

Review

# Transmission-Scale Battery Energy Storage Systems: A Systematic Literature Review

Kevin Marnell <sup>1</sup>, Manasseh Obi <sup>2</sup> and Robert Bass <sup>3,\*</sup> 

<sup>1</sup> Pacific Power, Portland, OR 97232, USA; kevin.marnell@pacificcorp.com

<sup>2</sup> Portland General Electric, Portland, OR 97204, USA; manny.Obi@pgn.com

<sup>3</sup> Department of Electrical & Computer Engineering, Portland State University, Portland, OR 97201, USA

\* Correspondence: robert.bass@pdx.edu

Received: 9 October 2019; Accepted: 28 November 2019; Published: 3 December 2019



**Abstract:** When the transmission capacity of an electrical system is insufficient to adequately serve customer demand, the transmission system is said to be experiencing congestion. More transmission lines can be built to increase capacity. However, transmission congestion typically only occurs during periods of peak demand, which occur just a few times per year; capitol-intensive investments in new transmission capacity address problems that occur infrequently. Alternative solutions to alleviated transmission congestion have been devised, including generation curtailment, demand response programs, and various remedial action schema. Though not currently a common solution, battery energy storage systems can also provide transmission congestion relief. Technological and market trends indicate the growing production capacity of battery energy storage systems and decreasing prices, which indicate the technology may soon become a viable option for providing congestion relief. Batteries can provide multiple ancillary services, and so can concurrently provide value through multiple revenue streams. In this manuscript, the authors present a systematic review of literature, technology, regulations, and projects related to the use of battery energy storage systems to provide transmission congestion relief.

**Keywords:** battery energy storage systems; transmission congestion; systematic literature review

---

## Preface to the Reader

This paper presents a systematic literature review (SLR) of transmission-scale battery energy storage systems. The authors compiled a library of literature, choosing to include or exclude documents based on a specific set of selection criteria. Some of the references in this review were not discovered through the SLR process, but nonetheless aid in explaining the context of the reviewed material. All references are labeled in the text using the '[#]' format. References in the text that were discovered through the SLR are labeled with an '\*' after the in-text citation. In the References section of this paper, the SLR sources are also labeled with an '\*' after their citation.

## 1. Introduction

High-voltage transmission lines link remote electrical generation to distribution networks, which serve end-use electrical loads. Greater loads necessitate greater power generation. When this power exceeds transmission line capacity, transmission congestion occurs, defined as when the least-cost generated power cannot reach a load due to inadequacy of the transmission network to safely and reliably deliver that power [1]\*. This can lead to system instability and, consequently, violation fines, when the lines are operated beyond permitted limits. Transmission congestion can cause network security violations in transmission lines like thermal violations, voltage regulation violations, angular stability violations, or reliability margin violations [2]\*. When congestion occurs,

generation is frequently rerouted, and customers must buy electricity from more expensive generation sources [3]\*.

Transmission congestion may be ameliorated by expanding transmission capacity. However, most nodes in a transmission system experience peak loads only a few days per year and for only a few hours during those days [1]\*. Zheng et al. observed that the duration for which the peak load exceeds 95% of the transmission capacity is less than 1% of the whole year [4]. Therefore, transmission expansion projects address congestion problems that occur during just a few peak hours and within a handful of days each year. During the rest of the year, however, the existing capacity is sufficient to satisfy demand.

These so-called new-wires solutions involve increasing transmission capacity by upgrading existing lines or adding new lines when replacement is not practical [2]\*. New-wires solutions have significant drawbacks. For one, they require a lengthy permitting process with no guarantee of approval. They are expensive investments, capital intensive to build, and are expensive to operate and maintain. Additionally, such solutions may carry a large carbon footprint [5]\*. Non-wires alternatives on the other hand offer approaches that do not require upgrades or installation of new conductors, do not require the acquisition of new transmission corridors, have a much smaller geographic footprint, are faster to commission and could be less expensive than new transmission line projects.

After the historic North America blackout of August 2003, the North America Electric Reliability Corporation tasked the Regional Transmission Operators (RTO) and Independent System Operators (ISO) with oversight of ensuring and enforcing grid reliability standards, which they do using several forms of Transmission Congestion Relief (TCR). The most common non-wires TCR approach RTOs and ISOs take is to request power producers to reduce generation. This is known as curtailment. Of all the generation sources (thermal, hydro, nuclear, wind, and solar), wind is one of the least expensive to operate and as such, is frequently designed with allowances for curtailment [6]\*.

Thermal units typically do not perform well economically when curtailed due to thermal cycling limitations. Sometimes, an order is put out by a balancing authority (BA) within an RTO or ISO requesting generation curtailment at one node and increased generation at another node, which is another non-wires solution to TCR. This balancing act is known as incrementing and decrementing: incrementing generation along an uncongested corridor while concurrently decrementing generation along a congested corridor. The goal is to ensure power is supplied to loads while keeping the area control error within allowable limits. Such orders are time-sensitive, with power producers only having minutes to respond or risk paying violation fines.

Another non-wires means for relieving TCR is demand response. Demand response programs reduce transmission congestion through peak shaving: the reduction of load during peak demand times. When a line becomes congested, a control signal is sent to electrical loads within the balancing area, often large industrial customers, requesting that certain predetermined loads be taken offline. Consequently, the load is reduced to match the power capacity limit of the line, thereby avoiding transmission congestion.

Battery energy storage systems (BESS) also have the potential to provide TCR. This literature review presents multiple means for addressing TCR using large-scale BESS. At its simplest, BESS placed at the receiving end of a constricted transmission corridor can be scheduled to preemptively charge during low-load periods and then discharge during peak load periods, thereby avoiding transmission congestion [2]\*. In addition to providing TCR, which is required only a few times per year, batteries can also be dispatched to provide other services when TCR is not required. These include providing resource adequacy in the form of additional “generation” capacity, or fast-acting ancillary services such as frequency response and frequency regulation [1]\*. The services provided by BESS are “stackable,” meaning a BESS can concurrently offer multiple services [7]\*, and as such BESS can draw revenues from multiple markets [8]\*.

As of the turn of the twenty-first century, BESS were mostly seen as a means of extending the life of stochastically distributed energy resources like solar and wind. With advancements in battery chemistries and manufacturing methods, and with a corresponding falling in prices, BESS have become viable solutions for many utility-scale applications, leading researchers and industry experts to re-examine BESS for TCR. Although a number of papers have been written on the topic, a comprehensive literature review has not yet been conducted.

In this manuscript, the authors present a systematic review of literature, technology, regulations, and projects related to TCR with emphasis on BESS. In Section 2, the authors discuss the methodology used to conduct this systematic literature review, as well as the research questions the authors aimed to answer. Section 3 elaborates on the research questions guiding this literature review. Section 4 provides an update to the governmental, regulatory and legal requirements of using BESS for TCR, while Section 5 summarizes the authors' findings in the review and offers concluding remarks.

## 2. Methodology

A systematic literature review (SLR) is a well-defined method for aggregating academic, technical, and professional literature to answer research questions using processes that are consistent and repeatable, in contrast to an ad hoc literature selection. An SLR is conducted in stages. In the first stage, potential research questions are formulated. In the second stage, a search for relevant literature, technologies, projects, and regulatory materials are conducted to answer the research questions. This yields a pool of documents that is shrunk in the third stage by the application of inclusion criteria. Documents that meet the inclusion criteria are included in the SLR, while documents that do not meet these criteria are excluded.

The authors considered the following six research questions (RQ):

- RQ1: What does literature (peer-reviewed or otherwise) discuss BESS as a solution to transmission congestion?
- RQ2: What BESS technologies are in development and which ones have recently been deployed?
- RQ3: What are the projected installation and operation costs?
- RQ4: What are the projected revenue streams or savings associated with BESS?
- RQ5: What are the economic indicators used for evaluating BESS?
- RQ6: Are storage models available that can model added value of BESS, such as arbitrage, TCR, and ancillary services?

In addition to answering these six questions, the authors conducted a review of laws and regulations related to energy storage in the U.S.

### 2.1. Search Criteria

To answer these RQ's, the authors approached this review by developing a large pool of material, while recording database names and search terms for replicability. The authors used the following databases, search terms, and criteria to produce a set of reproducible search results. The authors acknowledge that database searches can change over time. As such, future search results could yield a pool of materials that would later be considered for inclusion in the review.

#### 2.1.1. Inspec

The Inspec database catalogs academic articles across many fields including physics and electrical engineering. When searching the database, the authors required all articles to be available in English. Preference was given to journal articles. However, in some cases where technology was new, conference papers were considered. The five searches from Inspec yielded the following outcomes:

Search 1 was a basic search with the terms energy storage, congestion and transmission searched in all fields. The search was then limited to articles containing energy storage in the controlled vocabulary.

Documents were limited to journal articles, book chapters, and dissertations. Non-English documents were excluded. This search yielded 19 documents.

Search 2 was a basic search with the terms battery and transmission congestion searched in all fields. The documents were limited to journal articles. Since telecommunication research uses the terms battery and transmission congestion in different contexts, articles were excluded for having the following controlled vocabulary terms, telecommunications traffic, telecommunication power management, ad hoc networks, telecommunication network routing, routing protocols, wireless LAN, telecommunication congestion control, wireless sensor networks, telecommunication scheduling, mobile ad hoc networks, mobile radio, telecommunication network reliability, radiofrequency identification, radiofrequency interference, and telecommunication control. This search yielded 13 non-duplicated articles.

Search 3 was a basic search with the terms battery and levelized cost of electricity (LCOE) searched in all fields. This yielded 50 non-duplicated articles.

Search 4 was a basic search with the terms energy storage, utility, technology, and congestion searched in all fields. Search 4 yielded 21 non-duplicated documents.

Search 5 was a basic search with the terms energy storage and ancillary searched in all fields. Conference papers and conference papers were excluded from this search, and papers were limited to English. This yielded 49 non-duplicated results.

#### 2.1.2. Google Scholar

Google Scholar sorts through academic journals, scientific conference proceedings, and white papers from many published journals and open-access materials. When Google Scholar is accessed through an academic institution, the results are filtered to show only publications to which the academic institution subscribes and open-access publications. The authors performed a Google Scholar search using the terms cost, transmission, and BESS. The authors accepted the first 70 results in the search for consideration, although some of the search results were replicated by other search databases.

#### 2.1.3. DOE/Sandia National Labs Energy Storage Database

The Department Of Energy's (DOE) Sandia National Laboratory (SNL) tracks energy projects worldwide. The database was downloaded in its entirety and sorted through by this paper's authors.

#### 2.1.4. U.S. Congress

The U.S. Congress's website offers a searching feature for bills and laws. An advanced search was performed for the term energy storage in the titles or summaries of bills and further limited to bills that were signed into law since 2001. This search yielded five pieces of legislation.

#### 2.1.5. Federal Energy Regulation Commission (FERC)

FERC's website contains a dedicated page of major federal orders and regulations. On this page, FERC posts pertinent documents and other regulatory decrees. The authors combed through this page for a comprehensive review of FERC's current orders and projects pertaining to energy storage.

#### 2.1.6. Referenced Articles

The authors considered materials referenced from certain relevant publications in their search for materials. A publication from the National Renewable Energy Laboratory (NREL) that came out in September of 2014 [9] listed energy storage laws in a number of states. The regulations, bills, and laws that were mentioned in this survey and were relevant to utility-scale battery energy storage were looked upon the relevant state websites and databases.

Utility Dive (Utility Dive, [www.utilitydive.com](http://www.utilitydive.com)) is an online trade journal of news related to the electrical utility industry. A wide search was conducted of articles that were tagged energy storage.

Articles that mentioned laws and regulatory actions regarding energy storage were used as a basis for tracking down the original legal documents from their official government websites.

White papers from NREL and the Electric Power Research Institute (EPRI) were considered for inclusion in the literature review provided they were referenced by other documents included in the literature review. An EPRI presentation on energy storage was considered for probable relevance to this review [10]\*.

## 2.2. Inclusion Criteria

Having built a large pool of materials, the authors developed inclusion criteria to ensure that only the most useful and relevant material was included in this paper. The authors focused on large-scale BESS and high voltage transmission. The authors chose to focus on battery projects and legal materials within the U.S, but were willing to include international projects when they included technologies not prevalent in the U.S. Table 1 outlines the inclusion criteria that the authors used for the purpose of this literature review.

**Table 1.** Systematic literature review (SLR) inclusion and exception criteria.

Source	Inclusion Criteria	Exception Criteria
Journal Papers	Discuss TCR, transmission upgrade deferral, peak-shaving, or load leveling in relation to Utility-Scale energy storage.	Focus on renewables or focus on microgrids, demand response, battery energy storage transportation or electric vehicles.
Journal/conference papers	Discuss LCOE in relationship to Utility-Scale energy storage.	Focus on renewables or focus on microgrids
Journal/Conf/White Papers	Insights on battery legislation.	none
EPRI and NREL materials	Provide comparison analysis of BESS technologies	Sources must be referenced from other included materials.
Lead-acid battery Project	Operating or once operating and over 10 MW	Projects outside of U.S. Jurisdiction
Nickel Cadmium Battery Projects	Operating and over 10 MW	Projects outside of U.S. Jurisdiction
Lithium-ion battery projects	Operating and over 10 MW	Projects outside of U.S. Jurisdiction
Sodium–sulfur battery projects	Operating and over 10 MW	None.
Flow Batteries	Planned or operating and over 10 MW	None.
Any battery project	Analyzed in an Included Journal Paper	Projects that were not specifically analyzed, but spoke in generalities or thrown onto a table of projects.
Federal Laws	Discuss policy, regulation or incentives for Energy Storage	None.
Federal Regulation Paperwork	Discuss regulation or incentives for Utility-Scale Energy Storage	None.
State Laws	Discuss regulation or incentives for Utility-Scale Energy Storage	None.
State Regulation Dockets	Discuss regulation or incentives for Utility-Scale energy storage	Decided or finalized.
Paperwork submitted to state dockets	Discuss energy storage for TCR, transmission upgrade deferral, peak-shaving, or load leveling	None.

Inspec's electronic database and Google Scholar articles largely came from peer-reviewed journals. The authors included the selected journal articles that focused on TCR, transmission investment deferral or related topics like peak shaving and load-leveling. However, journal articles that met these criteria were excluded when the focus of the article was directed toward renewable power rather than energy storage or when the articles focused on microgrids, demand response, or electric vehicles.

By excluding these articles, the review would be more focused on large-scale BESS applicable to power transmission.

Peer-reviewed journal articles and conference papers that discussed LCOE or similar economic indicators in relation to energy storage were included as part of this literature review, provided their focus was on utility-scale energy storage rather than renewable energy or microgrids. Again, the authors tried to keep these materials focused on large-scale power. Journal, conference, and white papers with insights on battery legislation or regulatory policies were also included.

The energy storage projects that the authors considered were based on size and geographic location. The authors considered projects of 10 MW or greater as the definition of large-scale BESS. Inclusion criteria for lead-acid, nickel-cadmium, and lithium-ion projects were a minimum power of 10 MW, located in the U.S., and have been fully operational at some point in their lifetime. Sodium–sulfur projects, being rare in the U.S., were mentioned internationally. These were included provided they were over 10 MW and operational. As of the time of this review, the authors found no flow battery projects in the U.S. over 10 MW in size. International projects were included instead, provided they were over 10 MW, regardless of whether they were operational or in development. Additionally, battery projects mentioned in literature from the Inspec and Google Scholar searches were included, regardless of size, provided they were analyzed in specific detail rather than spoke of generally in a table.

For the legal review, the authors focused on legal materials in the U.S. The legal review was confined to bills, laws, proposed and current regulations, and dockets that apply to utility-scale energy storage in the U.S. The authors felt that federal laws and regulations, due to their wider area of jurisdiction, were most important to include. Enacted laws from the U.S. Congress that were part of the material pool were included. FERC regulations in the material pool were included regardless of enactment. State laws and regulations were included only if they were actually enacted.

### *2.3. Applying the Inclusion Criteria*

The search criteria from Inspec and Google Scholar yielded 218 non-duplicate documents. Of these, one document was not in English, one could not be found, and 165 were excluded by their titles and abstracts. The remaining 55 articles were read in full. An additional 23 documents were excluded upon complete reading. As such, the Inspec and Google Scholar searches yielded 32 included documents.

The DOE/Sandia database had 1635 entries. After removing all entries that were not electro–chemical storage or were under 10 MW, 102 entries remained. These results were then sorted by their technologies. Seven lead-acid projects, one nickel-cadmium battery project, twenty-two lithium-ion battery projects, five sodium–sulfur battery projects, and three flow battery projects met the inclusion criteria. Additionally, projects mentioned in included materials from the Inspec and Google Scholar searches were also included, which meant two battery projects in Italy (lithium-ion) and one in the U.K. (also lithium-ion) were also included. A total of 41 projects were included in this review.

Legal searches were conducted differently, looking for materials from the U.S. Congress and FERC searches as well as laws referenced from Utility Dive or NREL's issue brief [9]. All of the enacted laws from the U.S. congress search were included as well as all of the FERC regulations dealing with energy storage, regardless of enactment. From the NREL issue brief, laws and regulations from California, New York, and Texas met the inclusion criteria. The authors of this paper combed through roughly 850 utility dive articles tagged as “energy storage”. Articles with titles that suggested a law could be found that met the inclusion criteria were read further. The specific laws and regulations were then found at their respective state or federal websites.

White papers from EPRI and NREL, when referenced by documents already in the included materials, were included provided they offered some comparison analysis between BESS technologies. Additionally, the EPRI presentation on energy storage was included, as it also met the inclusion requirement.

The final pool of documents was parsed through by the authors of this SLR. The authors used these documents to answer the pre-formulated RQs and to round out the regulatory and legal review. This SLR included a total of 75 documents.

### 3. Research Questions

#### 3.1. RQ1: What Does Literature (Peer Reviewed or Otherwise) Discuss Regarding BESS as a Solution to Transmission Congestion?

Several papers examined energy storage and wind integration. When wind power produces too much power for the transmission grid to handle, generation can be curtailed. Nguyen et al. used an AC-power optimal power flow (OPF) model to determine the ideal siting of energy storage assets [11]\*. They found that the addition of energy storage reduces locational margin prices (LMPs). They further found that energy storage assets on a nodal transmission system are optimally-sited at nodes with high LMPs and that siting energy storage at the same node as the wind power was one of the least ideal placements for energy storage. The mere presence of energy storage, whether ideally sited or poorly sited, reduced wind curtailment, but optimal siting also provided TCR, thereby lowering LMPs.

Arabali et al. modeled stochastic wind generation with a probabilistic density function. From there, they built a DC probabilistic OPF to account for the uncertainties of wind generation [6]\*. They calculated the size and location of energy storage using particle swarm optimization in order to minimize two costs, the cost of operation and the cost of transmission congestion. Their results show that when wind penetration is low, transmission congestion does not become a major problem. Therefore energy storage is best placed at the same location as the wind generation, which is ideal for preventing wind curtailment. When wind penetration reaches levels high enough to require curtailment even with energy storage, then energy storage is best placed at a bus other than where wind power is generated. This optimal siting allows energy storage to both relieve transmission congestion and cut operating costs by reducing curtailment. Giving the optimization model the ability to distribute storage among two nodes allowed for more cost reductions. Arabali et al. used compressed air energy storage (CAES) assumptions in calculating their model.

Vargas et al. examined transmission congestion management considering the interactions of wind curtailment, energy storage, and ramp-up/down rates of wind and conventional generators [12]\*. Vargas et al. considered the operational costs incurred from re-dispatching conventional generators, noting that generators with slower ramp rates incurred higher costs. Their model assumed that energy storage was co-located with wind generation. Vargas et al. created an OPF model to analyze management strategies for transmission congestion including doing nothing, curtailing wind, using energy storage alone, and using energy storage in conjunction with wind curtailment. They further performed a sensitivity analysis to determine the effects of generator ramp rates and energy storage characteristics. They determined that strategies involving wind curtailment with or without energy storage could eliminate transmission line congestion. They also found that transmission line utilization increased when energy storage was used in conjunction with curtailment. Their sensitivity analysis showed that generators with slower ramp rates created large over-costs, and that energy storage systems (ESS) could reduce the re-dispatch of conventional generation.

Alqunun and Crossley used a mixed integer program to compare distributed energy storage against centralized energy storage in a nodal network [13]\*. They used a DC-OPF and combined economic dispatch with unit commitment problems to minimize operation costs of thermal generation and operation and maintenance costs of energy storage. They tested their model on a six-bus system with three gas generators and used lead-acid batteries for energy storage. They performed test cases with no storage, centralized storage at a single bus, and distributed storage at each of six buses. Their model indicated that both storage cases outperformed the no-storage case, and that distributed storage outperformed centralized storage. They also discovered less transmission and distribution congestion when using distributed storage, which could defer the upgrade of transmission and distribution (T&D) infrastructure.

While some articles arbitrarily sited energy storage [12]\*, other articles analyzed optimal siting of storage systems [6,11]\*. Dvorkin et al. examined energy storage from the outlook of ensuring profitability in the presence of low-cost wind availability [14]\*. They built a model for siting, sizing, and operation of an energy storage system in the presence of wind generation and conventional generation. They used a bi-level program for optimization. Their upper-level program made siting and sizing decisions, while their lower level program made operational decisions based on representative days. Their program calculated its own LMPs, which allowed it to account for the effects of energy storage on LMPs. They then turned this program into a mixed-integer linear programming (MILP) problem, and solved it using computer simulation. They found that coordinated distributed energy storage brought greater profits to the energy storage owner and savings to the system operator. They additionally showed privately-owned energy storage could draw additional profit by manipulating the LMPs to promote arbitrage, but that the overall system would be negatively effected.

Pandzic et al. devised an optimization model for siting, sizing, and operation [15]\*. They built a three-stage unit commitment problem formulated as a MILP. In the first stage, they allowed variable siting, sizing, and operation. In the second stage, they took the best sites from stage one and allowed for variable sizing and operation. In the third stage, they took the best sizing and siting from stage two and optimized for the best operation strategy. They demonstrated an advantageous connection between energy storage and wind penetration, which reduced LMP volatility. They demonstrated that the feasibility of energy storage was reduced when the price of energy storage increased. They showed distributed energy storage had advantages over centralized storage, but they showed limitations to the gains made from distributed storage after a point. Pandzic et al. performed sensitivity analysis on their model, finding that location and sizing did not change significantly with  $\pm 5\%$  changes to wind generation.

Rosso and Eckroad investigated battery energy storage to provide TCR by relieving thermal constraints on transmission lines [2]\*. They analyzed energy storage used as part of a corrective control scheme. They suggested that in the event of a fault, a battery placed at either the sending or receiving end of the line could prevent a contingency from occurring by absorbing or injecting power. Thus a battery could permit greater transmission capacity through a transmission line by protecting the line from going above its thermal limits. Rosso and Eckroad determined optimal siting of a battery through an analytical heirarchical process model, taking into account sensitivity factors of locations that led to congestion. After determining an optimal site for the battery, the battery power was then calculated from the desired boost in transmission capacity. They observed that adding a 50 MW battery to a transmission bus could increase the pre-contingency capacity of that line by roughly 55 MW.

Khani et al. crafted a real-time optimal dispatch (RTOD) algorithm to optimize privately-owned energy storage revenue [16]\*. In their RTOD, energy storage revenue came from providing TCR and participating in energy arbitrage, ignoring other possible revenue sources. They modeled their RTOD as a MILP. To participate in transmission relief, energy storage frequently needed to prepare itself by charging. Yet if the energy storage asset were trading on arbitrage positions, it might not be sufficiently charged to provide congestion relief. Khani et al. devised an adaptive penalty algorithm to disfavor energy storage participating in arbitrage when transmission congestion was forecasted. This penalty factor caused the energy storage to prefer charging for TCR over trading on the energy market. Khani et al. states that they assumed the revenue for providing congestion relief will reward the decision to prepare for providing TCR. They used CAES models in their simulation.

Berrada et al. devised a dispatch model to analyze energy storage participating in frequency regulation and energy arbitrage [17]\*. They built their model to compare the operation of gravity storage against CAES and pumped hydroelectric storage (PHS). They used a linear programming model and took historical energy market data from the New York ISO (NYISO). When simulated, the model chose to participate in frequency regulation almost exclusively because higher revenues were typically offered in that market. The dispatch model did show profitability for PHS and CAES

systems, but found gravity storage would not be profitable unless it could offer additional benefits like deferring T&D upgrades or avoiding distribution outages.

Lu and Shahidehpour examined the optimal scheduling of batteries as part of a photovoltaic (PV) system from a security-constrained unit commitment outlook [18]\*. Their model had a thermal unit sub-problem and a PV-battery unit sub-problem. PV-battery generation could substitute for thermal generation when thermal generation prices were high, causing thermal generation to revise its unit commitments. The overall problem was solved using a Lagrangian relaxation method and network flow programming. The simple optimization goal was to replace thermal generation with PV/battery generation. Lu and Shahidehpour used their model to show that PV/battery systems could mitigate congestion and reduce LMPs. They also looked at the effects of grid-connected PV/battery systems to both reduce LMPs and reduce unit commitment of thermal generation plants.

Mohsenian-Rad examined large-scale battery investments as price-makers rather than price-takers [19]\*. These deployments were large enough to influence pricing in energy markets. Mohsenian-Rad devised a coupled nonlinear optimization problem for market-moving energy storage, which he then reformulated into a MILP that he could optimize. He provided a deterministic version of his solution, as well as a stochastic version to account for market uncertainties. He optimized profits for the energy storage system, finding that energy storage made profits with and without transmission congestion. In general, the model showed that congestion benefited energy storage profits, but not always, as demonstrated in a few cases. Mohsenian-Rad showed that energy storage provided a service to the grid by reducing generation costs. Though energy storage is not directly compensated for this service, it is able to generate revenue directly through arbitrage during congested periods. His study determined that battery efficiencies as low as 80% were still capable of generating profit. He also determined that dispersed battery deployments performed better than centralized batteries, and that economic bidding proved advantageous over scheduled operation.

Das et al. developed a high-fidelity dispatch model that optimized for both bulk energy and ancillary services for various energy storage technologies, including CAES, PHS, BESS, and flywheels [8]\*. They crafted a high-fidelity production costing model using a bi-level program that first determined unit commitment using a MILP and then determined economic dispatch using linear programming. Their model incorporated cross-arbitrage, the act of taking energy from one market, like an upregulation in the ancillary services market, and selling it into a different market, like the energy market. By accounting for cross-arbitrage, they found their model predicted a value increase of a 100 MW CAES unit to be 3.2 times that of a model that did not account for cross-arbitrage. Das et al. examined the question of whether BESS should be designed to participate in both energy markets and ancillary service markets or to participate strictly in ancillary service markets. They found batteries designed for ancillary services made greater revenues than those designed to participate in both ancillary services and energy markets.

Hartwig and Kockar modeled strategic bidding and dispatch decisions of energy storage in a nodal market [20]\*. They created a bi-level optimization model, the upper level designed to maximize the difference in buy and sell LMPs and the lower level a DC-OPF problem. This non-linear model was further relaxed into a MILP. Hartwig and Kockar examined how generation assets and energy storage assets can game an energy market for maximum profit at the expense of overall grid welfare. Their model examined only the ability to bid into energy markets, not ancillary service markets, and focused in particular on the market incentives in Great Britain. Hartwig and Kockar demonstrated that the addition of energy storage to a market with strategically-bidding generation assets would still provide a net benefit to the system as a whole. They showed electrical grids operated best when neither generation assets nor energy storage assets were gaming the system. Hartwig and Kockar showed that as line congestion became a factor, strategic energy storage bidding was more damaging to the system welfare. They also suggested that incentivizing energy storage based on its capacity could improve the system welfare, allowing energy storage to remain available when needed most.

Kazempour et al. developed a near-optimal, self-scheduling model to compare the economic feasibility of PHS to sodium–sulfur batteries [21]\*. They considered day-ahead participation in energy markets, regulation markets, and spinning reserve markets. Their model demonstrated sodium–sulfur batteries and PHS both made economic sense, though PHS showed a much clearer promise of profitability.

While sitting, sizing, and operation are inherent to the planning process, some papers took a decided focus toward planning. Hartel et al. crafted a MILP to approximate the German T&D grid and determine the feasibility of battery energy storage projects [22]\*. Their study did not include market simulation nor allow batteries to participate in ancillary service markets. Hartel et al. demonstrated that energy storage for the purpose of relieving congestion was not financially prudent up to the year 2025. Additional renewable energy generation and decreasing future battery prices could make future deployments feasible. They also added that pure economic reasons for energy storage ignored the ability of BESS to provide resiliency and grid security.

Babrowski et al. analyzed energy storage on the German grid as a long-term planning strategy [23]\*. They used PERSEUS-NET-ESS (Package for Emission Reductions Strategies in Energy Use and Suppl–NET–Electricity Storage Systems) software, which is a bottom-up model of the German electricity system. Using this software model, Babrowski et al. estimated the present and predicted future costs of batteries, determining how batteries could be integrated into the grid starting in 2015 and going to 2040. They built a simplified weather model, ignoring catastrophic weather events, and simulated the present and future German grid. Based on their models, Babrowski et al. determined that energy storage does not show significant benefits until about 50% renewable penetration, or until 2030 in Germany. As a matter of policy, they suggested waiting to buy energy storage assets until the prices came down.

Huynh used an EPRI-created software, Energy Storage Valuation Tool 4.0, to compare energy storage technologies [5]\*. He compared PHS against battery energy storage, finding battery energy storage practical for the U.S. City of San Diego. He further explained how energy storage projects can replace new transmission, significantly reducing greenhouse gasses in the process.

Qiu et al. developed a model for co-planning energy storage projects along with transmission projects [24]\*. Their model incorporates the choices to build transmission infrastructure as well as to install modular energy storage projects that could be upscaled in future years. They built a stochastic co-planning model that included operational and capital costs associated with new BESS and new transmission installations. They then simulated their model on a 24-bus test system. Their model demonstrated that co-planning battery energy storage projects with transmission line projects reduces the number of new transmission lines built. They also found that when transmission congestion was an issue, BESS was optimally sited close to load that was at risk of curtailment. When congestion was not an issue, BESS was instead optimally placed near wind generation to prevent wind curtailment.

While most papers focused on relieving transmission congestion by operating batteries on the transmission grid, a few papers suggest placing energy storage closer to the customer. Xu and Singh developed a model predictive control-based operating strategy for minimizing purchased electricity costs using smart grid communication and controls [25]\*. These predictive control models were designed for distribution network-connected energy storage, but could be used to benefit either the distribution network or the transmission network. Xu and Singh used sequential Monte Carlo Simulation to test their model on a 24-bus system. They showed energy storage at the distribution level could improve the reliability of the bulk energy grid. Barsali et al. discussed smart grid applications for energy storage at the distribution level as a way to relieve transmission congestion, participate in load leveling, enhance power quality, and improve electrical efficiency [26]\*. Sidhu et al. considered storage on the distribution side of a substation, while Hartel et al. considered storage at both the transmission and distribution level [7,22]\*.

Other publications have presented literature reviews of energy storage research, applications, and projects, or have discussed energy storage in general terms. Yao et al. examined how energy

storage technologies are applied globally and noted that energy storage is being used to relieve transmission congestion, enhance renewables integration, provide ancillary services, and defer transmission upgrades [27]\*. Hamid et al. discussed small-scale models for the physics of batteries, but also discussed utility-scale batteries and their uses, including energy time-shifting, ancillary services, and resource adequacy [28]\*. Several review articles have been published in the past five years that address the use of BESS in transmission systems. Luo et al. provided a review of ESS technologies, sorting them into six categories based on the type of energy stored. The paper briefly mentioned the use of BESS for providing transmission stability and transmission upgrade deferral [29]. Yang et al. provided a review of battery sizing criteria and methods. The review focused on BESS for renewable energy systems and categorizes BESS based on specific renewable energy systems that complement different BESS technologies. The authors mentioned transmission upgrade deferrals and discussed curtailment as a means for addressing transmission congestion [30]. Poullikkas reviewed different types of BESS applicable to large-scale utility applications. The review highlighted two BESS chemistries as appropriate for transmission stabilization and regulation, specifically lead-acid and flow batteries. The paper is too dated to consider the recent advancements in lithium technologies that have made lithium BESS suitable for transmission applications [31]\*. Zakeri and Syri reviewed literature pertaining to the analysis of life cycle costs for utility-scale ESS, including BESS. The authors considered ESS for three transmission-scale scenarios: bulk energy storage, T&D support services, and frequency regulation [32]\*. May et al. analyzed several large-scale lead-acid BESS projects and identified lessons learned. The authors demonstrated that lead-acid BESS remain technically and economically viable for utility-scale applications. The review showed that these projects are able to provide transmission line support and dampen oscillations within transmission systems [33]. The review presented herein contributes to this body of knowledge by focusing on transmission-scale BESS, highlighting the potential for addressing transmission congestion through the deployment of large-scale BESS projects.

RQ1 surveyed existing literature in the context of using BESS as a means for providing transmission congestion relief. A significant body of literature was found that demonstrates the feasibility of using energy storage systems to relieve transmission congestion. The literature also makes clear that BESS can be used to provide a wide variety of utility services. Since transmission congestion occurs rarely, BESS dedicated to providing congestion relief can be redeployed during most of a year to provide other services, which would help recover investment costs. Energy storage technologies, particularly lithium-ion BESS, are developing rapidly and experiencing cost declines. The literature discusses ways to address siting, sizing, operation, and dispatch of energy storage systems.

### 3.2. RQ2: What Technologies Are in Development and Which Ones Have Recently Been Deployed?

Poullikkas detailed various battery technologies in 2013 [31]\*. At the time of publication, Poullikkas noted that large battery energy storage systems used sodium–sulfur batteries. He noted that sodium–sulfur and lithium-ion batteries both have high energy densities. Poullikkas made a qualitative analysis of lead-acid, lithium-ion, nickel-cadmium, sodium–sulfur, sodium–nickel–chloride, vanadium-redox, and zinc–bromine technologies. Yao et al. wrote a similar article in 2016, describing the current energy storage technologies, with a emphasis on the Chinese power grid [27]\*. They examined lead-acid, lithium-ion, vanadium-redox, zinc–bromine, and sodium–sulfur batteries. Rosso and Eckroads reviewed the research work of the Electric Power Research Institute (EPRI) pertaining to TCR and storage, particularly as it applies to thermal relief on the transmission lines [2]\*. When put side-by-side with other forms of storage technologies, they concluded that lead-acid, nickel-cadmium and sodium–sulfur batteries were very attractive from a design flexibility and economical standpoint.

Benato et al. examined the use of large-scale BESS on the Italian Transmission system [34]\*. They examined an energy-intensive sodium–sulfur battery deployment, and looked at two power-intensive installations in Ciminna and Codrongianos with both lithium-ion and sodium-nickel-chloride batteries. They described an operation mode for power-intensive projects,

where all available batteries would coordinate to mitigate transmission congestion. Benato et al. presented the performance and cost savings advantages that make lithium-ion batteries well-suited for power-intensive applications and make sodium–sulfur batteries well-suited for energy-intensive applications. Benato et al. further discussed the capabilities of the battery deployments, mentioning power-intensive installations could provide TCR, voltage regulation, and frequency regulation.

Due to the high penetrations of renewables, transmission congestion has increased for the island power systems of both Sardinia and Sicily, which have relatively weak transmission interconnections to the mainland of Italy. Consequently, these island networks suffer from slow frequency response due to a lack of system inertia, which is exacerbated by renewables. Schiavo and Benini presented these cases and discussed the pilot project efforts of TSO TERN to decrease transmission congestion and increase frequency stability through the strategic installation of BESS [35]. The pilot projects demonstrated both primary and secondary frequency regulation, as well as black-start capabilities. The authors also discussed the regulatory framework and planning that facilitated the development of these pilot projects. Corona et al. considered the Sardinia system in more detail, specifically considering modernization efforts for the island's system that would allow for high penetrations of renewables without compromising reliability [36].

Sidhu et al. performed a social cost–benefit analysis on the Smarter Network Storage project, a 6 MW/10 MWh lithium-ion BESS, installed at the Leighton Buzzard Primary Substation in Great Britain [7]\*. They measured social costs and benefits using Net Present Value (NPV) to compare the two. Sidhu et al. considered the stacking of assets, allowing for energy storage to provide multiple services to the grid, including frequency response, energy arbitrage, and carbon abatement. They mentioned reducing the maximum peak load during the year was a major benefit of energy storage. They ignored transmission upgrade deferral and TCR from their analysis, because they suggested that TCR requires network congestion that would be fixed by transmission upgrades, and they suggested that transmission upgrade deferral had no net social cost or benefit due to how the transmission system in Great Britain was operated.

In 2010, EPRI prepared a white paper describing various energy storage applications and technologies [3]\*. It rated many energy storage technologies with regard to their level of technological maturity. Among the mature technologies were lead-acid, valve-regulated lead-acid, and sodium–sulfur batteries as well as PHS. Advanced lead-acid, vanadium redox flow, and lithium-ion batteries were rated as demonstration projects. In 2015, EPRI updated its Energy Storage Handbook for the U.S. DOE. This paper classified the relative technological maturities of BESS technologies as roughly the same, but lithium-ion demonstration projects, in particular, had appeared to double [1]\*. In 2017, EPRI's Kaun and Minear presented a course, "Energy Storage for the Electric Grid," in which they describe lithium-ion batteries as a family of chemical technologies, some of which are deployed and some of which are still in demonstration [10]\*.

Lead-acid technology is the oldest type of utility-scale battery technology. Lead-acid batteries are characterized by short discharge times, limited life cycles, and low energy densities [32]\*. They also tend to require maintenance, and they have environmental impacts associated with lead [10]\*. Southern California Edison (SCE) commissioned a 10 MW, 40 MWh battery project in Chino in 1988, the largest of its time. This battery project was decommissioned in 1997 [37]\*. Puerto Rico Electric Power Authority (PREPA) commissioned a 20 MW battery system in 1993. Due to greater cycling than predicted, the battery system was forced to decommission prematurely in 1999. PREPA would later commission a new 20 MW lead-acid battery system in 2004, but due to a battery fire, had to decommission the plant in 2006. In 2000, STMicroelectronics commissioned a 10 MW lead-acid battery to support an uninterruptible power supply (UPS) in Phoenix, AZ. May et al. provide a comprehensive presentation of recent lead-acid battery innovations as well as a review of several large-scale lead-acid battery projects, including the Southern California Edison Chino project, which was used to demonstrate BESS transmission line support [33]. The authors conclude that the technology is still competitive in large-scale stationary applications.

More recently, improvements in lead-acid technology have resulted in advanced lead-acid batteries with life-cycles up to 10 times that of the original lead batteries [31]\*. In 2011, the Hawaiian Electric Company commissioned a 15 MW advanced lead-acid battery system to support a wind farm on Oahu. This project was partly funded by a loan guarantee from the U.S. DOE Office of Electricity Loan Guarantee [37]\*. The Maui Electric Company also commissioned a 10 MW advanced lead-acid battery system to support a wind farm in Oahu. In 2013, Duke Energy commissioned a 36 MW, advanced lead-acid battery system in Goldsmith, TX. These batteries were later replaced by lithium-ion batteries in 2016.

Nickel-cadmium batteries are among the older battery technologies. They provide high energy density and low maintenance with life cycles heavily dependent on depth of discharge [32]\*. This literature review identified just one example of a large-scale nickel-cadmium battery. The Golden Valley Electric Association built a 27 MW nickel-cadmium battery system in Fairbanks, AK, in 2003 [37]\*. In the event of an unplanned generation or transmission power outage, 15 minutes of power at rated nameplate capacity may be discharged into the grid from this battery. This battery system was still in operation as of 2019.

Lithium-ion batteries have high energy and high power densities, with typical AC efficiencies between 80% and 92% [10]\*. However, they do have life cycle limitations and safety concerns. Lithium ion technologies include a number of different chemistries including lithium manganese oxide, lithium cobalt oxide, lithium iron phosphate, lithium titanate, lithium nitric oxide, and lithium aluminate. From 2011 to present, the largest number of 10 MW+ battery projects were lithium-ion batteries. Between 2011 and 2018, the authors' survey identified 22 installations in the U.S. that were operational [37]\*.

Sodium–sulfur batteries were developed in the 1980's by NGK Insulators [32]\*. They operate at high temperatures, 570–660°F [31]\*, and serious damage can occur when temperatures drop below 150°F [34]\*. This survey could find no sodium–sulfur batteries deployments over 10 MW operating in the U.S. Multiple large-scale sodium–sulfur deployments were found in both Italy and Japan [37]\*, [38].

Flow batteries are a relatively new technology. These batteries store energy in an electrolytic solution, which undergoes redox as it is pumped through the space between the battery anode and cathode [32]\*. Consequently, ratings for power and energy can be designed independently of one another, as energy is determined by the amount of solution stored and power determined by the active area of the cell compartment. These batteries require the additional complexities of electrolyte pumping and storage [10]\*. Flow batteries have a variety of chemistries, including vanadium redox, zinc–bromine, iron–chromium, and polysulfide–bromide [32]\*. This paper found only one large-scale operational flow battery. Hokkaido Electric Power commissioned a 15 MW vanadium redox flow battery in Abira-Chou, Japan in December 2016 [37]\*. In 2015, Kazakhstan's Samruk Energy announced a partnership with Primus Power (a U.S.-based start-up) that would allow it would install a 25 MW zinc–bromine hybrid flow battery in Astana, Kazakhstan. In 2016, the China National Energy Administration announced it would install a 20 MW vanadium redox flow battery.

It has been observed that high energy ESS often have slow ramp rates, while high power ESS tend to have fast ramp rates. Given that two different ESS technologies may have such complementary characteristics, several researchers have proposed hybrid energy storage systems (HESS). Hemmati and Saboori provided a review of these technologies, wherein they discussed various HESS configurations, control strategies, and power electronics architectures [39]. They also presented applications, including coupling with renewable energy systems to improve stability and reliability. The authors did not discuss HESS in the context of transmission congestion. However, the applicability is evident. A large-scale energy storage system, such as pumped storage, that can provide peak demand mitigation during long periods of transmission congestion would compliment well with a smaller, fast-acting BESS that can provide ramp rate support and frequency regulation.

RQ2 considered what technologies are in development and which ones have recently been deployed. A list of battery deployments that met the inclusion criteria are listed in Table 2 along with

their technologies and year of commissioning. Researchers are investigating several different battery technologies. The most recent deployments found for nickel-cadmium and lead-acid batteries were in 2003 and 2011 respectively. Nickel-cadmium and lead-acid technologies may well be supplanted or relegated to niche markets by lithium-ion technology. Sodium–sulfur batteries, while not deployed in large-scale in the U.S., still have advantageous features particularly for providing energy services rather than power services to the grid. While flow batteries are still a developing technology, large-scale flow batteries have been demonstrated in Japan and Kazakhstan. Less developed battery technologies include metal air batteries and solid-state batteries [10]\*. This SLR did not find significant information on either of these technologies.

**Table 2.** Select battery energy storage projects [37].

Project Sponsor	Capacity	Technology	Location	Year
Southern California Edison	10 MW	Lead-acid	Chino, CA	1988
	10 MW	Lithium-ion	Norwalk, CA,	2017
	10 MW	Lithium-ion	Rancho Cucamonga, CA	2017
PREPA	20 MW	Lead-acid	San Juan, Puerto Rico	1994
	20 MW	Lead-acid	San Juan, Puerto Rico	2004
STMicroelectronics	10 MW	Lead-acid	Phoenix, AZ	2000
Golden Valley Elec Assoc	27 MW	Nickel-Cadmium	Fairbanks, AL	2003
Futamata Wind Development	34 MW	Sodium–sulfur	Rokkasho, Japan	2008
First Wind	15 MW	Adv lead-Acid	Kahuku, HI	2011
AES	32 MW	Lithium-ion	Elkins, WV	2011
	20 MW	Lithium-ion	Moraine, OH	2013
	10 MW	Lithium-ion	Cumberland, MD	2015
	37.5 MW	Lithium-ion	Escondido, CA	2017
	10 MW	Adv lead-acid	Maalaea, HI	2012
Maui Electric Company	11 MW	Lithium-ion	Kula, HI	2012
Duke Energy	36 MW	Adv lead-acid	Goldsmith, TX	2013
	36 MW	Lithium-ion	Goldsmith, TX	2016
UK Power Networks	6 MW	Lithium-ion	Leighton Buzzard, UK	2014
NextEra Energy Resources	20 MW	Lithium-ion	DeKalb, IL	2014
	18 MW	Lithium-ion	Somerset County, PA	2015
	10.4 MW	Lithium-ion	Somerset County, PA	2015
Terna S.p.A.	7.5 MW	Lithium-ion	Codrongianos	2014
	12 MW	Sodium–sulfur	Flumeri, Italy	2014
	12 MW	Sodium–sulfur	Castelfranco, Italy	2014
	10.8 MW	Sodium–sulfur	Scampitella, Italy	2015
	5.1 MW	Lithium-ion	Ciminna, Italy	2015
Invenergy LLC	31.5 MW	Lithium-ion	Marseilles, IL	2015
Beech Ridge Energy Storage	31.5 MW	Lithium-ion	Rupert, WV	2015
	19.8 MW	Lithium-ion	Joliet, Illinois	2015
RES Americas	19.8 MW	Lithium-ion	West Chicago, IL	2015
	19.8 MW	Lithium-ion	McHenry County, IL	2015
EDF Renewable Energy	15 MW	Vanadium-Redox Flow	Abira-Chou, Japan	2015
Hokkaido Electric Power	25 MW	Lithium-ion	Anchorage, AK	2016
ARCTEC	20 MW	Lithium-ion	Indianapolis, IN	2016
Indianapolis Power and Light	30 MW	Lithium-ion	El Centro, CA	2016
Imperial Irrigation District	10 MW	Lithium-ion	Georgetown, TX	2016
Ormat Technologies	10 MW	Lithium-ion	Wilmington, OH	2016
Exelon Generation	20 MW	Lithium-ion	Pomona, CA	2016
AltaGas	50 MW	Sodium–sulfur	Buzen, Japan	2016
Kyushu Electric Power	25 MW	Zinc–bromine Flow	Astana, Kazakhstan	TBD
Samruk Energy	200 MW	Vanadium-Redox Flow	Dalian, China	TBD
China Nat'l Energy Admin				

Lithium-ion BESS are the most promising technology for providing transmission congestion relief. The U.S., in particular, has seen an expansion of lithium-ion BESS projects at sizes large enough to influence transmission. The successful development of the 22 lithium-ion projects mentioned in this literature review lead the authors to conclude that lithium-ion BESS are commercially-viable solutions for providing utility-scale energy storage services. Lithium-ion technology has become the preferred choice for utility-scale BESS deployments. Rapidly declining capital costs will increase the likelihood that this technology will be the dominate BESS technology for utility-scale applications in the future.

### 3.3. RQ3: What Are the Projected Installation and Operation Costs?

Sidhu et al. looked at many of the costs associated with BESS, including capital costs, operational costs, and degradation costs [7]\*. Capital costs included the batteries themselves, the balance of plant, engineering, and construction. Operational costs included maintenance, administration, and control systems. Degradation costs included degraded performance due to cycling and to aging of the battery, a 6 MW, 10 MWh lithium-ion unit. They calculated the total cost of the battery in 2013 as \$14.1 million. Then they used a Monte Carlo simulation to estimate that future costs of the battery would drop to between \$12.0 and \$9.88 million by 2017–2020.

Benato et al. examined the costs of different BESS systems [34]\*. They described lithium-ion installations costing roughly \$1500/kW and \$1500/kWh, sodium-nickel-chloride installations costing roughly \$3000/kW and \$1200/kWh, and sodium-sulfur installations costing \$3800/kW and \$540/kWh. Benato et al. further suggested that these prices make lithium-ion batteries well-suited for power-intensive uses while sodium-sulfur batteries were better suited for energy-intensive uses. Palone et al. describe operating strategies for managing transmission congestion using sodium-sulfur batteries, specifically for transmission lines subjected to high penetration of wind generation [38].

Cutter et al. estimated costs for battery energy storage in a range from \$2400–\$4200/kW, while not explicitly accounting for costs per kWh [40]\*. They estimated installed capital costs of \$1115–\$3345/kW, and fixed operating and maintenance costs at \$30.80/kW, escalating 2% each year. Cutter et al. used a generalized understanding of battery technologies in their calculations, not specifying a specific technology. Rosso and Eckroads estimated advanced lead-acid battery installations cost of \$875/kWh, inverter costs of \$220/kW, balance of plant costs of \$520/kW, and O&M costs at 1.5% of investment costs [2]\*.

In the Qiu et al. model for co-planning transmission and battery energy storage investments, battery storage projects are assumed to be \$500/kW plus \$25/kWh, assuming a lifetime of ten years [24]\*. These are general assumptions of battery performance, without specifying a particular technology. They further assume that the price of a new 138 kV transmission line is \$927,000 per mile with a lifetime of 60 years.

Zakeri and Syri compared performance and cost characteristics of BESS and other forms of energy storage with one another based on data found in literature [32]. Table 3 describes the average comparative costs of some of the technologies they examined.

**Table 3.** Battery energy storage technologies and their associated costs [32]. Prices were converted from Euros using the exchange rate from 9 November 2017 [41].

Technology	Storage \$/kWh	PCS & BOP \$/kW	Fixed O&M \$/kW	Variable O&M \$/kW-yr	Replacement \$/MWh
Lead-acid	721	542	4.0	0.43	201
Nickel-cadmium	910	279	12.8	N/A	612
Sodium-nickel-chloride	594	551	6.4	0.70	212
Lithium-ion	927	540	8.0	2.45	430
Vanadium Redox	545	572	9.9	1.05	152
Zinc-bromine	227	518	5.0	0.70	227
Iron-chromium	169	422	3.8	0.47	34

Different from projected cost, break-even capital cost shows the maximum price at which an energy storage system would still be viable. In a project report for the California Energy Commission, Fioravanti et al. analyzed past regulation market data from CAISO (California Independent System Operator) [42]\*. They determine the break-even cost of a 20 MW, 5 MWh BESS participating in the CAISO market over a 20 year period is \$17.6 M. Fioravanti et al. state the average cost of 2-h lithium-ion batteries is \$3500/kW and \$1750/kWh. They also state the average cost of 4-h lead-acid batteries is \$3900/kW and \$975/kWh.

In an NREL white paper from 2013, Denholm et al. determined that a typical break-even costs for an 8 hr, 300-MW energy storage system providing load-leveling only was around \$300/kW and around \$1400/kW for a system providing load leveling and capacity. They also determined the break-even costs of an 8 hr 100 MW energy storage system to be around \$500/kW for providing spinning reserves only, around \$900/kW for providing frequency regulation only, around \$1700/kW for providing both spinning reserves and capacity, and around \$2300/kW for providing both frequency regulation and capacity [43]\*.

RQ3 addressed the projected installation and operation costs of BESS. BESS are priced by power (MW) and energy (MWh), and these costs vary widely by technology. To lesser degrees, replacement costs, and fixed and variable O&M costs also affect total system costs, with wide variations between system types. Several sources have noted the declining costs for BESS, and project additional decreases in the coming decade. Lithium-ion systems have been identified as particularly likely to experience continued decreases in costs, and thereby a very suitable technology for a wide variety of utility-scale energy storage applications. Several sources noted the break-even costs for BESS, and showed the break-even cost point increases as a BESS is dedicated to provide two or more services. As these technologies continue to mature, costs are likely to continue declining. Since the viability of BESS projects are critically dependant upon accurate cost estimates, continued research into current and projected costs is needed so that developers have reliable means for projecting project costs.

#### 3.4. RQ4: What Are the Projected Revenue Streams or Savings Associated with BESS?

Many use cases have been identified for energy storage systems that can be monetized to produce revenue or incur savings for system owners. The DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA identified use cases for energy storage, listed in Table 4 [1]\*. Additionally, Barsali et al. described additional uses for BESS including active filtering, islanding support, reduction of short term interruptions, and reduction of flicker [26]\*. These individual use cases could provide some sort of revenue stream or savings, and some of these revenue streams could be stacked [3]\*. Many of these revenue streams were elaborated further in the literature.

**Table 4.** Utility services that may be provided by energy storage systems [1].

Transmission	Bulk Energy	Ancillary Services	Distribution	Customer Energy Management
Congestion Relief	Arbitrage	Regulation	Congestion Relief	Reliability
Deferred Upgrades	Capacity	Reserves	Deferred Upgrades	Time of Use Charge Reduction
		Load following	Reactive Power Control	Demand Charge Reduction
		Voltage Support	Outage Mitigation	
		Black Start		

Taylor explained energy storage could be used to buy and sell energy through arbitrage, buying at one point in time and selling back that energy at another point [44]\*. In this case, energy storage profits were easy to calculate as energy storage generated revenue through the temporal differences in nodal prices. Dvorkin et al. showed that the ideal place to put energy storage is at buses with the largest differences in LMP throughout the day [14]\*. This placement promoted energy storage participation in energy arbitrage, making revenue by purchasing energy at a low price and then selling that energy at a higher price. Energy markets exist to facilitate the buying and selling of electricity. Energy arbitrage is typically exercised in either a day-ahead (DA) market or a real-time (RT) market. The DA market approximates the expected energy consumption and production for the next day. Generators make generation offers, load aggregators make demand bids, and based on these transactions, LMPs are determined. The RT market, or “spot” market, corrects the deficiencies in the predictions of the DA market. LMPs in the RT market are determined by the immediate energy needs of the system. The changes in the hourly LMPs of energy in these DA and RT markets offer the arbitrage positions for energy storage to profit [17]\*. Additionally, energy storage can often influence the LMPs, by making strategic offers to keep LMPs favorable for arbitrage albeit at the expense of the electrical grid as a

whole [20]\*. This strategic bidding is known as gaming [44]\*, and the cost of this gaming on the social welfare of the system as a whole is known as the price of anarchy [20]\*.

A strict look at peak rates and off-peak rates would not fully explain the arbitrage positions of batteries. The efficiency of the storage system must also be considered. An EPRI white paper described this loss: “With efficiency losses of 20%, the battery buys an additional 20% energy during the off-peak period” [3]\*. The processes of storing and releasing energy come at the price of efficiency losses during each transaction. Round-trip efficiency is typically specified for storage technologies, especially for systems with frequent use [2]\*. Round-trip efficiency declines over time in relation to charge-discharge cycles and depth of discharge, and it is a crucial parameter for BESS value calculations [1]\*. A list of round-trip efficiencies used in the EPRI White Paper are noted in Table 5.

**Table 5.** Round trip efficiencies associated with use cases [1].

Use Case	Li+	APba	PbA	NaS	VR	ZnBr
Frequency Regulation	85–90%	75–90%	N/A	N/A	N/A	N/A
T&D Grid Support	85–90%	60–90%	85–90%	78–83%	62–67%	63–68%
Renewable Integration	N/A	N/A	N/A	75–80%	65–70%	N/A

While energy storage could recuperate costs for providing TCR through energy arbitrage, energy storage would need to charge in advance of providing TCR. Energy storage that was designed to earn money only through energy arbitrage would frequently fail to charge in advance of transmission congestion. Khani et al. noticed this problem with the energy storage dispatch algorithm and created an adaptive penalty to cause energy storage to favor charging to relieve forecasted transmission congestion rather than optimize for energy arbitrage opportunities, as previously noted in Section 3.1 [16]\*. They further mentioned that for this adaptive penalty algorithm to be implemented in practice, system operators must provide better compensation for TCR than the energy storage asset could earn through arbitrage.

Taylor described a method for valuing passive storage in which energy storage did not buy and sell like a generator, but rather was utilized as part of the overall grid system, like transmission lines [44]\*. From a philosophical level, he likened transmission and storage, suggesting that transmission moves electricity spatially while storage moves electricity temporally, that is to say forward in time. Taylor elaborated on this similarity, suggesting that energy storage usage could be compensated passively through storage rights just as transmission was compensated through flowgate transmission rights. While transmission rights were limited to power capacity rights (as in how much capacity the transmission system had available), energy storage could be viewed as having both power capacity rights and energy capacity rights, the former referring to how much power the energy storage could discharge and the latter referring to how much energy the system could store. Taylor modeled power markets linked by energy storage by solving a multiperiod, linearized OPF problem. He then demonstrated how financial storage rights could be used to monetize energy storage in place of arbitrage. He described “storage congestion” occurring when the energy storage asset is charged to capacity. He then demonstrated that financial storage rights could reduce gaming interactions between generators and loads to improve social welfare. Taylor admitted that financial storage rights only described load shifting, and thereby ignored potential ancillary services for which the batteries could be used.

Energy storage can also bid its capacity into ancillary service markets such as frequency regulation or frequency reserve markets. Typically, ancillary service markets purchase the use of energy storage assets by way of a reservation payment for availability and a performance payment when the asset is called into use [45]\*. The most valuable of the ancillary service markets tends to be the frequency regulation market [17]\*. A frequency regulation service earns revenue for reservation capacity and for performance when the energy storage asset is dispatched. A frequency regulation service could receive 400 dispatch calls per day. A frequency reserve service, on the other hand, earns revenue

for reservation capacity, but dispatch calls come roughly just 20 times per year. Revenue streams for regulation and reserve service depend on the rules of the transmission operation [45]\*.

RTOs and ISOs have devised mechanisms for addressing these various versions of frequency services. PJM, an RTO in the Eastern U.S., devised performance-based frequency regulation, which splits the frequency regulation market in two parts, a RegA market and a RegD market, using a signal filtering process. The RegA market provides a low-pass regulation signal for traditional generation assets that are limited by their ramp rate. The RegD market provides a high-pass regulation signal more appropriate for assets that have high ramp rates, such as BESS. The California ISO, CAISO, distinguishes between up-regulation and down-regulation bids. CAISO offers a reservation payment, a performance payment for utilization, and an accuracy payment for how close the regulation service matches the prescribed set point.

Energy storage can provide revenue indirectly through savings. For instance, when an energy storage asset defers investment in a new wires transmission project, a cost savings may occur. Rosso and Eckroads analyzed energy storage projects from a savings standpoint [2]\*. By relieving transmission congestion and thereby allowing for power from cheaper generation sources, the batteries saved money over base generation. They also considered the capital cost comparison of reconductoring transmission lines to installing new battery systems. DNV-GL performed an analysis of energy storage options as part of Pacific Power’s 2017 submittal [46]\* to the Oregon Public Utilities Commission. DNV-GL, in its analysis of Pacific Power’s grid, calculated the cash flows associated with implementing an energy storage system to both provide frequency control and offer investment deferral. Navigant, in its analysis of Portland General Electric’s (PGE) vertically-integrated grid, calculated the NPV associated with placing energy storage projects at various levels of PGE’s electrical grid [47]\*. A summary of the savings per kWh is listed in Table 6. Of particular interest to transmission was Navigant’s analysis of a 20 MW energy storage system connected directly to the transmission grid. They tested a case where the energy storage provided transmission deferral 10 days out of the year and resource adequacy another 10 days out of the year while participating in energy and ancillary service markets for the other 345 days. The energy storage system, in this case, showed partial revenues and savings from deferring additional transmission and generation spending, selling into frequency regulation and other ancillary services markets, and participating in energy markets.

**Table 6.** Savings estimates of energy storage projects, Portland General Electric’s (PGE) [47].

Size (MW)	Site	Low Estimate \$/kW	High Estimate \$/kW	Services (from Most Prominent to Least)
20 MW	Transmission Line	1453	2214	Cap, Energy + Anc Serv, Tx Deferral
10 MW	Distribution/Substation	1510	1781	Cap, Energy + Anc Serv, Tx Deferral, Outage Mitigation
2 MW	Distribution Feeder	1513	2373	Cap, Energy + Anc Serv, Outage Mitigation, Tx Deferral
1 MW	Aggregate Customers	1505	1733	Cap, Energy + Anc Serv, Tx Deferral

System upgrade cost deferral is a major benefit of energy storage. Berrada et al. cite the value of energy storage to defer transmission and distribution upgrades can range from \$50–\$1000/kW-year [17]\*. When comparing energy storage against conventional generation, energy storage could offer fuel savings. Denholm et al. compare a system with no energy storage to one with energy storage, and demonstrated that energy storage reduced total fuel costs and total start costs (for starting a generator) [43]\*. Greenhouse gas emissions are often considered in energy storage decision-making internationally [2,32,48,49]\*. In California, Huynh figured greenhouse gas emissions to install a 50 kW, 4 hr battery system to be 152 tons of carbon dioxide per GWh of energy [5]. Huynh compares this to a natural gas peaker plant, producing 469 tons of carbon dioxide per GWh of energy.

Sidhu et al. examined social costs and benefits [7]\*. In this sense, the net social benefits are the revenues of social cost/benefit analysis. These include frequency response, arbitrage, network support, reduced distribution curtailments, carbon reduction, and the terminal value of the battery plant after decommissioning. By considering these values together, Sidhu et al. measured the total social benefits case for installing energy storage. Sidhu et al. ignored transmission deferral in their analysis because they viewed it as a transfer payment.

For RQ4, the projected revenue streams and savings associated with BESS were investigated. These values are difficult to measure due to the many ways BESS services can be combined and the situations under which they are deployed. As such, estimates of value range widely. Additionally, a BESS may be designated to provide a primary service, but its value may be increased by providing additional services when not being dispatched to provide its primary service. This stacking of services, however, is difficult to quantify, due to the stochastic nature of dispatching these services, and particularly if transparent markets do not exist that can express value for these services. Research into mechanisms for cost recovery should continue. As new means for dispatching batteries for grid support services are devised, these additional revenue streams will serve to economically justify utility-scale BESS deployment.

### 3.5. RQ5: What Are the Economic Indicators Used for Evaluating BESS?

Several economic cost metrics have been adopted or developed specifically for energy storage systems, including net present value (NPV), internal rate of return (IRR), levelized cost of electricity (LCOE), levelized cost of capacity (LCOC), levelized cost of storage (LCOS), cost of new entry (CONE), and flexible cost of new entry (FCONE). This review presents literature pertaining to each of these metrics and discusses their relative values.

LCOE has traditionally been applied to generation assets as a means for providing cost comparisons between multiple capital investment options. An LCOE analysis ascribes all future costs of a system to the present value, which provides a present price-per-unit energy value in \$/MWh. Akhil et al. defined LCOE as “the \$/MWh revenue for delivered energy needed to cover the life-cycle fixed and variable costs and provide the target rate of return based on financing assumptions and ownership types” [1]\*. Obi et al. developed a method for calculating LCOE for various energy storage systems, specifically for the purpose of weighing energy storage systems against one another [50]\*. Their analysis includes sensitivities of LCOE to technical factors including storage efficiency and system lifetime as well as economic factors including discount rate and capital costs. Obi et al. did not consider the ability of batteries to sell ancillary services to the grid, nor did they factor in the energy storage depth of cycling, which can be a considerable factor for BESS as it degrades over the lifetime of the asset.

Hartel et al. examined storage options from the outlook of using storage to prevent curtailment [22]\*. To compare the various storage methods, the paper used LCOE, though without going into any detail into how they calculated it. Zakeri and Syri used LCOE to compare energy storage options against each other [32]\*. They presented cost comparisons between storage technologies based on considerations like discharge time, use (whether bulk energy sales or transmission and distribution support), and discount rates. They considered the use of batteries to include bulk energy, T&D support, and frequency regulation. Zakeri and Syri determined that PHS and CAES plants outperformed battery technologies. However, the project sizes were extremely large and the data they used were current as of 2014.

Schmidt et al. demonstrated the utility of LCOS, which values the discounted cost of discharged electricity for specific energy services [51]. In contrast, LCOE values the discounted cost of one type of service generated electricity. Schmidt et al. applied LCOS to nine different storage technologies and considered the use of these technologies for providing twelve different energy services over a time period between 2015 and 2050. Services considered include peak demand mitigation, congestion relief, and several types of frequency response, among others. They conclude that lithium-ion BESS will prove

to be the most cost-effective technology for nearly all energy services by 2030 due to rapidly-decreasing capital cost.

Telaretti et al. analyzed the economic viability of transmission-scale BESS within the Italian transmission system, including lithium-ion, lead-acid, and sodium–sulphur chemistries [52]. They use net NPV and the IRR to estimate project value and provide a comparison between these various BESS technologies. The authors apply parametric analysis to investigate the effects of variations in both electricity prices and peak demand charges. They conclude that for BESS become economically viable, there need to be high peak demand prices as well as large differences between high and low energy prices.

Afanasyeva et al. used an LCOE calculation to compare hybrid solar and gas power plants to one another [48]\*. They examined a plant that used a photovoltaic array with a battery energy storage system to provide primary power but also included a gas turbine to keep up with peak demand. They compared the hybrid plant against standard coal-fired and natural gas power plants, and demonstrated that hybrid plants would outperform the gas and coal plants by 2030. Afanasyeva et al. used a Moroccan location as its case study, and they accounted for carbon emission costs.

Akhil et al. defined LCOC as “the \$/kW-yr. revenue per kW of discharge capacity needed to cover all life-cycle fixed and variable costs and provide the target rate of return based on financing assumptions and ownership types” [1]\*. Akhil et al. further say that LCOC is primarily used for comparing capacity resources like combustion turbines, whereas LCOE is primarily used for comparing energy resources like baseload fossil fuel generation or renewables. While Kaun and Minear admit that LCOE is an appropriate indicator for comparing renewable generation with storage to other generation options, they suggest that LCOE is a confusing economic indicator for energy storage in general because storage does not produce energy [10]\*. Kaun and Minear suggest using LCOC or lifetime project NPV instead. Akhil et al. presented LCOE and LCOC for various energy storage technologies including pumped hydro, CAES, sodium–sulfur batteries, sodium–nickel–chloride batteries, vanadium redox flow batteries, iron–chromium flow batteries, zinc–bromine hybrid flow batteries, and lead-acid batteries [1]\*. In an EPRI white paper, energy storage systems are compared to both combined cycle gas turbines and standard combustion turbines using LCOE and LCOC respectively [3]\*.

PGE and Pacific Power both submitted cost analyses to OPUC as part of Oregon’s storage mandate [53,54]\*. When Navigant, on behalf of PGE, modeled a 20 MW energy storage system connected to the transmission grid, it used NPV to compare the value of these projects against others [47]\*. When providing the service of resource adequacy and transmission asset deferral, the energy storage system had an NPV of \$1058/kW for 2 h of energy capacity and \$1649/kW for 4 h of energy capacity. DNV-GL, on behalf of Pacific Power, also used NPV for its cost comparisons of energy storage participation, particularly investment deferral and frequency regulation [46]\*.

Cutter et al. used net market revenues, cost of new entry (CONE), and their novel indicator, flexible cost of new entry (FCONE) to compare the market value of energy storage options against a traditional combustion turbine. They described an improvement to the CONE economic indicator that accounts for the ramping flexibility of energy storage equipment; FCONE considers ramping speed of the generation asset [40]\*. They compared BESS, CAES, and PHS against a traditional generation asset, the simple gas combustion turbine. Cutter et al. compared the assets by simulating them as price-takers. They used a MILP to optimize dispatch for each asset bid, applying historical CAISO market data. Examined from a strategic bidding standpoint, the energy storage equipment bid into the day-ahead energy and ancillary services markets while the combustion turbine primarily bid into the more volatile real-time market. From a net revenues perspective, the energy storage assets had almost complete market participation, bidding mostly into the ancillary services market. Combustion turbines tended to have a high bidding price that precluded them from day-ahead markets. Using traditional CONE, the combustion turbines outperformed BESS. However, when ramping rates were taken into

consideration, BESS outperformed combustion turbines, CAES, and Pumped Hydro for ramp rates of one second or less.

For RQ5, the economic indicators used for evaluating BESS were considered. Several quantifiable metrics were presented that allow comparison between multiple storage projects as well as against traditional generation technologies. These metrics include LCOE, LCOC, LCOS, NPV, and CONE, which are commonly used. Several researchers argue that LCOC is a better cost metric than LCOE since the latter is designed for evaluating the value of traditional energy-producing generation assets rather than storage systems. LCOS has been shown to be an effective metric for evaluating various energy storage systems based on the ancillary services that storage systems can provide. FCONE, a modification of CONE, was proposed as a means for accounting for the value of power ramp rate, a characteristic that is particularly advantageous for BESS, which have very high ramp rates. The economic viability of utility-scale BESS projects must be quantifiable as well as comparable to alternative, non-storage projects. The proliferation of economic indicators is enhancing the quantification of BESS projects. However, these different metrics are not directly comparable to each other, and each have their merits and deficiencies. A standardized set of metrics would allow for on par analysis between different ESS options as well as against non-storage options.

### *3.6. RQ6: Are Storage Models Available That Can Model Added Value of BESS, Such as Arbitrage, TCR, and Ancillary Services?*

Several evaluation tools have been developed that can model the economic value that BESS can provide. These tools can account for multiple BESS value streams, but no one package is comprehensive enough to cover all potential cases. Many evaluation tools have been developed by researchers, and a few are available as commercial products.

In an NREL technical report, Denholm et al. described a modeling tool for simulating energy storage at the transmission level [43]\*. They modeled transmission zonally, and accounted for energy storage along with other mixed assets included coal, combined cycle gas turbines, and standard gas turbines. Their model accounted for ancillary services and energy market sales.

Fioravanti et al. developed models for testing energy storage use cases in a project report for the California Energy Commission [42]\*. They used PLEXOS, a software package that simulates unit commitments, to estimate the pricing in the CAISO market. In one case, they modeled transmission energy storage against frequency regulation. In another, they model transmission energy storage against traditional base and peaker plant dispatch.

Hyunh used EPRI's Energy Storage Valuation Tool (ESVT) 4.0 to analyze the benefit of energy storage to the U.S. City for San Diego [5]\*. EPRI created ESVT as a simulation tool to provide a cost-benefit analysis of energy storage projects. Hyunh considered San Diego acting as a community choice aggregator to provide customers with cheaper power while still relying on San Diego Gas and Electric for T&D services. Hyunh determined that the use of small batteries either at the customer level, the substation level, or the transmission level can provide a net savings to power customers while also deferring the need for new transmission lines.

Kaun and Minear used an EPRI created software package, StorageVET [10]\*. StorageVET models grid services including TCR, T&D investment deferral, arbitrage, capacity, arbitrage, regulation, reserves, voltage support, black start, reactive power control, time of use charge reduction, and demand charge reductions [55]\*. While it was originally built for analyzing energy storage in California, it can be reconfigured for analysis in other regions. StorageVET is capable of forecasting prices using historical data and price curves. StorageVET essentially performs cost/benefit analysis on a single use case or a stacking of use cases. StorageVET is a work-in-progress product, so some of StorageVET's models are not fully developed.

In response to Oregon HB 2193 [54]\*, OPUC issued an order requiring its major utilities, Pacific Power and PGE, to analyze the value of uses for energy storage [53]\*. To perform this analysis, PGE commissioned engineering firm Navigant. Navigant analyzed PGE's balancing

area using the Navigant Valuation of Energy Storage Tool (NVEST). Navigant performed five test cases, connecting energy storage at various levels within PGE's network: within transmission, at a distribution substation, on a distribution feeder, and to large customers (like commercial/industrial) and small customers (like residences). Each storage use case was modeled individually using NVEST. Individually, capacity was the most valuable use for energy storage while TCR was deemed to have almost no value, as PGE does not frequently suffer from this problem. Navigant used an analysis that stacked energy storage values, but Navigant eliminated transmission congestion, distribution congestion, distribution upgrade deferral, black start, voltage support, and reactive power control from its analysis because "these applications were considered to have low value" [47]\*.

Berrada et al. developed an optimization method to test the feasibility of gravity storage compared to PHS and CAES, though the method could be applicable to battery storage [17]\*. Their model allows energy storage to participate in regulation service or energy markets, either day-ahead or real-time. The model showed a clear advantage to participating in the regulation control market, rather than buying and selling in the market. They ignore reserve service, as they assumed regulation service would pay higher revenues.

Kazempour et al. developed a near-optimal scheduling method to compare the economic feasibility of PHS to sodium–sulfur batteries. Their model considered energy markets, regulation markets, and spinning reserve markets and bidding into these markets on a day ahead basis [21]\*.

RQ6 investigated the available BESS models that account for added-value services such as economic arbitrage, TCR, and several types of ancillary services. Available modeling tools can capture some, but not all of the potential revenue streams from energy storage, and some allow for analysis of stacked services, wherein a BESS can be committed to providing multiple services concurrently. EPRI's software StorageVET may be the most complete of these software packages, capable of modeling multiple service cases, though many of its models are not yet fully developed. The utility industry would benefit significantly from open-source modeling software that could account for the intricacies of large-scale BESS. Further, modeling software should provide APIs so that BESS models can be integrated with utility simulation packages such as GridLab-D, CYME, PSS<sup>®</sup>E, and PowerWorld simulator.

#### 4. Legislative and Regulatory Factors Influencing BESS

Around 2005, legislators and regulators began making rules that would define and promote BESS in the U.S. This literature review considered relevant materials at the federal level and in seven states. These laws and regulations are establishing legislative precedent for the introduction of energy storage to electrical grids across the U.S. Though these actions do not directly address using BESS for TCR, they promote the development of utility-scale storage systems that have the potential to address the problems presented by transmission congestion.

##### 4.1. U.S. Congress

The U.S. Congress passed the Energy Storage Policy Act of 2005 [56]\*. This legislation required the creation of a research, development, and demonstration program that would ensure the integrity of the national transmission and distribution grids. Energy storage technologies were included as part of the program. The program would be managed by the U.S. DOE. Congress followed this by passing the Energy Storage Competitiveness Act of 2007 [57]\*. The legislation required the formation of an energy storage council and specifically required a research program to study energy storage technologies including ultracapacitors, flywheels, CAES, hydrogen storage, batteries and battery systems including flow batteries. The research of power conditioning electronics and manufacturing technologies for energy storage systems was also mandated by the program. Furthermore, \$80 million were allocated to fund the program from 2009 to 2018.

The U.S. Congress enacted a defense appropriation bill for the 2009 fiscal year that directed coordination with the U.S. Department of Energy to develop advanced energy storage technologies for

military use [58]\*. The following fiscal year, Congress enacted another defense appropriation bill that required the Comptroller General to assess the U.S. Department of Defense's coordination of its energy storage program [59]\*. This law required an analysis of how the U.S. Departments of Defense and Energy could coordinate with one another regarding research, development, and military procurement of energy storage systems.

#### 4.2. Federal Energy Regulatory Commission (FERC)

FERC is an independent federal agency that regulates the transmission of electricity as well as other energy resources. Unlike the U.S. DOE, which is managed by the President of the U.S. and his appointed cabinet secretary, FERC is not directly controlled by the president, though the president appoints FERC's commissioners to five-year terms.

In October of 2011, FERC issued Order 755 [60]\* requiring the regional transmission operators and independent system operators (excluding the Electrical Reliability Council of Texas, ERCOT) to adjust their frequency regulation tariffs to recognize the value of fast-ramping frequency regulation over slow-ramping frequency regulation. Energy storage and demand response assets can provide this higher-value, fast-ramping frequency regulation [45]\*.

In July 2013, FERC issued Order 784: third-party provision of ancillary services; accounting and financial reporting for new electric storage technologies [61]\*. This order requires ancillary service markets to specifically take into account new energy storage technologies with the goal of providing financial rewards and incentives to energy storage projects. Not only did this order open up storage project developers to ancillary services, but it was also expected to boost the production of large-scale batteries in general. In November of that same year, FERC issued Order 792, granting energy storage the legal status of a small generating facility [62]\*. This allows energy storage to connect to the grid and sell power just as a generation facility would.

In November of 2016, FERC issued a Notice Of Proposed Rulemaking (NOPR). The proposed rules would require RTOs and ISOs to revise their tariffs with regard to the specific characteristics of energy storage to allow energy storage to compete in wholesale markets, including ancillary service markets [63]\*. The final decision on this NOPR initially stalled due to FERC's lack of quorum, but talks have since resumed after the newly appointed commissioners were confirmed by the U.S. Congress. Moving forward, FERC is expected to become more heavily involved in crafting rules that will permit BESS to participate in wholesale markets [64,65].

#### 4.3. California

In September 2010, California passed a law ordering the California Public Utilities Commission (CPUC) to mandate energy storage targets for its major utilities [66]\*. In response to this, CPUC mandated 1325 MW of energy storage be procured by California's three major investor-owned utilities, San Diego Gas and Electric (SDG&E), Southern California Edison (SCE), and Pacific Gas and Electric (PG&E). Of this 1325 MW of mandated energy storage, a total of 700 MW are to be connected to the transmission grid [67]\*. The law additionally requires electrical service providers and community choice aggregators to procure energy storage equivalent to 1% of their total load [67]\*.

In March 2014, CPUC issued an order for additional generation and energy storage to replace the San Onofre Nuclear Plant [68]\*. SCE was ordered to procure 50 MW of energy storage by 2022, while SDG&E was ordered to procure 25 MW of energy storage by 2022 [68]\*. Energy capacities were not specified.

From October of 2015 to February 2016, a large natural gas leak occurred at the SCE Aliso Canyon gas storage facility, which has come to be regarded as the worst gas leak in U.S. history from a greenhouse gas perspective [69,70]. As a result of this leak, the Governor of California declared a state of emergency. In the aftermath of this disaster, the Aliso Canyon storage facility stored less than 20% of its capacity, and SCE was unable to inject additional gas until it completed safety tests [71]\*. Rolling blackouts during the 2016 summer peak were expected as well as unplanned outages during

the year [72]\*. To mitigate these risks, CPUC, the California Energy Commission, CAISO and the Los Angeles Department of Water & Power developed the “Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin.” This plan included 18 mitigation measures unrelated to additional procurement of energy storage aimed at reducing the risk to electrical reliability [72]\*. In light of this report and its conclusion that mitigation measures would reduce risk, but not eliminate risk to electrical reliability, CPUC ordered the acceleration of energy storage procurement required from the closing of the San Onofre Nuclear Power Plant [68,71]\*. CPUC effectively fast-tracked the approval and procurement processes of energy storage projects for SDG&E and SCE to improve energy reliability [71,73]\*.

In September 2016, California passed three bills related to energy storage. AB 33 requires CPUC to determine appropriate targets for long-duration energy storage to aid the implementation of renewable generation to the grid [74]\*. The bill specifically mentions PHS, but requires evaluation of all types of long-duration energy storage technologies. As part of the evaluation, the effects of energy storage on transmission and distribution systems are to be considered. AB 1637 increases funding to the Self-Generation Incentive Program (SGIP) and requires the SGIP to increase deployment of energy storage [75]\*. In addition to the 1.325 GW of energy storage projects required by AB 2514 [66]\*, in 2016, AB 2868 required the three investor-owned utilities of California to procure 500 MW of distribution-level or behind-the-meter energy storage [76]\*.

#### 4.4. Massachusetts

In May 2015, Massachusetts launched its Energy Storage Initiative, which set aside \$10 million to establish a market for energy storage as well as help fund energy storage projects for utilities [77]\*. In August 2016, Massachusetts passed an energy bill requiring energy storage targets for 2020 [78]\*. In the following year (2017), the State’s Department of Energy Resources set a 200 MWh procurement target for Massachusetts distribution companies [79]\*. The agency also allocated \$10 million for storage projects. In August 2017, the State’s Department of Environmental Protection introduced its “Clean Energy Standard,” which mandates electric utilities to increase their annual electricity sales that come from renewable energy from 16% in 2018 to 80% in 2050 [80]. Storage will have to play a larger role in the State’s electricity supply matrix, especially as the state pushes for annual increases in the minimum required renewable electricity supply.

#### 4.5. Oregon

Following the state of California, in June 2015, Oregon passed HB 2913. This bill tasked OPUC to set rules for utilities to procure energy storage by 2020. HB 2913 requires Oregon’s utilities to procure at least 5 MWh and up to the equivalent of 1% of their 2014 peak load [54]\*. In response, OPUC issued an order requiring major utilities to submit final project proposals by January of 2018. Once approved, the utilities would have until January of 2020 to procure the energy storage [81]\*. In November of 2017, PGE submitted its response to OPUC with the company proposing five projects, each with different use cases, in response to HB 2913. The company plans to integrate storage in its transmission, substation, mid-feeder, and downstream loads, a portfolio that was expected to cost more than \$100M.

In 2016, Oregon passed SB 1547, which mandated 50% of the state’s electricity to be sourced from renewable energy by 2040 [82]\*. The bill also allowed utilities to recover the costs associated with energy storage procurement to meet this 50% mandate.

#### 4.6. Other U.S. States

Nevada passed two bills in 2017 related to energy storage. SB 145 established an incentive program for installing certain energy storage systems [83]\*, while SB 204 requires the Public Utilities Commission to define targets for energy storage procurement by utilities [84]\*.

In 2013 the New Mexico State Legislatures passed Joint Memorials 10 [85]\* and 43 [86]\*, requesting the New Mexico Energy Minerals and Natural Resources Department to form

recommendations for new legislative and regulatory actions that could promote renewable energy storage technologies. As reasoning for these memorials, the legislature suggested that energy storage could help make renewable energy available 24 h a day. In 2017, the New Mexico Public Regulation Commission required that energy storage options be included in utilities' Integrated Resource Plans [87]\*. The commissions stated that energy storage had become commercially viable and therefore should be included in planning along with traditional energy resources.

In 2014, the New York State Energy Research and Development Authority (NYSERDA) and Consolidated Edison started offering incentives for energy storage projects that could be used to reduce loads [88]\*. This program offers incentives up to 50% of the project costs for energy storage projects of 50 kW and above, with additional bonuses available to projects above 500 kW. Although the intent of the program is to make up for the loss of generation capacity from the 2021 decommissioning of the Indian Point nuclear power plant, reduction of load could directly help with reducing transmission congestion. In April 2017, NYSERDA announced it would release \$15.5M to support energy storage projects for grid support, including to ease peak demand on the grid [89]\*.

The State of Texas passed SB 943 in September of 2011. This landmark bill defines any energy storage system used for bulk energy sales or ancillary services as a generation asset, able to interconnect to the grid, obtain transmission service, and sell into wholesale electricity and ancillary services markets [90]\*. A further rule by the Public Utility Commission of Texas in 2012 determined that charging energy storage would be considered a wholesale transaction and that it would be exempted from the ancillary services charges that apply to retail loads [91]\*.

Laws and regulations regarding energy storage are new, but starting to take hold. This review did not find any federal legislation passed in the U.S. since 2010, but the authors found three FERC rules and a notice of proposed rule making related to energy storage. This review found actions related to energy storage that have been enacted in seven U.S. states. California and Oregon have both passed energy storage mandates, while the other states have passed laws to promote energy storage or better define how energy storage interacts with the power grid as a whole [54]\*. Regulatory rules will likely need to change or new ones created as BESS become viable assets for transmission-scale projects. The industry is just now realizing the potential that large-scale BESS can have on the bulk transmission system, and as such effective regulatory rules will be needed to clarify the provision of ancillary services, classification of reserve assets, and means for market compensation of BESS-provided services.

## 5. Discussion and Conclusions

This systematic literature review investigated six Research Questions pertaining to the use of BESS for providing transmission congestion relief. The RQs examined BESS in the context of TCR, the various BESS technologies, installation and operation costs, revenue streams, economic metrics, and BESS modeling tools. The review also surveyed laws and regulations relevant to utility-scale BESS. The review gathered material from academic literature, technical reports, and legislation in order to develop a comprehensive understanding of the technical, economic, and governmental issues relevant to large-scale deployment of BESS, particularly for addressing transmission congestion.

Solutions to TCR include building new transmission lines and expanding existing transmission capacity, the so-called new wires solutions, in order to ensure transmission corridors are not overloaded during peak demand periods. Non-wires solutions are also deployed to address TCR, including generation curtailment, incrementing and decrementing generation, and demand response programs, among others. As energy storage becomes more economically viable, it offers an additional option for relieving congestion. Energy storage has the ability to shift energy through time, allowing transmission lines to be less loaded during peak hours and more loaded during off-peak hours.

Transmission congestion typically occurs during peak loading periods, which happen only occasionally and for very brief periods during a year. As such, energy storage assets have ample opportunity to provide other services when not relieving congestion. These services can provide

additional revenue streams to improve the economics of a utility-scale BESS project. Energy storage has been demonstrated to be capable of providing resource adequacy, frequency response, and regulation services, to name a few. These services can be stacked, meaning they can be concurrently scheduled and dispatched. Given well-developed cost functions for these services and an objective function, there are ample opportunities for optimizing scheduling and dispatch. This literature review has shown that these factors, along with legislation and regulations designed to promote energy storage, are driving the deployment of utility-scale energy storage projects.

Many of the reviewed academic articles and technical reports demonstrate that utility-scale BESS can be used to provide TCR. This literature discusses means for siting, sizing, operating, and dispatching utility-scale BESS, and several presented means for optimizing BESS dispatch. The dispatch of BESS for TCR depends on project capital costs and the value of potential revenue streams. BESS project costs are considered in terms of both power and energy, which vary considerably by technology. The costs for all utility-scale BESS technologies have been declining and are projected to continue doing so in the coming decade. Lithium-ion technologies, in particular, have been shown to be very well suited for utility-scale energy storage applications. Rapidly declining costs indicate that lithium-ion BESS will be the dominate battery energy storage technology in the foreseeable future. Projected BESS revenue streams can be difficult to measure because there are many ways services may be combined, and deployment situations vary widely. Nevertheless, a BESS scheduled to provide a primary service can increase value by also providing additional services while not dispatched for its primary service. Several quantifiable metrics have been developed that allow for quantification of the value of BESS. These include traditional LCOE, IRR, and NPV, and the storage-specific metrics LCOC, LCOS, CONE and FCONE. These metrics allow for a comparison between different storage project proposals. Several modeling tools are available to help define the value of BESS projects, though no one model is yet available that can evaluate the wide range of revenue streams from energy storage. Models that provide analysis of stacked services are particularly valuable.

Using BESS to provide transmission congestion relief will require large-scale projects, with power and energy capacity scales in the range of 10's to 100's of both MW and MWh. Despite rapidly declining costs, battery energy storage projects are capital-intensive, and building systems that solely provide TCR are not likely to be economically justified. However, by providing multiple services through stacking, the economics have been shown to improve. Further, new economic metrics for quantifying BESS value and modeling techniques for demonstrating that value are now available to aid the analysis of project value. These advances, coupled with continued legislative and regulatory support, are increasing the viability of using BESS to provide TCR.

**Author Contributions:** Conceptualization, R.B.; methodology, R.B. and K.M.; formal analysis, K.M.; investigation, K.M.; resources, K.M. and M.O.; data curation, K.M. and M.O.; writing—original draft preparation, K.M., M.O. and R.B.; writing—review and editing, K.M. and R.B.; visualization, K.M.; supervision, R.B.; project administration, R.B.; funding acquisition, R.B.

**Funding:** This research was funded by Portland General Electric.

**Conflicts of Interest:** The authors declare no conflict of interest.

## Abbreviations

The following abbreviations are used in this manuscript:

APbA	Advanced lead-acid	BA	Balancing area
BESS	Battery energy storage systems	BOP	Balance of plant
CAES	Compressed air energy storage	CONE	Cost of New Entry
DA	Day-ahead	DOE	Department of Energy
ESS	Energy storage systems	FCONE	Flexible cost of new entry
FERC	Federal energy regulatory commission	HB	House Bill
ISO	Independent system operator	kW	Kilowatts (power metric)
kWh	Kilowatt-hours (energy metric)	kW-yr	Kilowatt-years (energy metric)

LCOC	Levelized cost of capacity	LCOE	Levelized cost of electricity
LCOS	Levelized cost of storage	Li+	Lithium-ion
IRR	Internal rate of return	LMP	Locational margin price
MILP	Mixed-integer linear program	MW	Megawatts (power metric)
MWh	Megawatt-hours (energy metric)	NaS	Sodium–sulfur
NPV	Net present value	O&M	Operation and maintenance
OPF	Optimal power flow	OPUC	Oregon Public Utility Commission
PCS	Power conversion system	PHS	Pumped hydroelectric system
PbA	Lead-acid	RQ	Research question
RT	Real-time	RTO	Regional transmission operator
RTOD	Real-time optimal dispatch	SB	Senate Bill
SGIP	Self-Generation incentive program	SLR	Systematic literature review
TCR	Transmission congestion relief	T&D	Transmission and distribution
Tx	Transmission	VR	Vanadium-redox
ZnBr	Zinc–bromine		

## References

1. Akhil, A.; Huff, G.; Currier, A.; Kaun, B.; Rastler, D.; Chen, S. *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*; Technical report; Sandia National Laboratories: Albuquerque, NW, USA, 2015\*.
2. Del Rosso, A.; Eckroad, W. Energy storage for relief of transmission congestion. *IEEE Trans. Smart Grid* **2014**, *5*, 1138–1146\*. [[CrossRef](#)]
3. Electric Power Research Institute. *Electricity Energy Storage Technology Options, a White Paper Primer on Applications, Costs, and Benefits*; Technical Report; Electric Power Research Institute: Palo Alto, CA, USA, 2010\*.
4. Zheng, K.; Zheng, Z.; Jiang, H.; Ren, J. Economic analysis of applying the used EV battery to commercial electricity customer. In Proceedings of the 5th International Conference on Electric Utility Deregulation and Restructuring and Power Technologies, Changsha, China, 26–29 November 2015; pp. 2100–2103.
5. Huynh, J. *Quantifying the Cost-Effectiveness of Energy Storage Systems for the City of San Diego*; Technical report; Scripps Institution of Oceanography: La Jolla, CA, USA, 2016\*.
6. Arabali, A.; Ghofrani, M.; Etezadi-Amoli, M. Cost analysis of a power system using probabilistic optimal power flow with energy storage integration and wind generation. *Electr. Power Energy Syst.* **2013**, *53*, 832–841\*. [[CrossRef](#)]
7. Sidhu, A.; Pollitt, M.; Anaya, K. *A Social Cost Benefit Analysis of Grid-Scale Electrical Energy Storage Projects: Evaluating the Smarter Network Storage Project*; Technical report; Energy Policy Research Group, University of Cambridge: Cambridge, UK, 2017\*.
8. Das, T.; Krishnan, V.; McCalley, J. High-fidelity dispatch model of storage technologies for production costing studies. *IEEE Trans. Sustain. Energy* **2014**, *5*, 1242–1252\*. [[CrossRef](#)]
9. National Renewable Energy Laboratory. *Issue Brief: A Survey of State Policies to Support Utility-Scale and Distributed-Energy Storage*; Technical report; National Renewable Energy Laboratory: Golden, CO, USA, 2014.
10. Kaun, B.; Minear, E. *Energy Storage for the Electric Grid*; Technical report; Electric Power Research Institute: Palo Alto, CA, USA, 2017\*.
11. Nguyen, N.; Le, D.; Moshi, G.; Bovo, C.; Berizzi, A. Sensitivity analysis on locations of energy storage in power systems with wind integration. *IEEE Trans. Power Syst.* **2016**, *52*, 5185–5193\*. [[CrossRef](#)]
12. Vargas, L.; Bustos-Turu, G.; Larraín, F. Wind power curtailment and energy storage in transmission congestion management considering power plants ramp rates. *IEEE Trans. Power Syst.* **2015**, *30*, 2498–2506\*. [[CrossRef](#)]
13. Alqunun, K.; Crossley, P. The impact of distributed energy storage on total operation cost in power systems. *Int. J. Simul. Syst. Sci. Technol.* **2016**, *17*, 1.1–1.7\*.
14. Dvorkin, Y.; Fernandez-Blanco, R.; Kirschen, D.; Pandzic, H.; Watson, J.; Silva-Monroy, C. Ensuring profitability of energy storage. *J. Energy Storage* **2017**, *32*, 611–623\*. [[CrossRef](#)]
15. Pandzic, H.; Wang, Y.; Qiu, T.; Dvorkin, Y.; Kirschen, D. Near-optimal method for siting and sizing of distributed storage in a transmission network. *IEEE Trans. Power Syst.* **2015**, *30*, 2288–2300\*. [[CrossRef](#)]

16. Khani, H.; Zadeh, M.; Hajimiragha, A. Transmission congestion relief using privately owned large-scale energy storage systems in a competitive electricity market. *IEEE Trans. Power Syst.* **2016**, *31*, 1449–1458\*. [[CrossRef](#)]
17. Berrada, A.; Loudiyi, K.; Zorkani, I. Valuation of energy storage in energy and regulation markets. *Energy* **2016**, *115*, 1109–1118\*. [[CrossRef](#)]
18. Lu, B.; Shahidehpour, M. Short-term scheduling of battery in a grid-connected PV/battery system. *IEEE Trans. Power Syst.* **2005**, *20*, 1053–1061\*. [[CrossRef](#)]
19. Mohsenian-Rad, H. Coordinated price-maker operation of large energy storage units in nodal energy markets. *IEEE Trans. Power Syst.* **2016**, *31*, 786–797\*. [[CrossRef](#)]
20. Hartwig, K.; Kockar, I. Impact of strategic behavior and ownership of energy storage on provision of flexibility. *IEEE Trans. Sustain. Energy* **2016**, *7*, 744–754\*. [[CrossRef](#)]
21. Kazempour, S.; Moghaddam, M.; Haghifam, M.; Yousefi, G. Electric energy storage systems in a market-based economy: Comparison of emerging and traditional technologies. *Renew. Energy* **2009**, *34*, 2630–2639\*. [[CrossRef](#)]
22. Hartel, P.; Doering, M.; Jentsch, M.; Pape, C.; Burges, K.; Kuwahata, R. Cost assessment of storage options in a region with a high share of network congestions. *J. Energy Storage* **2016**, *8*, 358–367\*. [[CrossRef](#)]
23. Babrowski, S.; Jochem, S.; Fichtner, W. Electricity storage systems in the future German energy sector an optimization of the German electricity generation system until 2040 considering grid restrictions. *Comput. Oper. Res.* **2016**, *66*, 228–240\*. [[CrossRef](#)]
24. Qiu, T.; Xu, B.; Wang, Y.; Dvorkin, Y.; Kirschen, D. Stochastic multistage co-planning of transmission expansion and energy storage. *IEEE Trans. Power Syst.* **2017**, *32*, 643–651\*. [[CrossRef](#)]
25. Xu, Y.; Singh, C. Power system reliability impact of energy storage integration with intelligent operation strategy. *IEEE Trans. Power Syst.* **2014**, *5*, 1129–1137\*.
26. Barsali, S.; Ceraolo, M.; Giglioli, R.; Poli, D. Storage applications for smartgrids. *Electr. Power Syst. Res.* **2015**, *120*, 109–117\*. [[CrossRef](#)]
27. Yao, L.; Yang, B.; Cui, H.; Zhuang, J.; Ye, J.; Xue, J. Challenges and progresses of energy storage technology and its application in power systems. *J. Mod. Power Syst. Clean Energy* **2016**, *4*, 778–788\*. [[CrossRef](#)]
28. Hamidi, S.; Ionel, D.; Nasiri, A. Modeling and management of batteries and ultracapacitors for renewable energy support in electric power systems—An overview. *Electr. Power Components Syst.* **2015**, *43*, 1434–1452\*. [[CrossRef](#)]
29. Luo, X.; Wang, J.; Dooner, M.; Clarke, J. Overview of current development in electrical energy storage technologies and the application potential in power system operation. *Appl. Energy* **2015**, *137*, 511–536. [[CrossRef](#)]
30. Yang, Y.; Bremner, S.; Menictas, C.; Kay, M. Battery energy storage system size determination in renewable energy systems: A review. *Renew. Sustain. Energy Rev.* **2018**, *91*, 109–125. [[CrossRef](#)]
31. Poullikkas, A. A comparative overview of large-scale battery systems for electricity storage. *Renew. Sustain. Energy Rev.* **2013**, *27*, 778–788\*. [[CrossRef](#)]
32. Zakeri, B.; Syri, S. Electrical energy storage systems: A comparative lifecycle cost analysis. *Renew. Sustain. Energy Rev.* **2015**, *42*, 569–596\*. [[CrossRef](#)]
33. May, G.J.; Davidson, A.; Monahov, B. Lead batteries for utility energy storage: A review. *J. Energy Storage* **2018**, *15*, 145–157. [[CrossRef](#)]
34. Benato, R.; Bruno, G.; Palone, F.; Polito, R.; Rebolini, M. Large-scale electrochemical energy storage in high voltage grids: Overview of the Italian experience. *Energies* **2017**, *10*, 108\*. [[CrossRef](#)]
35. Schiavo, L.L.; Benini, M. Pilot projects on Battery Energy Storage Systems in the Transmission grid: Regulatory framework and first results. In Proceedings of the 2018 AEIT International Annual Conference, Bari, Italy, 3–5 October 2018; pp. 1–6.
36. Corona, P.; Ghiani, E.; Contreras, J. Analysis of Sardinia-Italy Energy Flows with Future Transmission Investments for Increasing the Integration of RES. In Proceedings of the 2019 1st International Conference on Energy Transition in the Mediterranean Area (SyNERGY MED), Cagliari, Italy, 28–30 May 2019; pp. 1–6.
37. Sandia National Laboratories. *DOE Global Energy Storage Database (Cited 24 July 2017)*; Sandia National Laboratories: Albuquerque, NM, USA, 2017\*.

38. Palone, F.; Rebolini, M.; De Simone, M.; Gentili, S.; Giannuzzi, G.M. Operating strategies for congestion management of HV lines using NaS batteries. In Proceedings of the 2015 AEIT International Annual Conference (AEIT), Naples, Italy, 14–16 October 2015; pp. 1–6.
39. Hemmati, R.; Saboori, H. Emergence of hybrid energy storage systems in renewable energy and transport applications—A review. *Renew. Sustain. Energy Rev.* **2016**, *65*, 11–23. [[CrossRef](#)]
40. Cutter, E.; Haley, B.; Hargreaves, J.; Williams, J. Utility scale energy storage and the need for flexible capacity metrics. *Appl. Energy* **2014**, *124*, 274–282\*. [[CrossRef](#)]
41. Bloomberg Markets. EUR to USD Exchange Rate. Available online: [www.bloomberg.com/quote/EURUSD:CUR](http://www.bloomberg.com/quote/EURUSD:CUR) (accessed on 9 November 2017).
42. Fioravanti, R.; Kleinberg, M.; Katzenstein, W.; Lahiri, S.; Tong, N.; Abrams, A. *Energy Storage Cost-Effectiveness Methodology and Results*; Technical report; California Energy Commission: Sacramento, CA, USA, 2013\*.
43. Denholm, P.; Jorgenson, J.; Hummon, M.; Jenkin, T.; Palchak, D.; Kirby, B. *The Value of Energy Storage for Grid Applications*; Technical report; National Renewable Energy Laboratories: Golden, CO, USA, 2013.
44. Taylor, J. Financial Storage Rights. *IEEE Trans. Power Syst.* **2015**, *30*, 997–1005\*. [[CrossRef](#)]
45. Kintner-Meyer, M. Regulatory policy and markets for energy storage in North America. *Proc. IEEE* **2017**, *102*, 1065–1072\*. [[CrossRef](#)]
46. *Energy Storage Potential Evaluation. Prepared for Pacificorp and Submitted to Docket UM-1857*; Technical Report; DNV-GL: Portland, OR, USA, 2017\*.
47. Navigant. *Energy Storage Potential Evaluation. Prepared for Portland General Electric and Submitted to Docket UM-1856*; Navigant: Chicago, IL, USA, 2017\*.
48. Afanasyeva, S.; Breyer, C.; Engelhard, M. Impact of battery cost on the economics of hybrid photovoltaic power plants. *Energy Procedia* **2016**, *99*, 157–173\*. [[CrossRef](#)]
49. Bortolini, M.; Gamberi, M.; Graziani, A. Technical and economic design of photovoltaic and battery energy storage system. *Energy Convers. Manag.* **2014**, *86*, 81–92\*. [[CrossRef](#)]
50. Obi, M.; Jensen, S.; Ferris, J.; Bass, R. Calculation of levelized costs of electricity for various electrical energy storage systems. *Renew. Sustain. Energy Rev.* **2017**, *67*, 908–920\*. [[CrossRef](#)]
51. Schmidt, O.; Melchior, S.; Hawkes, A.; Staffell, I. Projecting the Future Levelized Cost of Electricity Storage Technologies. *Joule* **2019**, *3*, 81–100. [[CrossRef](#)]
52. Telaretti, E.; Graditi, G.; Ippolito, M.; Zizzo, G. Economic feasibility of stationary electrochemical storages for electric bill management applications: The Italian scenario. *Energy Policy* **2016**, *94*, 126–137. [[CrossRef](#)]
53. Public Utility Commission of Oregon. *Order 17-118*; Public Utility Commission of Oregon: Salem, OR, USA, 2017\*.
54. 78th Oregon Legislative Assembly. *2015 Regular Session. HB 2193*; 78th Oregon Legislative Assembly: Salem, OR, USA, 2015\*.
55. *Energy Storage Valuation in California: Policy, Planning and Market Information Relevant to the StorageVET™ Model*; Technical Report; Electric Power Research Institute: Palo Alto, CA, USA, 2016\*.
56. 109th U.S. Congress. *H.R.6—Energy Policy Act of 2005. 42 USC 16215*; 109th U.S. Congress: Washington, DC, USA, 8 August 2007\*.
57. 110th U.S. Congress. *H.R.6—United States Energy Storage Competitiveness Act of 2007. 42 USC 17213*; 110th U.S. Congress: Washington, DC, USA, 19 December 2007\*.
58. 110th U.S. Congress. *Duncan Hunter National Defense Authorization Act for Fiscal Year 2009. Pub. L. No. 110-417 Sect. 218*; 110th U.S. Congress: Washington, DC, USA, 14 October 2008\*.
59. 111th U.S. Congress. *National Defense Authorization Act for Fiscal Year 2010. Pub. L. No. 110-140 Sect. 243*; 111th U.S. Congress: Washington, DC, USA, 19 December 2007\*.
60. U.S. Federal Energy Regulatory Commission. *Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets. 137 FERC 61,064*; U.S. Federal Energy Regulatory Commission: Washington, DC, USA, 20 October 2011\*.
61. U.S. Federal Energy Regulatory Commission. *Order No. 784, Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies. 144 FERC 61,056*; U.S. Federal Energy Regulatory Commission: Washington, DC, USA, 18 July 2013\*.
62. U.S. Federal Energy Regulatory Commission. *Order No. 792, Small Generator Interconnection Agreements and Procedures. 145 FERC 61,159*; U.S. Federal Energy Regulatory Commission: Washington, DC, USA, 22 November 2013\*.

63. U.S. Federal Energy Regulatory Commission. *Notice of Proposed Rulemaking, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*. 157 FERC 61,121; U.S. Federal Energy Regulatory Commission: Washington, DC, USA, 17 November 2016\*.
64. Walton, R. Facing Lack of Quorum, FERC Delegates Some Authority to Staff. *Util. Dive* 2017. Available online: <https://www.utilitydive.com/news/facing-lack-of-a-quorum-ferc-delegates-some-authority-to-staff/435720/> (accessed on November 2017).
65. Pyper, J.; Lacey, S. With a quorum, FERC now grapples with distributed energy trends outpacing market rules. *Greentech Media* 2017. Available online: <https://www.greentechmedia.com/articles/read/ferc-now-grapples-with-distributed-energy-trends> (accessed on November 2017).
66. California State Legislature. *California Legislative Session 2009–2010. AB 2514 Energy Storage Systems*; California State Legislature: Sacramento, CA, USA, 29 September 2010\*.
67. Public Utility Commission of the State of California. *Decision 13-10-040*; Public Utility Commission of the State of California: San Francisco, CA, USA, 17 October 2013\*.
68. Public Utility Commission of the State of California. *Decision 14-03-004*; Public Utility Commission of the State of California: San Francisco, CA, USA, 13 March 2014\*.
69. Melley, B. *California Declares Massive Natural Gas Leak Sealed*; Associated Press: New York, NY, USA, 2016.
70. Milman, O. *LA Gas Leak: Worst in US History Spewed as Much Pollution As 600,000 Cars*; Los Angeles Guardian: Los Angeles, CA, USA, 2016.
71. *Resolution E-4791, Authorizing Expedited Procurement of Storage Resources to Ensure Electric Reliability in the Los Angeles Basin Due to Limited Operations of Aliso Canyon Gas Storage Facility*; Technical Report; Public Utilities Commission of the State of California: San Francisco, CA, USA, 2016\*.
72. *Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin*; Technical Report; Joint Publication of California Public Utilities Commission, California Energy Commission, The California Independent System Operator and the Los Angeles Department of Water and Power: Sacramento, CA, USA, 2016\*.
73. San Diego Gas and Electric. *SDG&E to Add More Storage to Improve Regional Reliability*; San Diego Gas and Electric: San Diego, CA, USA, 2016.
74. California Legislative Session 2015–2016. AB 33 Electrical Corporations: Energy Storage Systems: Long Duration Bulk Energy Storage Resources, 26 September 2016\*.
75. California Legislative Session 2015–2016. AB 1637 Energy: Greenhouse Gas Reduction, 26 September 2016\*.
76. California Legislative Session 2015–2016. AB 2868 Energy Storage, 26 September 2016\*.
77. State of Massachusetts. *ESI Program Goals*; State of Massachusetts: Boston, MA, USA, 2015\*.
78. General Court of Massachusetts. *189th Legislative Session; H. 4385*; General Court of Massachusetts: Boston, MA, USA, 2016\*.
79. Massachusetts Executive Office of Energy and Environmental Affairs. *Baker-Polito Administration Sets 200 Megawatt-Hour Energy Storage Target*; Massachusetts Executive Office of Energy and Environmental Affairs: Boston, MA, USA, 2017\*.
80. Clean Energy Standard. *Massachusetts Department of Environmental Protection. 310 CMR 7.75*; Clean Energy Standard: Boston, MA, USA, 11 August 2017\*.
81. Public Utility Commission of Oregon. *Order 16-504*; Public Utility Commission of Oregon: Salem, OR, USA, 2016\*.
82. 78th Oregon Legislative Assembly. *2016 Regular Session. SB 1547*; 78th Oregon Legislative Assembly: Salem, OR, USA 2016\*.
83. Nevada Legislature 79th Session. *SB 145*; Nevada Legislature 79th Session: Carson City, NV, USA, 2017\*.
84. Nevada Legislature 79th Session. *SB 204*; Nevada Legislature 79th Session: Carson City, NV, USA, 2017\*.
85. New Mexico 2013 Legislative Session. *HJM 10*; New Mexico 2013 Legislative Session: Santa Fe, NM, USA, 2013\*.
86. New Mexico 2013 Legislative Session. *SJM 43*; New Mexico 2013 Legislative Session: Santa Fe, NM, USA, 2013\*.
87. New Mexico Public Regulation Commission. *Commission Unanimously Approves Amending Rule to Include Energy Storage*; New Mexico Public Regulation Commission: Santa Fe, NM, USA, 2017\*.
88. Acker, B. *ConEdison and NYSERDA Propose Major Energy Storage Program*; NYBEST: Albany, NY, USA, 2014\*.

89. New York State Energy Research and Development Authority. *NYSERDA Announces \$15.5 Million Available for Energy Storage Projects to Support the Electric Grid*; New York State Energy Research and Development Authority: Albany, NY, USA, 2017\*.
90. Texas Legislative Session 82(R). *SB 943*; Texas Legislative Session 82(R): Austin, TX, USA, 2011\*.
91. Public Utility Commission of Texas. *Project 39917*; Public Utility Commission of Texas: Austin, TX, USA, 2012\*.



© 2019 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<http://creativecommons.org/licenses/by/4.0/>).