Final Slide Deck

Resilience Optimization Proceeding

JRSP JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO

NEGOCIADO DE ENERGÍA DE PUERTO RICO

March 23, 2021

Optimization - Workshop #3

Agenda - Morning

- Introduction/Recap of Workshops #1 and #2 (10:00 AM)
- Objectives / Process (10:15 AM)
  - Summary: short-term and long-term objectives: near-optimal solutions for resiliency
  - Discussion of analyses as part of workshops – near term objectives
  - How to best utilize the resources and work of the DOE/National Labs efforts and analyses to date, and going forward, to help identify near-term and long-term solutions.
  - Encouragement for comments and responses to questions throughout proceeding
- DER Solutions – Part 1 (11:00 AM)
  - Scope of DER solution options
  - Cost of DER solutions
  - Stakeholder filings
- Break (12:30-1)

Agenda - Afternoon

- DER Solutions – Part 2 (1:00 PM)
  - How to value resiliency benefits of DER solutions
  - How to compare resiliency value of DER solutions to transmission/distribution hardening/undergrounding solutions
  - Cost / Benefit Analysis for DER solutions
  - Funding for DER solutions
- Guidelines and Metrics for Optimization (2:30 PM)
  - Overall guidelines to identify solutions
  - Metrics and analytical methods to use for identifying near-term solutions
  - Distribution issues that affect choice of near-term solutions
  - How to structure, and interpret results, of Cost/Benefit analyses of alternate/complementary solutions to inform “no regrets” solution sets.
- Wrap up and Next Steps (3:30 PM)
  - Next workshop (April): DOE/National labs to present
  - Agenda for next workshop

Recap: Optimization Proceeding Objective

- Identify "no regrets" resiliency solutions
- Determine a reasonable, near-optimal mix of:
  - Additional transmission investment for the PREPA identified MiniGrid regions; and
  - Local distributed resource deployment.
- Determine the way resiliency investments would be made:
  - Direct customer installation
    - energy or energy/capacity resources behind the meter,
    - with or without PREPA tariff-based or procurement-based support;
  - PREPA resource procurement (direct RFPs/PPOA, DR tariffs, other forms of feed-in tariffs);
  - PREPA installation of transmission or distribution equipment (traditional); or,
  - A combination of these mechanisms.

Recap: Near-Term and Long-Term Objectives

- These workshops to Inform Near Term Decisions
  - Identify no- or least regrets, low-hanging fruit – resiliency
    - Certain wires options (e.g., non-Minigrid solutions, selected MiniGrid candidate undergrounding) – blue sky and severe event
    - DERs – best candidate microgrids; other stand-alone DERs through VPP/PPOA, DR, self-funded, or other funding vehicle (FEMA resiliency programs?)
    - Allow / support / guide <u>rapid</u> deployment of near-term actions

- Longer-Term Decisions - ongoing
  - More complex circumstances
    - Increased stakeholder participation to vet specific locations for essential facility solutions, and procurement paths (e.g., public vs. private funding for DER solutions)
    - Public purpose microgrids, public purpose stand-alone DER?
    - DR/DER tariff – proportional to costs from VPP competitive procurement?
  - Other processes affect optimal choices: results of Procurement RFPs, DR initiatives, FEMA funding support
    - VPP decisions from procurement plan – resilience element?
    - Greater use of DOE/National Labs resiliency support

Process

- Discussion and analysis as part of these workshops
  - Load Segmentation to inform solution set – which critical and other load best served by DERs for resiliency?
  - Key Metrics - data collect, compute
    - Measure of resiliency: MWh not lost to storm event
    - Value of that resiliency, per MWh or other
    - Load MW – segmented – critical and other
    - DER solution costs per MW, MWh of resiliency
    - Transmission solution costs per MW, MWh of resiliency
  - Identifying complexities and acknowledging imperfect methods for near-term "no regrets" solutions.
  - Cost/Benefit analysis of alternate/complementary solutions?
    - How to structure C/B analyses to meet objectives – screening role only for near-term?
- How can the existing and future work of the DOE/National Labs support identification of "no regrets" solutions?
- Comments and responses to questions throughout proceeding

DER Solutions – Part 1

Scope of DER Solution Options

- Focus on resiliency attribute / but recognize blue sky value
  - IRP results and procurement proceeding results inform or will inform blue sky economics
    - Procurement proceeding: PREPA to address resiliency value for VPP/DER solutions in selection
- DER solution set: microgrid plus stand alone; different sizes
  - Potentially for all sectors of load (R, C, I) and within all MiniGrid regions
  - A MiniGrid region can have both hardened T, D w/ dependence on grid-connected resources; and DER solutions at "grid edges" (electrical).
  - Must be able to provide energy when isolated from grid
- Microgrids and Stand Alone DER – locations across entire island
  - Microgrids – multiple interconnected sites w/ resources to operate in isolation
  - Stand alone: one building, various sizes
- Primary purpose in this proceeding:
  - Identify broadly the location and critical load MW, MWh need of "no regrets" DER solutions (microgrid and stand alone) that lead to avoidance or deferral of need for transmission, distribution hardening for resilience
    - Detailed design of microgrids or stand-alone resource mix not needed initially
    - Neither <u>necessarily</u> contribute to restoration of grid, following weather event – "self resiliency"

Cost of DER Solution Options

- IRP: “Grid Defection” as proxy for residential standalone DER, but full blue sky estimate may not be appropriate proxy for resiliency (>> need).
  - NREL 2018 ATB for costs, assuming 6-hour battery (BESS).
  - Explicitly used NREL 2018 ATB for utility-scale costs for resource modeling
  - Roughly $6 million/MW (per MW of PV, w/ 6-hour battery) for residential scale (IRP Exhibits 3-12 and 3-16, Appendix 4)
- NREL 2020 ATB costs lower than 2018 for PV, battery storage
- For DER solution, could/should? assume <6h BESS (resiliency purposes)
- NREL current DER costs varies: configuration, performance and scale
  - Battery duration, ITC, utility vs. smaller scale, inverter config. are key determinants
  - Source: January 2021 Benchmark report, NREL
- These costs do not consider the avoided or deferred costs of T and/or D that could result
  - Depending on the scope, scale, location and timing of DER solutions for resiliency.

PV/Storage Costs – Utility Scale (100 MW)

- NREL utility scale: ~$1.7 million/MW, 4-hour battery storage plus PV

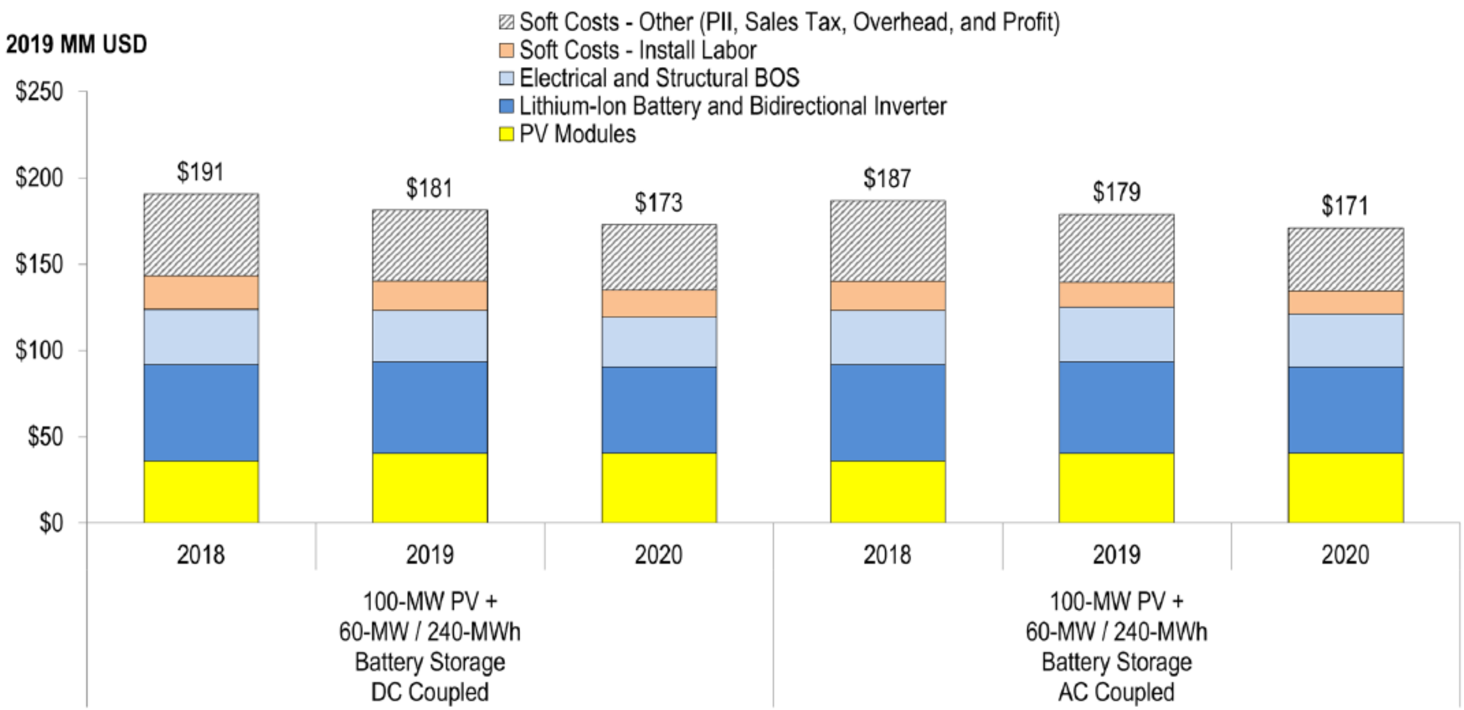

Figure ES-4. Utility-scale PV-plus-storage system cost benchmark summary (inflation-adjusted), 2018–2020, DC-coupled and AC-coupled

Source: NREL, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020 January 2021
https://www.nrel.gov/docs/fy21osti/77324.pdf

PV/Storage Costs – Residential Scale (7 kW)

- NREL residential scale: ~$ 4.1 – 5.4 million/MW, 2 to 4-hour battery storage + PV

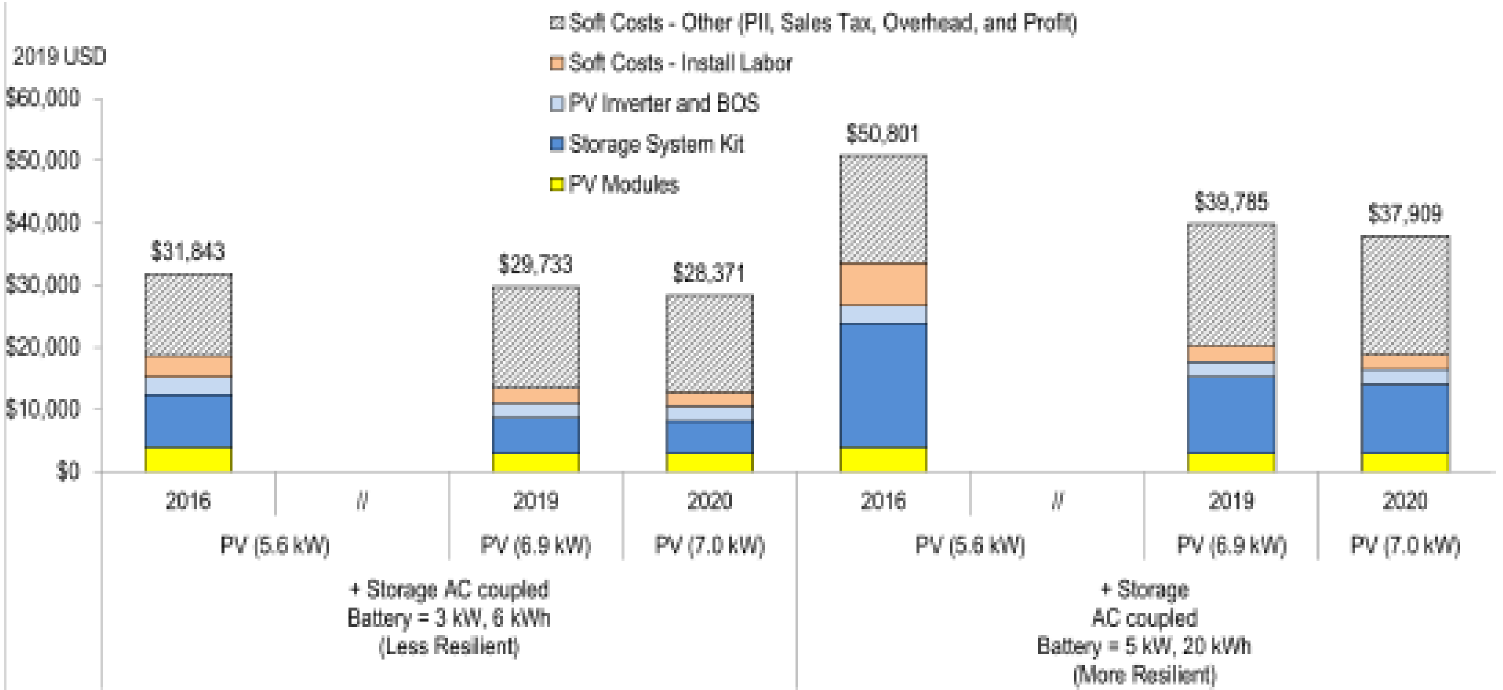

Figure ES-5. Residential PV-plus-storage system cost benchmark summary (inflation-adjusted), 2016, 2019, and 2020

Source: NREL, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020 January 2021
https://www.nrel.gov/docs/fy21osti/77324.pdf

PV/Storage and PV Costs – Residential Scale – Energy Basis

- NREL residential scale: ~$ 120-200/MWh 2-hour battery storage + PV

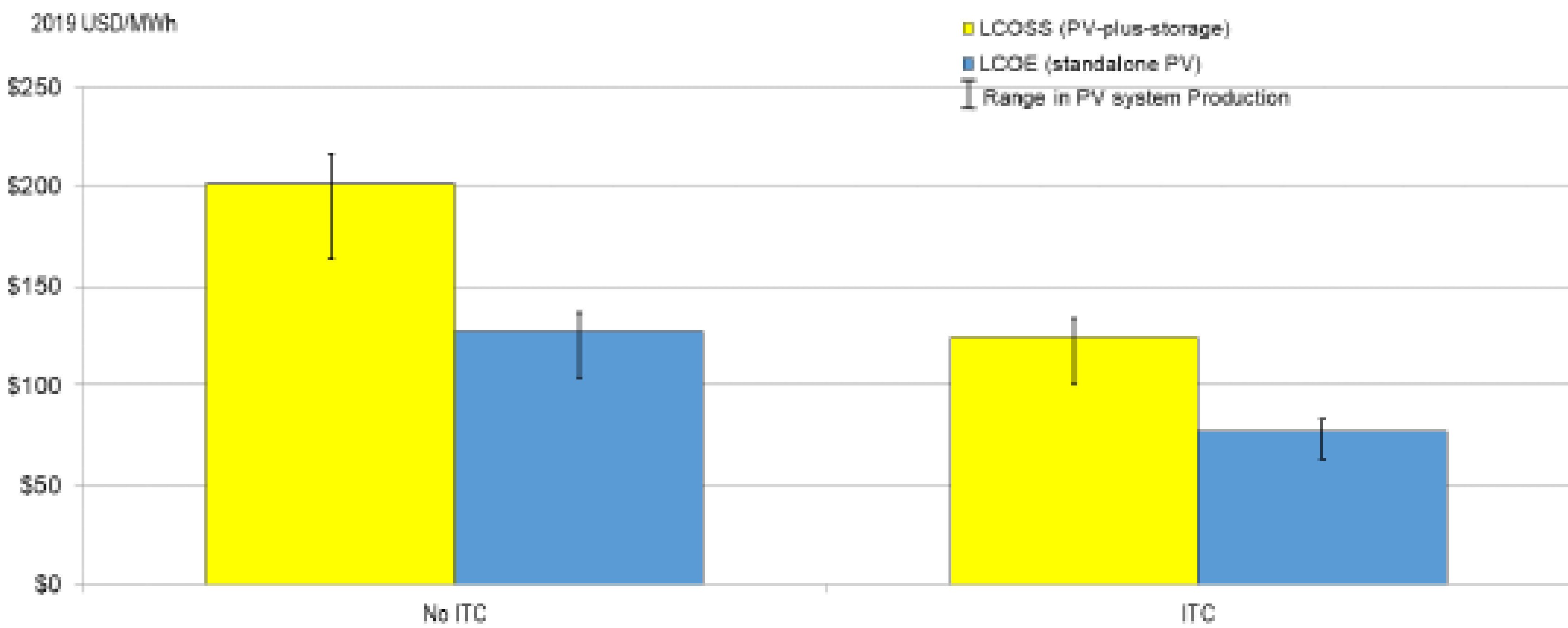

Figure 39. U.S. residential LCOSS for an AC-coupled PV (7 kW) plus storage (3 kW/6 kWh, 2-hour duration) system and LCOE for a 7-kW standalone PV system, Q1 2020

Source: NREL, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020 January 2021
https://www.nrel.gov/docs/fy21osti/77324.pdf

PV/Storage Costs – Commercial Scale (1 MW)

- NREL commercial scale: ~$2.1 – 2.7 million/MW, 4-hour battery storage plus

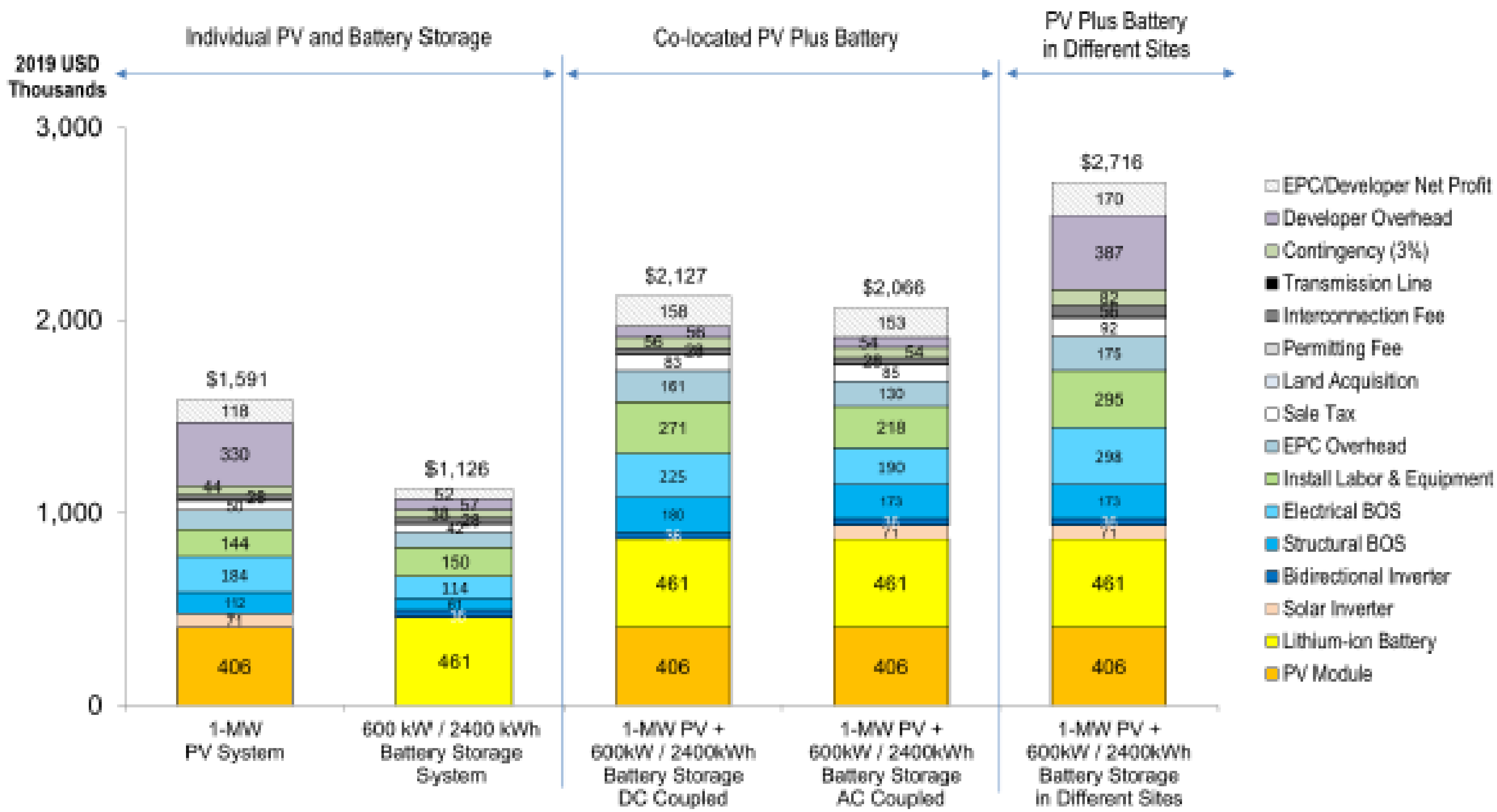

Figure 44. Cost benchmarks for commercial PV-plus-storage systems (4-hour duration) in different sites and the same site (DC-coupled and AC-coupled cases), Q1 2020

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https://www.nrel.gov/docs/fy21osti/77324.pdf

PV/Storage, and PV Costs – Size Comparison

- NREL comparison, energy basis

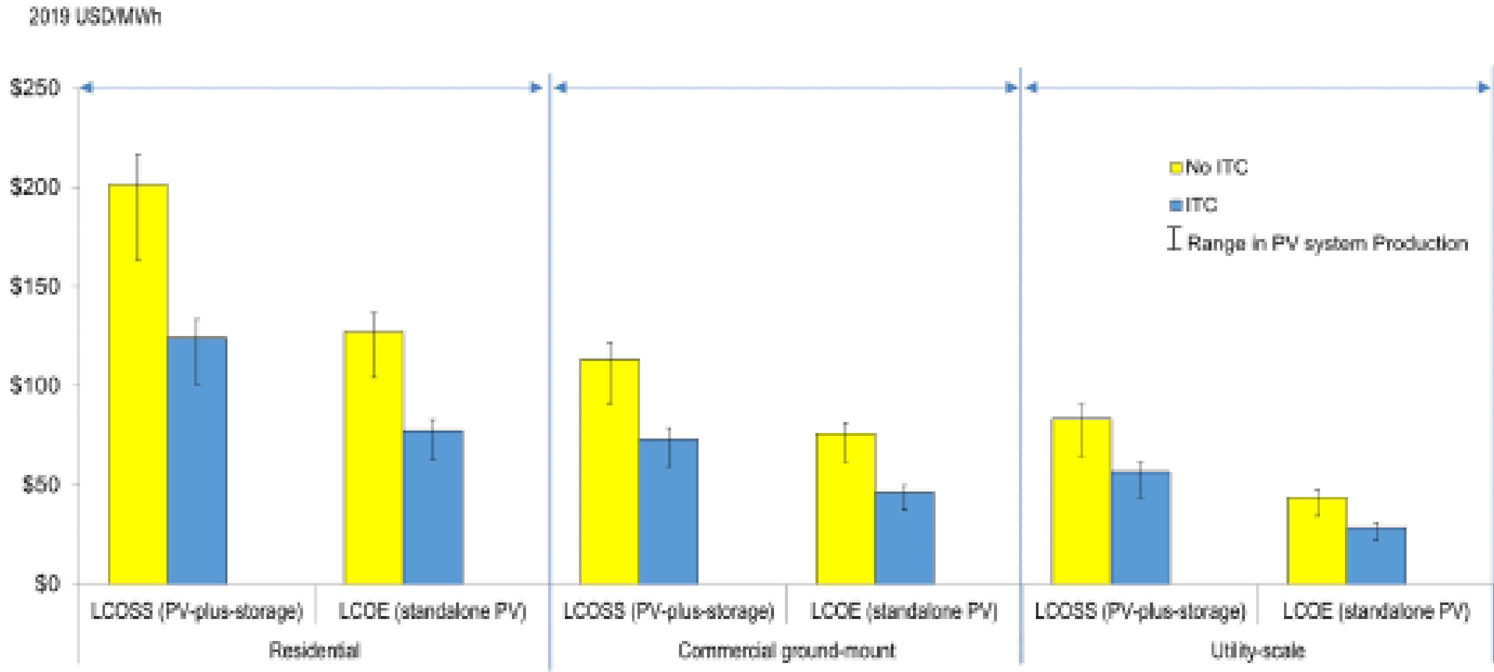

Figure ES-6. LCOSS for AC-coupled PV-plus-storage systems and LCOE for PV standalone systems, by market segment, Q1 2020

LCOSS and LCOE are calculated for each scenario under a medium resource location. The LCOSS and LCOE ranges are based on high and low capacity factor assumptions; all other values remain the same.

Source: NREL, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020 January 2021
https://www.nrel.gov/docs/fy21osti/77324.pdf

Residential Rooftop PV Only Costs – Variation Across Inverter Configuration

- Additional detail on cost components for residential scale PV, and differences across inverter configurations

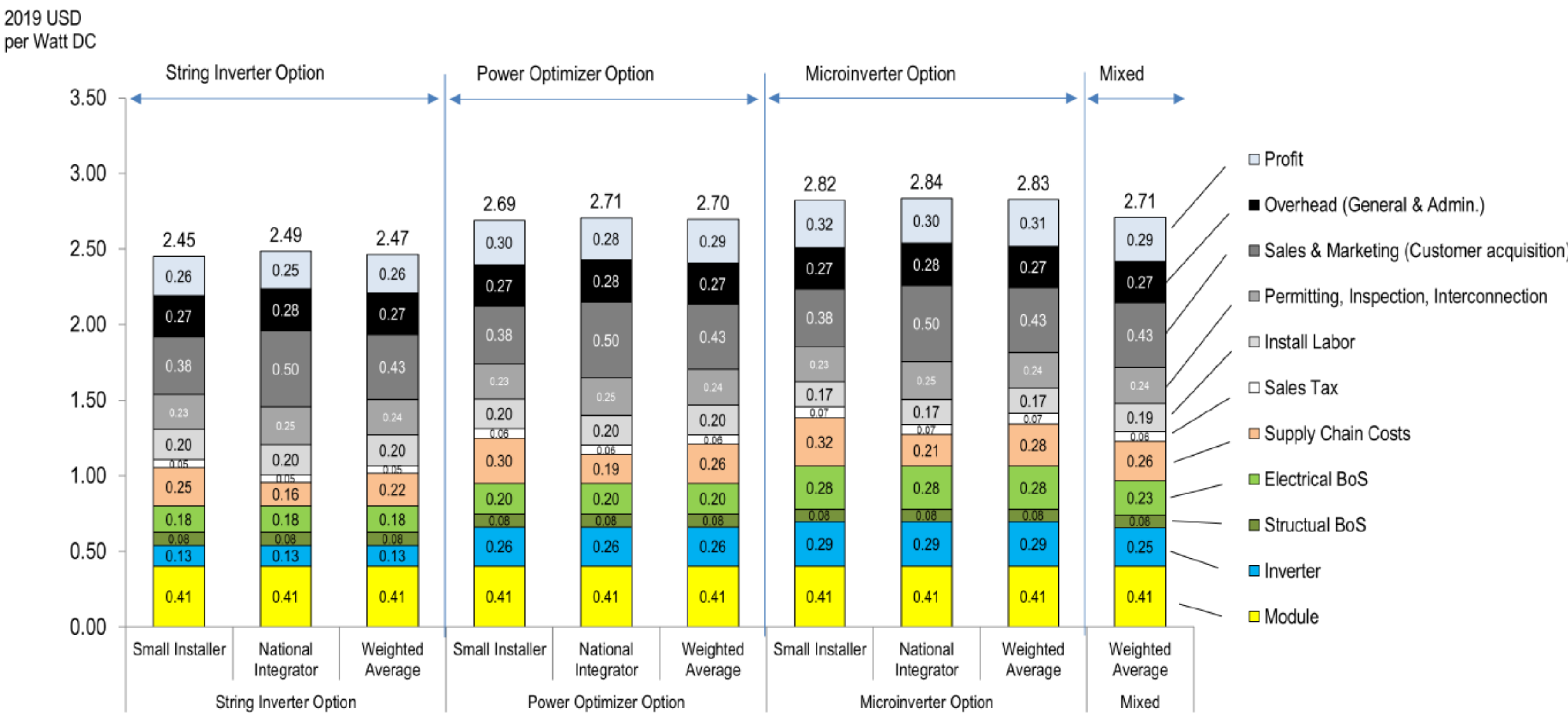

Figure 12. Q1 2020 U.S. benchmark: 7.0-kW residential PV system cost (2019 USD/W_{DC})

NREL Benchmark Summary: PV Costs

- PV alone – trends, cost components, scale differences (2020: $0.94 - $2.71/watt)

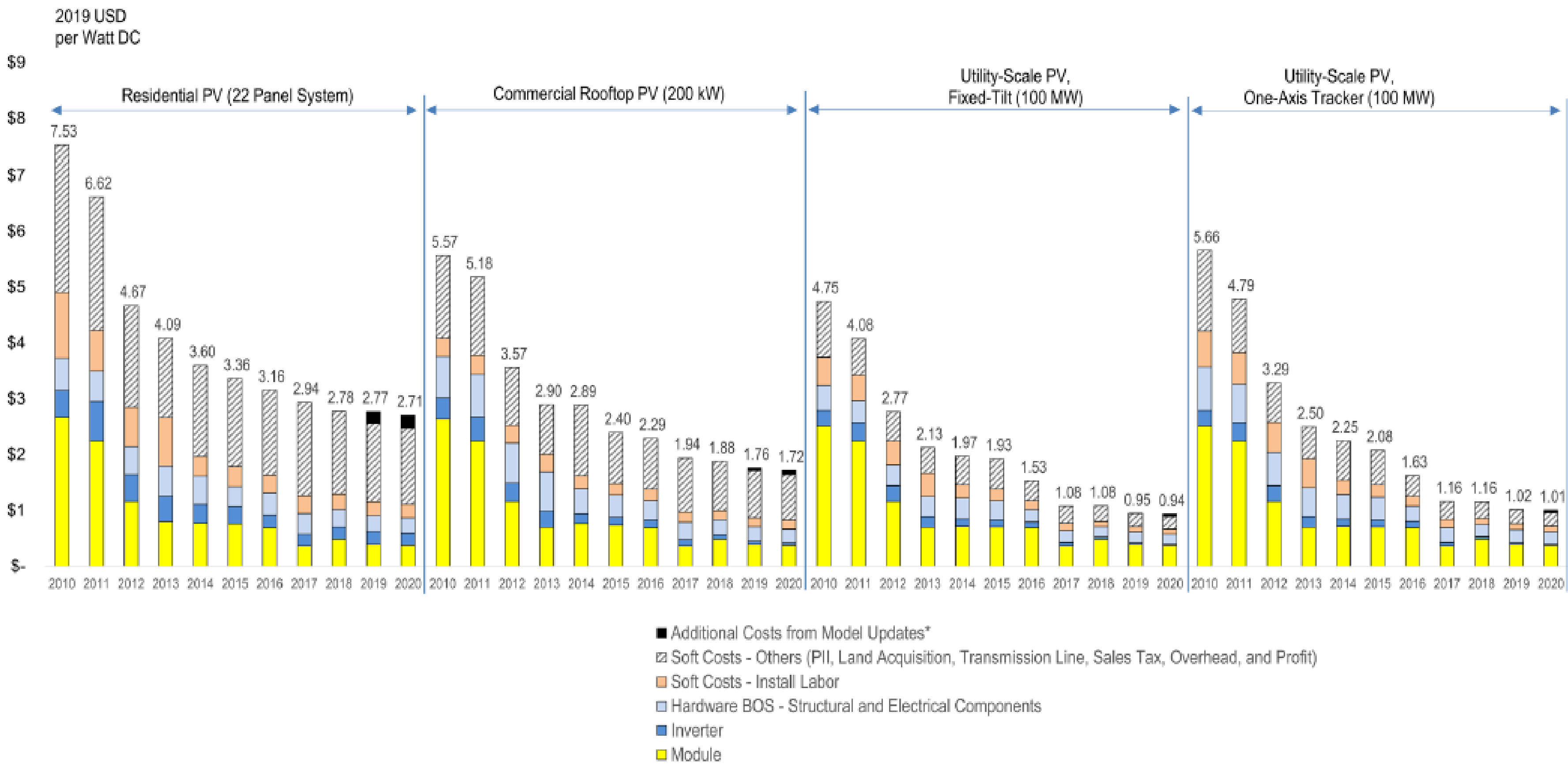

Figure 52. NREL PV system cost benchmark summary (inflation-adjusted), 2010–2020

Source: NREL, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020 January 2021 https://www.nrel.gov/docs/fy21osti/77324.pdf

DER Solutions – Practical Aspects

- Deployment/procurement – funding – PV, BESS, or both
  - Self-supplied
  - Third party supplied – VPP
  - FEMA/HUD funding, full or partial. FEMA 404, 428; HUD CDBG
  - On bill financing? PREPA, LUMA, or other Federal or PR agency?
- Funding dependent on resource type?
  - PV
  - Battery
  - Other renewable
  - Fossil? Diesel / propane
- Installation
  - Self-supplied
  - VPP
  - If FEMA funded: local contractors?
  - PREPA-outsourced – third party contractors
- Visibility / Control / Blue Sky and Dark Sky intended operation

Stakeholder Filings – DER Solutions – IRP Context

- CAMBIO/LEOs/IEEFA – Distributed solution
  - 100% homes, 2.7 kW, 2,700 MW PV
  - Commercial 2,282 MW PV
  - Total PV = 4,982 MW
  - Total BESS 2,528 MW BESS (@ 4.5 hour duration = 11.4 GWh)
  - Presumes FEMA funding may be available
- OIPC
  - Segmentation appropriate
  - DERs increase resilience, help avoid transmission during blue sky
- IRP
  - All PV and BESS installations / Preferred Plan presume fungibility between utility scale and distributed scale – economics driven
  - Procurement Plan, other procurement processes, and value of resiliency and potential avoided T, D costs factor into decisions between utility and distributed scale

DER Solutions – Part 2

DER Solutions Part 2

- Resiliency value
- How to compare resiliency value – DER vs. MiniGrid
- How to structure cost / benefit analysis
  - Total and incremental to utility-scale
  - How to compare costs and benefits across solution types
- Funding – energy, capacity, both
- Funding source
  - Self-supply,
  - Procurement (VPP - aggregator),
  - DR tariff,
  - Other procurement (DER tariff - individual)
  - Agency: FEMA, HUD, CDBG

Resiliency Value

- Metric: VOLL x preserved load
- IRP: assumption of duration of outage and load type

San Juan / Bayamon Only	Critical	Priority	Balance	Total
MWh from outage (1 week Level 2, 3 weeks Level 1)	95,244	50,725	127,861	273,830
VOLL per unit: $/MWh	$32,000	$10,000	$2,000	
Total costs ENS by load type	$3,047,815,247	$507,250,458	$255,722,354	**$3,810,788,060**

- This construct – expanded / extended to allow DER resiliency value computation
  - Direct computation of load not lost to storm event – DER parameters for energy, stored energy provision
  - But "coverage" comparisons to MiniGrid/wires solutions difficult because actual amount of load not lost under MiniGrid construct can vary dramatically:
    - Duration
    - Level of load

Discussion – Resiliency Comparison Approaches

- What loss of load is "allowed"? What is design basis for solutions?
- What role does vegetation management play in helping understand parameters?
- Attributes of Resiliency Provision – MiniGrid
  - Broader coverage across all "critical load", and some priority and balance load
  - But less certainty of provision unless wires hardening and substation hardening complete to all loads
  - Must incur all transmission, distribution hardening costs in order to attain coverage claimed
  - What is the timeline for provision / adaptation, penetration of solution – practical realities of wires hardening
- Attributes of Resiliency Provision – DER solutions
  - Greater certainty of resiliency provided (parameters of MW, MWh of DER)
  - Complex deployment – different types, different funding, different scales
  - What is the timeline for provision / adaptation, penetration of solution – practical realities of deploying hundreds, or thousands, of MW / MWh of resiliency

Cost Benefit Analysis

- C/B analysis for purposes of this proceeding:
  - Essentially: a screening analysis
  - Define costs; define benefits.
  - Determine net costs per resiliency provided for each solution set?
  - How to differentiate between baseline, and increment for resiliency, for each solution set.
- DER Costs
  - Total costs: estimated, NREL ATB
  - Incremental costs: difference between utility scale PV/BESS, and distributed scale PV/BESS – these resources must be procured anyway.
  - Avoided costs of T, D arising from use of DER – not a simple determination.
  - Net costs = Incremental DER costs minus T,D avoidance
- Benefits
  - Value of lost load avoided through DER – estimating duration = not easy.
- Comparing coverage of total VOLL across customers
  - DER value – per customer x customers covered x VOLL
  - MiniGrid value – total load covered by MG hardening x VOLL
    - How to account for less than total coverage? Distribution system failures.

C/B Analysis Structure

- Elements of structure
  - Incremental costs of DER solutions, vs. incremental costs of wires
  - Incremental benefits (resiliency, value not lost) of DER solution, and of wires solution
  - Comparisons:
    - $/MWh of provided resiliency under dark sky
- Difficulties: determining baselines to assess the resiliency increment
- Discussion: Other Ways to Approach?

Discussion: Funding for DER Solutions

- What role do possible funding sources for DER solutions play in determining which DER options are "no regrets"? Once decided, how are "no regrets" solutions deployed and funded?

Funding Options

- Self-supply.
- VPPs – via existing procurement processes just underway.
- Demand Response provision
  - Explicitly allows for storage.
- FEMA/Agency funding and implications for identifying "no regrets" near-term solutions
- New DER Tariff for no regrests DER solutions not amenable to VPP, DR, self-supply?
- PREPA roles: 1) VPP procurement. 2) DR tariff. 3) Other?
- How do different products – energy, capacity, controllable, visible, or not – affect funding options?

Procurement Plan – Inputs to DER Cost Metrics

- PV, BESS procurements underway.
- 150 MW carve out for VPP BESS.
- Pricing available after first round (May 1) for utility scale, distributed scale costs.
- How to utilize in this proceeding?
  - Benchmark for DER tariff costs?
  - Benchmark for incremental costs, utility scale vs. distributed scale?
- How does this proceeding affect next round of procurements?
  - No regrets DER determinations could influence structure of next tranche of renewables / battery procurement.

Discussion: DER Questions for Response

5. What are the best “no regrets” distributed energy resource solutions for Puerto Rico? Why? How should they be deployed, implemented, or procured? Please be as specific in your response as is possible, including identifying the scale and type of distributed resource solution, and the likely physical locations (i.e., e.g., rooftops, substations, brownfields, greenfields) and any other relevant attribute or consideration.
6. How should the resiliency value of specific distributed resource solutions be gauged?
7. How can the Energy Bureau support the most rapid deployment of distributed energy solutions for increased resiliency?
8. What is PREPA’s role or LUMA’s role in facilitating DERs for resiliency? Please comment on each of the following potential roles for PREPA or LUMA.
   a. Should PREPA or LUMA be responsible for analysis of microgrid options? Why or why not?
   b. PREPA currently facilitates the development and integration of distributed generation through procurement of VPPs, and through development of Demand Response programs. Should PREPA or LUMA support direct installation of DERs through specific procurement tariffs?
   c. Should PREPA or LUMA directly participate in the installation and maintenance of distributed photovoltaic systems with storage? Would this be in alignment with Act 17 and other Puerto Rico public policy that supports “prosumers”?

Discussion: DER Questions for Response

9. In general, concerning the best microgrid candidate sites across Puerto Rico:
   a) Comment on the number, size, facility type, and resource configurations identified at the microgrid sites in the Sandia microgrid report (159 sites) and in PREPA's Appendix 1 IRP filing ("50 potential zones").
   b) Should all of these sites be specifically targeted for microgrid development for resiliency reasons? Explain why or why not.
   c) Comment on how microgrid applications should be paid for, differentiating between "public" and "private" microgrids.
10. In general, concerning stand-alone DER solutions (i.e., not microgrids) across Puerto Rico:
    a) How should stand-alone DER solutions be procured or paid for?
    b) Should the Energy Bureau differentiate between resiliency provided by public purpose DER solutions (e.g., town centers, municipal buildings, water and sewer facilities), and private purpose DER solutions, when considering alternative deployment and procurement vehicles for these resources?
11. Provide any other additional comment, response, or supporting documentation that will help the Energy Bureau determine the optimum combinations of distributed resources and more conventional wires hardening approaches for providing resiliency for Puerto Rico load.

Guidelines and Metrics for Optimization

Guidelines and Metrics for Optimization

- “The discussions and analysis will start with the development of parameters as to how to measure and quantify the benefits and costs when comparing transmission and substation (new or existing) hardening options with distributed resiliency options.

  The cost benefit analysis will include an examination of avoided costs among other relevant variables that may be identified in the course of the proceeding.

  The first step will be to develop the general framework that can be applied to the decisionmaking on options for each region.

  The process will also include a determination of quantities, costs, types, location and deployment/procurement methods for specific distributed generation projects along with the mix of microgrid and stand-alone projects and their size and location.”

  Order, page 4.

Approach

1. Identify and define classes of customers regarding the criticality of electricity service and associated expected levels of resiliency.
    - Segmentation
2. Identify and describe the customers' roles in providing energy supply and DR.
    - Procurement / funding vehicles.
3. Provide microgrid and related single-site (individually, or in the aggregate as Virtual Power Plants) local capacity and energy solutions for both resiliency and normal energy and capacity needs where cost-effective.
    - Sandia, PREPA microgrid location identifications
    - Crucially: need to determine extent, scale, and categories of stand-alone DER solutions
4. Optimize the transmission and distribution system expenditures for resiliency, including aspects of PREPA's MiniGrid concept.
    - Compare $/unit of resiliency across approaches

Methods and Metrics From Analytical Approach Straw Proposal

- Determine resiliency needs (MW, MWh) by estimating what portion of load service (all, or partial) would meet minimum requirements for essential facilities
- Identify the value of lost load (VOLL) for these customers to be used in optimization, possibly by tier
- MiniGrid transmission costs:
  - Determine transmission costs for specific MiniGrid enhancements (IRP data), by segment and by ability to serve load
  - Map MiniGrid transmission to essential facility / customer loads (allocation of costs across customers served by MiniGrid)
  - Determine load density metrics (e.g., Peak MW/mile by feeder)
  - Determine distance from grid and related threshold parameters for identified load.
- Determine average or specific transmission cost avoidance when considering use of distributed resiliency solution for a set of customers that would otherwise require incremental transmission.

Distribution Issues

- How do distribution issues affect optimization?
  - Without distribution upgrades, MiniGrid transmission upgrades provide less/minimal resiliency assurance
  - Alignment/sequencing of distribution upgrades for resiliency is critical
- How does this affect the near-term decisions in this proceeding?

Outcomes

- Table from Analytical Approach (App. A of Order)
- Results of C/B Analyses
  - $/MWh of resiliency provided? (duration included)
  - $/MW of critical / other load served (at peak? at average load?)
  - Which $? Which MW, MWh?
- For each of DER solution sets, and the MiniGrid investment solution.

From Workshop #1: Overall Guiding Principles – Straw Proposal - Adaptation Needed

- Careful approach to examining each form of solution needed
  - Analytical complexities make head-to-head comparisons subject to error.
  - Substitution of capacity and energy resources to avoid transmission expenditures must consider the extent of customers affected/benefitting, and how costs of the different approaches are allocated across customer groups.
- A means to properly account for blue sky benefits must be directly included in any comparative approach – for both solutions.
  - Each solution provides resiliency benefits incremental to their normal day operational value.
  - So: net costs from a baseline? (transmission baseline: ? Resource baseline: ?)
- PREPA/LUMA must be able to better describe different levels of transmission investment required if large-scale, or larger-scale (than baseline) DER solutions were to be in place.
  - There are different transmission needs to support resilience under different scenarios of DER deployment where DER provides a resiliency solution for (some) load. Determining, or estimating what these differences are must be given immediate focus.
  - What is the minimum standard for transmission buildout? Building up to "codes and standards" as required does not imply full-scale hardening / GIS installation. Is an estimate of the value of resiliency the only way to support building beyond "codes and standards" levels?
- Microgrids potentially covering a sizable percentage of actual Puerto Rico critical load must be considered as a valuable part of any solution – and thus the overall level of remaining load requiring assurances of resiliency may be considerably lower than currently assumed by PREPA, even in dense load regions.
  - The greater the extent of microgrid penetration, the lesser the extent of remaining load for resiliency provision.

Can we draw path to making preliminary conclusions? How?

- Transmission solutions – 115 kV – especially new underground
  - If needed for blue sky – do it. But don't overbuild – net load on grid declining (EE, DERs). If not needed:
    - Is it needed to serve clusters of critical load after storm event? (what is analytical basis?)
    - Or: is it needed for overall resilience of densely-loaded region?
  - Metrics
    - Costs per MW or MWh of total load (duration?) on feeders with critical load, or total load?
    - Clusters: MW feeder critical load per substation?
    - Other?
  - Then: iterate for 38 kV? Coupled to 115 kV solutions?

- DER solutions
  - All PREPA identified microgrid (337 MW)? All Sandia microgrid (742 MW)?
    - Who designs? Who implements? How? Tariff/DR/VPP support for battery component?
  - Current procurement plan: 150 MW carve out VPP/DER for batteries.
    - In ~May: insight into possible locations?
  - Other: stand-alone DER at essential facilities, and at other locations (residences, small commercial)
  - Metrics:
    - Costs per MW or MWh of critical, priority, other load served (duration?)?
    - Actual critical load MW
    - Distance from likely hardened wires sections (T, sub-T, D)?
    - Avoided or deferred T costs, $. Avoided, deferred or reduced D costs, $.
  - If incremental cost of DER < resiliency value + avoided costs, do it.

Wrap-Up and Next Steps

- Wrap-Up
  - Comments post-workshop
- Next Steps / Remaining Workshops
  - April: DOE to present – how National Labs tools can help, and timeframe
  - May/June: Refine approach/timeline for longer-term solutions

Para más información:

http://energia.pr.gov

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Backup Slides Including Relevant Slides from Earlier Workshops

Commercial Rftp PV Costs – NREL Benchmarking Q1-2020

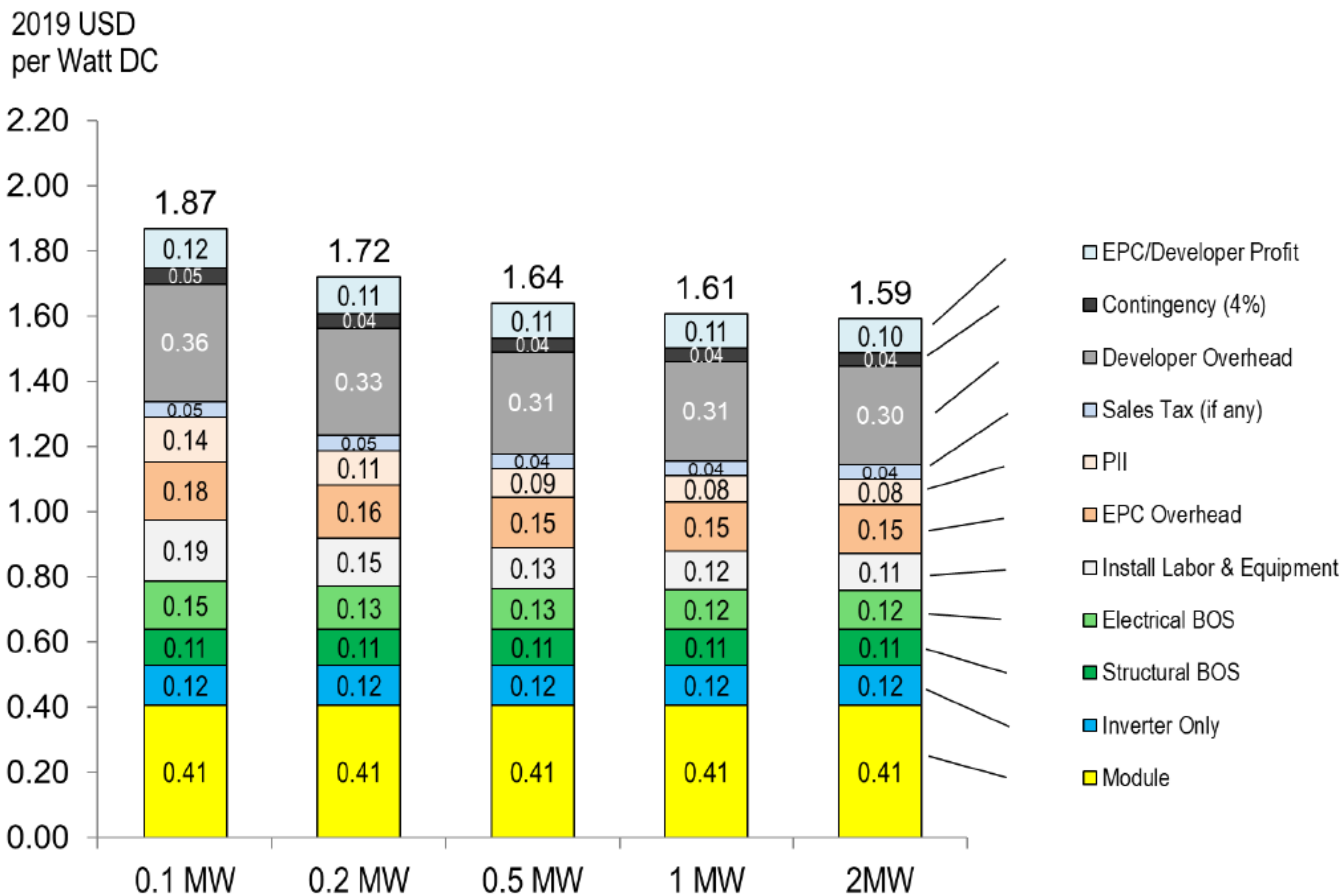

Figure 21. Q1 2020 U.S. benchmark: Commercial rooftop PV system cost (2019 USD/W_{DC})

Residential Rooftop Solar PV Cost Trends

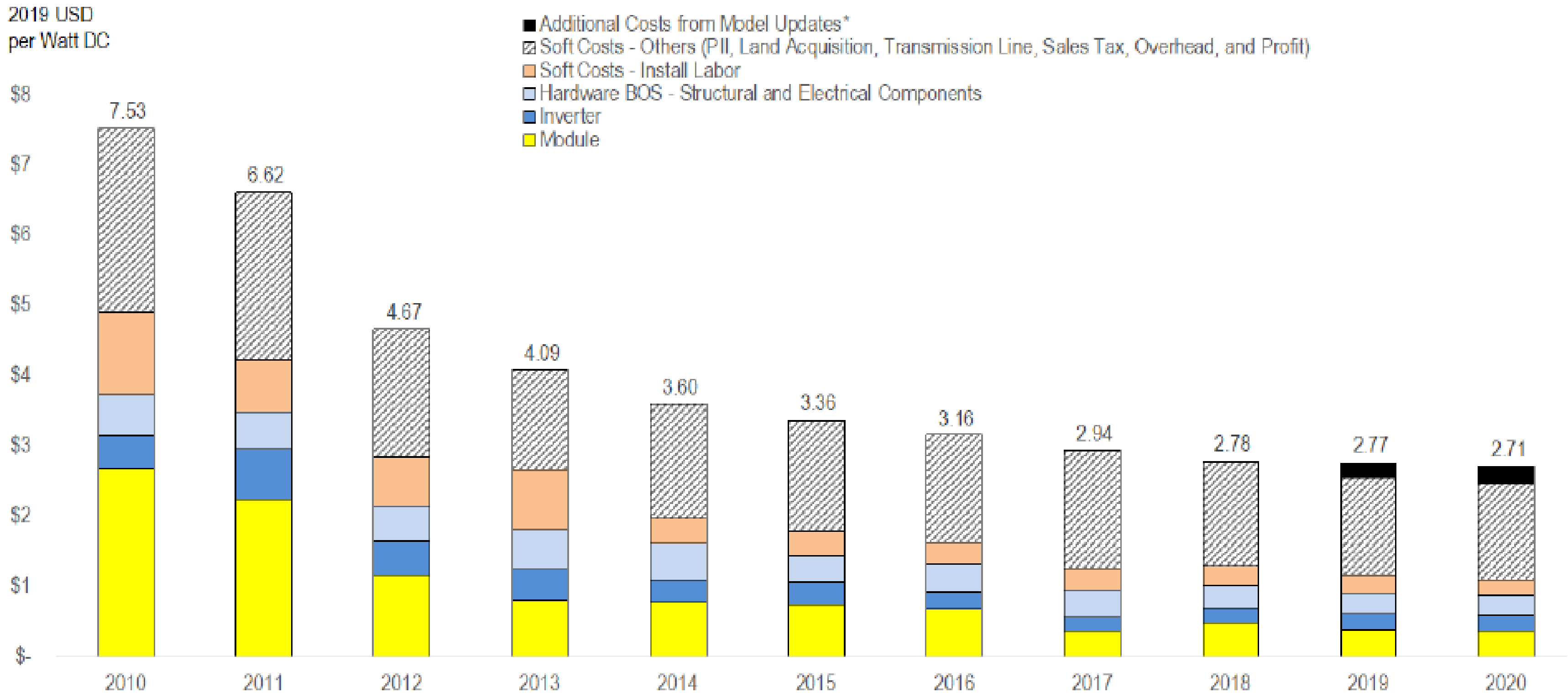

Figure 17. NREL residential PV system cost benchmark summary (inflation adjusted), 2010–2020

Commercial Rooftop Solar PV Cost Trends

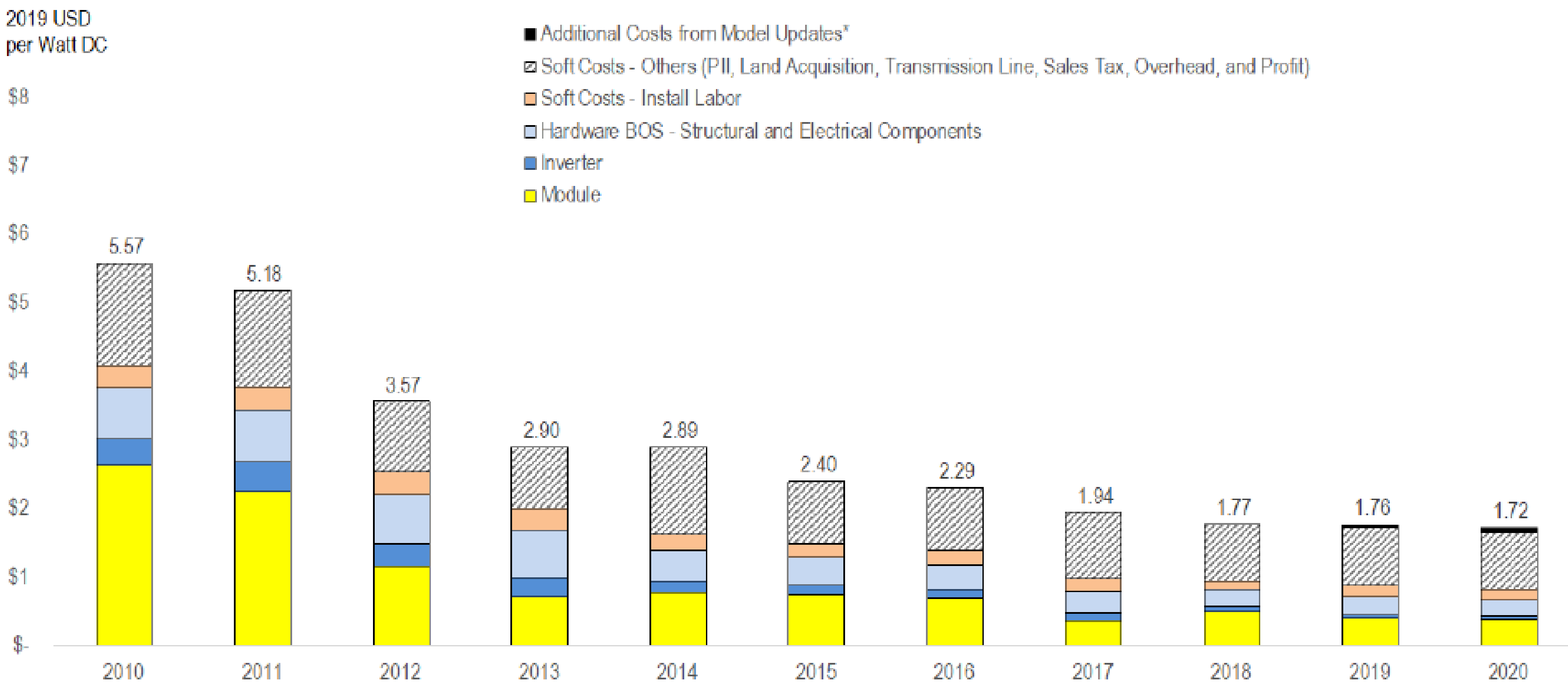

Figure 25. NREL commercial rooftop PV system cost benchmark summary (inflation-adjusted), 2010–2020

Storage for Resiliency

- DERs for resiliency: storage as key

  "The real value of storage is as a means to provide a key characteristic missing from power grids: the ability to absorb stresses with little or no loss of performance – the essence of resilience. Storage applied systematically throughout the grid can provide the missing "shock absorber" springiness that the grid is missing. To provide this value, storage must be incorporated into the grid as core infrastructure and must be deeply integrated into grid operations. Doing so will provide far-reaching benefits to users of electricity at all levels, including vastly increased system resilience, expanded system operational flexibility, support for critical lifeline functions during critical events, and even improved cyber security"

  PNNL, Taft, et al., The Use of Embedded Electric Grid Storage for Resilience, Operational Flexibility, and CyberSecurity October 2019

  https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29414.pdf

- Storage at utility-scale also brings resilience
- How do we trade off distributed storage and utility-scale storage?

What is PREPA's Role in Facilitating DERs for Resiliency?

- Analysis of Options?
  - MiniGrid proposal did not simultaneously analyze in detail DER complements.
  - Does PREPA have such an analysis? Do stakeholders?
  - Response to Appendix B questions: method to look at clusters of critical load?
- Facilitates the development and integration of distributed generation?
  - Through VPP PPOAs
  - Through DR programs
  - Through additional specific programs?
    - FEMA-funded resiliency programs?
    - Role in public purpose microgrids?
- Participates in the installation and maintenance of these distributed photovoltaic systems with storage?
  - Not considered – third party entities do this
  - Act 17: prosumer focus
- Manages the interaction and relationship of the various distributed generators and microgrids? Is this what LUMA will do?
- Participates in the development of large-scale renewable energy and storage and promotes the optimization of the existing hydroelectric system?

Update to MiniGrid Transmission Costs

- PREPA response to Appendix B, Q2. Note cost magnitude vs. Sandia microgrid cost estimate.
- Significant increase in costs over MG components from IRP filing ($5.9 Billion)

Revised Cost Estimates per 10 Yer Plan (Class 5 Estimates): Assets listed in IRP Exhibits 2-85 to 2-93

Minigrid Transmission System Required Investment			
Item	**Description**	**Cost ($M)**	**Notes**
1	**Controllers & SCADA: 8 Minigrids**	**$ 6.75**	***No change in estimate from IRP***
2	**115 kV Transmission system investment**	**$ 2,863.71**	**Class 5 Cost Estimates: Please refer to corresponding tab**
	2a. Existing Lines to Harden:	$ 447.44	List of 24 Projects ~198 miles from IRP Ex 2-11
	2b. New Lines (OH & UG):	$ 1,462.17	List of 16 Projects ~141 miles from IRP Ex 2-09
	2c. Existing Stations to Harden: 43 Projects	$ 954.10	List of Stations per IRP Ex 2-12
3	**38 kV Transmission system investment**	**$ 4,865.61**	**Class 5 Cost Estimates: Please refer to corresponding tab**
	3a. Existing Lines to Harden:	$ 476.97	List of ~241 miles per IRP Ex 24, 36 ,44 ,52, 62, 71, 84
	3b. New Lines (OH & UG):	$ 4,388.65	List of ~318 miles per IRP Ex 23, 35, 43, 51, 61, 69, 83
	3c. New Stations & Harden to Existing Stations:		List of Stations per IRP Ex 24, 36 ,44 ,52, 62, 71, 84
		$ 7,736.07	
	Total Peak Load at End User	~2,400 MW	(critical plus priority load = ~1,600 MW)
	Cost per MW Peak Load ($ Mill.)	$ 3.22	Sandia: $2 Million/MW for Microgrid
	Cost per MW critical + priority	$ 4.84	

Notes

1. A class 5 cost estimate is one that is prepared at an early stage in the project development process and is expected, based on industry standards, to range from 50% below to 100% above the actual final project cost. Leading industry practice is to revise estimates, so they become more accurate as engineering design progresses and project requirements are solidified.
2. PREPA will begin in Q1 2021 performing field assessment and A&E design on T&D assets. Once completed, PREPA can provide more accurate estimates

From Workshop #2: No Regrets Options – DERs – Questions for Discussion and Comment

- What are the best microgrid candidates?
  - Which public purpose microgrid should be pursued? How?
  - Which private purpose microgrids? How?
  - How is resiliency value considered?
- Stand Alone DER – larger scale
  - Public purpose – how to determine, and how to deploy?
  - Private – full prosumer deployment?
  - How is resiliency value considered?
- DER – Small Scale
  - Via VPP procurements
  - Via DR tariff
  - Via alternative resiliency programs
  - How are any of these best deployed, rapidly, in best locations?

Cost to Mitigate Lost Load with DER Solution - 1

- Considering how MG VOLL Assessment was done
- $3.8 billion cost of “energy not served” was much greater than $1.4 billion cost of MiniGrid expenditures for San Juan / Bayamon

San Juan / Bayamon Only	Critical	Priority	Balance	
MWh from outage (1 week Level 2, 3 weeks Level 1)	95,244	50,725	127,861	273,830
VOLL per unit: $/MWh	32,000	10,000	2,000	
Total costs ENS by load type	3,047,815,247	507,250,458	255,722,354	**3,810,788,060**
ave load factor 1st week	0.75	0.75	0.75	
ave load factor after 1st week	0.75	0.75	0.75	

Cost to Mitigate Lost Load with DER Solution - 2

- However: depending on how DER costs are allocated, costs can be lower than MG solution
- This illustration - NOT CORRECT? - You cannot <u>target</u> load that might be lost?

SEE Analysis San Juan / Bayamon Only		Critical	Priority	Balance	
MWh from outage (1 week Level 2, 3 weeks Level 1)		95,244	50,725	127,861	273,830
VOLL per unit: $/MWh		32,000	10,000	2,000	
Total costs ENS by load type		3,047,815,247	507,250,458	255,722,354	**3,810,788,060**
ave load factor 1st week		0.75	0.75	0.75	
ave load factor after 1st week		0.75	0.75	0.75	
DER Incremental and Total Cost Illustrations					
Bookend: Full DER PV/BESS, but costed on energy basis (rest of costs allocated to all other non-storm uses of resources).					
Idealized PV output/BESS storage patterns.					
Serving ALL of this outaged load with on-site DER solar/BESS					
150	PV cost per MWh	14,286,634	7,608,757	19,179,177	
500	BESS cost per MWh	47,622,113	25,362,523	63,930,589	
	Total	61,908,747	32,971,280	83,109,765	177,989,792

Cost to Mitigate Lost Load with DER Solution - 3

- However – you must consider allocating a smaller portion (than values shown) when considering that DERs serve blue sky needs also.
- Rough per unit costs used here – fuller analysis required.

DER Incremental and Total Cost Illustrations						
Bookend: Full DER PV/BESS, but costed on energy basis (rest of costs allocated to all other non-storm uses of resources).						
Idealized PV output/BESS storage patterns.						
Serving ALL of this outaged load with on-site DER solar/BESS						
150	PV cost per MWh	14,286,634	7,608,757	19,179,177		41,074,567
500	BESS cost per MWh	47,622,113	25,362,523	63,930,589		136,915,225
	Total	61,908,747	32,971,280	83,109,765	$	177,989,792
Bookend: Full DER PV/BESS						
Serving ALL of this outaged load with on-site DER solar/BESS, costed on full capacity basis (initial cost).						
Idealized PV output/BESS storage patterns.						
3,700,000	PV cost per MW	830,321,623	446,150,019	1,050,058,924		2,326,530,565
1,500,000	BESS cost per MW	336,616,874	180,871,629	425,699,564		943,188,067
	Total	1,166,938,497	627,021,648	1,475,758,487	$	3,269,718,632
Bookend: Full DER PV/BESS						
Serving ALL of regional load with on-site DER solar/BESS, costed on full capacity basis (initial cost).						
Idealized PV output/BESS storage patterns.						
3,700,000	PV cost per MW	1,476,300,000	684,500,000	1,727,900,000		3,888,700,000
1,500,000	BESS cost per MW	598,500,000	277,500,000	700,500,000		1,576,500,000
	Total	2,074,800,000	962,000,000	2,428,400,000	$	5,465,200,000

Cost to Mitigate Lost Load with DER Solution - 4

- Closer Look – last one – in comparison to MiniGrid cost for SJ/Bayamon of $1.4 billion
- But – cost provides both resiliency and blue sky services
- How to untangle? Capacity portion alone: much less than cost of ENS

DER Incremental and Total Cost Illustrations					
Bookend: Full DER PV/BESS					
Serving ALL of regional load with on-site DER solar/BESS, costed on full capacity basis (initial cost).					
Idealized PV output/BESS storage patterns.					
3,700,000	PV cost per MW	1,476,300,000	684,500,000	1,727,900,000	3,888,700,000
1,500,000	BESS cost per MW	598,500,000	277,500,000	700,500,000	1,576,500,000
	Total	2,074,800,000	962,000,000	2,428,400,000	$ 5,465,200,000

MG Transmission Costs per Peak Load Service

- Based on IRP Aggregate $, MiniGrid transmission

MiniGrid Transmission Cost	Arecibo	Bayamón	Caguas	Carolina	Isla	Mayaguez	Ponce	San Juan	Total	SJ/Baya
Total MG $ Millions, All Types/Justifications	548	528	1,008	657	104	914	1,193	904	5,855	1,432
Share by region	9.4%	9.0%	17.2%	11.2%	1.8%	15.6%	20.4%	15.4%	100.0%	24.5%
	Arecibo	Bayamon	Caguas	Carolina	Cayey	MayaG N+S	Ponce	San Juan	Total	SJ/Baya
2019 Peak Load, MW (at generator)	234	390	307	311	101	325	332	661	2,661	1,051
Share by region	8.8%	14.6%	11.5%	11.7%	3.8%	12.2%	12.5%	24.8%	100.0%	39.5%
MG Cost per Peak Load by Region, Mill. $/MW	2.34	1.35	3.62	2.11	-	2.81	3.59	1.37	2.20	1.36
Note: "Isla" costs assumed to be in Caguas region.										

MiniGrid Costs per average energy consumption

- Average energy basis to cover MG transmission costs

Annual Basis - cost of transmission, $ millions	Arecibo	Bayamon	Caguas	Carolina	Cayey	MayaG N+S	Ponce	San Juan	Total	SJ/Baya
Assume Fixed Charge Rate (10%)	54.80	52.77	100.77	65.68	10.40	91.38	119.29	90.40	585.50	143.17
Assume Fixed Charge Rate (15%)	82.21	79.16	151.16	98.53	15.61	137.07	178.93	135.59	878.25	214.75
Assume Fixed Charge Rate (20%)	109.61	105.54	201.54	131.37	20.81	182.76	238.58	180.79	1,171.00	286.34
Energy at 75% Load Factor, GWh	1,539	2,561	2,015	2,042	665	2,136	2,183	4,342	17,482	6,903

Annual Basis - cost of MG transmission, average $ per kWh	Arecibo	Bayamon	Caguas	Carolina	Cayey	MayaG N+S	Ponce	San Juan	Total	SJ/Baya
Assume Fixed Charge Rate (10%)	0.036	0.021	0.050	0.032	0.016	0.043	0.055	0.021	0.033	0.021
Assume Fixed Charge Rate (15%)	0.053	0.031	0.075	0.048	0.023	0.064	0.082	0.031	0.050	0.031
Assume Fixed Charge Rate (20%)	0.071	0.041	0.100	0.064	0.031	0.086	0.109	0.042	0.067	0.041

Adding it all up? Resiliency Value of DER and How it Affects Overall Costs

➤ Illustrative: Credit for DER for Avoided MG transmission:

Total annual load, SJ/Bayamon, GWh	2,621	1,215	3,068	6,905
credit: MG Tx only, $/kWh	0.03	0.03	0.03	0.03
Credit avoided Tx, $millions/year	79	36	92	207

➤ Considered with prior assessment: credit *lowers* capacity cost?

DER Incremental and Total Cost Illustrations					
Bookend: Full DER PV/BESS					
Serving ALL of regional load with on-site DER solar/BESS, costed on full capacity basis (initial cost).					
Idealized PV output/BESS storage patterns.					
3,700,000	PV cost per MW	1,476,300,000	684,500,000	1,727,900,000	3,888,700,000
1,500,000	BESS cost per MW	598,500,000	277,500,000	700,500,000	1,576,500,000
	Total	2,074,800,000	962,000,000	2,428,400,000	$ 5,465,200,000