0		0.09	0.0	4.3	4.3
12	offPeak	66.4	50.0	16.4	50.0			16.4		25.2	50.0		50.0		0.09	0.0	4.3	4.3
13	offPeak	88.4	50.0	38.4	50.0			38.4		59.0	50.0		50.0		0.09	0.0	4.3	4.3
14	offPeak	58.2	50.0	8.2	50.0			8.2		66.2	50.0		50.0		0.09	0.0	4.3	4.3
15	offPeak	64.2	50.0	14.2	50.0			14.2		78.7	50.0		50.0		0.09	0.0	4.3	4.3
16	Peak	78.3	50.0	28.3	50.0			24.2		100.0	50.0	50.0		0.09		4.3	0.0	4.3
17	Peak	84.5	50.0	34.5	50.0	7.0	152.2			100.0	50.0	50.0		0.09		4.3	0.0	4.3
18	Peak	40.6	50.0		40.6				9.4	90.6	50.0	50.0		0.09		4.3	0.0	4.3
19	Peak	22.9	50.0		22.9				27.1	63.5	50.0	50.0		0.09		4.3	0.0	4.3
20	Peak	23.2	50.0		23.2				26.8	36.7	50.0	50.0		0.09		4.3	0.0	4.3
21	Peak	5.8	50.0		5.8				36.7		42.5	42.5		0.09		3.6	0.0	3.6
22	offPeak	2.7	50.0		2.7						2.7		2.7		0.1		0.2	0.2
23	offPeak	2.8	50.0		2.8						2.8		2.8		0.1		0.2	0.2
24	offPeak	5.1	50.0		5.1						5.1		5.1		0.1		0.4	0.4
01	offPeak	12.7	50.0		12.7						12.7		12.7		0.1		1.1	1.1
02	offPeak	11.2	50.0		11.2						11.2		11.2		0.1		1.0	1.0
03	offPeak	4.7	50.0		4.7						4.7		4.7		0.1		0.4	0.4
04	offPeak	4.5	50.0		4.5						4.5		4.5		0.1		0.4	0.4
05	offPeak	9.0	50.0		9.0						9.0		9.0		0.1		0.8	0.8
06	offPeak	15.2	50.0		15.2						15.2		15.2		0.1		1.3	1.3
07	offPeak	27.9	50.0		27.9						27.9		27.9		0.1		2.4	2.4
08	offPeak	39.6	50.0		39.6						39.6		39.6		0.1		3.4	3.4
09	offPeak	31.4	50.0		31.4						31.4		31.4		0.1		2.7	2.7
10	offPeak	66.9	50.0	16.9	50.0			16.9		14.9	50.0		50.0		0.1		4.3	4.3
11	offPeak	52.0	50.0	2.0	50.0	2.0	18.9	2.0		16.6	50.0		50.0		0.1		4.3	4.3
12	offPeak	41.6	50.0		41.6				8.4	8.2	50.0		50.0		0.1		4.3	4.3
13	offPeak	26.5	50.0		26.5				8.2		34.7		34.7		0.1		3.0	3.0
14	offPeak	43.1	50.0		43.1						43.1		43.1		0.1		3.7	3.7
15	offPeak	15.5	50.0		15.5						15.5		15.5		0.1		1.3	1.3
16	Peak	26.0	50.0		26.0						26.0	26.0		0.1		2.2		2.2
17	Peak	19.3	50.0		19.3						19.3	19.3		0.1		1.6		1.6
18	Peak	29.9	50.0		29.9						29.9	29.9		0.1		2.5		2.5
19	Peak	30.0	50.0		30.0						30.0	30.0		0.1		2.6		2.6
20	Peak	16.3	50.0		16.3						16.3	16.3		0.1		1.4		1.4
21	Peak	18.9	50.0		18.9						18.9	18.9		0.1		1.6		1.6
22	offPeak	17.4	50.0		17.4						17.4		17.4		0.1		1.5	1.5
23	offPeak	16.4	50.0		16.4						16.4		16.4		0.1		1.4	1.4
24	offPeak	20.9	50.0		20.9						20.9		20.9		0.1		1.8	1.8

Source: BESS Spreadsheet Library {Wind+BESS.XLS}

261. Figure 26 shows the curtailments and state of battery for the first 48hours of 2016. Once the gross output falls after a curtailment, the battery is discharged to main the 50 MW output for as long as possible.

Figure 26: Battery operation

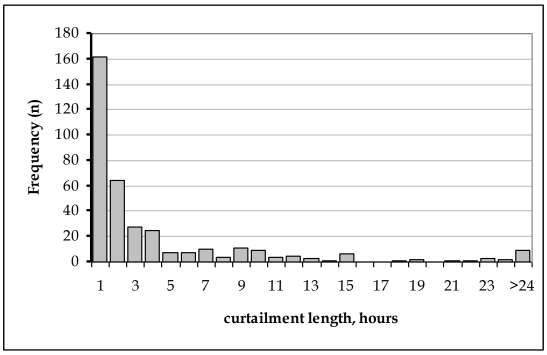


Source: BESS Spreadsheet Library {Wind+BESS.XLS}

262. To answer the question about how much battery storage one would need, it is necessary to examine each curtailment event - i.e. how much energy is in each of the individual set of hours of curtailment. - of which in 2018 there are 365 curtailment events,[67] lasting a total of 1,742 hours. The longest curtailment lasts 76 hours. The largest continuous curtailment would need a battery of 2,822 MWh.

263. Figure 27 shows the frequency distribution of curtailment lengths. 45% of curtailments are of 1 hour (or less), and 75% of curtailments are 4 hours or less.

Figure 27: Frequency distribution of curtailment hours



Source: BESS Spreadsheet Library {Wind+BESS.XLS}

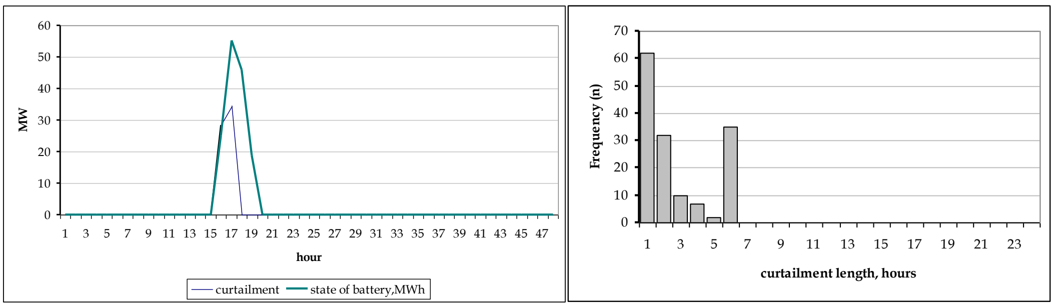
Transmission constraints

264. There are two types of transmission constraints. The first is a constraint imposed by a specific line necessary for evacuation, a constraint that operates throughout the day. The second is caused by deeper network congestion constraints, likely to be present only during peak hours.

265. If we suppose that the 50 MW constraint is binding only during peak hours, then the operating regime requirements of the battery change significantly. As shown in Figure 28A, in the first 48 hours there is only one curtailment event; and the maximum length of each curtailment is (necessarily) 6 hours (corresponding to the tariff block in question).

Figure 28: Curtailment during peak hours only

A: Battery charge condition **B. Curtailment Frequency distribution**



Source: BESS Spreadsheet Library {Wind+BESS.XLS}

266. The total annual generation without curtailment is 156 GWh. At the applicable feed-in tariff of 8.5USc/kWh, the corresponding annual revenue is $13.3 million. The total curtailed energy is 12.9 GWh, resulting in a lower annual revenue of $12.2 million, with a revenue loss of $1.1million. The question, therefore, is whether a battery system would be financially feasible to avoid the curtailments.

67 It is purely coincidental that this averages one event per day!

267. Assume a cost of energy storage of $400/kWh (which is about the price of storage revealed by recent reviews). From the above assessment a 15 MW system would be required with 4 hour storage, so 60 MWh, that would require an additional capital cost of $27 million. Even with an optimistic 15 battery year life, and ignoring the fall in battery performance over time, such a battery would not be financially feasible.

Economic analysis

268. But suppose in place of a fixed price FIT the wind farm operates under an avoided cost tariff, that reflects the difference in economic value between peak and off-peak hours. Under this regime the battery would not only hedge against curtailment, but shift production into the peak hours. The battery would function in exactly the same way as the reservoir in daily peaking small hydro project: the operating rule is to charge the battery in off-peak hours for discharge during peak hours.

269. Table 37 shows the necessary calculations. It is assumed the off-peak valuation is 3US/kWh (at the avoided economic cost of coal generation), and the peak valuation is taken at 12 USc/kWh (avoided cost of gas peakers).

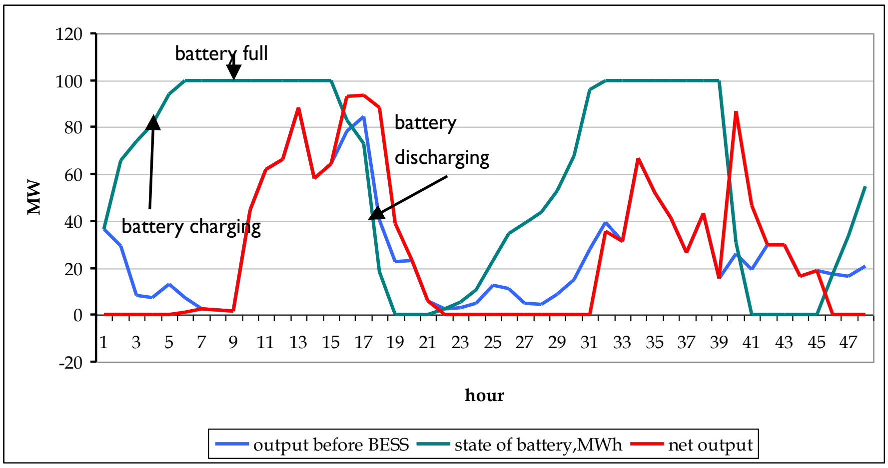
Table 37: Tariff impact assessment

		Power	Battery price arbitrage					Actual Output			Tariff		Revenue		
hour of day	tariff block	total	charge	discharge	state of charge	available for discharge	adjusted gross output	output with battery	peak	off-peak	peak	off-peak	peak	off-peak	total
	Total>>	230	69	61			222	222	118	104			14.1	3.1	17.3
	Max>>														
	Count>>														
		[1]	]2]	[3]	[4]	[4]	[5]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]
[ ]		MW	MW	MW	MW	MW	MW	MW	MW	MW	$/kWh	$/kWh	$000	$000	$000
01	offPeak	36.7	36.7		36.7	58.3	0					0.03	0.0	0.0	0.0
02	offPeak	29.2	29.2		65.9	65.8	0	0.0		0.0		0.03	0.0	0.0	0.0
03	offPeak	8.1	8.1		74.0	86.9	0	0.0		0.0		0.03	0.0	0.0	0.0
04	offPeak	7.1	7.1		81.1	87.9	0	0.0		0.0		0.03	0.0	0.0	0.0
05	offPeak	12.9	12.9		94.0	82.1	0	0.0		0.0		0.03	0.0	0.0	0.0
06	offPeak	7.2	7.2		101.2	87.8	0	0.0		0.0		0.03	0.0	0.0	0.0
07	offPeak	2.6	2.6		103.8	92.4	0	0.0		0.0		0.03	0.0	0.0	0.0
08	offPeak	2.1	2.1		105.9	92.9	0	0.0		0.0		0.03	0.0	0.0	0.0
09	offPeak	1.4	1.4		107.3	93.6	0	0.0		0.0		0.03	0.0	0.0	0.0
10	offPeak	44.6	44.6		151.9	50.4	0	0.0		0.0		0.03	0.0	0.0	0.0
11	offPeak	62.2	62.2		214.1	32.8	0	0.0		0.0		0.03	0.0	0.0	0.0
12	offPeak	66.4	65.9		280.0	28.6	1	0.5		0.5		0.03	0.0	0.0	0.0
13	offPeak	88.4			280.0	6.6	88	88.4		88.4		0.03	0.0	2.7	2.7
14	offPeak	58.2			280.0	36.8	58	58.2		58.2		0.03	0.0	1.7	1.7
15	offPeak	64.2			280.0	30.8	64	64.2		64.2		0.03	0.0	1.9	1.9
16	Peak	78.3		14.7	263.3	16.7	93	93.0	93.0		0.12		11.2	0.0	11.2
17	Peak	84.5		9.2	252.8	10.5	94	93.7	93.7		0.12		11.2	0.0	11.2
18	Peak	40.6		47.9	198.4	54.4	88	88.5	88.5		0.12		10.6	0.0	10.6
19	Peak	22.9		63.4	126.3	72.1	86	86.3	86.3		0.12		10.4	0.0	10.4
20	Peak	23.2		63.2	54.5	71.8	86	86.4	86.4		0.12		10.4	0.0	10.4
21	Peak	5.8		48.0		89.2	54	53.8	53.8		0.12		6.5	0.0	6.5
22	offPeak	2.7	2.7		2.7	92.3	0					0.0			
23	offPeak	2.8	2.8		5.5	92.2	0					0.0			
24	offPeak	5.1	5.1		10.6	89.9	0					0.0			
01	offPeak	12.7	12.7		23.3	82.3	0	0.0		0.0		0.0		0.0	0.0
02	offPeak	11.2	11.2		34.5	83.8	0	0.0		0.0		0.0		0.0	0.0
03	offPeak	4.7	4.7		39.2	90.3	0	0.0		0.0		0.0		0.0	0.0
04	offPeak	4.5	4.5		43.7	90.5	0					0.0			
05	offPeak	9.0	9.0		52.7	86.0	0					0.0			
06	offPeak	15.2	15.2		67.9	79.8	0	0.0		0.0		0.0		0.0	0.0
07	offPeak	27.9	27.9		95.8	67.1	0	0.0		0.0		0.0		0.0	0.0
08	offPeak	39.6	39.6		135.4	55.4	0	0.0		0.0		0.0		0.0	0.0
09	offPeak	31.4	31.4		166.8	63.6	0	0.0		0.0		0.0		0.0	0.0
10	offPeak	66.9	66.9		233.7	28.1	0					0.0			
11	offPeak	52.0	46.3		280.0	43.0	6	5.7		5.7		0.0		0.2	0.2
12	offPeak	41.6			280.0	53.4	42	41.6		41.6		0.0		1.2	1.2
13	offPeak	26.5			280.0	68.5	27	26.5		26.5		0.0		0.8	0.8
14	offPeak	43.1			280.0	51.9	43	43.1		43.1		0.0		1.3	1.3
15	offPeak	15.5			280.0	79.5	16	15.5		15.5		0.0		0.5	0.5
16	Peak	26.0		60.7	211.0	69.0	87	86.7	86.7		0.1		10.4		10.4
17	Peak	19.3		66.6	135.3	75.7	86	85.9	85.9		0.1		10.3		10.3
18	Peak	29.9		57.3	70.2	65.1	87	87.2	87.2		0.1		10.5		10.5
19	Peak	30.0		57.2	5.2	65.0	87	87.2	87.2		0.1		10.5		10.5
20	Peak	16.3		4.6		78.7	21	20.9	20.9		0.1		2.5		2.5
21	Peak	18.9				76.1	19	18.9	18.9		0.1		2.3		2.3
22	offPeak	17.4	17.4		17.4	77.6	0					0.0			
23	offPeak	16.4	16.4		33.8	78.6	0					0.0			
24	offPeak	20.9	20.9		54.7	74.1	0					0.0			

Source: BESS Spreadsheet Library {Wind+BESS.XLS}

270. Figure 29 shows the result of the operating rule. The blue line shows output of the wind farm without the BESS. With the BESS, charging starts at midnight, until the battery is full (green line) in hour 5. The battery then discharges during peak hours (16:00-22:00) until it is empty (at 19:00) with a maximum total output equal to the project's installed capacity (red line). The battery starts recharging at the start of the next off-peak cycle at 23:00.

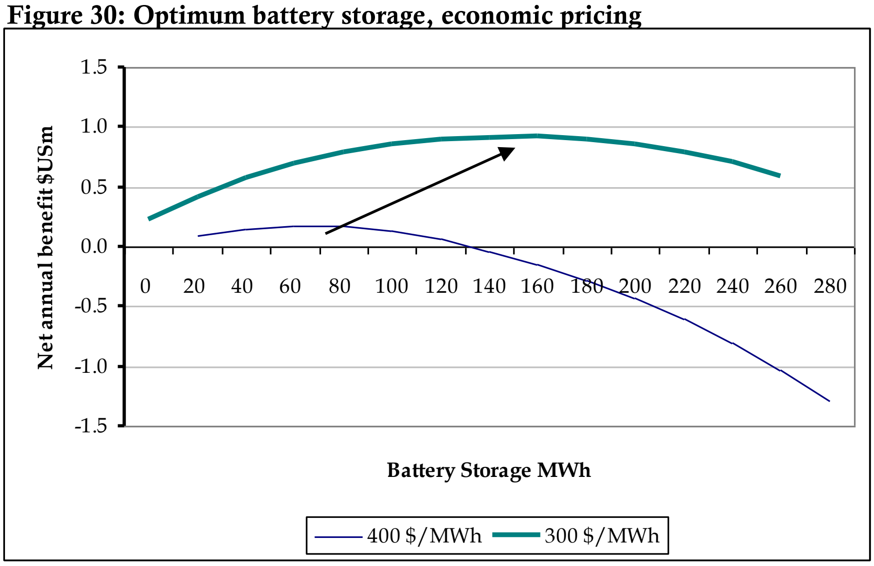
Figure 29: State of battery, wind+BESS system



Source: BESS Spreadsheet Library

271. The results of the battery size optimization are shown in Figure 30. As one may expect, as storage prices decline, the optimum size of BESS will increase. At present prices of $400/kWh, the optimum size is around 60 MW; at $300/kWh, the optimum battery size increases to 150 MWh.

Figure 30: Optimum battery storage, economic pricing



Source: BESS Spreadsheet Library

272. The economics of BESS for curtailment avoidance and price arbitrage for solar PV, or the combined output of a solar+wind hybrid (as in the Ramagiri assessment) can use exactly the same procedure, driven by a time series on time steps no longer than hourly.

Lessons of the case study

273. The main lesson is that any assessment of BESS requires both economic and financial analysis. In particular we note

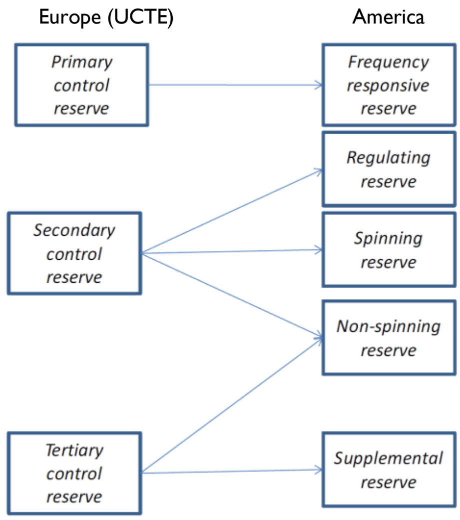
- Fixed feed-in tariffs are set on the basis of producers *costs*, not on system benefits. The justification of a BESS necessarily requires the value of energy and capacity during discharge hours to be greater than their corresponding value during charging hours.
- A private wind farm operating under a fixed feed-in tariff will therefore see little benefit to a BESS, but such may still be economic from the point of view of the system when the higher economic value of energy during peak hours is considered.

ANNEX I: FLEXIBLE OPERATION

AI.1: RESERVES

274. A first problem for the economist is the proliferation of definitions in the technical literature. Procedures and definitions in North America are different to European practice (Figure 31).

Figure 31 : European v American categorizations



Source: Ela, A., M. Milligan and B. Kirby *Operating reserves and variable generation*, NREL, Technical Report, August 2011, Figure 30

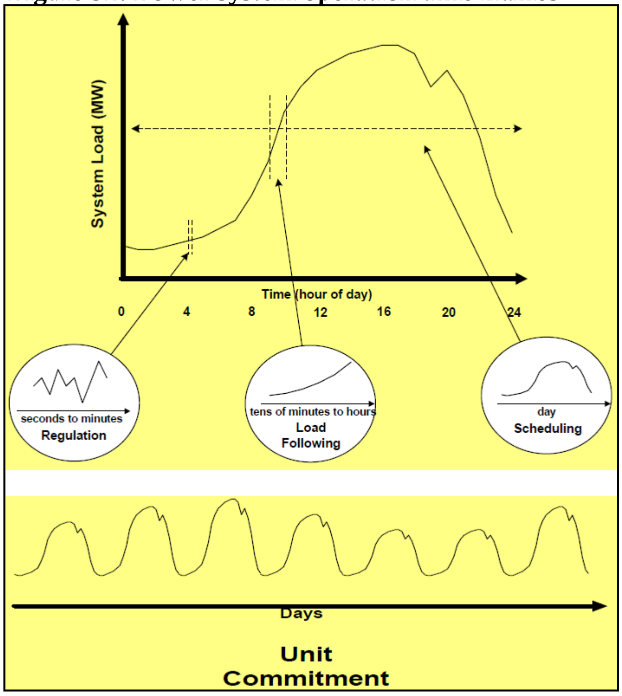
275. The three levels of control can be defined as follows (see Reading list 3)

- **Primary control**: local automatic control which delivers reserve power in opposition to any frequency change;
- **Secondary control**: centralized automatic control which delivers reserve power in order to bring back the frequency and the interchange programs to their target values;
- **Tertiary control**: manual change in the dispatching and unit commitment in order to restore the secondary control reserve, to manage eventual congestions, and to bring back the frequency and the interchange programs to their target if the secondary control reserve is not sufficient.

276. Supply and demand must be maintained at all times with voltage level and frequency standards (60 Hz in North America, 50 Hz in most other places) to be met at all times (Figure 32).[68]

[68] This section relies heavily on Ela, A., M. Milligan and B. Kir. 2011. *Operating reserves and variable generation*, NREL, Technical Report, August 2011.

Figure 32: Power system operation time frames



Source: Ela, A., M. Milligan and B. Kirby *Operating reserves and variable generatio*n, NREL, Technical Report, August 2011, Figure 2

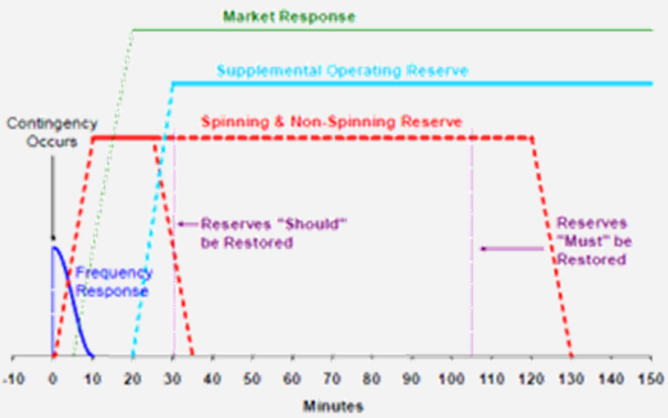
277. This figure shows the different time frames where different strategies are used to ensure that the load is balanced.

- **Forward scheduling** of the power system includes schedules and unit commitment directions to meet the general load pattern of the day.
- **Load following** is the action to follow the general trending load pattern within the day. This is usually performed by economic dispatch and sometimes involves the starting and stopping of quick-start combustion turbines or hydro facilities.
- **Regulation** is the balancing of fast second-to-second and minute to-minute random variations in load or generation. This is done by centralized control centers sending out control signals to generating units (and some responsive loads) that have the capability to rapidly adjust their dispatch set points.

278. These strategies represent the balancing during normal conditions of the power system. The load is never constant and therefore each of these strategies helps correct the load balance - and the load forecast itself is never 100% accurate. The system must also be flexible to maintain stability and reliability during emergency events (Box 5).

Box 6: Emergency events

During loss of supply events, additional supply needs to respond to the disturbance immediately. As can be seen in the Figure, this includes a number of different responses that vary by response time and length of time the response needs to be sustained.



Initially, when the loss of supply occurs, synchronous machines must supply kinetic energy to the grid, and by doing so, slow down their rotational speeds and therefore the electrical frequency. This inertial response that comes from synchronous generators and synchronous motors helps slow down the frequency decline. In other words, the more inertia in the system, the slower the rate of frequency decline.

During this decline in frequency, generators will automatically respond to the change in frequency through governor response, and some load response will balance the generation and load at some frequency less than the nominal frequency.

Spinning reserve that is synchronous to the grid and unloaded from its maximum rating and non-spinning reserve, which can be off-line but able to be synchronized quickly, are both deployed to fill the gap in energy needed from the loss and restore the frequency back to its nominal level. In market-based systems spot prices may increase during supply shortages and incentivize response from resources that can assist in the event.

Lastly, supplemental reserves are deployed with slower response to allow the other reserves to be unloaded once again so that the system can be again secure for a subsequent event. For over-frequency events, as might happen when large wind generation may increase very rapidly, a similar response might occur, but a reduction in output from other generators would be required.

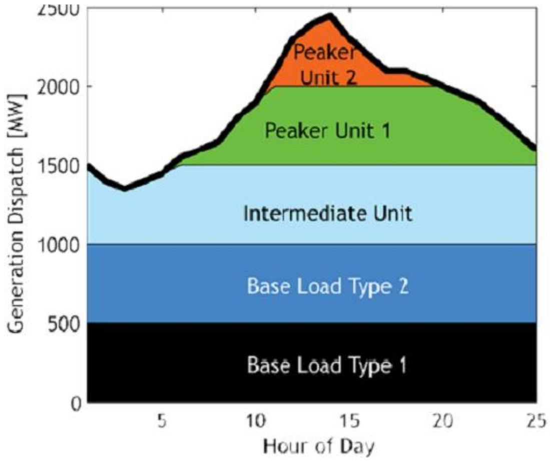
Source: Text and Figure from Ela, A., M. Milligan and B. Kirby *Operating reserves and variable generatio*n, NREL, Technical Report, August 2011, Figure 3

AI.2. SPINNING RESERVES & RAMPING

279. Most systems experience significant load variation during the day, which means supply must be ramped up and down (or in the case of large solar PV inputs during the day, ramped down and up). The rate of change may be quite steep and may be steeper than the achievable ramp rates of thermal capacity - and of low-cost base load projects in particular. This ramping up and down therefore needs to be facilitated by generators with faster ramp rates. Hydro and pumped hydro typically can respond much faster than thermal projects.

280. Figure 33 illustrates ideal dispatch, with thermal units stacked in merit order: as demand increases during the morning hours, more expensive units are switched on one by one.

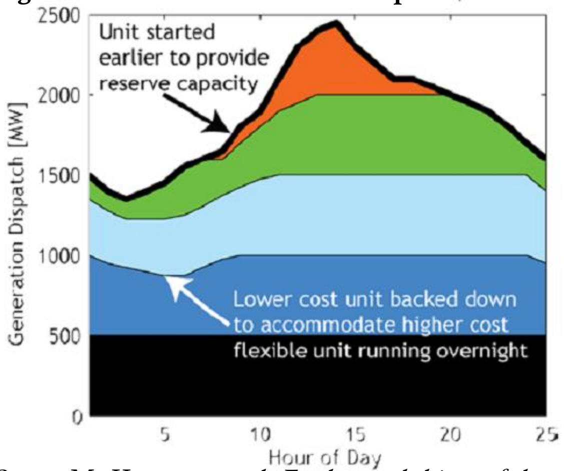
Figure 33: Ideal dispatch



Source: M. Hummon *et al. Fundamental drivers of the cost and price of operating reserves*, National Renewable Energy Laboratory, July 2013

281. But if this dispatch is to observe the usual reliability criteria - i.e. needs to accommodate the loss of the largest generator in the system (so called n-1 reliability), or accommodate a sudden decrease (or increase) in VRE output, then some units must be run at part load so they can be rapidly ramped up restore the necessary supply (Figure 34).

Figure 34: Reserve constrained dispatch



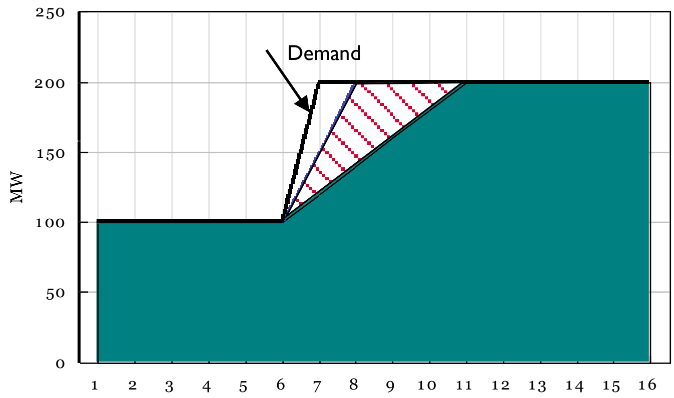
Source: M. Hummon *et al. Fundamental drivers of the cost and price of operating reserves*, National Renewable Energy Laboratory, July 2013

282. Notice that in this illustrative example, there are *two* impacts. The first is that Peaker 1 is operated at part load for many more hours per day than under "ideal" dispatch. The second is that intermediate and base load type 2 needs to be backed down to make room during off-peak hours for the Peaker 1 and Peaker 2 to be in part-load operation.

283. But such generators running at part load may still not provide instantaneous increase or decrease of output because they are subject to ramping constraints. This is illustrated in Figure 35. Suppose demand increases by 100 MW between 6:00 and 7:00 am. Low cost base-load is constrained by its ramping capacity, and takes 4 time-steps to increase output to 200 MW. Therefore, ramping must be supplied by a peaking unit that has much faster ramping rate - which ramps up, and then down once the base load unit has adjusted to the higher loading (the hatched area in Figure 35). This ramping support will generally cost much more per kWh than the base load unit. Exactly the same is true when there is a drop in demand. But even a GT peaker

cannot provide ramping fast enough, and therefore in the absence of other corrections the white area would adjust itself by lowering the frequency

Figure 35: Ramping constraints



Source: BESS Spreadsheet Library

284. Table 38 compares ramp rates for typical thermal units: combustion turbines (particularly aero-derivatives) have the best ramping performance, nuclear the worst.

Table 38: Ramp rate comparisons of thermal units

	Ramp rate down		Ramp rate up		Instant ramp rate up	
	[%/hr]	[MW/hr]	[%/hr]	[MW/hr]	[%/min]	[MW/min]
Nuclear* (ST)	35.7	138	35.7	138	5	19
Coal (ST)	31.1–39.4	35–184	26.2–44.3	28–146	2	2.2–10
Gas (ST)	73.7–81.4	57–77	47.0–61.4	43–47	2	1.4–2.0
Gas (CC)	43.4–83.0	44–336	29.7–50.0	42–336	5	4.4–34
Gas (CT)	81.3–100	19–103	70.0–100.0	19–103	8.33	1.6–8.6
Oil (CT)	100	16–54	100.0	16–54	8.33	1.3–4.5

Source: Argonne National Laboratory, *Integrating solar PV in Utility System operations, ANL/DIS-13/18, Oct 2913*

285. BESS is ideally suited to provide this additional support - with near instantaneous response time, both the hatched and the white areas of Figure 35 can be provided from battery discharge - with charging energy provided by a slight increase in output of the low cost base load project in the low load (100 MW) time slice.

286. The main disadvantage of using thermal capacity to provide spinning reserves is that operating at part load carries significant cost penalties because heat rates increase as loading decreases. Moreover, non-fuel operating costs also increase when units cycle up and down (and even more when starting up).

287. Table 39 shows the heat rate and OPEX penalties incurred as a consequence of part loading of a typical Indian 600 MW coal unit. The total incremental cost of 0.38 USc/kWh at 50% loading is about 10% of the full load cost of 3 USc/kWh (as per CERC study). Annex III provides a more detailed discussion of flexible operation of coal projects - which is particularly important in many countries where large scale introduction of VRE is into systems with high shares of coal generation (Germany, USA, India, China).

Table 39: Impact of part loading on a typical 600 MW project

load	output	Heat Rate Increase	Heat Rate Penalty	O&M penalty	total	total	total	step increment
[ ]	MW	[%]	Paisa /kWh	Paisa /kWh	Paisa /kWh	IRp/kWh	USc/kWh	USc/kWh
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1	600	0	0	0	0	0	0	0.000
0.9	540	0.80%	1.6	7.1	8.7	0.087	0.1299	0.130
0.8	480	1.70%	3.5	7.1	10.6	0.106	0.1582	0.028
0.7	420	3.30%	6.6	7.1	13.7	0.137	0.2045	0.046
0.6	360	5.70%	11.5	7.1	18.6	0.186	0.2776	0.073
0.5	300	9.20%	18.4	7.1	25.5	0.255	0.3806	0.103
0.4	240	14.40%	28.7	7.1	35.8	0.358	0.5343	0.154
0.3	180	20.40%	40.8	7.1	47.9	0.479	0.7149	0.181

100 Paise=1 IRp; $1 US=67 IRp
Source: Central Electricity Authority, *Flexible Operation of thermal power plant for integration of renewable energy*, January 2019, Table 18.

288. Heat rate corrections are a key part of tariff schedules in CCGT PPAs with IPPs (Table 40). This PPA also stipulates numbers of cold and hot starts, any increase of which required by the dispatch center will require additional remuneration to the IPP.

Table 40: Heat rate corrections, Phu My 2.2 CCGT

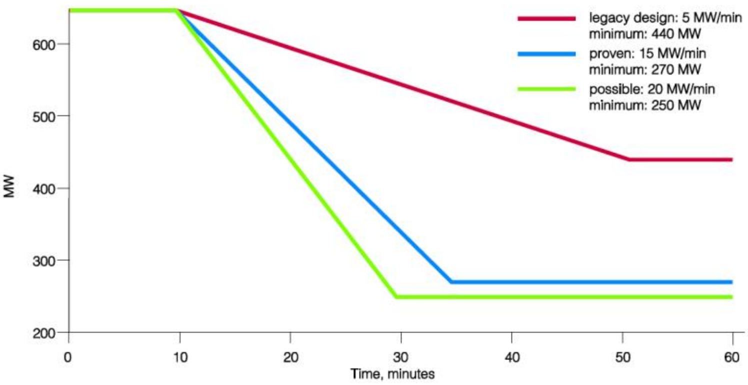
loading	fuel adjustment
1.00	1.0000
0.95	1.0059
0.90	1.0122
0.85	1.0208
0.80	1.0310
0.75	1.0442
0.70	1.0573
0.65	1.0797
0.60	1.0927
0.55	1.1123

Source: Phu My 2.2 PPA Table 3.5

289. Consumers can also provide the equivalent of spinning reserve, particularly during ramping down: a consumer who agrees to be disconnected or reduce is load upon request of the TSO can also be considered to provide reserve (described in the literature as a *demand response*).

290. Retrofitting older units to improve ramp rates is now accepted practice. Figure 36 shows that a 600 MW lignite plant, with legacy ramp rate of 5 MW/minute to a minimum load of 440 MW, can be improved to 15 MW/minute to a minimum of 270 MW through modern control systems.

Figure 36: Improvements in ramp rates and minimum load from retrofitting modern control systems



Source: G. Henderson, *Increasing the Flexibility of Coal-fired Power Plants*, IEA Clean Coal Center, September 2014.

291. The issue for VRE integration is how much additional spinning reserve is required for given levels of VRE penetration. Different systems have different requirements for the amount of spinning reserve required. Traditionally these are defined as a function of the size of the largest unit in the system, or as a function of load (Table 41). Credible estimates of how much additional spinning reserve is required to accommodate increasing levels of VRE is less straightforward (and often controversial).

Table 41: Calculation of spinning reserve requirements in different systems

Country	*Calculation of the amount of spinning reserve*
UCTE	No specific recommendation. The recommended maximum is $\sqrt{10L_{max\ zone}+150^2}-150$
Belgium	UCTE rules. Currently at least 460 MW by generators.
France	UCTE rules. Currently at least 500 MW.
The Netherlands	UCTE rules. Currently at least 300 MW.
Spain	Between $3\sqrt{L_{max}}$ and $6\sqrt{L_{max}}$
California	$50\% \times \max(5\% \times P_{hydro} + 7\% \times P_{other\ generation}; P_{largest\ contingency}) + P_{non-firm\ import}$
PJM	1.1% of the peak + probabilistic calculation on typical days and hours

Where:

- L_{max}: the maximum load of the system during a given period;
- $L_{max\ zone}$: the maximum load of the UCTE control area during a given period;
- P_{hydro}: scheduled generation from hydroelectric resources;
- $P_{other\ generation}$: scheduled generation from resources other than hydroelectric;
- $P_{largest\ contingency}$: value of the power imbalance due to the most severe contingency;
- $P_{non\text{-}firm\ import}$: total of all the interruptible imports.

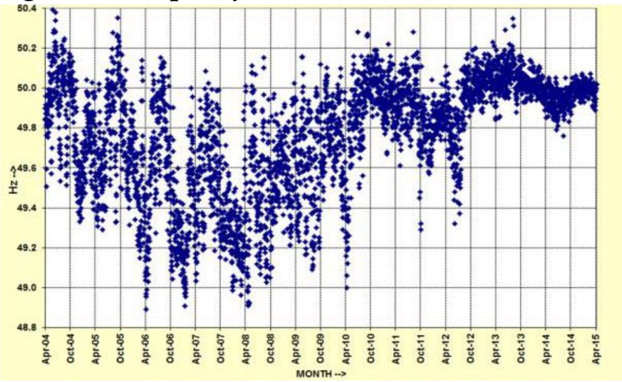
Source: Rebours, Y and D. Kirschen, *What is spinning reserve*?, University of Manchester, Sept 2005
PJM = Pennsylvania- (New) Jersey - Maryland Power Pool (USA)
UCTE= Union for the Coordination of Transmission of Electricity (now ENSTOE-E), the EU synchronized grid.

AI.3 FREQUENCY REGULATION

292. Power system operators must implement several mechanisms to maintain frequency stability. Traditionally regulation frequency control services are provided by generators on Automatic Generation Control (AGC) which under which the dispatch operator who monitors system sends control signals out to generators providing regulation in such a manner that the frequency is maintained within the normal operating band around 50 Hz. Among World Bank client

countries, India is the classic example of grids having frequency control problems – though as shown in Figure 37, in recent years performance has improved dramatically (performance in the 1990s was even worse than in the early 2000s).

Figure 37: Frequency variations in the Indian Eastern Region 2004-2015



Source: Central Electricity Regulatory Commission, New Delhi. *Report of the Committee on Spinning Reserve*, Sept 17, 2015.

293. Battery energy storage systems represent an effective method to provide instantaneous active power output in few milliseconds to maintain frequency stability. The challenge for economic analysis of a BESS is how to evaluate the economic value of frequency control ancillary services (FCAS). The key is whether there exists a market for ancillary services, and for fast frequency control in particular.

294. We have noted that quantifying and valuing reliability is difficult. But why and how do markets serve as the mechanism for determination of the benefits of BESS - even in the absence of an explicit benefit quantification to the consumer?

295. The answer lies in regulation and institutional structure. If a system operator is required meet a given level of reliability (as in the UK, or Australia, or in US power pools), then he is bound to ensure that reliability by defining quantity of such services that are required to meet that standard, for which providers of that service can bid to supply. The market price for that service is then given by the marginal clearing price. In other words, the market functions only where an independent regulator ensures the TSO meets some required standard of reliability.

296. Annex II describes the markets for FCAS in the UK and Australia: the Regulation market in the American PJM Power Pool is summarized in Box 8.

Box 7: The PJM Regulation Market

Regulation is a reliability product that corrects for short-term changes in electricity use that might affect the stability of the power system. In technical terms, the main goal of regulation is to keep the system's area control error, also called ACE, within acceptable bounds. ACE is the difference between scheduled and actual electrical generation, accounting for variations in the system's frequency.

Regulation helps match generation and demand to keep the grid functioning normally by:

- Maintaining a system frequency of 60 Hertz (in the USA), tracking moment-to-moment fluctuations in customer electricity use
- Correcting for unintended fluctuations in generation (such as a large generating unit disconnecting from the system)
- Managing differences between forecasted or scheduled power flow and actual power flow on the system

PJM generates two different types of automated signals that Regulation Market resources can follow.

- The Regulation D signal is a fast, dynamic signal that requires resources to respond almost instantaneously.
- Regulation A is a slower signal that is meant to recover larger, longer fluctuations in system conditions.

These two signals communicate with each other and work together to match the system requirements

297. The prices in such markets vary, but can be as much as $12/MW-h in the UK. In the case study of Section 6.3, prices for a potential Indian FCAS market are assumed at $2 and $4/MW-h.

298. We note the following for any economic analysis for a BESS that seeks to list FCAS as a benefit:

- Markets are complex, with different definitions and sub-markets in each case. Generalizations useful for recording FCAS benefits in the table of economic flows is difficult.
- In the absence of a market, estimating the *potential* benefits is speculative (see case study of Section 6.4 for some attempts at this).
- Absent the involvement of an experienced electrical engineer with experience in FCAS market transactions, attempts by the project economist to include economic benefits of FCAS should be avoided.

UK

299. In the UK, BESS can participate in the Firm Frequency Response (FFR) market and receive bidding FFR payments. FFR participants register their provided services and bidding payments price. Through the monthly online tender process, the value of these registered services is evaluated by National Grid and only the most economical tenders are accepted. The FFR payments include the availability fee (£/h) for the hours that they are available, nomination fee (£/h) for the hours that they are dispatched, and the response energy payments (£/MWh) for the change in energy output while they are dispatched.

300. Four services are as defined in Table 42: separate tenders are issued for each.

Table 42: UK FFR services

<table>
<tr><th colspan="2">FFR product type</th><th>Response speed</th><th>Length of response</th></tr>
<tr><td colspan="2">Non-Dynamic – Secondary response is the only Non-Dynamic response currently procured.</td><td>Within 30 secs</td><td>30 mins</td></tr>
<tr><td rowspan="3">Dynamic – A Dynamic service can provide Primary, Secondary and High response, or Primary and Secondary only or High only.</td><td>Primary</td><td>Response required within 2 secs, with full response by 10 secs.</td><td>20 secs</td></tr>
<tr><td>Secondary</td><td>Within 30 secs</td><td>30 mins</td></tr>
<tr><td>High</td><td>Within 10 secs</td><td>Indefinitely unless otherwise agreed.</td></tr>
</table>

Notes

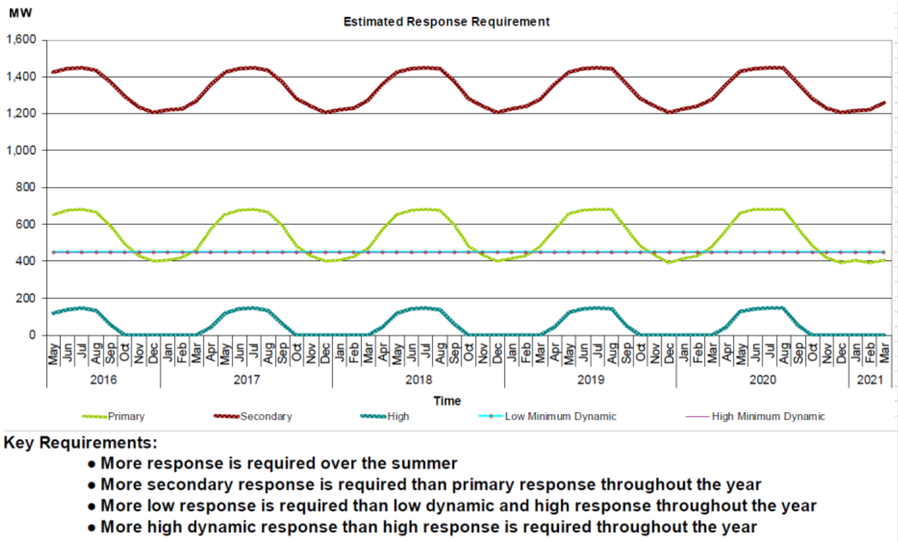
(1) Dynamic frequency response is continuously provided and is used to manage second-by-second frequency variations. Dynamic response is automatically delivered for all frequency variations outside of the band (50Hz ±0.015Hz)

(2) Non-Dynamic frequency response is triggered at a defined frequency deviation which is specified in the providers Framework Agreement, which must be in place before tendering. No response is required within the operating range.

Source: National Grid, *Firm Frequency response(FFR) Interactive Guidance*, v1.0 December 2017

301. The UK National Grid issues 5-year forecasts for each type of product: again note the seasonal differences (Figure 38).

Figure 38: FFR forecasts



Source: UK National Grid, *Firm Frequency Response: Frequently Asked Questions*, Version 1.3, August 2017.

Australia

302. In Australia, BESS could participate in the FCAS market and receive bidding FCAS payments. FCAS participants register their provided FCAS products with the Australian Energy Market Operator (AEMO). During each 5-min dispatch interval, the National Electricity Market Dispatch Engine (NEMDE) enables the sufficient amount of FCAS from these registered FCAS products and determines the market clearing price. The FCAS payment for each 5-min dispatch interval is calculated by Equation [1], where MWE is MW enabled by this service, and CP is the clearing price ($/MWh) determined by NEMDE.

$$\text{Payment} = \text{MWE} \times \text{CP}/12 \qquad \text{Eq.[1]}$$

303. There are eight markets in the NEM for procuring sufficient FCAS at any given time.

Regulation

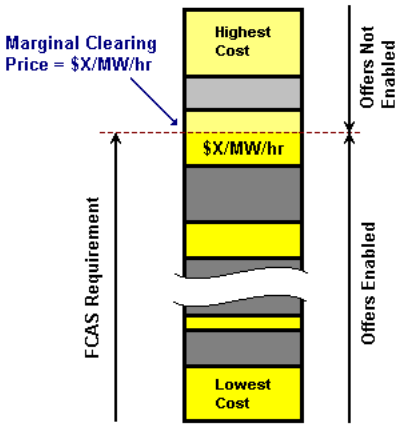
- Regulation Raise: Regulation service used to correct a minor drop in frequency.
- Regulation Lower: Regulation service used to correct a minor rise in frequency.

Contingency

- Fast Raise (6 Second Raise): 6 second response to arrest a major drop in frequency following a contingency event.
- Fast Lower (6 Second Lower): 6 second response to arrest a major rise in frequency following a contingency event.
- Slow Raise (60 Second Raise): 60 second response to stabilize frequency following a major drop in frequency.
- Slow Lower (60 Second Lower): 60 second response to stabilize frequency following a major rise in frequency.
- Delayed Raise (5 Minute Raise): 5 minute response to recover frequency to the normal operating band following a major drop in frequency.
- Delayed Lower (5 Minute Lower): 5 minute response to recover frequency to the normal operating band following a major rise in frequency.

304. An FCAS offer or bid submitted for a raise service represents the MW that a participant can add to the system, in the given time frame, in order to raise the frequency. An FCAS offer or bid submitted for a lower service represents the MW that a participant can take from the system, in the given time frame, in order to lower the frequency. During each and every dispatch interval of the market, National Electricity Market Dispatch Engine (NEMDE) must enable a sufficient amount of each of the eight FCAS products, from the FCAS bids submitted, to meet the FCAS MW requirement (Figure 39).

Figure 39: Marginal clearing price for FCAS



Source: Australian Energy Market Operator (AEMO), *Guide to Ancillary Services in the National Electricity Market*, April 2015.

Reading List 5: Frequency Control

Australian Energy Market Operator (AEMO), *Guide to Ancillary Services in the National Electricity Market*, April 2015. The Australian FCAS market is widely cited as a good example of how such markets function. Essential reading.

Yuan-Kang Wua and Kuo-Ting Tanga, *Frequency Support by BESS – Review and Analysis*, 5th International Conference on Power and Energy Systems Engineering, 19–21 September 2018, Nagoya, Japan. A simple, brief summary.

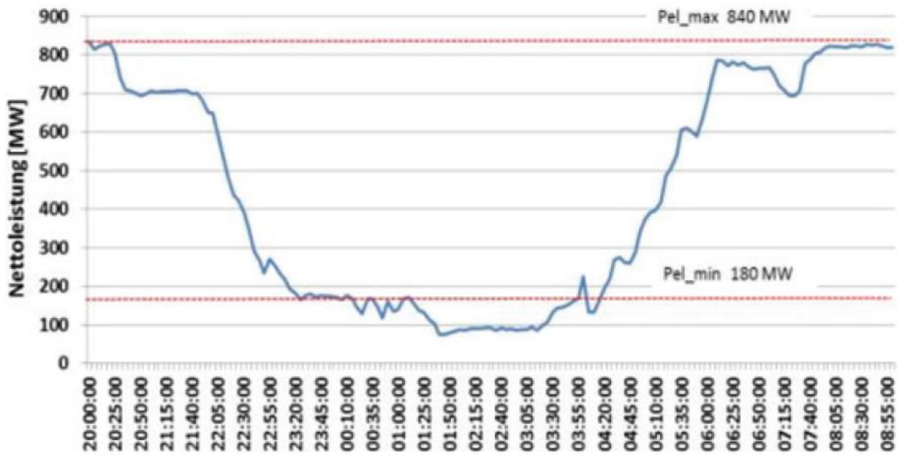
UK National Grid, *Firm Frequency Response: Frequently Asked Questions*, Version 1.3, August 2017.

UK National Grid: *Firm Frequency Response: Interactive Guidance*, V1.0 December 2017. More essential reading (together with the FAQ noted above)

ANNEX III: FLEXIBLE OPERATION OF COAL PROJECTS

305. Traditionally, coal units are unsuited load followers, since base load units are particularly sensitive to part load operation. However, in countries with a large proportion of coal generation, load following of large coal units has been unavoidable. Figure 40 shows a typical daily operation of the 875 MW Heyden coal project in Germany, where during peak renewable generation hours output has been stable at 100 MW, below the design minimum load of 180 MW (20% part load)

Figure 40: Operation for the 875MW Heyden coal project, Germany



306. The question of incremental cost of flexible operation of coal projects is now receiving much world wide attention, particularly in countries with high shares of coal generation such as India, Germany and the USA, that at the same time have ambitious targets for increasing the share of VRE. Box 9 summarizes a North American study that presents a cost-benefit assessment of retrofits to CCGT and coal units.

307. The topic has also received much attention in India, where ambitious targets for VRE occur in the context of heavy dependence on coal generation. A study by the Indian Central Electricity Regulatory Commission (CERC) on flexible operation highlights the cost penalties associated with part-load operation. These include

- CAPEX associated with modification to enable stable operation at low loadings (generally needed only for operation at less than 55%); these are however relatively small.[69]
- Increased OPEX: Flexible operation leads to a higher rate of deterioration of plant components. This is observed in increased failure rate and more frequent replacement of components. The impact on reduction in life of components is a function of the number of starts and stops the unit undergoes in a year.
- Penalties associates with oil consumption used for start-ups.[70]

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69 Siemens has estimated the cost of modifying Dadri Unit 6 (490 MW) to operate at 40% minimum load at IRp 20 Crores ($US3 million); General Electric estimated that the Talcher Unit 2 would require a IRp 50Crores ($7.5 million) for a similar modification to operate at low loads.

70 The use of HFO for startups in Indian coal projects is perhaps unique to India, and is a consequence of the characteristics of domestic Indian coal of generally poor quality that necessitate use of a more combustible fuel at start-up.

Box 8: Cost benefit analysis of thermal project retrofits in North America

This study assessed the benefits of retrofits to existing coal projects to reduce the costs of VRE integration in the Rock Mountain Power Pool, where base load coal has been used to accommodate a 44% share of VRE, imposing additional costs on these thermal projects. In a previous study, the number of cold starts for thermal units has been found to increase by 40% for a 30% share of VRE. This raises the question of whether such additional costs of VRE integration can be reduced by modifications to the coal and CCGT units. Three coal units in the system, accounting for 23% of the coal capacity were selected for study, with the following results on production cost.

	RMPP System - Case 4 (44% Penetration)	RMPP System - Case 4 (44% Penetration) - with retrofits	Difference
Fuel Cost ($)	679,659,987	668,431,932	11,228,056
VO&M Cost ($)	106,289,366	105,653,808	635,559
Start & Shutdown Cost ($)	57,087,248	55,012,198	2,075,050
Regulation Bid Cost ($)	10,199,155	10,406,849	(207,694)
Total Generation Cost ($)	853,235,756	839,504,786	13,730,970

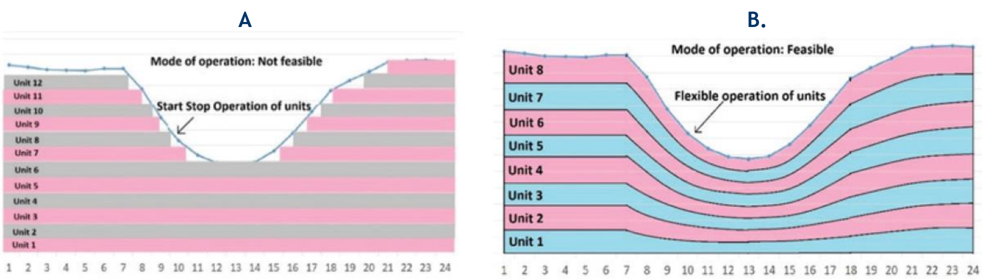
The decrease in system-level production cost is some $13million/year. The capital cost associated with the retrofits is $9million. No additional operating costs are associated with these retrofits. Using an fixed charge rate of 16%, the annual revenue requirement associated with the investment of $9 million is calculated to be $1.44 million. This annual revenue requirement is well below the savings in annual production cost, indicating that the retrofits have a net-benefit to the system. Therefore, in a regulated, vertically-integrated utility environment, the investment in these retrofits has merit. These investments would have an economic rate of return of >100% (with payback of less than 1 year!)

Although this study does not directly address the question of whether BESS could achieve the necessary flexibility at lower cost than adjusting the operations of the thermal units, it does set a benchmark for the economic performance of a BESS.

Source: Venkataraman *et al*., *Cost-Benefit Analysis of Flexibility retrofits for Coal and Gas-fueled Power Plants*, NREL, Report 60862, December 2013.

308. Coal fired plants usually take much time to start up due to the necessary time required to achieve required steam parameters. Therefore, daily start stop operation of the entire fleet is not feasible, technically as well as financially. In other words, the scenario given in Figure 41A, where some plants are started and stopped at the requirement of grid operator while others run at full load, is not possible

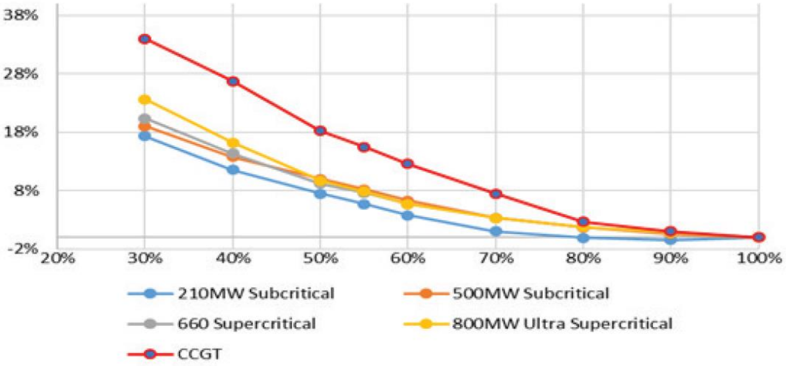
Figure 41: Mode of operation of thermal projects in the presence of large solar PV output



Source: Central Electricity Authority, *Flexible Operation of thermal power plant for integration of renewable energy*, January 2019, Figure 32.

309. Figure 42 shows the extent of heat rate penalties associated with part loading, as a function of technology and unit size. Older 210 MW scale coal units have proportionally lower heat rate penalties than large modern supercritical and ultra-supercritical (USC) units.

Figure 42: Heat rate penalties as a function of size and technology



310. Table 43 shows the heat rate and OPEX penalties incurred as a consequence of part loading of a typical 600 MW coal unit. The total incremental cost of 0.38 USc/kWh at 50% loading is about 10% of the full load cost of 3 USc/kWh (as per CERC study)

Table 43: Impact of part loading on a typical 600 MW project

load	output	Heat Rate Increase	Heat Rate Penalty	O&M penalty	total	total	total	step increment
[ ]	MW	[%]	Paisa /kWh	Paisa /kWh	Paisa /kWh	IRp/kWh	USc/kWh	USc/kWh
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1	600	0	0	0	0	0	0	0.000
0.9	540	0.80%	1.6	7.1	8.7	0.087	0.1299	0.130
0.8	480	1.70%	3.5	7.1	10.6	0.106	0.1582	0.028
0.7	420	3.30%	6.6	7.1	13.7	0.137	0.2045	0.046
0.6	360	5.70%	11.5	7.1	18.6	0.186	0.2776	0.073
0.5	300	9.20%	18.4	7.1	25.5	0.255	0.3806	0.103
0.4	240	14.40%	28.7	7.1	35.8	0.358	0.5343	0.154
0.3	180	20.40%	40.8	7.1	47.9	0.479	0.7149	0.181

100 Paise=1 IRp; $1 US=67 IRp

Source: Central Electricity Authority, *Flexible Operation of thermal power plant for integration of renewable energy*, January 2019, Table 18.

311. For the ubiquitous 200/210 MW scale coal unit still much used in India, the corresponding impacts are shown in Table 44.

Table 44: Impact of part loading on a typical 200 MW project

load	output	Heat Rate Increase	Heat Rate Penalty	O&M penalty	total	total	total	step increment
[ ]	MW	[%]	Paisa /kWh	Paisa /kWh	Paisa /kWh	IRp/kWh	USc/kWh	USc/kWh
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1	200	0	0	0	0	0	0	0.000
0.9	180	0.00%	0	7.1	7.1	0.071	0.106	0.106
0.8	160	0.00%	0	7.1	7.1	0.071	0.106	0.000
0.7	140	1.10%	2.1	7.1	9.2	0.092	0.1373	0.031
0.6	120	3.80%	7.5	7.1	14.6	0.146	0.2179	0.081
0.5	100	7.50%	15	7.1	22.1	0.221	0.3299	0.112
0.4	80	11.60%	23.2	7.1	30.3	0.303	0.4522	0.122
0.3	60	17.30%	34.6	7.1	41.7	0.417	0.6224	0.170

Source: Adapted from Central Electricity Authority, *Flexible Operation of thermal power plant for integration of renewable energy*, January 2019, Table 18.

312. These tables illustrate the difficulties of generalizations. We note

- significant differences between size of units.
- significant differences between the type of units (CCGT having proportionally greater penalties at part load than coal)
- the impacts are not linear: the incremental penalty (column [9]) is a function of what is the starting point. For example, if the loading is 60%, and decreases to 50%, in a 200 MW the incremental penalty is 0.112 USc/kWh. But if the initial loading is 40%, and decreases to 30%, the incremental penalty is 0.17 USc/kWh.

Annex IV: Lazard's Levelized Cost of Storage

313. **The levelized cost of storage LCoS, published by Lazard in their publication "*Lazard's levelized cost of Storage*", the most recent being version 6.0 of November 2019, are widely quoted.** It is important to understand how these estimates are actually defined - they are calculated in a *financial* model as that levelized cost, which when multiplied by the total annual generation (discharge), provides sufficient revenue to achieve a stipulated equity return for investors. The Lazard methodology is illustrated in Table 45.[71]

Table 45: Lazard's Cost of Storage Analysis - Methodology

Peaker Lithium—Low Case Sample Calculations								
Year (1)		0	1	2	3	4	5	20
Capacity (MW)	(A)		100	100	100	100	100	100
Total Generation ('000 MWh)(2)	(B)*		140	140	140	140	140	140
Levelized Storage Cost ($/MWh)	***(C)***		***$203.5***	***$203.5***	***$203.5***	***$203.5***	***$203.5***	***$203.5***
Total Revenues	**(B) x (C) = (D)***		**$28.5**	**$28.5**	**$28.5**	**$28.5**	**$28.5**	**$28.5**
Total Charging Cost (3)	(E)		($5.4)	($5.4)	($5.4)	($5.5)	($5.5)	($6.0)
Total O&M(4)	(F)*		(5.7)	(5.8)	(7.3)	(7.3)	(7.3)	(8.0)
Total Operating Costs	**(E) + (F) = (G)**		($11.1)	($11.2)	($12.7)	($12.8)	($12.8)	($14.0)
EBITDA	**(D) - (G) = (H)**		**$17.4**	**$17.3**	**$15.8**	**$15.7**	**$15.6**	**$14.5**
Debt Outstanding - Beginning of Period	(I)		$22.8	$22.3	$21.8	$21.2	$20.5	$2.1
Debt - Interest Expense	(J)		(1.8)	(1.8)	(1.7)	(1.7)	(1.6)	(0.2)
Debt - Principal Payment	(K)		(0.5)	(0.5)	(0.6)	(0.6)	(0.7)	(2.1)
Levelized Debt Service	(J) + (K) = (L)		(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)
EBITDA	**(H)**		$17.4	$17.3	$15.8	$15.7	$15.6	$14.5
Depreciation (7-yr MACRS)	(M)		(27.9)	(19.9)	(14.2)	(10.2)	(10.2)	0.0
Interest Expense	(J)		(1.8)	(1.8)	(1.7)	(1.7)	(1.6)	(0.2)
Taxable Income	**(H) + (M) + (J) = (N)**		**($12.3)**	**($4.4)**	**($0.2)**	**$3.8**	**$3.8**	**$14.4**
Tax Benefit (Liability)	**(N) x (Tax Rate) = (O)**		**$4.9**	**$1.8**	**$0.1**	**($1.5)**	**($1.5)**	**($5.7)**
After-Tax Net Equity Cash Flow	**(H) + (L) + (O) = (P)**	**($91.2)(7)**	**$20.0**	**$16.8**	**$13.5**	**$11.8**	**$11.8**	**$6.5**
IRR For Equity Investors		12.0%						

Key Assumptions (5)	
Power Rating (MW)	100
Duration (Hours)	4
Usable Energy (MWh)	400
100% Depth of Discharge Cycles/Day	1
Operating Days/Year	350
Capital Structure	
Debt	20.0%
Cost of Debt	8.0%
Equity	80.0%
Cost of Equity	12.0%
Taxes	
Combined Tax Rate	40.0%
Contract Term / Project Life (years)	20
MACRS Depreciation Schedule	7 Years
Total Initial Installed Cost ($/MWh)(6)	$814
O&M, Warranty & Augmentation Cost ($/MWh)	$43
Charging Cost ($/kWh)	$0.033
Charging Cost Escalator (%)	0.55%
Efficiency (%)	87%

Source: Lazard. *Lazard's Levelised cost of Storage Version 4.0*, Nov 2018

314. This methodology invites several comments

- This LCoS is not really a *cost*, but is the ***tariff*** that is necessary to meet a given revenue requirement.
- As a financial cost, it requires a range of assumptions about depreciation, taxes and debt service packages that has ***no*** relevance to economic analysis, and which by their nature are highly specific to the country in question.
- Lazard uses the term "fade" which presumably means the deterioration of battery performance over time. It is stated that "Lazard accounts for fade in augmentation costs included in O&M". This may or may not be reasonable for a financial analysis (and indeed O&M costs may increase over time), but for an economic analysis (and/or carbon accounting) this would not be appropriate:" it indeed matters how many GWh of energy are required for charging, and how many GWh are displaced when a BESS discharges, and how these change over time.
- The assumed financial structure of 80% equity and 20% debt is unusual. Few World Bank financed projects would have such a structure.[72]

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71 Lazard also presents values for "Storage+PV" for which Lazard assumes that the charging cost is provided from the PV rather than from the grid. Again, such estimates have no place as input assumptions in an economic analysis: costs always need to be considered on a case by case basis - as explained in the CAR case study of Section 6.2.

72 However, it is worth noting that there are some examples of the first VRE projects being financed with high equity shares for lack of access to domestic financing. The first IPP wind project in Sri Lanka was funded with 100% equity.

315. In this presentation, under the stated assumptions, the LCoS is calculated as $203.5/MWh (or 20.35 USc/kWh). In this example, Lazard assumes any degradation has been offset by augmentation. The annual cost as a percentage of original CAPEX is intended to reflect a combination of over-sizing and planned replacements which would typically modeled explicitly. Warranty costs are often included in CAPEX but in Lazard examples are estimated at an annual cost 1.5% of CAPEX from year 3 onwards.

316. Table 46 presents the corresponding economic analysis in our standard format. The result will be a function of the discount rate: at 10% the levelized *economic* cost of storage with four hours duration calculates to $185/MWh, somewhat lower than the Lazard financial cost of $203.5/MWh. In this case all augmentation (and warranty costs) have been added to annual O&M

Table 46: Economic analysis of Lazard's illustrative case

				NPV	2020	2021	2022	2023	2024	2025	2026
				[1000$]	0	1	2	3	4	5	6
[1]	**Assumptions**										
[2]	Battery capacity	100	[MW]								
[3]	Duration	4	[hours]								
[4]	Energy	400	[MWh]								
[5]	Cycles per day	1	[ ]								
[6]	Operating days	350	[days/year]								
[7]	Annual generation	140	[GWh]								
[8]	Inverter cost	49	[$/kW]								
[9]	BoS	27	[$/kWh]								
[10]	Module cost	205	[$/kWh]								
[11]	EPCcost	0.167	[%]								
[12]	**Energy balance**										
[13]	Energy output		[GWh]	*1083.5*	0	140.0	140.0	140.0	140.0	140.0	140.0
[14]	RT efficiency	0.87	[ ]								
[15]	Charging energy	0.006	[GWh]		0	160.9	160.9	160.9	160.9	160.9	160.9
[16]	Charging cost	0.033	[$/kWh]			0.033	0.033	0.033	0.034	0.034	0.034
[17]	**Economic analysis**										
[18]	***CAPEX***										
[19]	Module cost		[$USm]	*74.5*	82						
[20]	BoS		[$USm]	*9.8*	10.8						
[21]	Inverter		[$USm]	*4.5*	4.9						
[22]	EPC		[$USm]	*14.8*	16.3						
[23]	**OPEX**										
[24]	O&M		[$USm]	*54.0*	0	5.7	5.7	7.3	7.3	7.3	7.3
[25]	Warranty costs		[$USm]	*0.0*	0.0	0.0					
[26]	Charging cost		[$USm]	*42.6*	0.0	5.3	5.3	5.4	5.4	5.4	5.5
[27]	total costs		[$USm]	*200.2*	114.0	11.0	11.0	12.7	12.7	12.7	12.8
[28]	Levelised cost		[$/kWh]	0.185							
[29]	total CAPEX		[$USm]		114						
[30]			[$/kW]		1140						
[31]			[$/MWh]		814						

317. Note again that in both financial and economic analysis, estimates of LCoS are always *outputs*, not inputs.

GLOSSARY

Battery Life	The energy capacity of battery packs degrade with use. The life of a battery pack typically refers to when the available energy has declined to some pre-specified value (e.g. 70%). Beyond this point for some chemistries the rate of decline may increase rapidly.
Battery Management System	Battery-based storage systems typically employ a battery energy management system (BMS) that is responsible for monitoring and maintaining safe, optimal operation of each battery in the system. (Byrne et al 2017)
C-Rate	The fraction of total battery energy capacity that can charged or discharged in one hour. A battery energy system with a charge rate of C/3 and discharge rate of 1.5C could be charged in 3 hours but discharged in 40 minutes. Note: The C-rate for discharging and charging may not be the same.
Depth of discharge (DoD):	DoD is the fraction of the total energy stored that that is discharged during normal operation. DoD may be limited to reduce the energy degradation rate for the battery and is technology dependent. For a Li-ion battery used for daily cycling the DoD might be 70% or more. In contrast for a lead-acid battery the DoD is typically limited to 50%.
Duration	Duration is time the energy storage system can discharge at rated power. For example, a utility scale battery used for energy management might have 4 hours storage. Duration is often referred to as the energy-to power-ratio (kWh/kW).
Energy capacity	The energy capacity or energy rating is the total amount of energy (kWh) that can be stored by the battery.
Energy density	Specifies the energy stored per kg (or per unit volume). For example, Li-ion has a much higher energy density than lead acid batteries which make them more suitable for transportation. Energy density is less important for stationary applications. There is also a power density counterpart to energy density.
Energy management system	The EMS is responsible for optimal and safe operation of the energy storage systems. The EMS system dispatches each of the storage systems. Depending on the application, the EMS may have a component co-located with the energy storage system (Byrne 2017).
energy retention/standby loss	A battery will slowly discharge when not in use, though the rate varies significantly by technology and depends on the environment. This loss is given a fractional loss of energy per day or month.
Float charging	A method of maintaining a battery in a charged state by continuous, long-term constant-voltage charging, at a level sufficient to balance its self-discharge rate (DOE/EPRI: Linden's Batteries Handbook).
Flow Batteries	Flow batteries store energy through chemically changing the electrolyte (vanadium) or plating zinc (zinc bromide). Physically, systems typically contain two electrolyte solutions in two separate tanks, circulated through two independent loops, separated by a membrane. Emerging alternatives allow for simpler and less costly designs utilizing a single tank, single loop, and no membrane. The subcategories of flow batteries are defined by the chemical composition of the electrolyte solution; the most prevalent of such solutions are vanadium and zinc bromide (Lazard 2018b). Power and energy capacity can be sized separately which favors high duration devices. While round-trip efficiency lower than Li-ion they have advantage that electrolyte may not degrade, so may last for 20 years or more.
Flywheels	A Flywheel is a mechanical storage device that converts electrical energy into rotational kinetic energy and back to an electrical energy using a electrical motor-generator. The flywheel speeds up as it stores kinetic energy and slows down when it is discharging. A flywheel is composed of five primary components: a flywheel, a group of bearings, a reversible electrical motor/generator, a power electronic unit and a vacuum chamber. They achieve rotational speeds of 10,000 rpm to over 50,000 rpm, with rated power of between 200kW to 1,500kW and typical energy storage duration of 15 to 30 minutes: multi-hour duration flywheels are under development. Although flywheels presently account for a very small part of the global market,

	some believe that for the specific purpose of absorbing short-term fluctuations (as opposed to energy management applications such as arbitrage), flywheel technology may be the preferred technology by the mid to late 2020s, particularly for applications with multiple daily cycles This technology has several key advantages, notably that it has unlimited cycling over a 20-30-year lifetime, and involve no potentially hazardous materials. A first commercial scale project is underway at a 17 MW wind farm in Alaska. Flywheels can also be aggregated to provide larger power capacity. Stephentown, New York is the site of Beacon Power's first 20 MW plant (40 MW overall range) and provides frequency regulation service to the NYISO. The facility includes 200 flywheels Wind-diesel systems using only batteries as an energy storage show short battery life times. The reason for this short battery lifetime is rapidly changing charge and discharge due to the fluctuation wind speeds, especially in small systems. Modern wind diesel systems use flywheels for removing short term fluctuations and batteries for medium term energy storage and achieve much better lifetimes than batteries.
Lifetime/cycle life	Energy capacity degrades with use. One definition of battery life is the time (in years) or number of cycles that a battery energy system can be used before the energy capacity degrades to 70% of its original value, or some similar value. A good battery life for stationary applications may be 10+ years or 3,500+ deep discharge cycles. Flow batteries may have lifetimes of 20+ years or 10,000+ cycles.
Lithium Cobalt Oxide (LCO)	commonly used in portable electronics as they offer the highest energy density of commercial lithium battery technologies. The use of cobalt results in high energy density, but it is an expensive metal that displays thermal instability (unsafe) and fast capacity fade (short life) as a cathode material. These characteristics, combined with low power density, result in other lithium-ion chemistries being preferred for EV and stationary storage applications. (ITP Renewables)
Lithium ion batteries	are ubiquitous in portable electronics and electric vehicles, but are now cost-competitive in stationary storage applications where lead-acid and nickel-metal hydride technologies once dominated. "Lithium-ion" may refer to a number of technologies which use an electrolyte composed of a lithium-salt dissolved in an organic solvent. A graphite (carbon) anode is typically used, though alternative anode technologies are being widely investigated. The name of the technology generally relates to the cathode in use. As an example, a lithium cobalt oxide (LCO) battery has a carbon (C6) anode and a lithium cobalt oxide ($LiCoO_2$) cathode. Li^+ ions move between the two during charging and discharging, as electrodes swell and contract to accept/give-up ions. (ITP Renewables)
Lithium Iron Phosphate (LFP)	high thermal stability, long lifespan, and cheap cathode materials make LFP the obvious choice for stationary storage applications. However, owing to low energy density they are unsuited to EVs, and manufacturing volumes have not yet reached the point where system costs reflect the low materials costs. (ITP Renewables)
Lithium Manganese Oxide	once the chemistry of choice for EV manufacturers, the use of manganese in place of cobalt allows for higher power density and greater thermal stability when compared to LCO. However, lifetime remains short, and energy density is lower. (ITP Renewables)
Lithium Nickel Cobalt Aluminum Oxide (NCA	competes with NMC for market share in EV power trains. They exhibit high power density, high energy density, and long shelf life, but degrade more quickly with use than NMC cells. The increased cobalt content improves energy and power density, but also makes cells more expensive and less thermally stable.
Lithium Nickel Manganese Cobalt Oxide (NMC)	blending nickel with manganese and cobalt oxide improves cathode lifespan. Combining all three results in good performance across all metrics discussed thus far (energy density, power density, lifespan, and thermal stability). NMC can be thought of as an "all-rounder" chemistry, and production volumes are increasing

	owing to their suitability across many applications, particularly EVs. (ITP Renewables)
Power capacity – Size	MW or kW: Power capacity or power rating (kW) is the designed (or nameplate) maximum power output of the battery.
Energy capacity	MWh or kWh: The energy capacity or energy rating is the total amount of energy that can be stored by the battery (kWh).
Duration or storage time	Duration is maximum time the energy storage system can discharge at rated power. For example, a utility scale BESS used for energy management might have 4 hours storage. Duration is also referred to as the energy-to power-ratio (kWh/kW)
Efficiency or Round-trip efficiency	Efficiency is the fraction of energy that can be delivered as electricity compared to the amount of electricity that was used to charge the energy storage system. The round-trip efficiency varies from less than 65% to over 85% depending on technology (See Table 3). The round-trip efficiency of the system will be lower than the battery pack due to parasitic system losses, including any thermal cooling requirements
Depth of discharge (DoD) and State of charge (SoC)	For a Li-ion battery used for daily cycling the DoD might be 70% or more. In contrast for a lead-acid battery the DoD may be limited to 50% to limit degradation (see Lifetime). The state of charge (SoC) measures how full the battery is.
Lifetime/Cycle life	Energy capacity degrades with use. One definition of battery life is the time (in years) or number of cycles that a battery energy system can be used before the energy capacity degrades to 70% of its original value (or some similar value.) A good battery life for stationary applications may have a life of 10+ years or 3,500+ deep discharge cycles. Flow batteries can have chemistries that are resistant to degradation and may have lifetimes of 20+ years or 10,000+ cycles.
Energy density	kWh/kg (or kWh/m^3) Specifies the energy stored per kg (or per unit volume). For example, Li-ion battery packs have a much higher energy density than lead acid batteries which make them more suitable for transportation. Energy density is less important for stationary applications. There is also a power counterpart to energy density.
Charge and discharge rate ’	Fraction of total battery energy capacity that can charged or discharged in one hour. A battery energy system with a charge rate of C/3 and discharge rate of 1.5C could be charged in 3 hours but discharged in 40 minutes.
Energy retention/standby Loss	A battery will slowly discharge when not in use, though the rate varies significantly by technology and depends on the environment. This loss is given a fractional loss o energy per day or month.
Response time	Time to go from zero output to nameplate capacity. Batteries can respond ver quickly compared to conventional generation
MW-hour	For ancillary services that are **capacity** related, this indicates capacity that is available for one hour. This is to be distinguished from MWh, which is a unit of **energy**
Power capacity	Power capacity or power rating (kW) is the designed (or nameplate) maximum power output of the battery. Power capacity or power rating (kW) is the designed (or nameplate) maximum power output of the battery
power conversion efficiency	The power conversion system (PCS) is responsible for the grid electrical interface and managing power flows. The PCS receives commands from the EMS and interfaces to a battery management system (BMS) (Byrne 2017).
Primary control (reserve)	local automatic control which delivers reserve power in opposition to any frequency change;
Ramp rate	The ramp rate describes how fast a power plant can change its net power during operation. Mathematically, it can be described as a change in net power, ΔP, per change in time, Δt. Normally the ramp rate is specified in MW per minute (MW/min), or in the percentage of rated load per minute (% P/ min). In general, ramp rates greatly depend on the generation technology
response time	Time to go from zero output to nameplate capacity. Batteries can respond very quickly compared to conventional generation

Round trip efficiency	The round-trip efficiency of a BESS is the fraction of energy that can be delivered as electricity compared to the amount of electricity that was used to charge the energy storage system. The round-trip efficiency varies from less than 65% to over 95% depending on technology. The round-trip efficiency of the system will be lower than the battery pack due parasitic system losses, including any thermal cooling requirements.
Secondary control (reserve)	centralized automatic control which delivers reserve power in order to bring back the frequency and the interchange programs to their target values;
Spinning reserve	Generation capacity that is on-line but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. "Frequency-responsive" spinning reserve responds within 10 seconds to maintain system frequency. Spinning reserves are the first type used when shortfalls occur
Start up time	The time interval (generally measured in hours), from the beginning of the start sequence to the point of generator breaker closure
State of charge	The state of charge (SoC) measures how full the battery is.
Tertiary control	manual change in the dispatching and unit commitment in order to restore the secondary control reserve, to manage eventual congestions, and to bring back the frequency and the interchange programs to their target if the secondary control reserve is not sufficient
Toxicity and recycling	Varies widely by battery chemistry. According to ITP renewables "Lead-acid batteries are composed of highly toxic lead and highly corrosive sulfuric acid. For this reason, cell rupture or disposal in standard waste streams can be extremely hazardous. However, ruptures are rare and recycling initiatives are widespread. Over 95% of a standard lead-acid battery can be recycled Though primary (non-rechargeable) lithium batteries possess toxic metallic lithium, the components of secondary (rechargeable) lithium-ion batteries are much more stable. With recycling initiatives in their infancy, lithium ion batteries are most often disposed of in traditional waste streams. As large-format lithium-ion battery sales accelerate due to the expanding EV and stationary storage markets, these recycling options will necessarily expand. At present, disposal and recycling options for lead-acid batteries are much more advanced." ((ITP Renewables)
Zinc-air batteries	Zinc air or Zn-Air batteries a type "metal-air electrochemical cell technology. Metal-air batteries use an electropositive metal, such as zinc, aluminum, magnesium, or lithium, in an electrochemical couple with oxygen from the air to generate electricity. Because such batteries only require one electrode within the product, they can potentially have very high energy densities." DOE/EPRI 2015

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