SGIP GHG Signal Working Group Final Report

June 15, 2018

AESC, Inc.
for California Public Utilities Commission
Rulemaking 12-11-005

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Acronyms

Acronym	Definition
AES	Advanced Energy Storage
AESC	Alternative Energy Systems Consulting
AMS	Advanced Microgrid Solutions
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CalSSA	California Solar & Storage Association
CCA	California Carbon Allowance
CDM	Clean Development Mechanism
CESA	California Energy Storage Association
CPP	Critical Peak Pricing
CPS	Custom Power Solar
CPUC	California Public Utilities Commission
CSE	Center for Sustainable Energy
DER	Distributed Energy Resource
DR	Demand Response
EF	Emissions Factors
GHG	Greenhouse Gas
GHGP	Guidelines for Quantifying GHG Reductions from Grid Connected Electricity Projects
IDER	Integrated Distributed Energy Resources
IOU	Investor Owned Utility
ITC	Investment Tax Credit
LMP	Locational Marginal Pricing
M&E	Monitoring and Evaluation
M&V	Measurement and Verification
NDA	Non-Disclosure Agreement
NP15	North of Path 15
OASIS	Open Access Same-time Information System
ORA	Office of Ratepayer Advocates
OTC	Once-Through Cooling
PA	Program Administrator
PBI	Performance Based Incentive
PG&E	Pacific Gas & Electric
PV	Photovoltaic
RT	Real-Time
RTE	Roundtrip Efficiency
SCRTE	Single-Cycle Roundtrip Efficiency
SGIP	Self-Generation Incentive Program
SOP	Super Off-Peak
SP15	South of Path 15
TBD	To Be Determined
TOU	Time of Use
UNFCCC	United Nations Framework Convention on Climate Change
WG	Working Group

Executive Summary

Background

This report is the result of the discussions and work products of the Greenhouse Gas Signal Working Group (the "Working Group"). The Working Group was established by an Assigned Commissioner Ruling on December 29, 2017 with instructions to;

- Develop a proposal for a greenhouse gas signal
- Develop operational requirements for SGIP energy storage systems based on the GHG emissions of the electric grid
- Develop a verification mechanism to ensure GHG tracking and close monitoring of system performance.
- Consider an enforcement mechanism to be used in the event that a system's operation results in net GHG emissions on an annual basis.

The Working Group started meeting in early January 2018 on a weekly basis with in-person meetings once every two weeks and conference calls in- between. It was comprised of Program Administrators, SGIP participants, and Commission staff.

Key Modeling Findings

The initial focus of the Working Group was to develop a process by which to comply with the requirements of the Assigned Commissioner Ruling. The group reached consensus fairly quickly that the best way to comply was to brainstorm a number of possible solutions to improving greenhouse gas (GHG) emission reductions from energy storage systems and then to model these solutions to determine which ones were the most promising. The recommendations for SGIP proposed reforms were intended to fall out of the modeling results.

The Working Group relied upon five proprietary models and one newly-developed public model (see appendices for detailed modeling findings and public model description) to explore the impacts of a GHG signal amid different combinations of system and customer characteristics (i.e. operational requirement options). The modeling effort resulted in over 5,000 model runs with varying parameters and GHG reduction strategies.

Overall, submitted data from the Working Group's modeling runs suggest several key takeaways that can help drive GHG-reducing operation of energy storage systems.

1. Residential energy storage systems **under old rates:**
    a. **When paired with solar**, are helped by the GHG signal to achieve GHG benefits in the majority of cases irrespective of Single Cycle Round Trip Efficiency (SCRTE), but the combination of utilizing the GHG signal and a higher SCRTE of 85% guarantees GHG reduction. Without the GHG signal, a higher SCRTE of 85% increases the chances of achieving GHG reduction but does not guarantee it.
    b. **Without solar**, appear highly unlikely to reduce GHGs.
2. Residential energy storage systems **under new rates**:
    a. **When paired with solar with SCRTE of 85%**, almost always achieve GHG benefits with or without the GHG signal, but even lower SCRTE (here 70%) systems can reduce GHGs in the majority of cases when the GHG signal is utilized.
    b. **Without solar**, appear to always reduce both GHGs and customer bills when performing GHG signal co-optimization, regardless of SCRTE. But without the GHG signal, a higher SCRTE of 85% or above is required to achieve GHG reduction.
3. Commercial energy storage systems **under old rates**:
    a. **With solar**, when performing GHG signal co-optimization with 85% SCRTE, achieved GHG reduction 82% of the time (compared to 49% with a lower SCRTE of 70%). Without the GHG signal, the model runs achieved GHG reduction only 24% of the time regardless of SCRTE.
    b. **Without solar**, appear highly unlikely to reduce GHGs.
4. Commercial energy storage systems **under new rates**:
    a. **With solar and performing GHG signal co-optimization**, give GHG reduction 85% of the time regardless of SCRTE and 100% of the time with 85% SCRTE. Without a GHG signal, GHG reduction was achieved 69% of the time irrespective of SCRTE, but with a higher SCRTE of 85% the proportion increased to 86%.
    b. **Without solar**, while benefiting from co-optimization, are generally are unlikely to reduce GHGs (40% of commercial standalone model runs reduced GHGs when performing co-optimization under newer rates,

regardless of SCRTE; the frequency increased modestly to 44% when a constraint of 85% SCRTE was added).

Certain modeling teams expressed a concern with regard to the aggregated modeling results and stated that the Working Group did not model grid services, such as demand response, due to the complexity and uncertainty involved in such a modeling effort. Grid services, along with GHG emissions reductions and transforming the market for DERs, are all SGIP goals. Many developers of stand-alone storage systems focus on providing grid services in addition to customer demand charge management, as opposed to simple energy arbitrage to enhance customer savings. So, depending on the developer's business model (energy arbitrage or demand charge management/grid services), some systems may not perform as well on reducing marginal GHG emissions, yet they may be avoiding the need to bring more gas peakers online and facilitating the integration of higher levels of variable renewable energy resources.

Working Group Crosscutting Recommendations

The Working Group proposed the following recommendations that may be applied to multiple project types (residential, <30kW non-residential or ≥30kW non-residential). Each is discussed below.

GHG Signal Proposal

- **Status**: Consensus
- **Description:** The Commission should provide a digitally accessible real-time marginal GHG emissions factor for NP15 and SP15 CAISO zones, at 5-minute and 15-minute intervals in units of kg/kWh. There will also be provided a 72 hour-ahead (updated hourly), month-ahead (updated daily) and year-ahead forecasts (updated monthly). The emissions factor signal be based on Locational Marginal Pricing (LMP) using real-time (5-minute) LMP and CO2 price data.
- The historical 5-minute GHG emission factors to be used by SGIP to verify GHG performance. Verified GHG emission may impact PBI payment and/or invoke SGIP infraction processes depending on the customer class and size of energy storage systems, as well if it is a new or legacy project.
- **Modeling Findings:** Model findings support GHG co-optimization; relative to scenarios without a GHG reduction solution, co-optimization almost always increased the proportion and magnitude of outcomes with net GHG benefits.

Fleet Compliance Mechanism

- **Status:** Non-consensus
- **Description:** Under a fleet compliance mechanism, developers would be subject to verification and compliance for all or a portion of their fleet of energy storage systems, with each project staying in its developer's fleet for a period of 5 (depending on PBI period) or 10 years (the "fleet evaluation period"). After the fleet evaluation period, no projects will be subject to GHG emissions accounting for compliance and enforcement. Verification will be applied to a project developers fleet or portion of a fleet of SGIP projects. Each developer would have a rolling five-year fleet or ten-year fleet of systems upon which they are evaluated. Enforcement will be applied to a project developers fleet or portion of a fleet of SGIP projects.
- **Modeling Findings:** This compliance mechanism was not modeled.

Carbon Feebate

- **Status:** Non-consensus
- **Description:** A carbon feebate mechanism involves adjusting PBI payments up or down based on the amount by which an individual project increases or reduces GHG emissions, to motivate good GHG behavior. This could be designed as a revenue neutral approach within SGIP. There are several variations of this recommendation, that are detailed later in the report, covering relative "carrot" versus "stick" proportions, threshold level to avoid a penalty, which projects to include in a feebate concept, whether applied at project or fleet level, and price of carbon ($/MT) used to reward or penalize emissions. Would not change enforcement but would adjust PBI payments up or down based on the amount by which an individual project increases or reduces GHG emissions and the assumed price of carbon.
- **Modeling Findings:** This compliance mechanism was not modeled.

Build Margin

- **Status:** Non-consensus

- **Description:** This proposal recommends including build margin benefits provided by SGIP storage projects to evaluate the specific impacts on GHG reduction and include these benefits in a future SGIP modification. Include build margin benefits when assessing energy storage GHG impacts, in project verification and program evaluation.
- **Modeling Findings:** This benefit methodology was not modeled.

Solar Credits for GHG

- **Status:** Non-consensus
- **Description:** Capture GHG credits for solar system installations when a customer would not have installed solar but for the SGIP incentive for energy storage. Must be charged from the solar system and ITC compliant. SGIP to confirm that solar system installation is caused by energy storage system through application documentation and field inspection.[1]
- **Modeling Findings:** This was not modeled (the results involved the calculation of GHG impacts when storage was added to solar, but the scenario discussed in this proposal was not modeled).

Recommendations for New Projects

The working group developed the following recommendations for operational requirements, verification mechanisms, and enforcement mechanisms to be applied to new projects. All proposals are non-consensus.

New >30 kW Non-Residential Projects (PBI)

"PBI + GHG Signal"

- **Description:** ≥30 kW PBI projects will continue to receive incentives as currently defined by SGIP; 50% paid up front and the remaining 50% paid over a five-year period based on meeting an annual cycling requirement. GHG performance will be calculated from the projects' or fleet's monthly performance data. The SGIP will not prescribe how projects must reduce GHG emissions; each project is given "optionality" to decide how it will achieve this goal. While the GHG Signal will be made available to all projects, the SGIP PAs will not require that projects receive and/or follow the signal. Achieving a specific annual round trip efficiency will no longer serve as a proxy for GHG reductions and will not be a GHG verification metric or program requirement.
- **Operational Requirement:** No annual RTE requirement. GHG signal available but not required to use.
- **Verification Mechanism:** GHG performance calculated monthly or quarterly for feedback with Developers and fleet managers, and annually for compliance using PBI interval data and historical GHG signal.
- **Enforcement Mechanism:**
    - ***Alternative 1:*** No automatic loss of PBI incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions at a project level.
    - ***Alternative 2****:* Projects will lose a portion of the annual PBI payment for increasing GHG emissions calculated by multiplying the net CO2 emissions increase over the year by a specified $/kilogram penalty. The penalty could be 4x multiple of the California Cap and Trade price of carbon, or the Societal Cost of Carbon which was recently established in the IDER proceeding (R.14-10-003) to include the full impacts of carbon pollution, including environmental externalities (currently $69.50 per ton), by at the time in which the project applied to the program.
    - ***Alternative 3:*** "Exceedance bands" would determine how much the incentive would be reduced, similarly to what currently exists for generation projects. The exceedance bands would be based on the amount of CO2 emitted per the rated kWh of the project and would reduce the annual PBI payment by 5%, 10%, or 25% depending on the level of CO2 emitted per kWh
    - ***Alternative 4*****:** For projects that increase GHG emissions, the full PBI incentive for that year would be forfeited. An additional penalty in the form of a multiple factor of California Carbon Allowance prices would be applied. Any developer/vendor that is found to have its fleet of projects increase GHGs overall during a program year will be barred from applying for SGIP incentives for future projects for a specified period of time.

[1] It would be beneficial for stakeholders and the CPUC to develop a protocol to facilitate crediting storage with GHG reduction associated with installing solar. Itron has done research in this area and should be consulted.

- **Modeling Findings:** Model findings generally support this proposal; the lack of an annual RTE requirement is appropriate given that it is a model output without a causal influence on GHG impacts (correlative only), and a minimum number of cycles per year could be beneficial but is not necessary and would not guarantee GHG benefits. Availability of a GHG signal is crucial and, assuming verification and enforcement are effective, projects will most likely utilize the signal to achieve GHG reductions.

"GHG PBI"

- **Description:** Under this proposal, the CPUC would set a target for the GHG reductions energy storage systems should deliver by using cycling requirements to calculate kWh and then calculate GHG reductions based on the existing CO_2 emission targets for generation technologies using biogas; as biogas can be seen as GHG free fuel. This would allow a target for energy storage to strive for, while allowing flexibility in how the system is operated.
- **Operational Requirement:** N/A
- **Verification Mechanism:** N/A
- **Enforcement Mechanism:** N/A
- **Modeling Findings:** This compliance mechanism was not modeled.

New <30 kW Non-Residential Projects (Non-PBI/Non-Residential)

"PBI-like"

- **Description:** Apply PBI-like rules to non-residential projects <30 kW, where part of their SGIP incentive is paid out over multiple years.
- **Operational Requirement:** PBI-like rules for non-residential projects <30 kW. No annual RTE requirement. GHG signal available but not required to use.
- **Verification Mechanism:** GHG impact calculated monthly for feedback and annually for compliance using PBI data and historical GHG signal. Non-revenue meters allowed.
- **Enforcement Mechanism:**
    - ***Alternative 1:*** Same as PBI; 50% upfront incentive, 50% performance based incentive, 10% paid per year over five years. Where a project is determined to increase GHG emissions, the developer will also pay for any GHG emissions associated with a project, in addition to forgoing their PBI incentives in a given year.
    - ***Alternative 2:*** Same mechanism as PBI; 70% upfront incentive, 30% performance based incentive 10% available for pay out over 3-years. Where a project is determined to increase GHG emissions, the PBI incentive will be reduced according to recommended rules for ≥30kW PBI projects.
    - ***Alternative 3:*** Same as Alternative 2, but with 80% upfront incentive and 20% performance based incentive.
- **Modeling Findings:** Similar to the recommended ≥30kW PBI, model findings generally support this proposal; the lack of an annual RTE requirement is appropriate given that it is a model output without a causal influence on GHG impacts, and a minimum number cycles per year could be beneficial but is not necessary and would not always guarantee GHG benefits. Availability of a GHG signal is crucial and, assuming verification and enforcement are effective, projects will most likely utilize the signal to achieve GHG reductions.

"Deemed Compliance for <30kW Non-Residential"

- **Description:** A deemed project eligibility approach, that allows <30 kW non-residential projects to receive up front incentives.
- **Operational Requirement:** 85% SCRTE, agreement to follow GHG signal.
- **Verification Mechanism:** 1) Up-front SGIP PA review of the application to verify the system has a single cycle round trip efficiency of at least 85%; 2) confirmation that the developer has signed an affidavit promising a to follow the GHG Signal; 3) quarterly monitoring reporting; and 4) random selection for inspection (akin to the SGIP Inspection Sampling Protocol which is in effect now).
- **Enforcement Mechanism:** No claw back of incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions
- **Modeling Findings:** The model findings support this proposal, with some significant caveats. Model findings suggest that these operational requirements are highly likely to result in GHG benefits, provided that the

following additional requirements are imposed: 1) residential projects should either be on new rates or paired with solar (or both), and 2) commercial systems should always be paired with solar.

New Residential Projects

"Deemed Compliance for Residential"

- **Description:** This deemed approach is an effort to establish GHG compliance in the application process and to simplify GHG compliance for hundreds or potentially thousands of residential applications. Projects would be deemed compliant with SGIP rules if one of the following listed operational requirements exist.
- **Operational Requirement:** One of the following options selected at application reservation request.

  Option 1: Solar-plus-Storage
    - New rates – any rate schedule with peak period starting at 3 pm or later
    - Minimum ITC compliant; currently 75%
    - Cycling – remain at 52
    - 85% SCRTE

  Option 2: Solar-plus-Storage
    - Time constraint; no charge 4-9pm
    - Minimum ITC compliant; currently 75%
    - Cycling – remain at 52
    - 85% SCRTE

  Option 3: Solar-plus-Storage
    - Solar self-consumption mode (programmed to maximize amount of solar consumed onsite) Minimum ITC compliant; currently 75%
    - Cycling – remain at 52
    - 85% SCRTE
    - New rates

  Option 4: Solar-plus-Storage
    - GHG Signal co-optimization; obligatory [Is this agreeing to an operating mode?]
    - Minimum ITC compliant; currently 75%
    - Cycling – remain at 52
    - 85% SCRTE

  Option 5: Solar-plus-Storage
    - 100% solar charging
    - New Rates
    - Cycling – remain at 52
- **Verification Mechanism:** 1) Up-front SGIP PA review of the application; 2) confirmation that the developer has signed an affidavit promising a specific configuration and/or rate; 3) random selection for inspection (akin to the SGIP Inspection Sampling Protocol which is in effect now). Residential discharge data (statistically significant sampling by Itron) would be pulled for the Energy Storage Impact Analysis and assessed by the Program Administrators for compliance.
- **Enforcement Mechanism:** No claw back of incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions
- **Modeling Findings:** The model findings do not support Option 2 (no-charging time constraints were not found to have significant impacts on GHG emissions) or Option 5 (in this case, a non-co-optimizing system with 70% SCRTE is expected to reduce GHGs only 50% of the time, and the 100% solar charging attribute was not modeled). The other options were all supported by the model findings; those sets of conditions all consistently resulted in GHG benefits.

"Non-Deemed Compliance for Residential"

- **Description:** This non-deemed is similar to the residential deemed approach above, but requires GHG signal co-optimization and performance monitoring and quarterly reporting. Also unlike the deemed compliance approach, should a project be found to increase GHG emissions, the developer may be found out of compliance and subject to infractions.

- **Operational Requirement:** One of the following options selected at application reservation request.
  Option 1: Resi @ 70% RTE
    - Solar + Storage mandatory
    - New rates
    - Discharge 52/yr
    - Reporting requirement
  Option 2: Resi Stand-alone
    - 70% SCRTE
    - New rates
    - GHG Signal co-optimization; obligatory
    - Reporting requirement
  Option 3: Resi Stand-alone
    - 85% SCRTE
    - New rates
    - Discharge 52/yr
    - Charge only 8am-4pm
    - Reporting requirement
- **Verification Mechanism:** 1) Up-front SGIP PA review of the application; 2) confirmation that the developer has signed an affidavit promising a specific configuration and/or rate; 3) quarterly reporting of GHG performance; 4) random selection for inspection (akin to the SGIP Inspection Sampling Protocol which is in effect now). Residential discharge data (statistically significant sampling by Itron) would be pulled for the Energy Storage Impact Analysis and assessed for compliance.
- **Enforcement Mechanism:** No claw back of incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions.
- **Modeling Findings:** Model findings don't support Option 1 strongly because this option has a weak case of 0.7 SCRTE coupled with No GHG signal, giving reductions only 50% of the times, cannot comment on the reporting benefits based on modeling results. Model findings support Option 2, as co-optimizing residential standalone projects on new rates reduced GHGs in 100% of model runs for both 70% and 85% SCRTEs.; Option 3 is not supported by modeling results since such a scenario wasn't modeled.

Recommendations for Legacy Projects

Discussion of the rules around legacy projects were particularly contentious and certain industry participants were concerned that that any proposal that involves the mandatory application of new rules that include potential penalties or reduced incentives for legacy projects represents retroactive rule changes that developers and customers could not have reasonably anticipated, potentially undermining investment decisions and calling into question the extent to which customers/developers/investors can rely on Commission rules to guide investment decisions given potential risk of those rules being changed after the fact.

The working group developed the following recommendations for operational requirements, verification mechanisms, and enforcement mechanisms to be applied to legacy projects. All proposals are non-consensus.

Legacy >30 kW Non-Residential Projects (PBI)

"Opt-in to new PBI project rules"

- **Description:** This proposal would permit existing projects to voluntarily opt-in to the same rules as will be applied for future PBI projects for the remaining portion of their PBI period. Depending on the specific revised rules for future PBI projects that are adopted, the legacy projects may enjoy relaxed cycling and eliminate RTE requirements while accepting a more rigorous GHG verification and reporting process and the risk of reduced PBI payments.
- **Operational Requirement:** Opt-in to revised future PBI project rules, which may reduce cycling and eliminate the annual RTE requirement.
- **Verification Mechanism:** Same as revised future PBI project rules.
- **Enforcement Mechanism:** Same as revised future PBI project rules.

- **Modeling Findings Support:** This proposal would permit existing projects to voluntarily opt-in to the same rules as will be applied for future PBI projects for the remaining portion of their PBI period. Depending on the specific revised rules for future PBI projects that are adopted, the legacy projects would enjoy relaxed cycling and eliminate RTE requirements while accepting a more rigorous GHG verification and reporting process and the risk of reduced PBI payments.

Legacy <30 kW Non-Residential Projects (Non-PBI/Non-Residential)

"Opt-in to new project <30kW Non-Residential rules"

- **Description:** Legacy <30kW Non-Residential projects would be provided the option to accept the revised rules for new project <30kW Non-Residential, which may reduce the cycling requirement and eliminate the annual RTE requirement for legacy systems. This would not include any PBI structure associated with the new project <30kW rules. If not included in the new project <30kW Non-Residential rules, feebate and/or fleet compliance could be added as an alternative.
- **Operational Requirement:** Same as new <30kW Non-Residential projects.
- **Verification Mechanism:** Same as new <30kW Non-Residential projects.
- **Enforcement Mechanism:** Same as new <30kW Non-Residential projects, but no PBI structure associated with legacy projects.
- **Modeling Findings:** Modeling didn't include any penalty protocol, so no comments can be made about the same based on the modeling results. But each modeler was observed to use a proprietary algorithm (to decide charge and discharge times), so it seems plausible to apply rules across the entire fleet of a developer and measure the collected performance of the fleet.

Legacy Residential Projects

"Opt-in to new project Residential rules"

- **Description:** This proposal provides for legacy residential projects to opt-in to the same revised rules as new residential projects. If projects opt-in, it would, under the proposed deemed compliance approach, provide relative assurance that these projects are meeting GHG emission reductions, increase monitoring and provide a mechanism for PA management of these projects through the infraction process.
- **Operational Requirement:** *Opt-in to the revised new residential project rules.*
- **Verification Mechanism:** Same as the new residential project rules.
- **Enforcement Mechanism:** Same as the new residential project rules
- **Modeling Findings:** Cannot be commented based on the modeling results. But since this proposal involves reporting the performance on a regular basis, the developers get a chance, through feedback, to alter their algorithms to achieve greater GHG reduction.

Summary of Stakeholder Positions Regarding Each Proposed Recommendation

The positions of each Working Group participant are summarized in the table below.

“S”= Strongly supports
“s”= Mostly/partially supports
“ ”= Neutral or no opinion
“o”= Mostly/partially opposes
“O”=Strongly opposes

			Utilities				Organizations			Industry				
Proposal	**Description**	**Consensus**	**PG&E**	**SCE**	**SoCalGas**	**CSE**	**ORA**	**CESA**	**CalSSA**	**CPS**	**AMS**	**Stem**	**Tesla**	**Avalon**
<u>Crosscutting</u>														
GHG Sig Proposal 1	Provide RT marginal GHG signal	Y	S	S	S	S	S	S	S	S	S	S	S	S
Fleet Proposal 1	Fleets, instead of projects, for compliance		S	O	o	s	O	S	S	S	S	o	S	s
Feebate Proposal 1	Adjust PBI payments up or down based on if project increases or reduces GHG emissions		S	S	O			s	S	S	S	O	O	
Feebate Proposal Opt 1	Balanced carrot & stick			s	O					S	O	o	O	S
Feebate Proposal Opt 2	Stick only			S	s					O	S	s	O	o
Feebate Proposal Opt 3	Big stick, little carrot		S	O	O					S	O	O	O	S
Feebate Proposal Opt 4	Zero threshold			O	O					S	O	S	O	S
Feebate Proposal Opt 5	Threshold = max(0,total fleet average GHG reductions)		S	O	O					O	S	O	O	S
Feebate Proposal Opt 6	Zero threshold, but asymmetrical payments			O	O					O		O	O	S
Feebate Proposal Opt 7	New non-residential, non-PBI projects required		S	s	O					O		s	O	S
Feebate Proposal Opt 8	New non-residential, non-PBI projects opt-in		O	s	O					S		O	O	S
Feebate Proposal Opt 9	New residential projects		O	s	O					S		s	O	S
Feebate Proposal Opt 10	Legacy non-residential projects		S	O	O					O	S	s	O	S

			Utilities				Organizations			Industry				
Proposal	**Description**	**Consensus**	**PG&E**	**SCE**	**SoCalGas**	**CSE**	**ORA**	**CESA**	**CalSSA**	**CPS**	**AMS**	**Stem**	**Tesla**	**Avalon**
Feebate Proposal Opt 11	Evaluated by project		S	S						S	S	o	O	O
Feebate Proposal Opt 12	Evaluated by fleet		O	O	O					S	S	s	O	S
Feebate Proposal Opt 13	carbon price = 4X average CCA		O	O	O			O		s	S	s	O	S
Feebate Proposal Opt 14	carbon price = Social cost of carbon in ACC model for current year		S	O	O					o		s	O	S
Feebate Proposal Opt 15	carbon price = Administratively set price above C&T ceiling		O	O	O			O		O		O	O	S
Feebate Proposal Opt 16	carbon price =			O	O			s		s	S		O	
Feebate Proposal Opt 17	Exceedance bands rather than carbon price, PBI reduced % depending on kg/kWh CO2.		O	S	s					O		O	O	S
Build Margin Proposal 1	Include build margin benefits		O	O	O	s	O	S	S	S	S	S	S	S
Solar Credit Proposal 1	Credit for solar that is caused/enabled by energy storage		O	O	O		O	s	S	S	S	S	S	S
<u>**New Projects**</u>														
PBI Proposal 1 (see subproposals for enforcement)	RT GHG signal available, GHG performance determine using historical GHG signal	Y	S	S	S	S	S	s	S	S	S	S	S	S
PBI Proposal 1(a)	Enforcement: SGIP PAs use existing Handbook infraction language to enforce GHG reductions		S	O	O	o	O	s	o	S	S	S		S
PBI Proposal 1(b)	Enforcement: PBI reduced by GHG production x (N x price of carbon).		S	O	o	s	O	s	S	S	S	O	S	S
PBI Proposal 1(c)	Enforcement: PBI reduced by a % based on exceedance bands.		O	S	s	s	O	o	o	O		O	S	S
PBI Proposal 1(d)	Enforcement: Loss of full annual PBI payment if GHG producing		O			O	S	O	O	O	O	<u>O</u>	O	O

			Utilities				Organizations			Industry				
Proposal	**Description**	**Consensus**	**PG&E**	**SCE**	**SoCalGas**	**CSE**	**ORA**	**CESA**	**CalSSA**	**CPS**	**AMS**	**Stem**	**Tesla**	**Avalon**
PBI Proposal 2	Base GHG target on existing biogas requirement for SGIP generation		O		S	o			O	O	O	O	O	O
New Non-PBI/Non-Res Proposal 1	“PBI<30 kW”, same as PBI Proposal 1, except non-rev meters allowed.	Y	S	S	S	S	S	s	S	S		S		S
New Non-PBI/Non-Res Proposal 1(a)	Enforcement: Same as current PBI; 50% upfront, 50% PBI, 10% available for payment over 5-years		O	s		O	S	o	O	O		O		O
New Non-PBI/Non-Res Proposal 1(b)	Enforcement: Similar to current PBI; 70% upfront, 30% PBI, 10% available for payment over 3-years		S	S	o	s	O	o	o	O		o		s
New Non-PBI/Non-Res Proposal 1(c)	Enforcement: Similar to current PBI; 80% upfront, 20% PBI, 10% available for payment over 2-years		O		O	s	O	s	S	S		S		S
New Non-PBI/Non-Res Proposal 2	Deemed compliance. 85% SCRTE, follow GHG signal, minimum of 100 full discharges. PAs use SGIP infraction process.		O	O	s	o	O	s	s	S		o		S
New Res Proposal 1	Deemed Compliance. Multiple options for compliance. Verify through app docs, inspection & random discharge measurements. PAs use infraction process for enforcement.		S	S	s	s	S	s	S	S			S	S
New Res Proposal 2	Same as proposal 1, but requires GHG signal co-optimization.		O	O	s	s	S	s	S	S			O	S
Legacy Projects														

			Utilities				Organizations			Industry					
Proposal	**Description**	**Consensus**	**PG&E**	**SCE**	**SoCalGas**	**CSE**	**ORA**	**CESA**	**CalSSA**	**CPS**	**AMS**	**Stem**	**Tesla**	**Avalon**
PBI Proposal 1	Opt-in to revised future PBI project rules.		S	o		S	O	s	S	S	S	s	S	S
Non-PBI/Non-Res Proposal 1	Opt-in to revised future Non-PBI/Non-Res .		S	O	s	S	O	s	S	S		s	S	o
Non-PBI/Non-Res Proposal 1(a)	Same as proposal 1 but allows for feebate feature.		S	O	O	o	O			S				o
Non-PBI/Non-Res Proposal 1(b)	Same as proposal 1 but requires purchase of external credits for GHG producing fleets on top of ACC CO2 cost penalty.		S	O		o	O		O	O		S		o
Non-PBI/Non-Res Proposal 1(c):	Same as proposal 1(b) but allows for feebate.			O	O	o	O			O				o
Residential Proposal 1	Opt-in to revised new Res project rules		S	O	s	s		S	s	S			S	S

Final AESC Recommendations

The following are AESC's recommendations based on the Working Group's deliberations and modeling effort.

Crosscutting

GHG Signal

Based on GHG reduction improvement seen in modeling and Working Group consensus, we recommend that the program should begin implementation of a real-time marginal GHG emission signal, as described in this report, as quickly as possible. In general, we agree that the signal should be optional, but verification of GHG emissions using the historical 5-minute GHG signal should be mandatory for both performance incentives and infraction processes.

Fleet Compliance Mechanism

Recognizing the broad and varied expectations of the benefits from behind the meter energy storage, fleet compliance provides makes sense because of the flexibility that it can provide. We recommend that fleet compliance be included in SGIP. While SGIP requires 10 -year permanency for project's we do not believe that the program intent is to subject projects to GHG compliance for the full 10-year term. Therefore, we further recommend that the Fleet Compliance Period match the PBI period; 5-years for ≥30kW PBI and 3-years for <30kW Non-Residential. PBI adjustments for GHG performance would be applied at the fleet level. All projects and fleets would still be subject to measurement and evaluation purposes regardless if they are within or beyond the Fleet Compliance Period.

Build Margin

We do not recommend that build margin benefits from energy storage be included in SGIP because more information is needed to justify it and to determine the proper way to calculate build margin GHG benefits. Instead, we recommend that Itron study build margin as a potential GHG benefit for SGIP energy storage systems and report their findings and recommendations for implementation to the PAs and Commission staff.

Solar GHG Credits

We do not recommend that allowing solar credit benefits for solar systems installed with energy storage be included in SGIP at this point in time. While it is plausible that some solar system installations are enabled because of the concurrent installation of energy storage, it is unclear under what conditions that may be true. Instead, we recommend that Itron determine what conditions that solar GHG credits would be realized when installed with energy storage and how to calculate the GHG benefits from those solar installations.

New Projects

New >30 kW Non-Residential Projects (PBI)

The Working Group supports, and we recommend, that the SGIP provide a GHG signal for project developers to optionally utilize to control their energy storage systems, so they are GHG reducing. In addition, the annual RTE requirement should be eliminated and the number of required annual cycles should remain at the current 130 cycles. This is supported by the modeling results. Verification of GHG performance, based on historical 5-min RT GHG signal, of projects and fleets should be reported monthly for feedback purposes for the project developer and SGIP PAs.

Although the modeling results suggest that "…for commercial storage systems, adding solar on new rates with GHG signal co-optimization gives best GHG impacts but if new rates are not possible in near future, at least GHG signal co-optimization should be used with or without solar (though pairing with solar gives much better results)". The Working Group did not propose a recommendation that would restrict operational requirements to energy storage systems with solar, new rates and GHG co-optimization. Instead the Working Group chose to allow "optionality" to permit energy storage systems the flexibility to reduce GHG emissions, with the best methods available to them accounting for the specific customer and grid needs they are fulfilling.

None of the proposed enforcement mechanisms for new PBI >30kW projects reached Working Group consensus. We favor the use of exceedance bands, but would simplify the bands to one level such that any GHG production during the year would result in a penalty. Allowing multiple exceedance bands provides for a gradual penalty, but could risk program wide increases in GHGs. A single threshold would be straight forward to implement and it would be clear to program participants what percent of the PBI payment is at risk for poor GHG performance. We recommend that any projects or fleets, if fleets are implemented as recommended, that increase GHG emissions should lose 25% of their annual PBI incentive, which is the highest penalty that was proposed by the Working Group for exceedance bands.

- **Operational Requirement:** Same as current PBI except for no annual RTE requirement. GHG signal available but not required to use.
- **Verification Mechanism:** GHG performance calculated monthly or quarterly for feedback with Developers and fleet managers, and annually for compliance using PBI interval data and historical GHG signal.
- **Enforcement Mechanism:** Annual PBI payment is reduced by 25% if annual GHG emissions increase. Penalty can be applied to individual projects or fleets.

New <30 kW Non-Residential Projects (Non-PBI/Non-Residential)

The Working Group agreed that the program do away with 100% upfront incentives for new <30kW non-residential projects and in its place adopt a modified PBI approach, which would make available a GHG signal and eliminate the RTE requirement.

However, the Working Group did not reach consensus on a specific enforcement mechanism. We believe that 30% of the incentive withheld for PBI, paid out over three years, is a good compromise for these smaller projects. While this was not directly modeled, we feel that it provides enough economic incentive to perform according to program rules. It is unclear to us if lower cost systems targeting disadvantaged communities would be impacted as suggested in the opposing comments. If the Commission is concerned that this would impede deployment in disadvantaged communities, a custom PBI incentive could be established for these communities with an incentive of 80% paid up-front with 20% PBI.

We further recommend that these projects be eligible for Fleet Compliance and that the penalty for GHG production is 25% of the PBI payment.

- **Operational Requirement:** PBI-like rules for non-residential projects <30 kW. Same cycling requirement as current PBI. No annual RTE requirement. GHG signal available but not required to use.
- **Verification Mechanism:** GHG performance calculated monthly or quarterly for feedback with Developers and fleet managers, and annually for compliance using PBI interval data and historical GHG signal. Non-revenue grade meters allowed for measurement and verification. PBI period is 3-years.
- **Enforcement Mechanism:** 70% of total incentive paid upfront for qualifying projects. 30% withheld for PBI payments over a 3-year period. Annual PBI payment is reduced by 25% if annual GHG emissions increase. Penalty can be applied to individual projects or fleets.

New Residential Projects

We recommend the deemed pathway described in this report for new residential systems, but only for options 1, 3, and 4. We do not support option 2 or 5 because these options failed to show GHG reduction potential in the modeling results. We share the concern that this approach may not address the backup operating issue identified by Itron. However, we believe that for these systems, a PBI like approach would both be a burden for the program and decrease program participation. We do encourage routine quarterly GHG reduction reporting for both the Program Administrator's and customer's benefit. The Program Administrator could exercise the infraction mechanism for poor performing systems. We also recommend the availability of a GHG signal for these projects, but its use would be optional under this proposal.

We also support a non-deemed compliance path for new residential projects that do not meet the deemed compliance requirements but only for option 2 because these operating requirements were supported by the modeling findings. The non-deemed compliance approach provides additional flexibility for new residential projects for SGIP participation beyond the deemed requirements. We also recommend that for option 2, model results be provided, before project installation, to the Program Administrator to ensure that the GHG's will be reduced. The model used could be proprietary to the developer, which should be vetted under NDA by a third-party, or a public model be made available and used.

- **Operational Requirement:**
    - For Deemed;

    Option 1: Solar-plus-Storage
        - New rates – any rate schedule with peak period starting at 3 pm or later
        - Minimum ITC compliant; currently 75%
        - Cycling – remain at 52
        - 85% SCRTE

    Option 3: Solar-plus-Storage
        - Solar self-consumption mode (programmed to maximize amt of solar consumed onsite) Minimum ITC compliant; currently 75%
        - Cycling – remain at 52
        - 85% SCRTE
        - New rates

    Option 4: Solar-plus-Storage
        - GHG Signal co-optimization; obligatory [Is this agreeing to an operating mode?]
        - Minimum ITC compliant; currently 75%
        - Cycling – remain at 52?
        - 85% SCRTE
    - For Non-Deemed;

    Option 2: Resi Stand-alone
        - 70% SCRTE
        - New rates
        - GHG Signal co-optimization; obligatory
        - Reporting requirement
- **Verification Mechanism:** 1) Up-front SGIP PA review of the application; 2) confirmation that the developer has signed an affidavit promising a specific configuration and/or rate; 3) quarterly reporting of GHG performance; 4) random selection for inspection (akin to the SGIP Inspection Sampling Protocol which is in effect now). Residential discharge data (statistically significant sampling by Itron) would be pulled for the Energy Storage Impact Analysis and assessed for compliance.
- **Enforcement Mechanism:** No claw back of incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions.

Legacy Projects

Legacy >30 kW Non-Residential Projects (PBI)

Although the Working Group could not reach consensus, we recommend providing an opt-in pathway to the new recommended project PBI rules for legacy PBI projects. We believe that the potential for cycling relief and RTE elimination would encourage legacy PBI systems to opt-in to the new PBI rules thus increasing GHG reduction compliance. These projects that opt-in would be also eligible for Fleet Compliance. See new project ≥30kW PBI for operational requirements and verification/enforcement mechanisms.

Legacy <30 kW Non-Residential Projects (Non-PBI/Non-Residential)

The Working Group could not reach consensus for this recommendation. However, we support an opt-in pathway to the new recommended project <30kW non-residential rules for legacy <30kW Non-Residential projects. We believe that the potential for cycling relief and RTE elimination would encourage legacy PBI systems to opt-in to the new PBI rules thus increasing GHG reduction compliance through GHG performance monitoring and verification. Note that these projects would not be subject to the <30kW Non-Residential PBI payments per our recommendation, since they already have been paid all of their incentive per existing SGIP rules. See new project <30kW Non-Residential for operational requirements and verification mechanisms.

Legacy Residential Projects

The Working Group could not reach consensus for this recommendation. However, we support an opt-in pathway to the recommended new project residential rules for legacy residential projects. Since these are already deemed projects, the intent here would be to encourage quarterly monitoring and reporting for GHG performance and use of the GHG signal to improve overall GHG performance. See new project <30kW Non-Residential for verification mechanism 2, 3, 4, and enforcement mechanism.

Introduction

Background

SGIP Statutory Requirements

Public Utilities Code Section 379.6 defines the intent and requirements for SGIP. Subsection (a) sets the purpose of SGIP, stating, "It is the intent of the Legislature that the self-generation incentive program [to] increase deployment of distributed generation and energy storage systems to facilitate the integration of those resources into the electrical grid, improve efficiency and reliability of the distribution and transmission system, and reduce emissions of greenhouse gases, peak demand, and ratepayer costs." This has been interpreted as three distinct goals on equal footing: peak demand reduction, greenhouse gas reduction, and market transformation[2].

The SGIP Handbook explains these goals in its opening paragraph: "The purpose of the SGIP is to contribute to Greenhouse Gas (GHG) emission reductions, demand reductions and reduced customer electricity purchases, resulting in the electric system reliability through improved transmission and distribution system utilization; as well as market transformation for distributed energy resource (DER) technologies."[3]

Section 379.6 establishes eligibility criteria for technology types, stating that the Commission must determine that technologies must be determined to "achieve reductions in emissions of greenhouse gases"4 and that a technology "shifts onsite energy use to off-peak time periods or reduces demand from the grid by offsetting some or all of the customer's onsite energy load, including, but not limited to, peak electric load."5

Section 379.6 provides criteria for evaluation of success of the program overall, including "The amount of reductions of greenhouse gases" and "The amount of reductions of customer peak demand."[6]

The statute does not apply any of these requirements to individual systems that receive SGIP incentives. However, all participants in this Working Group are highly concerned about the GHG program goal and recommend creating requirements for individual installations or fleets of installations.

Regulatory Background of Greenhouse Gas Emission Reduction Requirement

Decision 15-11-027 adopted a minimum round-trip efficiency for energy storage systems of 66.5% over ten years of operations to qualify for SGIP, equivalent to a first-year round-trip efficiency of 69.6%[7]. This was based on operating margin emission factors, build margin emission factors, line losses, and performance degradation parameters.

Itron's 2016 SGIP Advanced Energy Storage Impact Evaluation, August 31, 2017, concluded, "While the evaluation's findings indicate that SGIP is generally helping to reduce system peak demand, customer peak demand, and customer bills, a key goal of the SGIP program is to reduce greenhouse gas (GHG) emissions, which is not currently being met."[8] Specific to the program's GHG performance, the study concluded that "GHG impacts for both PBI and non-PBI non-residential projects are positive, reflecting increased emissions. The magnitude and the sign of GHG impacts is dependent on the timing of AES charging and discharging. During 2016, non-residential SGIP Advanced Energy Storage projects increased GHG emissions by 726 metric tons of CO2."[9,10] Because of data quality issues, Itron was unable to perform an assessment of GHG impacts from residential systems.

Rate Design Background Related to SGIP Program Goals

One of the key use cases for storage is helping customers manage their electricity bills, whether through TOU arbitrage or by managing exposure to demand charges.

Rates are designed to recover three broad categories of utility costs: capacity costs, energy costs, and fixed costs. Hourly energy costs and GHG intensity of the grid are closely aligned. The same is true for system capacity costs: transmission, sub-transmission, and primary distribution. However, many commercial and industrial rates have traditionally been designed with much of the transmission and distribution capacity costs recovered via non-coincident demand charges, which do not align with GHG intensity. Unfortunately, the resulting non-coincident demand charges have been the portion of rates that have provided the greatest opportunity for commercial customers to reduce their bills with energy storage.

In addition, the design of the time-varying demand and volumetric portions of the rates have not kept pace with changes in utility hourly costs. Rates have remained highest in mid-day hours while utility costs have increasingly been concentrated in the late afternoon and early evening, although recently the Commission has begun to adopt decisions that move the peak periods to later in the day.

These two mismatches are the largest factors that have led to GHG increases from SGIP-funded energy storage systems. For commercial customers, systems have been managed to reduce customer peak demand at the expense of GHG reduction. For residential customers, systems have been cycled in response to inaccurate price signals.

If rate design in the future becomes more aligned with GHG intensity, rate structure may provide the greatest assurance that SGIP will meet its GHG program goal. This is expected for residential customers. For commercial customers there is more uncertainty, so additional program rules are needed at least as an interim solution.

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[2] This summary of Public Utilities Code Section 379.6 and references to the goals of the SGIP program in the report do not represent the views of all working group members.
[3] Self-Generation Incentive Program Handbook, December 18, 2017, p. 9.
[4] P.U. Code Section 379.6(b)(1).
[5] P.U. Code Section 379.6(e)(1).
[6] P.U. Code Section 379.6(l).
[7] D.15-11-027 pg XX
[8] *2016 SGIP Advanced Energy Storage Impact Evaluation,* Energy Division Foreword, pg. 1.
[9] Ibid., pg. 1-23
[10] Itron assessed the GHG emissions impact of SGIP AES projects by developing a dataset of marginal power plant GHG emission rates for each 15-minute interval in 2016.

Working Group Objectives per Assigned Commissioner's Ruling

The Energy Division held a stakeholder workshop on November 15, 2017 to review and discuss the Itron impact report findings. Some of the key comments captured during the workshop were;

- There was widespread agreement by workshop participants that the RTE metric employed by D.15-11-027 may be an imperfect metric for achieving GHG reductions.
- A diverse group of participants suggested a working group to help develop alternative operational requirements to improve GHG emissions impacts from storage projects.
- Many stakeholders also indicated that a "GHG signal" provided to participants in advance could help SGIP energy storage systems to operate (i.e., charge and discharge) to reduce net GHG emissions to at least zero. In absence of data on the GHG intensity of the grid, it is hard to manage systems for GHG performance.

  Only those technologies that reduce GHG emissions are eligible for SGIP funding. However, there was no consensus view on whether this means that each and every project must reduce greenhouse gas emissions, or whether taken as a whole, the program should reduce greenhouse gas emissions.

Following the workshop, an Assigned Commissioner Ruling on December 29, 2017 established a working group ("Greenhouse Signal Working Group", or the "Working Group") to develop recommended changes to the SGIP to improve GHG emission reductions from energy storage systems with instructions to:

- Work efficiently so that new rules can be considered in the next several months
- Develop a proposal for a greenhouse gas signal
  - Include the following minimum characteristics:
    - The marginal GHG emissions of the grid reported for either NP15 or SP15, as applicable,
    - In 60, 30, 15 or 5-minute increments as determined by the working group
    - Forecasted for the day ahead
    - Automatically transmitted to the energy storage system, or the controller of the system if systems are controlled remotely
- Develop operational requirements for SGIP energy storage systems based on the GHG emissions of the electric grid
- Develop a verification mechanism to ensure GHG tracking and close monitoring of system performance
- Consider an enforcement mechanism to be used in the event that a system's operation results in net GHG emissions on an annual basis

The Working Group first met in January 2018 and has met regularly since then to conduct modeling of energy storage operation and develop proposals for the GHG Signal and SGIP rule modifications. This report is the final product of the Working Group, which contains the Group's recommendations to the Commission.

Working Group Participants

	Organization name
1	Stem
2	Avalon Battery
3	EDF
4	PG&E
5	Advanced Microgrid Solutions
6	CPUC
7	WattTime
8	Energy Center
9	Sempra Energy
10	CalSSA
11	Better Energies LLC.
13	AESC, Inc.
14	Enel Enernoc
15	Itron
16	Storage Alliance
17	SCE
18	Custom Power Solar
19	Tesla

Working Group Observers

	Organization name
1	E.On
2	NextEra Energy
3	CLEANSPARK
4	LADWP
5	Sunrun
6	Energy Attorney
7	TRC Solutions
8	Engie

Working Group Process

1. Meeting duration and frequency

The Working Group started meeting in early January 2018 on a weekly basis with in-person meetings once every two weeks and conference calls in between. The in-person meetings would typically last five hours, and the conference calls would typically take two hours.

2. Process for developing recommendations and drafting report

The initial focus of the Working Group was to develop a process by which to comply with the requirements of the Assigned Commissioner Ruling. The group reached consensus fairly quickly that the best way to comply was to brainstorm a number of possible solutions to improving greenhouse gas (GHG) emission reductions from energy storage systems and then to model these solutions to determine which ones were the most promising. The recommendations for SGIP proposed reforms were intended to fall out of the modeling results.

Most of the month of February was spent gathering load profiles and tariffs to model in the three IOU territories. This was a lengthy process as the various parties needed to reach out to their customers and get permission to use their anonymized load profiles.

The initial modeling efforts took a month and a half, starting in early March and ending in mid-April. Six parties were involved in the modeling process. These included Stem, Avalon, Advanced Microgrid Solutions (AMS), Enel Enernoc, Tesla, and Custom Power Solar (CPS). Each party with the exception of Enel Enernoc used proprietary models in the effort. Enel Enernoc focused on developing an energy storage model for the Working Group whose methodology and results were publicly available. During this process the modelers presented their results to the Working Group.

Their modeling data was provided to AESC under an NDA for analysis. The aggregation, anonymization and analysis of the data was performed by AESC between mid-April and mid-May. During this time multiple presentations of the results were made to the Working Group by AESC.

3. Working group's efforts to develop consensus recommendations

Beginning in April, the Working Group began the process of collecting policy proposals that would improve GHG emission performance of SGIP incentivized energy storage projects through surveys and in meetings with the Working Group. With the presentation of the modeling results by AESC in May the Working Group focused on crafting proposed reforms to the SGIP. Clarification of proposed policies and identification of consensus and non-consensus policies and policy specifics was deliberated by the Working Group in May and June.

Modeling Findings

Introduction

The cost and GHG impacts of an energy storage system are highly sensitive to a multitude of factors. Rather than relying on blanket assumptions for policy recommendations, the Working Group developed models that would simulate system operations to gauge sensitivity to certain characteristics and to detect consistent outcomes. For example, minimum or maximum operational requirements could be developed for a system characteristic found by all models to be decisive in leading to either net GHG emissions increases or reductions relative to a baseline scenario.

The Working Group relied upon five proprietary models and one newly-developed public model to explore the impacts of a GHG signal amid different combinations of system and customer characteristics (i.e. operational requirement options). Utilizing multiple proprietary and public models allows the Working Group's results to accommodate different technical methodologies and business approaches. The models determined emissions, customer cost, cycles, and annual RTE[11,12] impacts when operation was bound by a GHG signal (co-optimizing) or charging and/or discharging constraints, versus no GHG solution base case scenarios (operation without regard to GHG impacts). Relative to the baseline of no storage system, reduction in emissions or bills (or both) is desirable.

Modeling Results

Table 1 summarizes the effect of GHG signal co-optimization on GHG and cost impacts across different scenarios. The GHG reporting metric used here is kg of GHG reduction per kWh of usable storage capacity.[13] Negative values denote increases (not desired) and positive values denote reduction (desired). It is clear from the modeling results that, in all cases, GHG signal co-optimization yields better GHG impacts compared to scenarios without a GHG reduction solution.[14] In general, the data indicate that:

- New rates[15] seem to perform better than old rates[16] and storage paired with solar seems to perform better than standalone storage in terms of GHG impacts[17].
- Using GHG signal co-optimization does not diminish cost savings. Cost savings are even enhanced in some cases.

The table shows that co-optimization leads to equal or better GHG impacts and equal or better cost impacts when compared to the No GHG Reduction Solution ("no constraints") scenario. This is generally true for both the average impacts and the percentage of beneficial model runs. The exception is commercial systems paired with solar on new rates; the average GHG impacts are slightly better for the "no constraints" approach, but the co-optimization runs more frequently showed benefits by a decisive margin (85% to 69%). The red bars in Table 1 represent negative values (an increase in emissions or costs) whereas the green bars represent positive values (a decrease in emissions or costs).

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[11] RTE stands for Round Trip Efficiency of a storage system. It is defined as the efficiency of charging and discharging the battery- i.e. how many kWh do you get out for every kWh you put in. It includes battery thermal losses, inverter efficiency, and parasitic losses.

[12] Annual RTE is an output of the modeling process. For a given energy storage system, annual RTE is equal to the total energy charged over the course of a year divided by the total energy discharged over the same year. It is a function of the number of cycles per year, system parasitic loads and SCRTE.

[13] The 'usable storage capacity' of a storage system mentioned here is the total energy that the system can hold at any given time, usually expressed in kWh. This was obtained by multiplying the battery nominal power capacity in kW with its rated discharge duration in hours.

[14] This result is not surprising; it merely confirms the assumptions on which the GHG Signaling Working Group was formed in the first place. However, a short discussion regarding how a GHG signal impacts residential charging behavior (the simpler case, without demand charges) may be in order. Essentially, if the combination of rate/load profile/solar profile creates an economic incentive to charge a certain amount and discharge a lesser amount (due to RTE) on a certain day, there are generally many hours in which the charging and discharging could occur and have the same rate impact. For example, under new rates, discharging 1 kWh any time between 4PM and 9PM will have the same impact on residential charges, ignoring ITC effects. What the GHG signal does is *choose the highest-GHG hours within 4-9 PM* to discharge (rather than randomly or starting right at 4PM), thus maximizing both the GHG benefit due to displacing high-GHG thermal generation, and the GHG "credit". This discussion implies that the *magnitude* of the GHG signal is almost immaterial, as long as it is strong enough for the storage operation algorithm to rank hours within a TOU period from highest to lowest emissions – and that was indeed found to be the case using the public model.

[15] Throughout this report, the term "new rates" refers to rate plans proposed by the utilities (and in a few cases already in effect) that are subject to TOU schedules substantially different to the conventional TOU rates of the last 30 years. These TOU rates shift the on-peak period much further into the evening hours, thereby better aligning period of high cost with periods of high marginal grid emissions.

[16] The reason for this is that new rates have their peak Time of Use (TOU) periods aligned with the highest marginal GHG emissions, so storage systems operating under new rates are incented to discharge at times when GHG emissions tend to be high. Some new rates also have "Super Off-Peak" (SOP) periods when energy prices (and usually, GHG emissions) are low; storage systems operating under those new rates are also incented to charge when marginal emissions tend to be low.

[17] The reasons that the presence of paired solar tends to improve the GHG performance of a storage system are somewhat different between commercial and residential systems. For commercial customers, the on-site solar creates a "local duck curve" in the customer load, pushing the peak of metered load later in the day just as the grid-scale duck curve pushes the CAISO's net load curve later in the day. This means that storage discharges used for demand charge reduction will tend to align with high-GHG periods (whereas without the paired solar, the peak loads and therefore demand-related storage discharges may occur in the middle of the day when marginal GHGs are lower).
For residential systems, most paired systems apparently take the Investment Tax Credit (ITC), and are therefore operated so as to charge the storage at least 75% from on-site solar – which means charging mid-day (when marginal GHGs are low). And residential load tends to peak in the evening (especially after accounting for the local duck curve effect), so paired systems tend to discharge in the evening when GHG emissions are high.

Table 1: GHG Signal Benefit Comparisons by Scenario

CUSTOMER CLASS	MODEL TYPE INPUT	RETAIL RATE	GHG REDUCTION SOLUTION	MODEL RUNS	% RUNS WITH GHG REDUCTION	MEAN GHG REDUCTION kg/kWH	% RUNS WITH COST REDUCTION	MEAN COST REDUCTION %
Commercial and Industrial	Storage Only	OLD	GHG Signal Co-Optimization	985	23.86	-7.73	99.99	12.53
			No GHG Reduction Solution	153	0	-16.78	97.32	11.45
		NEW	GHG Signal Co-Optimization	792	40.4	-3.63	99.12	21.20
			No GHG Reduction Solution	112	17.86	-10.64	88.68	13.20
	Solar Plus Storage	OLD	GHG Signal Co-Optimization	667	60.12	3.32	100.00	16.08
			No GHG Reduction Solution	148	24.32	-3.45	100.00	13.29
		NEW	GHG Signal Co-Optimization	418	85.41	9.89	100.00	21.30
			No GHG Reduction Solution	176	69.32	10.52	100.00	12.92
Residential	Storage Only	OLD	GHG Signal Co-Optimization	216	3.7	-2.14	33.33	-1.17
			No GHG Reduction Solution	36	0	-2.96	33.33	-1.17
		NEW	GHG Signal Co-Optimization	108	100	21.33	100.00	16.73
			No GHG Reduction Solution	18	22.22	-6.07	100.00	16.73
	Solar Plus Storage	OLD	GHG Signal Co-Optimization	216	58.8	4.57	0.00	-11.27
			No GHG Reduction Solution	36	22.22	-3.48	0.00	-11.27
		NEW	GHG Signal Co-Optimization	243	84.36	14.21	100.00	15.81
			No GHG Reduction Solution	72	72.22	5.08	100.00	14.68

Key Takeaways

Overall, submitted data from the Working Group's modeling runs suggest several key takeaways that can help drive GHG-reducing operation of energy storage systems.

1. Residential energy storage systems **under old rates:**
   a. **When paired with solar**, are helped by the GHG signal to achieve GHG benefits[18]in the majority of cases irrespective of Single Cycle Round Trip Efficiency (SCRTE), but the combination of utilizing the GHG signal and a higher SCRTE of 85% guarantees GHG reduction. Without the GHG signal, a higher SCRTE of 85% increases the chances of achieving GHG reduction but does not guarantee it.
   b. **Without solar**, appear highly unlikely to reduce GHGs.
2. Residential energy storage systems **under new rates:**
   a. **When paired with solar with SCRTE of 85%,** almost always achieve GHG benefits with or without the GHG signal, but even lower SCRTE (here 70%) systems can reduce GHGs in the majority of cases when the GHG signal is utilized.
   b. **Without solar**, appear to always reduce both GHGs and customer bills when performing GHG signal co-optimization, regardless of SCRTE. But without the GHG signal, a higher SCRTE of 85% or above is required to achieve GHG reduction.
3. Commercial energy storage systems **under old rates:**
   a. **With solar**, when performing GHG signal co-optimization with 85% SCRTE, achieved GHG reduction 82% of the time (compared to 49% with a lower SCRTE of 70%). Without the GHG signal, the model runs achieved GHG reduction only 24% of the time regardless of SCRTE.
   b. **Without solar,** appear highly unlikely to reduce GHGs.
4. Commercial energy storage systems **under new rates:**
   a. **With solar and performing GHG signal co-optimization,** give GHG reduction 85% of the time regardless of SCRTE and 100% of the time with 85% SCRTE. Without a GHG signal, GHG reduction was achieved 69% of the time irrespective of SCRTE, but with a higher SCRTE of 85% the proportion increased to 86%.
   b. **Without solar**, while benefiting from co-optimization, are generally are unlikely to reduce GHGs (40% of commercial standalone model runs reduced GHGs when performing co-optimization under newer rates, regardless of SCRTE; the frequency increased modestly to 44% when a constraint of 85% SCRTE was added).

Certain modeling teams expressed a concern with regard to the aggregated modeling results and stated that the Working Group did not model grid services, such as demand response, due to the complexity and uncertainty involved in such a modeling effort. Grid services, along with GHG emissions reductions and transforming the market for DERs, are all SGIP goals. Many developers of stand-alone storage systems focus on providing grid services in addition to customer demand charge management, as opposed to simple energy arbitrage to enhance customer savings. So, depending on the developer's business model (energy

[18] Assuming the storage system is charged primarily, if not exclusively from the solar system

arbitrage or demand charge management/grid services), some systems may not perform as well on reducing marginal GHG emissions, yet they may be avoiding the need to bring more gas peakers online and facilitating the integration of higher levels of variable renewable energy resources.

Working Group Criteria for Recommendations

Areas of Agreement – Programmatic Modifications

1. GHG Signal: Implement a GHG signal tool which can send 1) real- time and predictive grid emissions factors to SGIP projects and 2) provide a useful and actionable prediction of future grid emissions factors; the technology is commercial ready and can support GHG reductions.
2. Financial Claw-Backs: Avoid ex-post incentive claw-backs if possible – they are legally and administratively difficult/burdensome.
3. Complexity vs. Simplicity: Avoid complex program changes that would shut the program down for a long period – the program sunset date in 2020 means any solution should be implemented quickly and cost-effectively. Minimize complexity of rules for program participants.
4. Optionality: Support optionality where feasible to allow developers to pick a reasonable pathway to support the GHG reduction.
5. Adaptability: The efficacy of new rules can be reviewed regularly and rule changes can be again considered if the desired outcome of GHG reduction is not accomplished.
6. Enforcement: Enforcement should penalize poor performance via incentive reduction. The group prioritizes improved enforcement and developing a reasonable system to encourage GHG-reducing behavior. Various incentive reduction options are proposed.
7. Residential Deemed: A residential "Deemed" approach has been supported by the group whereby residential systems would continue to receive the SGIP incentive 100% up front but predicated on agreement to meet specified requirements or operational modes.
8. Meters: Permit non-revenue grade meters for Non-Res/Non-PBI & Res where required for implementation.

9. Itron: Keep GHG calculation methodology consistent with Itron/E3 methodology as described in their 2016 report; measure projects using the same GHG signal as the real-time grid emissions factor described in Item 1, above; Itron's role stays the same.

Areas of Disagreement or Diverse Working Group Opinion

1. Fleet or Project: Variants of compliance verification and enforcement of 'fleets' versus 'project-level', for both new and legacy projects have been proposed.
2. GHG Emission Penalty: A $/ton GHG penalty to be applied against PBI payments for PBI systems based on any net GHG emission increases a project is found to have caused. The $/ton penalty should be based on/tied to the price of GHG emission certificates in CA's cap and trade program, the price of carbon offsets in the voluntary carbon offset market, or other measure of GHG costs, like the social cost of carbon or the marginal GHG abatement cost.
3. Legacy projects: Rule changes on legacy projects to bring them into GHG compliance are unsettled issues, given the investment decision was made based on the rules in place at the time of application, yet it would be dissonant with program goals to allow continued non-compliance with GHG goals.
4. Carbon feebate mechanism: implementation of a carbon feebate mechanism to promote GHG reductions could encourage better GHG performance but may be overly complex to implement. Further, unless the structure of the carbon feebate mechanism is well-designed, such a system may not be effective.
5. Non-Res/Non-PBI projects: rules changed to require all non-residential projects to be PBI.
6. Cycling: How would they factor into calculating payment, which currently expects a specific number of discharges?
7. M&E: More frequent GHG compliance verification is needed to be sure program goals are met. Minimum quarterly verification for the first year of the project's life, which starts on the first incentive payment date.
    a. Regular monitoring of non-res non-PBI projects
    b. Statistical sampling for residential projects
8. Build Margin: Build margin effects are not reflected, but are non-negative (i.e. storage build does not by itself increase GHGs)
9. GHG reductions: The statutory requirement for the program to reduce GHG emissions should be honored, without unduly sacrificing other program goals (market transformation, grid support).[19].
10. Balancing Program Goals: The working group disagreed on how new rules should balance SGIP's three program goals of market transformation, GHG reductions, and grid support. Some argued that the requirement to reduce GHG emissions should be prioritized per the guidance provided in the Commission's ruling launching the working group. Others argued that achieving GHG emission reductions at the expense of market transformation and/or grid support is not an acceptable outcome and arbitrarily places one statutory program goal over others. This question of how to balance program goals is discussed throughout the Recommendations sections.

[19] While there is consensus that one of the goals of the program is to reduce GHG emissions, there was not consensus on the level at which realization of that objective should be assessed – on a system by system basis, at the fleet level or at the programmatic level. There was also no consensus on the GHG emission threshold. Some were in favor of a zero threshold while others were in favor of a more negative threshold.

Working Group Crosscutting Recommendations for All or Multiple Types of SGIP Projects

This section covers Working Group proposals that can be applied to all or multiple types of SGIP projects such as new and legacy PBI, non-PBI, non-residential, and residential projects.

Forecasted and Real-Time Marginal GHG Emissions Signal

GHG Signal Proposal:

- *Operational Requirement:* SGIP to make available a grid marginal GHG emissions signal for energy storage control.
- *Verification Mechanism:* SGIP to use the historical real-time (5-minute) emission factors to calculate incentivized energy storage project GHG impact for determining PBI payments and monitor PBI and non-PBI projects.
- *Enforcement Mechanism:* Depending on the customer class and size of energy storage systems, GHG emissions may impact PBI payment and/or invoke SGIP infraction processes. Quarterly monitoring for the first year of a new project; feedback provided to Developers on performance each quarter. Annual review and potential payment reduction or other enforcement action.

Consensus Status:

Consensus.
Supported by: PG&E, SCE, SoCalGas, CSE, ORA, CESA, CalSSA, CPS, AMS, Stem, Tesla, Avalon
Opposed by: N/A

Proposal description:

The real-time and forecasted marginal GHG Emissions Factors (EFs) to be provided publicly for NP15 and SP15[20]. The EFs signal will be provided at both 5-minute and 15-minute granularity and formatted in kg/kWh. The Signal is based on Locational Marginal Pricing (LMP) like the existing SGIP emissions factor evaluation methodology, but the GHG signal also uses real-time (5-minute) LMP and CO2 price data. The SGIP Annual Program Evaluation and real-time signal should use the same GHG factors dataset. After year 1 of program operation according to the GHG signal, an analysis should be conducted to ensure no material difference between real-time and ex-post values.
Also, a real-time and predictive renewables curtailment signal can be provided to assist in targeting moments of renewables waste.
The EF generation methodology will be reviewed annually.
The GHG signal will be provided in three forecasts:

1. 72 hour-ahead forecast
    a. Marginal GHG emission rates every 5 minutes, updated hourly
    b. Ranking, and other relevant contextual information as needed to support the optimal dispatch of storage
2. Month-ahead forecast
    a. Forecast of future days as easier/harder to reduce GHGs based on variability, predictability, and ramp speed.
    b. Updated daily
3. Year-ahead forecast
    a. Monthly trends in ease of GHG reduction
    b. Updated monthly

Forecasts should include uncertainty measurement:
  a. For each time step
  b. *Not* assuming independent, identically distributed values
  c. Formatted with input from storage developers, via iterative testing

The signal delivery platform description:
  Accessibility and Security:
    1. Both webhook and RESTful API with standard JSON output
    2. Downloadable CSV files in human-readable format
    3. No write access to storage developer/user servers
  Reliability:
    1. 99.99% uptime (per WattTime)
    2. System downtime triggers real-time notification
    3. Continues operation, using reasonable estimated values, when CAISO OASIS is down or is missing data
  Funding:
    1. The GHG signal should be provided at no incremental cost to SGIP participants
    2. Funding for the signal should come from SGIP M&V funds

Supporting Discussion:

N/A

[20] This signal could be provided by WattTime or other potential public/private/non-profit entity capable of providing this service.

Opposing Discussion:
N/A

Model Findings Support:
Model findings support GHG co-optimization; relative to scenarios without a GHG reduction solution, co-optimization almost always increased the proportion and magnitude of outcomes with net GHG benefits.

AESC Recommendations:
Based on GHG reduction improvement seen in modeling and broad consensus, we recommend that the program should begin implementation of a real-time marginal GHG emission signal as quickly as possible. In general, we agree that the signal should be optional, but verification of GHG emissions using the historical 5-minute GHG signal should be mandatory for both performance incentives and infraction processes.

Fleet Compliance Mechanism

Fleet Proposal 1:
- *Operational Requirement: N/A*
- *Verification Mechanism:* Verification will be applied to a project developer's fleet or portion of a fleet of SGIP projects. Each developer would have a rolling five-year or ten-year fleet of systems upon which they are evaluated.
- *Enforcement Mechanism:* Enforcement will be applied to a project developer's fleet or portion of a fleet of SGIP projects based on the fleet verification. However, projects receiving PBI payments would be subject to enforcement at the project level during the full PBI period – they would fall into their developer's fleet after the last PBI payment.

Consensus Status:
Non-consensus.
Supported by: PG&E, CSE, CESA, CalSSA, CPS, AMS, Tesla, Avalon
Opposed by: SCE, SoCalGas, ORA, Stem

Proposal description:
Under a fleet compliance mechanism, developers would be subject to verification and compliance for a portion of their fleet of energy storage systems, with each project staying in its developer's fleet for a period of 5-10 years (the "fleet evaluation period"). Each developer would have a rolling fleet of systems upon which they are evaluated after project installation.

New PBI systems, including smaller PBI <30 kW, non-residential systems (to be described later), would be evaluated on an individual system basis for the duration of their PBI payments. These systems would not be included in the fleet compliance (no "double-dipping" or "double jeopardy" concept) while they are still receiving a PBI payment. These new PBI systems would be paid their incentives based on meeting cycling requirements and would be subject to GHG emissions penalties on an individual basis, as discussed in the sections below. Once the PBI incentives have been paid for these systems, they would then be included in the fleet evaluation and compliance until 5-10 years after the initial incentive was awarded. This provides extra motivation to continue to reduce GHG emissions for the full fleet evaluation period.

For legacy PBI:
- Project is measured/enforced per project until end of PBI period, however long that is.
- Project then goes into the 'fleet' for remainder of the 10-year permanency/warranty period, i.e. if >30 kW and complete with 5-year PBI, it's 5 more years of M&E in the fleet (enforced at the fleet level). There are two types of fleet level compliance being proposed:
  - Project goes into an exclusive legacy fleet
  - Project goes into a pooled legacy and new fleet for balance of fleet compliance
- There are differences of opinion as to whether the fleet compliance period should be 5 or 10 years. Some parties maintain that the period should be 5 years with projects immediately going into fleet compliance during the PBI period.

For legacy Non-Res <= 30 kW:
- Project goes into the 'fleet' for remainder of the 10-year permanency/warranty period. There are two types of fleet level compliance being proposed:
  - Project goes into an exclusive legacy fleet
  - Project goes into a pooled legacy and new fleet for balance of fleet compliance
  - Some parties maintain that the fleet compliance period should be 5 years and not 10. Their rationale is that it is extremely difficult to predict marginal emissions that far out into the future, and recognizing that customer equipment, loads, and profiles can change over time and are difficult to predict and beyond the ability of a developer to predict or control.

For new PBI:
- Project is measured/enforced per project until end of PBI period; 3 years (70/30 or 80/20 for <30 kW) or 5 years (50/50 for +30 kW).
- Project then goes into the 'fleet' for remainder of the 10-year permanency/warranty period, i.e. if >30 kW and complete with 5-year PBI, it's 5 more years of M&E in the fleet (enforced at the fleet level). If a 70/30 or 80/20 project, there would be 7 more years in the fleet to satisfy the permanency requirement. There are two types of fleet level compliance being proposed:
  - Project goes into an exclusive new project fleet
  - Project goes into a pooled legacy and new fleet for balance of fleet compliance

There are differences of opinion as to whether the fleet compliance period should be 5 or 10 years. Some parties maintain that the period should be 5 years with projects immediately going into fleet compliance during the PBI period.In general:

- Fleetwide compliance provides flexibility to developers to manage GHG emissions.   This can be helpful recognizing that depending on the use case and customer load profile, each and every project may not reduce GHG emissions, even if overall, the fleet does reduce emissions.
- To the degree the Commission believes that the program overall should reduce GHG emissions, but that each system does not need to do so, a fleetwide approach appears more consistent with that.
- By having systems transition from individual compliance to fleetwide compliance, this structure provides continued incentives for developers to continue to manage their fleets in a way that reduced GHG emissions.

Supporting Discussion:This approach is consistent with the text of Section 379.6(b)(1) of the Public Utilities Code, which states that "Eligibility for [SGIP] shall be limited to distributed energy resources that the [CPUC]… determines will achieve reductions in emissions of greenhouse gases…." The text does not specify whether the DERs must reduce GHG emissions individually or collectively.

- Pooled fleetwide compliance allows high GHG reducing projects to offset GHG producing projects but maintains overall program goals of reducing GHGs. This also supports the principle of ensuring meeting GHG goals do not unduly harm the other SGIP goals of providing grid services and transforming the market for DERs. Many energy storage systems are providing grid services that help avoid the need to build new gas generation and/or enable the reliable integration of higher penetrations of variable wind and solar into the grid in support of the State's clean energy and GHG reduction goals.
- Recognizes that marginal GHG emissions are extremely difficult to predict five years in the future, much less 10. Also recognizes that many other things may change that are beyond the control of the storage developer – such as customers adding/removing load and equipment, adding solar or other forms of DER (consistent with SGIP market transformation goals), or the ability of storage to provide multiple grid benefits via future markets, programs, tariffs or incentives.
- As the 2016 Itron Evaluation pointed out, the best solution for achieving GHG reductions with energy storage is aligning the rates with GHG emissions signals. Limiting systems to a 5-year compliance/penalty period provides enough time for utilities to develop, seek approval for and implement new tariffs.
- Pooled fleetwide compliance provides flexibility to developers to manage GHG emissions.   This can be helpful recognizing that depending on the use case and customer load profile, each and every project may not reduce GHG emissions, even if overall, the fleet does reduce emissions. This is similar to the justification for California's Cap and Trade Market under AB32.
- This approach is compatible with some storage providers that operate fleets of installations as a single system. They balance different customers' needs and available capacity to provide grid services.

Opposing Discussion:

- Each system should be evaluated on their own merit because SGIP could be incentivizing too many storage systems that do not meet GHG standards.
- Removing the obligation to reduce GHGs at the project level after only 5 years goes against SGIP rules and the spirit of the program. Systems should be subject to evaluation and compliance for the full 10-year term of the permanency requirement.

Model Findings Support:

This compliance mechanism was not modeled.

AESC Recommendations:

Recognizing that customers, grid operators, regulators, policy makers and society have broad and varied expectations of the benefits from behind the meter energy storage, fleet compliance makes sense because of the flexibility that it can provide. We recommend that a fleet compliance be included in SGIP, but only after the PAs, working with industry, define what constitutes a "fleet" and how SGIP would administer "fleets" in the program and database. While the program GHG rules are based on 10 -year permanency we do not agree that the program intent is subject projects to compliance for the full 10-year term.

Carbon Feebate

Feebate Proposal:

- *Operational Requirement:* N/A.
- *Verification Mechanism:* N/A.
- *Enforcement Mechanism:* Would not change enforcement but would allow PBI payments up or down based on the amount by which an individual project increases or reduces GHG emissions.

Consensus Status:

Non-consensus.
Supported by: PG&E, SCE, CESA, CalSSA, CPS, AMS
Opposed by: SoCalGas, Stem, Tesla

Proposal description:

A carbon feebate mechanism in SGIP involves adjusting PBI payments up or down based on the amount by which an individual project increases or reduces GHG emissions[21], to motivate good GHG behavior. This could easily be designed as a revenue neutral approach within SGIP, as will be explained in greater detail below.

[21] Relative to the emissions site would have produced *without* energy storage.

Projects subject to the feebate would have an incentive to reduce annual emissions at some defined carbon price (in $/metric ton). Payments (or in some cases, credits) would generally be applied to projects' PBI payments and would be computed annually using the same data and analytical machinery used for the current M&E program. Thus, no new analysis would be required; but to the extent the feebate covered more projects (e.g. opt-in residential), the data requirements would be increased.

The feebate would be relative to a threshold defined in net GHGs per kWh of storage capacity. For example, a 30 kW, 2-hr battery has 60 kWh capacity. If the threshold is set to 0.1 MT/kWh capacity then this battery would neither receive a credit nor incur a penalty for if it reduced GHGs by exactly 0.1*60 = 6.0 MT; if it did better (greater reduction) then under some variants it would have a credit, determined by the number of MTs of GHG reduction beyond its 6 MT threshold; under all variants it would be subject to disallowance if it did worse.

Many variants have been proposed by parties; these are covered as separate topics within the larger proposal. The layout is chosen to help elucidate the nuances involved in the feebate proposal; if this proposal is accepted then one or more options would need to be chosen under each subsection below.

1) Should feebates include both "carrot" and "stick"?

    Description: If stick only, then projects (or developer fleets) that perform better than the threshold would not receive an additional payment or credit, but those that do not would be subject to a penalty (and funds would be added to SGIP pot for future incentives). If carrot and stick, then projects that do better than the threshold would receive a credit, i.e. all penalty funds would be delivered to over-performers in the current year.

    a) Advantages of carrot and stick: Because all projects could see an incentive, GHG reductions are expected to be more than under a "stick only" approach. The program increases the visibility of GHG emissions, such that customers and developers may be incented to do better than average for the "green glow" beyond financial incentives – this is how Opower works with energy conservation. Avoids perception of "pay to pollute" that could be leveled at stick-only approach.
    b) Advantages of stick only: Avoids the perception that projects are being paid extra to do what they were supposed to do already (since they received SGIP incentive based in part on GHG reductions). Would reduce SGIP payments and allow rollover to new projects.
    c) Additional variant: Big stick, small carrot. Here projects that increase GHGs must BOTH pay the standard penalty AND purchase CCAs (California Carbon Allowances) to offset their emissions; those that reduce GHGs are subject only to the $/t incentive, whether or not the threshold is greater than zero. Advantages are that GHG-increasing systems are given a stronger signal, and not only offset their emissions but also pay better-performing systems to reduce GHGs more.

2) What is the appropriate threshold (the "bar" that projects must meet to avoid penalty)?

    Description: Some parties argue for a zero threshold (i.e., projects should only be penalized if they increase GHG emissions). Others propose the threshold be at least the average emissions reductions of existing SGIP funded systems, making the feebate program inherently revenue-neutral.

    a) Zero threshold: Advantages - Reward and penalty are not dependent on behavior of other systems. Disadvantages – Not revenue neutral, so would require funding source if carrot and stick (reducing funding for future energy storage projects), or way to add to SGIP pot if stick only. Adds to perception that "zero is good enough".
    b) Threshold equals maximum of zero and total fleet average GHG reductions: Advantages – Revenue neutral if total fleet is reducing GHGs, and revenue positive (i.e. net penalty) if fleet increases GHGs even under carrot and stick; automatically raises the bar as fleet becomes more GHG-negative. Disadvantages – Reward and penalty are dependent on other systems' behavior (so harder to plan for).
    c) Zero threshold, but asymmetrical payments: Zero threshold, with penalty at nominal $/t and credits at whatever $/t makes the program revenue neutral. This means that the reward for reducing emissions is higher when the majority of other systems are increasing emissions, the reward is lower when the majority of other systems are reducing emissions, and the reward is $0 if all systems are reducing emissions. Advantages: Penalty is not dependent on behavior of other systems. Disadvantages: Amount of credit is dependent on behavior of other systems; and as program becomes more GHG-reducing the credit will drop, potentially reducing the rate of improvements.

3) What projects are included in the feebate program?

    Description: All parties that support the feebate concept[22] agree that all new PBI projects should be subject to the feebate, and the credits/penalties would be applied to their annual PBI payments. Others may be required to be part of the program, or perhaps could opt in.

    a) New non-residential, non-PBI projects (perhaps required, perhaps opt-in)
    b) New residential projects (opt-in only)
    c) Legacy non-residential projects (opt-in; perhaps to replace cycling and RTE requirements with participation in the feebate program)

4) Are projects evaluated individually, or on a (developer) fleet basis?

    Description: For projects evaluated on a fleet basis, developer could apportion any increased GHG emissions can be set to appropriate rebates to projects however they wished (or keep the rebate themselves); would likely decide to pay any penalties themselves to avoid customer claw back. Projects that are evaluated on an individual basis would not also be included in their developer's fleet evaluation[23] so as to avoid double dipping/double penalties. Options include:

    a) All projects evaluated at (developer) fleet level; none individually
    b) New PBI projects individually, all others (including legacy and opt-in) at fleet level
    c) New non-residential projects (PBI and < 30kW) individually, all others at fleet level

[22] PG&E, Avalon, Enernoc, Stem, Custom Power Solar, CSE

[23] These systems would still be measured, however, for purposes of determining program-level GHG performance.

d) All projects measured individually but GHG performance of developer fleets to be based on performance of systems that are not (or are no longer) subject to PBI payments.

5) What should the effective carbon price ($/t) be?

Description: Current prices in auctions and on ICE are around $15/t, which appears to be too little to incent behavior change. D.16-06-007 specifies that DERs should be evaluated using the social cost of carbon in the ACC model - currently the cap and trade ceiling prices are between $65-70/t. However, even $70/t works out to a small proportion of the SGIP payment for the systems modeled by the WG.

a) Multiple (say 4X) of the average CCA price when the project was commissioned. This works out to about $60/t. Advantages: Increases automatically as CCA price increases. Disadvantages: More complex tracking of build year.

b) Requirement to purchase carbon offsets from the voluntary carbon market in a multiple (4X?) of the total increase in GHG for the fleet. Advantage: Carbon offsets are certified and easily verified by PAs. Developer can purchase any amount (no minimum value) and by purchasing a multiple of the actual emissions increase, is achieving a reduction in GHG via the carbon offset mechanism. Disadvantage: Minor PA administrative change to account for verifying certified offsets were purchased.

c) Social cost of carbon in ACC model for current year (currently $65-70/t). Advantages: Follows D.16-06-007 (though this is for incenting, not evaluation); automatically increases as cap and trade ceiling price increases. Disadvantages: May get out of balance the multiple objectives of the program if ACC model changes significantly.

d) Administratively set price above C&T ceiling (e.g. $150/t increasing 5% per year). Advantages: Stronger incentive to drive GHG reductions, which may be needed early in the program. Disadvantages: More difficult to justify based on societal costs.

e) Exceedance bands rather than carbon price: If project emits net GHGs, PBI payment would be reduced proportionally depending on how many kg/kWh of capacity the project emitted. TBD: Would different tiers have same proportional reduction, or same penalty based on proportional reduction from Tier 1?

- Example:
  - >0 – 10 kg/kWh – 5% PBI payment reduction
  - >10 – 20 kg/kWh – 10% PBI payment reduction
  - >20 – 30 kg/kWh – 25% PBI payment reduction

Supporting Discussion:

- If implemented as a “carrot and stick” or “big stick, little carrot”, every single SGIP project that is part of the feebate mechanism has an incentive to reduce GHGs as much as economically or operationally feasible, whereas penalties for increasing GHGs merely incent projects to do “just good enough”.
- The revenue-neutral version of the mechanism rewards systems that do better than average and penalizes those that do worse in a given year, thus automatically yielding two benefits: 1) being revenue-neutral, it counters the argument that SGIP should not “pay systems for doing what they were supposed to do anyway”, and 2) it automatically raises the bar every year as projects become better at reducing GHGs, much as the EnergyStar program resets every few years as appliances become more efficient.
- Any additional funds from penalties for increasing GHGs (under “big stick, little carrot” or “stick only”) go to either retiring GHG allowances (thus making the program at worst GHG-neutral), or incenting new, more effective projects.
- While some suggest that the feebate adds complexity, it leverages the calculations that are already being made for verification, and the PBI payment mechanism that is already in place, so there would be relatively little additional work required.
- With the carbon prices set to approximately $70/t, the potential gain or loss from reducing GHGs more or less than the average is significantly less than a PBI payment (thus not onerous), but still enough to make a difference, especially if top-performing systems receive recognition to enhance their property’s “green glow” – approximately $300/yr for a 30 kW, 2-hr system assuming 75 kg/kWh differential between top and bottom performers.
- Much of the co-optimization modeling, and WattTime’s experience suggests that even small incentives (or disincentives) can materially affect the GHG performance of storage. Units without even a small incentive have little reason to continue using even the simplest GHG reduction measures, and in doing so contribute to the existing emissions problem. This suggests any fleet-level performance requirements be accompanied by a non-punitive incentive/cost, for the full duration of the program/up to ten years.

Opposing Discussion:

- This approach represents a potentially significant change in the program design/structure and could take significant time and resources to implement.
- The idea of feebate for energy storage is outside the existing principles of SGIP. If a generation project achieves a number well under the target, there is no extra incentive provided, as it is following the goals of the program to provide grid and customer benefits in an environmentally superior fashion.
- If this idea achieves the intended effect of having all systems reducing larger amounts of GHGs, then additional funds would be required, potentially reducing the amount of funding for future SGIP projects.
- The proposals for providing credits for GHG reductions add significant complexity and would create significant administrative costs and burden. Furthermore, the amount of potential additional GHG reductions could likely be quite small, yielding a high cost per ton of GHG reduced and a poor investment of ratepayer funding.
- Forcing developers to chase varying and uncertain GHG reduction levels under the fleet average threshold method could actually do harm to the storage industry by creating uncertainty over project repayment/financing. Similarly, focusing on maximizing GHG reductions to avoid penalties would create a significant disincentive for storage to provide multiple uses and grid services – key benefits of the technology, as recognized by enabling legislation and enabling regulatory policy.

Model Findings Support:
This mechanism was not modeled.

AESC Recommendations:
We do not recommend a feebate approach for SGIP. It appears that adding the feebate feature to SGIP would complicate PBI payments, creating excessive administrative burden, and potentially delay implementation.

Build Margin

Background: SGIP GHG emissions compliance is currently based on the marginal emissions for the system at any given period of time. Marginal emissions are determined by the mix of generating resources being dispatched at the time its measured. Build margin, on the other hand, reflects avoided emissions from fossil generation that was displaced because the need was met through energy efficiency, demand response, energy storage or carbon-free resources such as solar and wind energy. Since energy storage can provide demand response and local capacity/resource adequacy, it helps avoid building or contracting for gas peakers. Energy storage can also enable high penetrations of variable renewable energy from solar and wind, which can also defer the need for new fossil resources.

SGIP does not currently credit energy storage for the avoided gas generation that might have otherwise been built or retired, nor does it get credit for enabling the integration of higher penetrations of variable wind and solar resources into the grid. It's important to note that non-storage SGIP resources do get a build margin credit under SGIP Handbook rules.

Though storage can and frequently does support the development of renewable energy. However, it does not always do so. Should a decision be made to incorporate a build margin, it should not simply be assumed to be any particular amount, but rather measured and verified like any other form of GHG performance. Generally accepted tools to estimate build margins are readily available, such as those developed by the UNFCCC (CDM Tool 7) and by the GHGP (Guidelines for Quantifying GHG Reductions from Grid Connected Electricity Projects) among others.

Build Margin Proposal 1:
- *Operational Requirement:* N/A.
- *Verification Mechanism:* Include build margin benefits when assessing energy storage GHG impacts, in project verification and program evaluation.
- *Enforcement Mechanism: N/A*

Consensus Status:
Non-consensus.
Supported by: CSE, CESA, CalSSA, CPS, AMS, Stem, Tesla, Avalon
Opposed by: PG&E, SCE, SoCalGas, ORA

Proposal description:
This proposal recommends including build margin benefits provided by SGIP storage projects to evaluate the specific impacts on GHG reduction and include these benefits in a future SGIP modification. In the meantime, the Commission should view build margin as justification for avoiding overly harsh penalties and enforcement mechanisms, recognizing the multiple objectives of SGIP, and multiple benefits energy storage can provide. It may be appropriate for the Commission to initiate a working group or investigation as soon as practicable into quantifying the build margin contribution from energy storage in the appropriate proceeding and include this in future SGIP revisions.

Supporting Discussion:
- Avoiding build margin GHG emissions is a valuable benefit provided by energy storage systems and, currently, that benefit is not included in SGIP.
- SGIP eligible generating technologies receive credit for build margin.
- There is evidence of the benefits of energy storage in avoiding the need to build GHG-emitting resources and those benefits have been used to evaluate numerous peaker and baseload plants and concluded that renewable energy, storage and energy efficiency can obviate the need to replace older, inefficient gas-powered plants.
- Energy storage is uniquely capable of integrating higher levels of variable wind and solar energy reliably into the grid, which supports the State's clean energy and GHG reduction policy goals, yet does not receive credit for this.
- Build margin benefits should, at the minimum, highlight that the SGIP GHG picture is better than calculated.
- In the long run, storage is needed to integrate high levels of renewables on the grid. Making energy storage a mainstream product will allow us to increase storage capacity over time, which will help enable the deep GHG reductions that are needed.
- As renewable energy capacity gains an increasing share of the generation portfolio, storage will be necessary to integrate those clean resources into the grid. This will hasten the points at which fossil generators can be retired without replacement.
- It is not practical to translate this benefit into a kg GHG / kWh value to use for near term compliance with the GHG goal of the program, but there is a large long-term benefit.

Opposing Discussion:
- There is no need for new gas-fired units until at least 2023 and retirement of OTC units is determined by Coastal Commission, so storage won't reduce new build or speed OTC retirements
- Only a few gas generators are now being replaced by renewables + storage + transmission + DR based on local constraints
- Even if storage can partially replace peaking capacity, remaining gas generators will run harder as happened with SONGS retirement

- Also, grid storage is more efficient at replacing gas generation and integrating renewables than customer storage, by participating in energy and Ancillary Services markets directly or even via CAISO control
- The Commission has already determined in D.15-11-027 that, "the emission rates of the new gas-fired plants displaced by SGIP projects and other demand-side measures will be lower than the existing plants whose output is avoided on the operating margin."[24]

Model Findings Support:

This benefit was not modeled.

AESC Recommendations:

We do not recommend that build margin benefits from energy storage be included in SGIP at this point in time because more information is needed to justify it and determining the proper way to calculate build margin GHG benefits. Instead, we recommend that Itron study build margin as a potential GHG benefit for SGIP energy storage systems, and develop a paper describing their findings. The paper findings should be used to decide policy and rule changes in SGIP for GHG verification and program evaluation.

Solar Credits for GHG

When an SGIP incentive motivates a customer to install storage paired with solar and the customer would not otherwise have installed solar, SGIP is credited with the GHG reduction associated with the solar production. This is incorporated in the SGIP Impact Evaluations (See 2016 report, pp. A-3, A-10). The challenge is determining when the solar system was only installed due to the SGIP incentive.

Solar Credit Proposal 1:

- *Operational Requirement:* Must be charged from the solar system and ITC compliant.
- *Verification Mechanism:* SGIP to confirm that solar system installation is caused by energy storage system through application documentation and field inspection.[25]
- *Enforcement Mechanism:* Does not change the enforcement mechanism but allows solar GHG benefits to be assigned to the energy storage project.

Consensus Status:

Non-consensus.
Supported by: CESA, CalSSA, CPS, AMS, Stem, Tesla, Avalon
Opposed by: PG&E, SCE, SoCalGas, ORA

Proposal description:

CPUC and Stakeholders develop a methodology for determining when a customer would not have installed solar but for the SGIP incentive. When that is found to be true, the project is deemed compliant because the GHG reduction from the solar system certainly overwhelms any hourly behavior of the storage system in relation to GHG intensity of the grid. The GHG Signal Working Group had diverse opinions on whether or how such a new approach could be established; most agree this needs diverse stakeholder involvement, including the expertise of Itron who has experience in this area.

Supporting Discussion:

- Due to the changes in rate design, in order to make solar projects economically attractive/viable, energy storage is increasingly a necessary element of a solar installation.
  - CALSSA found, in modeling they performed separately from this study, that the capital recovery period under new rate structures is 8%-28% worse for solar than for solar plus storage. This modeling can be found in Appendix H.
  - Better Energies found that typical customers under new rates would have rates of return of 6% for solar investments, which is not enough to motivate investments, and 11%-12% for solar plus storage. This modeling can be found in Appendix I.
  - Custom Power Solar found that customer savings from solar are greatly diminished under new rates, but storage can partially make up for that loss. This modeling can be found in Appendix J.
- Commercial solar development is greatly reduced from previous levels due to changes in rate design. This approach appropriately recognizes the increasing role that storage is expected to have in supporting and catalyzing additional solar deployment.
- Commercial customers will continue installing solar plus storage to get the combined benefits of demand management and the federal tax credit.
- If the SGIP develops parameters that accurately determine if the solar PV is attributable to the SGIP incentive, (i.e. the customer is on a new TOU rate with evening peak and is installing the solar PV with the energy storage) this would more reliably depict the GHG impacts that SGIP incentives cause.

Opposing Discussion:

- There is little evidence that energy storage enables behind the meter solar system installations. Under current and proposed rates, stand-alone PV is cost-effective for residential and C&I customers (installation rate has been constant since 2017)
- For PG&E residential systems, even switching to EV-A rate and adding storage saves customers less than adding more PV under E-TOU-A (up to 100% annual production)
- For C&I customers, customer benefits from storage are mostly demand charge reduction, independent of solar, so again storage is not selling PV

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[24] D.15-11-027, pp. 20-21.

[25] It would be beneficial for stakeholders and the CPUC to develop a protocol to facilitate crediting storage with GHG reduction associated with installing solar. Itron has done research in this area and should be consulted.

Model Findings Support:

This proposal is not supported by the modeling results; the analysis only considered impacts attributable to the storage system, and the modeling effort did not address causality between storage and solar. Furthermore, the policy question of whether solar should get the credit is not resolved.

AESC Recommendations:

We do not recommend that allowing solar credit benefits for solar systems installed with energy storage be included in SGIP at this point in time. While it is plausible that some solar system installations are enabled because of the concurrent installation of energy storage, it is unclear under what conditions that may be true. Instead, we recommend that Itron determine what conditions that solar GHG credits would be realized when installed with energy storage and how to calculate the GHG benefits from those solar installations.

Working Group Recommendations for New Projects

New PBI Projects

There was broad Working Group agreement on the operational requirement and verification mechanism for new PBI projects, however there was disagreement on the enforcement mechanism, primarily how much the PBI payment is at risk when GHG emissions are not reduced. The SGIP Signal Working Group developed several proposals on how to enforce GHG compliance for projects that increase GHG emissions over a 12-month PBI period.

New PBI Proposal 1: PBI + GHG Signal

- *Operational Requirement:* No annual RTE requirement. Cycling requirement of 130 remains. GHG signal available but not required to use.
- *Verification Mechanism:* GHG Impact calculated monthly or quarterly for feedback with Developers and fleet management, and annually for compliance using PBI data and historical GHG signal.
- *Enforcement Mechanism:* Multiple approaches outlined in the following proposals. See below.

Consensus Status:

Consensus. (Excluding enforcement mechanism)
Supported by: PG&E, SCE, SoCalGas, CSE, ORA, CESA, CalSSA, CPS, AMS, Stem, Tesla, Avalon
Opposed by: N/A

Proposal description:

PBI projects (30 kW and greater) will continue to receive incentives as currently outlined in the SGIP Handbook, meaning that 50% of the incentive will be paid up front and the remaining 50% will be paid over a five-year period based on meeting an annual cycling requirement. Additionally, PBI projects' GHG performance will be calculated from the projects' monthly performance data. The SGIP will not prescribe how PBI projects must reduce GHG emissions; each project is given "optionality" to decide how it will achieve this goal. While the GHG Signal will be made available to all projects, the SGIP PAs will not require that projects receive and/or follow the signal. Achieving a specific annual round trip efficiency will no longer serve as a proxy for GHG reductions and will not be a GHG verification metric or program requirement.

Calculating monthly GHG impacts will be an automated process built into the SGIP database and will use the real-time GHG Signal marginal emissions for each 15-minute interval (averaged from the 5-minute real-time signal) to calculate monthly net GHG impacts. With GHG impacts made available monthly, SGIP PAs will have the ability to monitor projects throughout the year and work with projects that are not reducing GHG emissions. Projects that do not reduce GHG emissions for a given month will receive a notice from the SGIP database alerting the project of its performance.[26] At the end of a project's 12-month data submission, the net GHG emissions for the entire year will be calculated and determined. It is essential that the compliance determination be done on an annual basis because systems may be operated differently in summer and winter.

Supporting discussion

Opposing discussion

Model Findings Support:

Model findings generally support this proposal; the lack of an annual RTE requirement is appropriate given that it is a model output without a causal influence on GHG impacts, and a minimum number of cycles per year could be beneficial but is not necessary and would not guarantee GHG benefits. Availability of a GHG signal is crucial and, assuming verification and enforcement are effective, projects will most likely utilize the signal to achieve GHG reductions.

AESC Recommendations:

We recommend that the SGIP provide a GHG signal for project developers to optionally utilize to control their energy storage systems, so they are GHG reducing. In addition, the annual RTE requirement should be eliminated and the number of required annual cycles should remain at the current 130 cycles. This is supported by the modeling results. Verification of GHG performance, based on historical 5-min RT GHG signal, of projects and fleets should be reported monthly for feedback purposes for the project developer and SGIP PAs.

New PBI Proposal 1(a):

- *Operational Requirement:* Same as Proposal 1.
- *Verification Mechanism:* Same as Proposal 1.
- *Enforcement Mechanism:* No automatic loss of PBI incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions at a project level.
    - SGIP PAs can determine if a project or developer warrants a warning or an infraction based upon project performance
    - SGIP PAs have the ability to withhold payment or assign other infractions, as deemed necessary.
    - Project-level enforcement would be only during PBI payment period; after that the project would switch to fleet-level compliance (assuming that period is 5 years after PBI payments are complete).

Consensus Status:

Non-consensus.
Supported by: PG&E, CESA, CPS, AMS, Stem, Avalon
Opposed by: SCE, SoCalGas, CSE, ORA, CalSSA

[26] Note that high volume providers will want the ability to select a separate email address for these notices to avoid excessive messages to the main contact email during winter months for systems with winter rates that are more misaligned with GHG hours.

Proposal description:
Same as Proposal 1.

Supporting Discussion:
- Easy to implement
- Provides discretion to PAs to determine on a case-by-case basis whether a given developers activities merit punitive action

Opposing Discussion:
- Does not provide a clear economic incentive or signal that developers or customers can respond to and thus may have only limited impact on system dispatch/operations resulting in GHG reduction.
- Use of warnings and infractions on individual projects that do not reduce GHG emissions could run counter to the other SGIP goals – market transformation and grid services.
- The Handbook would have to be revised to include explicit guidelines for how the PAs would determine when and how to issue warnings and infractions.
- This approach is not compatible with a fleet compliance structure where under-performing project performance can be offset with over-performing projects.
- Warnings and infraction mechanism has been arguably ineffective so far (since the program has witnessed GHG emissions) and enforcement has consumed a lot of PA and Developer time. A less onerous mechanism is preferable.
- Loss of a portion of PBI money should be mandatory if GHG reductions are not met. A case by case basis left to the PAs discretion creates uncertainty and risk for all parties involved.

Model Findings Support:
Same as Proposal 1.

AESC Recommendations:
We do not recommend using the infraction mechanism alone as a path to encouraging GHG reductions because it is not enough economic incentive. The infraction process is already in place and GHG emissions have been identified as an issue by Itron. Another economic incentive is needed.

New PBI Proposal 1(b):
- *Operational Requirement:* Same as Proposal 1.
- *Verification Mechanism:* Same as Proposal 1.
- *Enforcement Mechanism:*
    - Projects will lose a portion of the annual PBI payment for increasing GHG emissions
    - The forfeited payment will return to the SGIP incentive budget
    - The forfeited payment will be calculated by multiplying the net CO_2 emissions increase over the year by a specified $/kilogram penalty. The penalty could be calculated by using a 4x multiple of the California Cap and Trade price of carbon at the time in which the project applied to the program
    - Alternatively, the forfeited payment could be calculated by multiplying the net CO_2 emissions increase over the year by the Societal Cost of Carbon which was recently established in the IDER proceeding (R.14-10-003) to include the full impacts of carbon pollution, including environmental externalities, which is currently $69.50 per ton.

Consensus Status:
Non-consensus.
Supported by: PG&E, CSE, CESA, CalSSA, CPS, AMS, Tesla, Avalon
Opposed by: SCE, SoCalGas, ORA, Stem

Proposal description: Same as Proposal 1.

Supporting Discussion:
- The proposed level of the penalties should have a cap so that, if the carbon price increases dramatically, developers will not be subject to penalties that exceed 10% of their PBI incentives.
- The combination of loss of performance incentives and appropriate compensation should be sufficient to deter developers from directing ratepayer funds to projects that increase GHG emissions.
- Tying the GHG penalty to an existing California standard, such as Cap and Trade or Social Cost of Carbon, reflects how the State views the price of carbon. This would keep SGIP GHG penalties consistent with other State-sponsored metrics.
- Appears fair in that this approach penalizes projects based on a reasonable estimate or proxy for the harm caused should a project increase emission.
- Provides a way of balancing the various objectives of the program by explicitly factoring GHG emissions impacts into the incentive framework.

Opposing Discussion:
- Does not provide enough of an economic incentive or signal that developers or customers can respond to and thus may have only limited impact on system dispatch/operations resulting in GHG reduction.
- Increases the complexity of the PBI payment calculation.
- Ratepayers would be unreasonably burdened if required to fund performance incentives for projects that increase GHG emissions.

- Artificially inflating the moving target of the California Cap and Trade price of Carbon to bring it in line with what we think is a more appropriate value is bad policy.
- This amounts to double-dipping – a customer would lose a portion of the incentive and be liable for a penalty, both of which are based on a $/ton of carbon. This makes little sense and sets a bad precedent.

Model Findings Support:

Same as Proposal 1.

AESC Recommendations:

We do not recommend using the cost of carbon to determine the penalty for increasing GHGs. We feel this would add complexity to the program and would not give enough economic incentive for GHG reduction, and the modeling results did not show improved GHG reduction. There is significant disagreement if the penalty should be a multiple of the cost of carbon or just the cost of carbon.

New PBI Proposal 1(c):

- *Operational Requirement:* Same as Proposal 1.
- *Verification Mechanism:* Same as Proposal 1.
- *Enforcement Mechanism:*
    - Forfeited funds return to the SGIP incentive budget
        - "Exceedance bands" would determine how much the incentive would be reduced, similarly to what currently exists for generation projects
    - The exceedance bands would be based on the amount of CO_2 emitted per the rated kWh of the project.
    - The exceedance bands would reduce the annual PBI payment by 5%, 10%, or 25% depending on the level of CO_2 emitted per kWh

Consensus Status:

Non-consensus.

Supported by: SCE, SoCalGas, CSE, Tesla, Avalon

Opposed by: PG&E, ORA, CESA, CalSSA, CPS, Stem

Proposal description: Same as Proposal 1.

Supporting Discussion:

- Relative easy to implement – can leverage existing data submission requirements to evaluate GHG impacts and associated reduction in PBI payments.
- Allows the penalty (in the form of reduced PBI payments) to be set at a level that reasonably balances the GHG objectives of the program with other program goals.
- Provides a clear economic signal that developers/customers would be able to factor into their dispatch decisions.
- Provides developers maximum flexibility to determine for themselves how to reduce their exposure to penalties (e.g. some might choose to actively co-optimize dispatch using a GHG signal, others may simply decide to only charge during certain times, etc.).
- This proposal has merit and bears further investigation if an appropriate level for the exceedance bands is determined, along with the PBI payment reduction.
- Basing exceedance bands on standard deviations of the spread of project GHG emission increases would provide a rational justification for each exceedance band level.

Opposing Discussion:

- Depending on the level of the penalty and sensitivity thereto, there is no guarantee under this approach that storage systems will be operated in a way that reduces GHG emissions.
- Difficult to implement because it would require a process to create the exceedance bands. It would be difficult to get the numbers right.
- Ratepayers would be unreasonably burdened if required to fund performance incentives for projects that put too much priority on grid support and fail to meet minimum GHG performance standards and increase GHG emissions.

Model Findings Support:

Same as Proposal 1.

AESC Recommendations:

We favor the use of exceedance bands, but would reduce the band to one level, any GHG production during the year would result in a penalty. This would be straightforward to implement and it would be clear what percent of the PBI payment is at risk. We recommend that projects or fleets, if fleets are implemented, that increase GHG emissions should lose 25% of their incentive. Allowing multiple exceedance bands provides for a gradual penalty, but could risk program wide increases in GHGs.

New PBI Proposal 1(d):

- *Operational Requirement:* Same as Proposal 1.
- *Verification Mechanism:* Same as Proposal 1.
- *Enforcement Mechanism:*
    - For projects that increase GHG emissions, the full PBI incentive for that year would be forfeited.

- An additional penalty in the form of a multiple factor of California Carbon Allowance prices would be applied.
- Any developer/vendor that is found to have its fleet of projects increase GHGs overall during a program year will be barred from applying for SGIP incentives for future projects for a specified period of time.

Consensus Status:

Non-consensus.

Supported by: ORA

Opposed by: PG&E, CSE, CESA, CalSSA, CPS, AMS, Stem, Tesla, Avalon

Proposal description:

Same as Proposal 1.

Supporting Discussion:

- Would ensure that no ratepayer funds go to any large, new storage projects that are found to increase GHG emissions in any year
- Provides a meaningful financial deterrent to ensure developers comply with program mandates to reduce GHG emissions
- Provides for a mechanism to increase deployment of SGIP funded GHG reducing energy storage systems through penalties collected from GHG increasing energy storage systems
- Ensures that the "reduce GHGs" goal of SGIP is prioritized along with the other goals of grid support and market transformation, the last of which has thus far received the most attention. For California and ratepayers, it is paramount to see reduced GHGs, not just a lack of an increase of GHGs. This is a very big stick option that developers would respond to.

Opposing Discussion:

- Doesn't support the objective of the SGIP program which is to provide incentives to encourage the deployment of new demand side energy resources including storage, which provide multiple benefits to customers, the grid and to ratepayers, and which are critical for ensuring the State meets its climate goals.
- Would likely undermine the finance-ability of energy storage projects, limiting the ability of SGIP incentives to support investment in energy storage.
- Appears unduly punitive to the degree any developer would not only have to forfeit their PBI payments for the year should a system be found to be GHG increasing, but they would also be subject to an additional penalty and potentially be barred from the program. Developers are unlikely to want to participate in the program under these conditions.
- Subordinates the other goals of the program, including market transformation and grid services, to the objective of reducing GHG emissions.
- The reason projects have failed to meet GHG reduction is that they have focused on reducing customer peak demand. Reducing customer peak demand has been a long-time goal for the purpose of benefitting ratepayers. Non-coincident demand charges are an intentional price signal to encourage the very behavior that storage customers have been engaging in.

Model Findings Support:

Same as Proposal 1.

AESC Recommendations:

We do not support eliminating all of the PBI payment based on when a system is GHG producing. This would ignore the other benefits that energy storage provides that are objectives of SGIP.

New PBI Proposal 2: GHG PBI

Operational Requirement:

Under this proposal, the CPUC would set a target for the GHG reductions energy storage systems should deliver. One target to consider, using existing SGIP mechanisms, would be to use cycling requirements to calculate kWh and then calculate GHG reductions based on the existing biogas requirements generation is required to meet, as biogas can be seen as GHG free fuel. This would allow a target for energy storage to strive for, while allowing flexibility in how the system is operated. The GHG reductions expected are seen in the table below.

Challenge: GHG signal is being developed to aid energy storage systems in reducing GHGs. However, the old performance based metric was paid out on kWh and cycling requirements, which may not fit with the new GHG signal being developed.

	2017	**2018**	**2019**	**2020**
GHG Target (kg/MWh)	347	344	340	337
Biogas %	10%	25%	50%	100%
GHG Reduction (kg/MWh)	34.7	86	170	337

Using a 1 MW commercial system as an example, it is required to discharge 130 times. Using that number, the minimum expected hours can be calculated. For example, a 2-hour energy storage system would need to discharge 2 hr x 130 = 260 hrs. Using this we can calculate the GHG targets for each energy storage system hour.

	2017 Reductions (kg/MW)	2018 Reductions (kg/MW)	2019 Reductions (kg/MW)	2020 Reductions (kg/MW)
1 hr	4,511	11,180	22,100	43,810
2 hr	9,022	22,360	44,200	87,620
3 hr	13,533	33,540	66,300	131,430
4 hr	18,044	44,720	88,400	175,240
5 hr	22,555	55,900	110,500	219,050
6 hr	27,066	67,080	132,600	262,860

These numbers can be tied to the existing incentives for energy storage. Using Large Storage, Step 1 as an example, the incentives would be $500/kWh. For a 2 hr, 1 MW energy storage system,

- The max incentive would be 1000 kW x 2 hr x $500/kWh = $1,000,000.
- The expected GHG reductions in 2018 would be 86 kg / MWh x 1 MW x 2 hr x 130 cycles = 22,360 kg CO2.
- Therefore, the storage system would be paid $1,000,000 / 22,360 kg CO2 = $44.72 / kg CO2.
- Using this number, the developers can design their system, find their expected CO2 and decide if the incentive is worth it. For example, a developer chooses a project that, after optimizing for a customer, would provide 15,000 kg CO2 reduction.
- Their maximum incentive would be 15,000 kg CO2 x $44.72 = $670,800.
- Assuming PBI stays the same (50/50), the PBI can be paid out on a kg/CO2 basis.
- Continuing the example of the 2 MWh energy storage system, the at-risk incentive is $335,400.
- Yearly incentive = $335,400 / 5 = $67,080.
- PBI is calculated using $67,080 / 22,360 kg CO2 = $3 / kg CO2.
- At the end of the year, if the project reduces 14,000 kg CO2, it is paid ***$3 x 14,000 = $42,000.***

<u>Comparison</u>: While this may pose some difficulties for energy storage now having to meet targets, through the SGIP program, energy storage will still be paid a premium compared to generation.

- For a 1 MW Generation system, using 2018 numbers
    - Generation is required to operate 1MW x 24 x 7 x 52 x .80 = 6,989 MWh.
    - GHG Reductions will be 6,989 MWh x 86kg/MWh = 601,054 kg CO2.
    - Incentive for a 1 MW system is ***$600/kW x 1000kW = $600,000.***
    - The at-risk incentive is $600,000*50% = $300,000
    - Paid out over 5 years this is $60,000/year
    - Cost per GHG reduced = $60,000 / 601,054 = $0.1/ kg CO2
- For a 6 hr, 1 MW energy storage system, using 2018 numbers and a Step 5 incentive,
    - Incentive (1000kW x 2hrs x $250/kWh) + (1000kW x .5 x 2hrs x $250/kWh) + (1000kW x 25% x 2hrs x $250/kWh) = $500,000 + $250,000 + $125,000 = $875,000
    - The at-risk incentive is $875,000*50% = $437,500
    - Paid out over 5 years this is $87,500/year
    - GHG target = 67,080 kg CO2
    - Cost per GHG reduced = $87,500 / 67,080 = $1.30/kg CO2 reduced
- Generation = $0.1/kg CO2 reduced
- Energy Storage = $1.30/kg CO2 reduced

Verification Mechanism: Verification can be done through adherence to the GHG signal.

Enforcement Mechanism: PBI, as now payments would be made after verifying GHG reductions.

Consensus Status

Supported by: SoCalGas

Opposed by: PG&E, CSE, CalSSA, CPS, AMS, Stem, Tesla, Avalon

Supporting Discussion:

- Ensures that SGIP incentives are only provided to projects that reduce GHG emissions.

Opposing Discussion:

- Subordinates the other goals of the program, including market transformation and grid services, to reducing GHG emissions. The finance-ability of this incentive structure is unknown. Unclear how many projects or developers would be able to reasonably anticipate the kg of GHGs their projects would reduce and that the resulting amount of incentive they would be eligible for would be sufficient to motivate deployments. This appears to put this approach at odds with the market transformation and grid services goals of the program.
- SGIP is already a complicated program for participants to deal with. To achieve market transformation, we need to get more companies to participate, not limit it to a few companies that are willing to tolerate major regulatory complexity. Requiring a developer to first determine how much GHG is likely to be reduced in order to calculate the incentive level is not reasonable. This proposal would discourage companies from getting involved in storage and would discourage customers from installing storage.
- Would violate the principle of simplicity. Getting the numbers right on this proposal would take a lot of work and create turmoil in the program. Reinventing the incentive structure yet again with two years left in the program would be harmful.
- This fails to recognize the multiple program goals. The reason some installations have a challenge meeting the GHG goal is that they are focused on reducing peak demand on local circuits, which has ratepayer benefits. It is not realistic to go above and beyond the goals for GHG and demand reduction and market transformation.

Model Findings Support:

The model findings do not support the operational requirements, as they are based on implementing a cycling requirement. Model results did not show that a cycling requirement would necessarily result in GHG reductions. Despite apparent correlation, there was no evidence of causality between cycling and GHG benefits.

AESC Recommendations:

We do not support development of a GHG PBI that is based on SGIP generation eligibility rules. This proposal has limited support. While it can be desirable to develop GHG rules that bring generation and energy storage into harmony, we feel this would complicate GHG calculations for energy storage, and does not, by itself, suggest a path to improved energy storage GHG reduction in the program.

New Non-PBI/Non-Res Projects

There was broad agreement, but not consensus, within the Working Group that non-residential projects up to 30 kW projects should move to a PBI-like structure PBI <30 kW, where part of their SGIP incentive is paid out over multiple years. However, there were varied suggestions on how much should be paid up front and how long the extended period should be.

New Non-PBI/Non-Res Proposal 1: PBI <30 kW

- *Operational Requirement:* PBI-like rules for non-residential projects <30 kW. No annual RTE requirement. GHG signal available but not required to use.
- *Verification Mechanism:* GHG impact calculated monthly for feedback and annually for compliance using PBI data and historical GHG signal. Non-revenue meters allowed.
- *Enforcement Mechanism:* Multiple approaches outlined in the following proposals.

Consensus Status:

Consensus. (Excluding enforcement mechanism)
Supported by: PG&E, SCE, SoCalGas, CSE, ORA, CESA, CalSSA, CPS, Stem, Avalon
Opposed by: N/A

Proposal description:

Move non-residential projects <30 kW to PBI-like rules, where part of their SGIP incentive is paid out over multiple years. There was apparent consensus that paying remaining PBI funds at 10% per year was a reasonable compromise between "keeping skin in the game" and the added difficulty of obtaining financing. The Working Group has proposed for this class of projects three options: 50% up front and 50% paid over 5 years based on GHG performance; 70% up front with 30% paid over 3 years (10% available per year); 80% up front with 20% paid over 2 years. The payment and enforcement options provided by Parties are described below.

Supporting Discussion:

Opposing Discussion:

- Deemed is the only path that is administratively simpler and more cost effective than a PBI <30 kW path.

Model Findings Support:

Model findings generally support this proposal; the lack of an annual RTE requirement is appropriate given that it is a model output without a causal influence on GHG impacts, and a minimum number cycles per year could be beneficial but is not necessary and would not always guarantee GHG benefits. Availability of a GHG signal is crucial and, assuming verification and enforcement are effective, projects will most likely utilize the signal to achieve GHG reductions.

AESC Recommendations:

This proposal, excluding the enforcement mechanism, has broad support among the WG members. We recommend that the program do away with 100% upfront incentives for new <30kW non-residential and adopt this modified PBI approach, which would make available a GHG signal and eliminate the RTE requirement.

New Non-PBI/Non-Res Proposal 1a: PBI<30 kW

- *Operational Requirement:* Same as proposal 1 PBI <30 kW.
- *Verification Mechanism:* Same as proposal 1 PBI <30 kW.
- *Enforcement Mechanism:* Same as PBI; 50% upfront incentive, 50% performance based incentive. This is 10% available for pay out over 5 years. Where a project is determined to increase GHG emissions, the developer will also pay for any GHG emissions associated with a project, in addition to forgoing their PBI incentives in a given year.

Consensus Status:

Non-consensus.
Supported by: SCE, ORA
Opposed by: PG&E, CSE, CESA, CalSSA, CPS, Stem, Avalon

Proposal description: Same as proposal 1 PBI<30 kW.

Supporting Discussion:

- According to the 2016 Itron evaluation of SGIP storage projects, nonresidential projects that received 100% of their incentives upfront were associated with greater GHG emissions per rebated capacity than PBI projects.
- In order to deter developer gaming, the size of compensatory payments should be sufficient to align developer and ratepayer interests in reducing GHG emissions.
- Proposed compensation structure would mitigate the risk ratepayer dollars will be used to fund projects that may not meet all program requirements.
- Any proposal that gives 70-90% of incentives upfront to such projects puts ratepayer funds at risk by assuming that 1) projects would perform according to program requirements and 2) developers do not determine that other financial incentives are more valuable than the 10-30% of remaining SGIP incentives.

Opposing Discussion:

- The financial impact of this proposal to smaller projects (≤30 kW) is significant and will reduce the number of projects that can be deployed. Small projects will not be financeable if they only receive 50% of the incentive upfront.
- Proponents of this approach cite the Itron backward-looking evaluation rather than the forward-looking modeling that is the subject of this working group.
- This proposal makes incentive payments based entirely on GHG reductions and thus ignores the other goals of the SGIP.
- This could make financing smaller systems in disadvantaged communities quite difficult, given the long and uncertain payment of incentive funds. This is in direct contradiction of the SGIP's recently established Equity Budget to support storage in disadvantaged communities.

Model Findings Support:

Same as proposal 1 PBI <30 kW.

AESC Recommendations:

We do not support this proposal primarily because we believe that project financing for smaller projects is more difficult. We do recognize that this project class was evaluated by Itron to have particularly poor GHG emissions, but we believe that going from 100% upfront incentives to 50% is too drastic of a change and may result in greatly reduced participation.

New Non-PBI/Non-Res Proposal 1b: PBI<30 kW

- *Operational Requirement:* Same as proposal 1 PBI <30 kW.
- *Verification Mechanism:* Same as proposal 1 PBI <30 kW.
- *Enforcement Mechanism:* Same as PBI; 70% upfront incentive, 30% performance based incentive 10% available for pay out over 3-years. Where a project is determined to increase GHG emissions, the PBI incentive will be reduced according to PBI rules for >= 30 kW projects.

Consensus Status:

Non-consensus.
Supported by: PG&E, SCE, CSE, Avalon
Opposed by: SoCalGas, ORA, CESA, CalSSA, CPS, Stem

Proposal description: Same as proposal 1 PBI <30 kW.

Supporting Discussion:

- This scheme involves the right amount of disincentive (30%) for poor performance.
- The 10% per year payout has enough incentive per year to cover any feebate reductions (if that proposal is accepted), and leaves enough money at risk to incent good behavior on other performance metrics.

Opposing Discussion:

- Withholding 30% for future years with payments at risk will make financing very difficult and more expensive, resulting in fewer projects in this size range.
- This is especially restrictive for smaller, less expensive projects that provide customer bill savings, particularly in disadvantaged communities which is supported by recent SGIP changes that allocate a portion of the funds, the equity budget, for projects that serve these communities.

Model Findings Support:

Same as proposal 1 PBI <30 kW.

AESC Recommendations:

We believe that 30% of the incentive withheld for PBI, paid out over three years, is a good compromise for these smaller projects, and, while this was not directly modeled, provides enough economic incentive to perform according to program rules. It is unclear to us if lower cost systems targeting disadvantaged communities would be impacted as suggested in the opposing comments.

New Non-PBI/Non-Res Proposal 1c: PBI <30 kW

- *Operational Requirement:* Same as proposal 1 PBI <30 kW.
- *Verification Mechanism:* Same as proposal 1 PBI <30 kW.
- *Enforcement Mechanism:* Same as PBI; 80% upfront incentive, 20% performance based incentive 10% available for pay out over 2-years. Where a project is determined to increase GHG emissions, the PBI incentive will be reduced according to PBI rules for >30 kW projects.

Consensus Status:

Non-consensus.
Supported by: CSE, CESA, CalSSA, CPS, Stem, Avalon
Opposed by: PG&E, SoCalGas, ORA

Proposal description: Same as proposal 1 PBI<30 kW.

Supporting Discussion:

- The 10% per year payout has barely enough incentive per year to cover any feebate reductions (if that proposal is accepted) and leaves enough money at risk to incent good behavior on other performance metrics.
- This supports financing of smaller projects at favorable terms, supporting both the market transformation goal and the SGIP focus on disadvantaged communities, where smaller projects might be deployed and where financing may be more challenging.

Opposing Discussion:

- A 20% or lower PBI payment is easily forfeitable by the developer, leaving ratepayers at risk.
- Withholding 20% for future years with payments at risk will make financing very difficult and more expensive, resulting in fewer projects in this size range.
- This is especially restrictive for smaller, less expensive projects that provide customer bill savings, particularly in disadvantaged communities which is supported by recent SGIP changes that allocate a portion of the funds, the equity budget, for projects that serve these communities.

Model Findings Support:

Same as proposal 1 PBI <30 kW.

AESC Recommendations:

We believe that 20% of the incentive withheld for PBI, paid out over two years, is too little an economic incentive to encourage good performing systems. With 80% of the incentive provided upfront, we feel it a possibility that some projects may choose to forgo the 20% PBI payment.

New Non-PBI/Non-Res Proposal 2: Deemed Compliance

- *Operational Requirement:* 85% SCRTE, agreement to follow GHG signal.
- *Verification Mechanism*: 1) Up-front SGIP PA review of the application to verify the system has a single cycle round trip efficiency of at least 85%; 2) confirmation that the developer has signed an affidavit promising a to follow the GHG Signal; 3) quarterly monitoring reporting; and 4) random selection for inspection (akin to the SGIP Inspection Sampling Protocol which is in effect now).
- *Enforcement Mechanism:* No claw back of incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions
    - SGIP PAs can determine if a project or developer warrants a warning or an infraction based upon project performance

Consensus Status:

Non-consensus.
Supported by: SoCalGas, CESA, CalSSA, CPS, Avalon
Opposed by: PG&E, SCE, CSE, ORA, Stem

Proposal description:

A deemed project eligibility approach, that allows >30 kW projects to receive upfront incentives, as an alternative to PBI.

Supporting Discussion:

- Avoids the at-risk portion of a PBI structure.
- Provides for performance monitoring, with consequences for out of compliant systems
- This avoids the need for a new PBI mechanism for projects that are currently non-residential and non-PBI would require a large effort for a small capacity and possibly higher costs that were not envisioned by original budgets.
- Deemed eligibility provides a solution that is most consistent with policy, and prevents a programmatic change that would now provide incentives that induce or monitor a customer’s change in behavior, similar to how demand response programs operate.

- This approach avoids withholding incentives. Small businesses typically have very tight budget constraints, and have very limited funding access – even more so than residential. Forcing these projects to withhold ANY portion of payments would kill that segment of the industry.

Opposing Discussion:

- According to the 2016 Itron evaluation of SGIP storage projects, nonresidential projects that received 100% of their incentives upfront were associated with greater GHG emissions per rebated capacity than PBI projects.
- Of the 436 nonresidential projects ≤30kW awarded SGIP incentives to date, 177 (41%) have capacity of 28kW or greater and 93 (21%) have capacity of 29.5kW or greater, suggesting that some developers may be designing their systems to fit into the less stringent incentive scheme. This proposed approach will allow this to continue.
- This proposal should include more specifics that follow the model results, such as a requiring solar and new rate.
- Determining that a project has "followed a GHG signal" is fraught with difficulties; developers are unwilling to share their optimization code and it is impossible to determine after the fact whether a project's operation "followed a signal".
- This is essentially the same as PBI proposal 1 (a) except with only random selection for inspection so most projects would get off scot-free.
- This could lead to developers gaming the system to receive SGIP funding when they may not be able to comply. It is difficult to predict marginal GHG emissions 5 – 10 years out with any certainty, or changes in customer loads, equipment or load profiles that could affect the ability of a system to produce GHG savings. Developers taking this route are not subject to clawback, meaning other developers who could receive penalties or reductions in PBI payments would be at a competitive disadvantage, and the pool of available funding for future SGIP projects could be permanently reduced from "deemed compliant" systems that don't actually reduce GHG emissions, yet receive SGIP incentives.

Model Findings Support:

The model findings support this proposal, with some significant caveats. Model findings suggest that these operational requirements are highly likely to result in GHG benefits, provided that the following additional requirements are imposed: 1) residential projects should either be on new rates or paired with solar (or both), and 2) commercial systems should always be paired with solar.

AESC Recommendations:

We do not recommend a deemed pathway for <30 kW non-residential systems. This is similar to existing program rules, which also have an infraction mechanism and process – which did not deter these systems from performing poorly. We do not feel that "staying the course" would help the situation.

New Residential Projects

New Res Proposal 1: Deemed Compliance

All residential proposals are to comply with current SGIP program requirements unless specifically changed in the following proposals. The different options provide a menu from which residential projects may choose to demonstrate that they will be operated in a way that modeling has shown will likely reduce GHG emissions. The different options try to cater to different storage and/or rate configurations. Upon submitting the Reservation Request Form, projects must select which option they will follow and verify this at the Incentive Claim stage. Residential projects can switch between different options during the lifetime of the project without needing to inform Program Administrators as long as the projects are still operated in ways that reduce GHG emissions. For example, a system that is deployed by a customer who is taking service under new rates, and where the system is primarily charged from solar, has an SCRTE of at least 85% and is subject to a 52-cycle requirement can be safely assumed to reduce GHG emissions regardless of whether the system is placed in solar self-consumption mode or TOU bill management mode. Thus, customers should be allowed to switch between these modes at will while still being eligible for the deemed compliant approach.

Operational Requirement: One of the following options.

Option 1: Solar-plus-Storage

- New rates – any rate schedule with peak period starting at 3 pm or later
- Minimum ITC compliant; currently 75%
- Cycling – remain at 52
- 85% SCRTE

Option 2: Solar-plus-Storage

- Time constraint; no charge 4-9pm
- Minimum ITC compliant; currently 75%
- Cycling – remain at 52
- 85% SCRTE

Option 3: Solar-plus-Storage

- Solar self-consumption mode (programmed to maximize amt of solar consumed onsite) Minimum ITC compliant; currently 75%
- Cycling – remain at 52
- 85% SCRTE
- New rates

Option 4: Solar-plus-Storage

- GHG Signal co-optimization; obligatory [Is this agreeing to an operating mode?]
- Minimum ITC compliant; currently 75%

- Cycling – remain at 52?
- 85% SCRTE

Option 5: Solar-plus-Storage

- 100% solar charging
- New Rates
- Cycling – remain at 52

- *Verification Mechanism:* 1) Up-front SGIP PA review of the application; 2) confirmation that the developer has signed an affidavit promising a specific configuration and/or rate; 3) random selection for inspection (akin to the SGIP Inspection Sampling Protocol which is in effect now). Residential discharge data (statistically significant sampling by Itron) would be pulled for the Energy Storage Impact Analysis and assessed for compliance.
- *Enforcement Mechanism:* No clawback of incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions
    - SGIP PAs in coordination with Energy Division, can determine if a project or developer warrants a warning or an infraction based upon project performance

Consensus Status:

Non-consensus.
Supported by: PG&E, SCE, SoCalGas, CSE, ORA, CESA, CalSSA, CPS, Tesla, Avalon
Opposed by: N/A

Proposal description:

The deemed approach is an effort to establish GHG compliance in the application process and to simplify GHG compliance for hundreds or potentially thousands of residential applications. Projects would be deemed compliant with SGIP rules if one of the previously listed operational requirements exist.

Supporting Discussion:

- Although residential projects make up a significant number of projects, in terms of total capacity and incentives paid they represent a relatively small share of the incentive budget, suggesting that a less administratively onerous/complicated approach to compliance is reasonable.
- Relatively straightforward to implement with limited administrative costs.
- Provides reasonably sufficient certainty that participating projects will reduce GHG emissions
- Preserves provision of incentives on an upfront basis, which is critical for this customer segment, both in terms of the willingness of customers to participate in the program but also avoiding the significant administrative costs that would be incurred if residential systems were subject to a PBI type incentive structure.
- In support of Option 3, if storage is operated in conjunction with solar in either a mode that only charges from solar or a mode that maximizes use of storage discharges for on-site load and the customer is on new rates, it is certain that the battery is performing load shifting in ways that reduce GHG emissions.

Opposing discussion:

- This approach does not address the residential energy storage backup problem that was identified in the 2016 Itron Energy Storage Impact Analysis. This is out of compliance with program rules; backup-only systems of any size or technology are ineligible for SGIP incentives.
- Oppose the 52-cycle minimum. Push to 100 and get more GHG reduction from the fleets.
- This rule change is not needed. New residential TOU rates, with later on-peak periods, are available. If a customer is on new rates and cycles the battery regularly there is very high assurance that the system will be discharging during peak hours
- Limits project/customer options/flexibility to the extent they are subject to upfront prescriptive requirements and applications

Model Findings Support:

The model findings do not support Options 2 (no-charging time constraints were not found to have significant impacts on GHG emissions) or 5 (in this case, a non-co-optimizing system with 70% SCRTE is expected to reduce GHGs only 50% of the time, and the 100% solar charging attribute was not modeled). The other options were all supported by the model findings; those sets of conditions all consistently resulted in GHG benefits.

AESC Recommendations:

We recommend a deemed pathway for new residential systems, but only for options 1, 3, and 4. We do not support options 2 or 5 because these options failed to show little GHG reduction potential in the modeling results. We share the concern that this approach may not address the backup operating issue identified by Itron. However, we believe that for these systems, a PBI-like approach would both be a burden for the program and decrease program participation. We do encourage GHG reduction reporting for both the Program Administrator's and customer's benefit. The Program Administrator could exercise the infraction mechanism for poor performing systems. We do support the availability of a GHG signal, but its use would be optional under this proposal.

New Res Proposal 2: Non-Deemed Compliance

Residential projects not able to meet the deemed compliance requirements must meet one of the following options:

- *Operational Requirement:* One of the following options.

Option 1: Resi @ 70% RTE

- Solar + Storage mandatory
- New rates

- Discharge 52/yr
- Reporting requirement

Option 2: Resi Stand-alone

- 70% SCRTE
- New rates
- GHG Signal co-optimization; obligatory (applicant will have to present information to PAs that demonstrates ahead of time that the dispatch algorithm will cause the storage system to react appropriately in response to the GHG Signal).
- Reporting requirement

Option 3: Resi Stand-alone

- 85% SCRTE
- New rates
- Discharge 52/yr
- Charge only 8am-4pm
- Reporting requirement

- *Verification Mechanism:* 1) Upfront SGIP PA review of the application; 2) confirmation that the developer has signed an affidavit promising a specific configuration and/or rate; 3) quarterly reporting of GHG performance; 4) random selection for inspection (akin to the SGIP Inspection Sampling Protocol which is in effect now). Residential discharge data (statistically significant sampling by Itron) would be pulled for the Energy Storage Impact Analysis and assessed for compliance.
- *Enforcement Mechanism:* No clawback of incentive; SGIP PAs use existing Handbook infraction language to enforce GHG reductions
  - SGIP PAs can determine if a project or developer warrants a warning or an infraction based upon project performance

Consensus Status:

Non-consensus.
Supported by: SoCalGas, CSE, ORA, CESA, CalSSA, CPS, Avalon
Opposed by: PG&E, SCE, Tesla

Proposal description:

The non-deemed is similar to the residential deemed approach, but requires GHG signal co-optimization and performance monitoring and quarterly reporting. Also unlike the deemed compliance approach, should a project be found to increase GHG emissions, the developer may be found out of compliance and subject to infractions.

Supporting Discussion:

Opposing discussion:

- Time constraints were found to be inconclusive on whether or not they would reduce GHGs, therefore they should not be an option for standalone residential storage.

Model Findings Support:

Model findings don't support Option 1 strongly because this option has a weak case of 70% SCRTE coupled with No GHG signal, giving reductions only 50% of the times, cannot comment on the reporting benefits based on modeling results. Model findings support Option 2, as co-optimizing residential standalone projects on new rates reduced GHGs in 100% of model runs for both 70% and 85% SCRTEs. Option 3 is not supported by modeling results since such a scenario was not modeled.

AESC Recommendations:

We support a non-deemed compliance path for new residential projects that do not meet the deemed compliance requirements but only for options 1 and 2 as these were definitively supported by the modeling findings. The non-deemed compliance approach provides additional flexibility for new residential projects for SGIP participation beyond the deemed requirements. We would recommend that for option 2, model results be provided, before project installation, to the Program Administrator to ensure that GHGs will be reduced. The model used could be proprietary to the developer, which should be vetted under NDA by a third party, or a public model be made available and used.

Working Group Recommendations for Legacy Projects

Legacy PBI

Legacy PBI Proposal 1: Opt-in to revised future PBI project rules

- *Operational Requirement:* Opt-in to revised future PBI project rules, which may reduce cycling and eliminates the annual RTE requirement.
- *Verification Mechanism:* Same as revised future PBI project rules.
- *Enforcement Mechanism:* Same as revised future PBI project rules.

Consensus Status:

Non-consensus.
Supported by: PG&E, CSE, CESA, CalSSA, CPS, AMS, Stem, Tesla, Avalon
Opposed by: SCE, ORA

Proposal Description:

This proposal would permit existing projects to voluntarily opt-in to the same rules as will be applied for future PBI projects for the remaining portion of their PBI period. Depending on the specific revised rules for future PBI projects that are adopted, the legacy projects would enjoy relaxed cycling and eliminate RTE requirements while accepting a more rigorous GHG verification and reporting process and the risk of reduced PBI payments.

Supporting Discussion:

Opposing Discussion:

Model Findings Support:

GHG signal co-optimization was found to generally improve the GHG impact (by achieving GHG reduction for more model runs and also giving higher mean GHG reduction in kg/kWh) compared to its No GHG Reduction Solution counterpart for all the scenarios modeled. So, the developers having access to such a signal with a GHG-reducing incentive can help the program achieve its GHG reduction goals, according to overall model findings. While this is clear in an aggregate sense, the support is not unanimous among all modelers, and some strongly disagree.

AESC Recommendations:

We support providing an opt-in to new project PBI rules for legacy PBI projects. We believe that the potential for cycling relief and RTE elimination would encourage legacy PBI systems to opt-in to the new PBI rules thus increasing GHG reduction compliance.

Legacy <30kW Non-Residential Projects

Legacy <30 kW Non-Res Proposal 1:

- *Operational Requirement:*
  - Same as new Non-PBI/Non-Res projects.
- *Verification Mechanism:*
  - Same as new Non-PBI/Non-Res with the following specifics.
    - Legacy Project GHG compliance period stops after 5 years of operations for each project.
    - Specific projects can still be reflected in findings of the SGIP Impact analyses for up to 10 years, per today's M&V rules.
- *Enforcement Mechanism:*
  - Same as new Non-PBI/Non-Res.
    - For additional compliance needs, SGIP PAs continue to have ongoing oversight capabilities.

Consensus Status:

Supported by: PG&E, SoCalGas, CSE, CESA, CalSSA, CPS, Stem, Tesla
Opposed by: SCE, ORA, Avalon

Proposal Description:

Legacy Non-PBI/Non-Res projects would be provided the option to accept revised Non-PBI/Non-Res rules (which means they are not subject to PBI payments but would fall under fleet compliance), which may reduce the cycling requirement and eliminate the annual RTE requirement.

Supporting Discussion:

- This 'stick-only' approach encourages good performance by legacy projects, and even better performance by new projects by bundling their enforcement at the fleet level.
- This design – fleet-wide measurement and enforcement that ties legacy to new projects, with moderately high penalties – could result in better performance by legacy systems, very good performance by new systems, and overall GHG reduction.

Opposing Discussion:

Model Findings Support:

Same as for Proposal 1. The modeling did not include any penalty protocol, so no comments can be made about the same based on the modeling results. But each modeler was observed to use a proprietary algorithm (to decide charge and discharge times), so it seems plausible to apply rules across the entire fleet of a developer and measure the collected performance of the fleet.

AESC Recommendations:

We support providing an opt-in to new project <30 kW non-residential rules for legacy <30 kW non-residential projects. We believe that the potential for cycling relief and RTE elimination would encourage legacy PBI systems to opt-in to the new PBI rules thus increasing GHG reduction compliance through GHG performance monitoring and verification. Note that these projects would not be subject to the <30 kW non-residential PBI payments per our recommendation, since they already have been paid all of their incentive per existing SGIP rules.

Legacy Non-PBI/Non-Res Proposal 1(a):

- *Operational Requirement:* Same as Proposal 1.
- *Verification Mechanism:* Same as Proposal 1.
- *Enforcement Mechanism:* Same as Proposal 1. Except would allow for Feebate approach.

Consensus Status:

Non-consensus.
Supported by: PG&E, CPS
Opposed by: SCE, SoCalGas, CSE, ORA, Avalon

Proposal Description:

Same as Proposal 1 except would work with Feebate approach. Underperformers would pay the ACC carbon cost on their tons of GHG emissions. What they pay could be a) added to the Program Administrator's current budget if there is no 'feebate' system in place, which would provide for more projects, or b) provided as a 'carrot' for Developers who are reducing GHGs. Such developers could earn more incentive for their customers from poor-performing Developers.

Supporting Discussion:

- This stick and carrot approach would encourage good legacy projects performance by providing them both a positive and negative incentive, and even better performance by new projects by bundling their enforcement at the fleet level, if the fleet proposal is accepted and applied.
- This category requires special attention. The SGIP program approved these projects trusting that program rules would encourage operations that would reduce GHGs.

Opposing Discussion:

- The effort of developing a feebate program could close the program for a substantial amount of time and add additional complexity to an already complex program.

Model Findings Support:

Same as for Proposal 1. No comments can be made about the feebate based on modeling results.

AESC Recommendations:

We do not support the feebate approach per our previous discussion.

Legacy Non-PBI/Non-Res Proposal 1(b):

- *Operational Requirement:* Same as Proposal 1.
  - Legacy non-Residential/non-PBI projects would accept the revised Non-PBI/Non-Res program rules, (which means they are not subject to PBI payments but would fall under fleet compliance).
  - In addition, projects must follow a GHG signal, managed at the fleet-level by developers.
- *Verification Mechanism:* Same as Proposal 1.
  - The developer's fleet is measured in its totality, which would include new *and* legacy projects.
  - The developer's fleet is analyzed by Itron on a quarterly basis, summed for enforcement on an annual basis.
- *Enforcement Mechanism:*
  - If the fleet increases GHGs, the Developer is assessed two penalties: first, the Developer pays the ACC carbon cost ($/ton CO2) on its emissions; second, the Developer must purchase external credits at the market price in the AB32 cap-and-trade market and retire allowances. Verification of purchase would be required.

Consensus Status:

Non-consensus.
Supported by: PG&E, Stem
Opposed by: SCE, CSE, ORA, CalSSA, CPS, Avalon

Proposal Description:

This proposal would permit existing projects to voluntarily opt-in to the same rules that will be applied for future PBI projects for the remaining portion of their PBI period. Depending on the specific revised rules for future PBI projects that are adopted, the legacy projects would enjoy relaxed cycling and eliminate RTE requirements while following a GHG Signal and accepting a more rigorous GHG verification and reporting process. Verification would occur on the fleet level which would include new and legacy projects. If the fleet increases GHGs, enforcement would entail payment of a penalty based on the ACC carbon cost and purchase of external credits in the cap and trade market.

Supporting Discussion:

Opposing Discussion:

- The reason projects have failed to meet GHG reduction is that they have focused on reducing customer peak demand. Reducing customer peak demand has been a long-time goal for the purpose of benefitting ratepayers. Non-coincident demand charges are an intentional price signal to encourage the very behavior that storage customers have been engaging in.
- This amounts to double-dipping by penalizing the customer twice. This sets a very bad precedent and could discourage storage deployment, particularly for grid support.

Model Findings Support:

Same as for Proposal 1 regarding the GHG signal (point 2 of this proposal). And the modeling results couldn't strongly or clearly justify the use of a cycling or an annual RTE constraint, so the first point of this proposal is also supported by the modeling results.

Legacy Non-PBI/Non-Res Proposal 1(c):

- *Operational Requirement:* Same as Proposal 1(b).
- *Verification Mechanism:* Same as Proposal 1(b).
- *Enforcement Mechanism:* Same as Proposal 1(b). Except would allow for Feebate approach.

Consensus Status:

Non-consensus.
Supported by:
Opposed by: SCE, SoCalGas, CSE, ORA, CPS, Avalon

Proposal Description:

Same as Proposal 1(b) except would work with Feebate approach. Underperformers would pay the ACC carbon cost on their tons of GHG emissions. What they pay could be a) added to the Program Administrator's current budget if there is no 'feebate' system in place, which would provide for more projects, or b) provided as a 'carrot' for developers who are reducing GHGs. Such developers could earn more incentive for their customers from poor-performing developers.

Supporting Discussion:

Opposing Discussion:

Model Findings Support:

Same as for Proposal 1(b). And as mentioned before, no comments can be made about the feebate approach based on modeling results.

AESC Recommendations:

We support a fleet option for legacy <30 kW non-residential systems.

Legacy Residential

Legacy Residential Proposal 1:

Proposal 1:

- *Operational Requirement:*
  - Opt-in to the revised new residential project rules.
  - If the customer does not choose to opt in existing rules apply.
- *Verification Mechanism:*
  - Same as the new residential project rules.
  - If the customer does not choose to opt in existing verification mechanisms apply through measurement and evaluation (M&E) or data required as part of an audit.
- *Enforcement Mechanism:*
  - Same as the new residential project rules.
  - If the customer does not choose to opt in existing enforcement mechanisms apply through the infraction process.

Consensus Status:

Non-consensus.
Supported by: PG&E, SoCalGas, CSE, CESA, CalSSA, CPS, Tesla, Avalon
Opposed by: SCE

Proposal Description:

This proposal provides for legacy residential projects to opt-in to the same revised rules as new residential projects. If projects opt-in, it would, under the proposed deemed compliance approach, provide relative assurance that these projects are meeting GHG emission reductions; increase monitoring and provide a mechanism for PA management of these projects through the infraction process.

Supporting Discussion:

- Developers would have reasonable latitude to reduce GHG emissions from their energy storage projects using their own preferred methods but must adhere to strict reporting requirements that verify compliance with SGIP program requirements.

- Most newly installed (perhaps virtually all since 2017) residential storage projects are paired with solar and agreeing to the ITC requirements. Thus, the Working Group is confident they should perform better than previous iterations of this technology.

Opposing Discussion:

- It is unclear why a legacy residential project would opt-in to a more stringent requirements and process, when they have already received their incentive. It would be prudent to add a feebate/carrot feature to this proposal so that there is some incentive for legacy projects to opt-in.

Model Findings Support:

Cannot be commented based on the modeling results. But since this proposal involves reporting the performance on a regular basis, the developers get a chance, through feedback, to alter their algorithms to achieve greater GHG reduction.

Appendices

Appendix A: Unabridged Modeling Results Discussion

Introduction

The cost and GHG impacts of a given energy storage system are highly sensitive to a multitude of factors including single-cycle round trip efficiency (SCRTE)[27], cycling frequency, system sizing, parasitic losses, customer class, dispatch behavior, pairing with solar, customer load profile, and more. The intersection of so many variables makes it impossible to rely on blanket or limited assumptions when classifying energy storage systems in a policy context. Consequently, the Working Group developed models that would simulate system operations to gauge sensitivity to certain characteristics and to detect consistent outcomes. For example, minimum or maximum operational requirements could be developed for a system characteristic found by all models to be decisive in leading to either net GHG emissions increases or reductions relative to a baseline scenario.

The modeling effort evaluated GHG, customer cost and grid cost impacts. However, the modeling did not explicitly evaluate impacts on demand reduction. Trade-off between GHG reduction and customer costs were evaluated, but to the extent there is a trade-off between demand reduction or other grid cost impacts and GHG reduction, the relative benefits were not analyzed in the Working Group's modeling.

The Working Group relied upon five proprietary models and one newly-developed public model to explore the impacts of a GHG signal amid different combinations of system and customer characteristics (i.e. operational requirement options). The models determined emissions, customer cost, cycles, and annual RTE[28,29] impacts when operation was bound by a GHG signal or charging and/or discharging constraints, versus no GHG solution base case scenarios (operation without regard to GHG impacts). The GHG signal was designed to include marginal emissions of the grid[30] (reported for either NP15 or SP15), forecasted for the day ahead and/or provided in real time and automatically transmitted to the storage system or a controller. Descriptions for all the GHG reduction solutions are presented in Table 2. Aside from dispatch behavior, additional input variables included different new and old electric rates[31] available in the three major IOU territories, system sizing, SCRTE, parasitic losses, customer class (commercial and residential), individual load profiles[32], and pairing with solar PV.[33, 34] See the additional sections in the appendices for tables summarizing input values, including specific rates and load profiles evaluated. It is important to recognize that, in many cases, different modelers chose to evaluate different scenarios; as such, some observations are based on data received from only a subset of the modelers (see Table 3 for a summary of the allocation). Ultimately, the modeling results are intended to inform determinations regarding the efficacy of various potential operational requirements for SGIP energy storage systems based on the GHG emissions of the electric grid, in a manner that allows system performance monitoring and GHG emissions tracking for verification and enforcement.

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[27] SCRTE stands for single cycle round trip efficiency, which is defined as an energy storage system's total energy charged divided by its total energy discharged during one full charge/discharge cycle.

[28] RTE stands for Round Trip Efficiency of a storage system. It is defined as the efficiency of charging and discharging the battery- i.e. how many kWh do you get out for every kWh you put in. It includes battery thermal losses, inverter efficiency, and parasitic losses.

[29] Annual RTE is an output of the modeling process. For a given energy storage system, annual RTE is equal to the total energy charged over the course of a year divided by the total energy discharged over the same year. It is a function of the number of cycles per year, system parasitic loads and SCRTE.

[30] The marginal emissions data was generated by Watt Time based upon data from the CAISO for 2017

[31] Old rates are existing rates that typically have peak periods between 12 and 6 pm. New rates are rates that in most cases are in GRC proceedings and are to be implemented in 2019 that have peak periods between 4 and 9 pm.

[32] See Appendix for summary tables describing each load profile.

[33] When paired with solar, the storage system is assumed to only charge from the onsite solar.

[34] Modeling results were received for a variety of different solar sizes. The final analysis utilized normalized solar sizes, calculated by dividing annual solar production (kWh) by the baseline energy consumption (kWh), and expressed as percentages of annual consumption.

Table 2: GHG Reduction Solution Descriptions

GHG Reduction Solution	Description
GHG Signal Co-Optimization	A GHG signal tracks the grid marginal emissions to reveal charging and discharging time A GHG signal tracks the grid marginal emissions to reveal charging and discharging time frames that help reduce GHG emissions and customer costs. Available signals included day-ahead predictions and real-time "right now" 5-minute emissions factor signals from WattTime. In some cases, modelers used a third alternative to serve as a proxy; for example, some modelers used data from the previous year to define charging periods based on low marginal emissions and costs and to define discharging periods based on high marginal emissions and costs.
No-Charging Time Constraint	Systems are prevented from charging between 4:00 p.m. and 9:00 p.m. - assumed to be a peak period for most utility rates.
Charging and Discharging Time Constraint	Includes No-Charging Time Constraint, plus additional conditions: 1) at least 50% of total charging must occur between 9:00 a.m. and 2:00 p.m. and 2) at least 50% of total discharging must occur between 4:00 p.m. and 9:00 p.m.
No GHG Reduction Solution	Minimize customer costs without regard to GHG emissions.

Table 3: Number of Runs for Each Modeler by Parameter

Modeler	Runs	Customer Class			Model Type		Rates		GHG Solution			
		Large Comm-ercial	Small Comm-ercial	Residential	Solar Plus Storage	Storage Only	New	Old	Charging and Discharging Time Constraints	GHG Signal Co-Optimiza-tion	No GHG Reduction Solution	No-Charging Time Constraint
A	66	30	-	36	56	10	54	12	-	-	66	-
B	324	252	72	-	-	324	104	220	-	216	72	36
C	757	757	-	-	4	753	438	319	-	750	7	-
D	98	67	4	27	53	45	90	8	-	70	16	12
E	3,908	1,625	1,149	1,134	2,226	1,682	1,476	2,432	432	2,592	452	432
F	175	86	89	-	147	28	141	34	-	17	138	20

Utilizing multiple proprietary and public models allows the Working Group's results to accommodate different technical methodologies and business approaches. Applying a range of technical methodologies in this manner allows the results to be relied upon with more confidence if distinct approaches lead to common conclusions. For example, a given energy storage model could be a spreadsheet-based heuristic model, a sophisticated numerical optimization algorithm, or some other alternative.[35]Two of the models tested used perfect foresight (where future load requirements are known with certainty for each interval), two used a load forecast (generating estimates of future load requirements based on past and present conditions with a neural net-based model), and two used historical data along with the current system state (amount of energy stored and available for consumption). Some models may focus on customer energy price arbitrage, while other models may also include algorithms for providing grid services. When agreement is reached between different methodologies, the conclusions are more robust in the face of scrutiny.

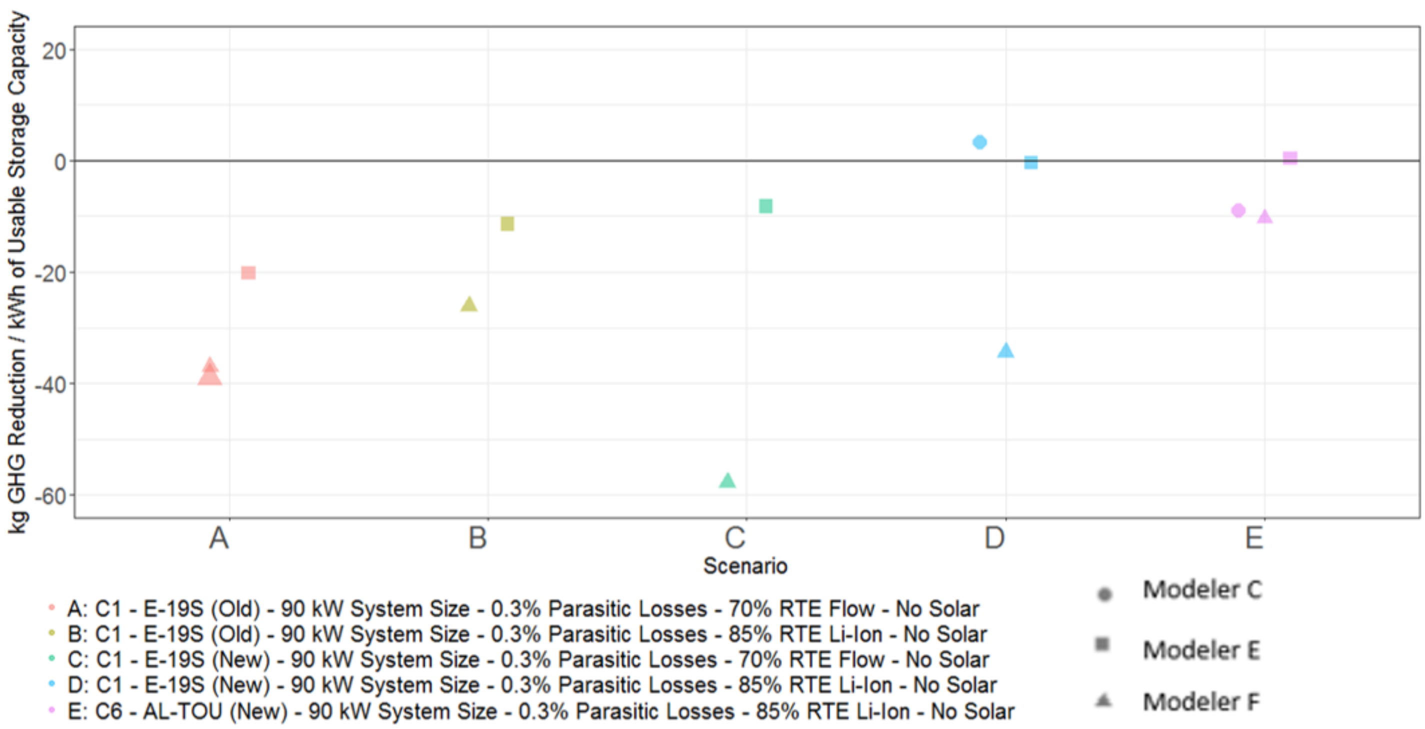
Figure 1 - Figure 3 display calibration comparisons between modelers for several common scenarios; when input combinations are held constant, differences in model output reflect the differences in technical approaches.[36] For example, the difference between modelers' estimated GHG impacts in Scenario C could be due to differences caused by using perfect foresight instead of a load forecast, but these differences are surely not attributable to system size, because size has

[35] A heuristic model operates according to a set of practical and understandable decision rules to arrive at a desirable, though not necessarily optimal, solution. A numerical optimization approach, on the other hand, typically solves for a minimum or maximum given one or more mathematical formulas with constraints.

[36] In the calibration comparison plots, different shapes correspond to different modelers. The large triangle in Scenario A represents a larger usable storage capacity compared to the other points. Note that a more positive value on the Y axis in Figure 1 represents a greater GHG *reduction*, i.e. a more desired result than a negative value on this score.

been held constant at 90 kW. The grid cost impacts in Figure 3 are presented as dollars of reduction per rebated capacity (i.e. power rating) in kW (so positive values are beneficial reduction whereas negative values are increases in grid costs). The purpose of the grid cost comparison is to check on the reasonableness of the magnitude of the cost reductions. There is a high degree of variation between modelers for each scenario, and this is not surprising; marginal grid costs vary over time, so different dispatch behavior (due to different technical approaches) is expected to lead to different grid impacts. The grid impacts range from an increase of about $13 to reduction of about $44 per kW of rated capacity. The lower end of this range compares reasonably well to the lower end observed in Itron's 2016 SGIP Advanced Energy Storage Impact Evaluation, but the high range observed here is much higher compared to that report's largest values ($44 / kW compared to a little over $2 / kW). While the highest reduction here of $44 / kW is an outlier likely resulting from an especially large usable storage capacity, there are plenty of other values here that are much higher than any of Itron's reported cost impacts. This is likely due in part to differences in sources for marginal grid cost data.[37] Note that not all modelers' results are shown in the calibration comparisons, because only a subset of modelers submitted comparable results (that is, results for runs consistent with the established calibration criteria).
It should also be noted that the different models represent different underlying businesses and as such have different prioritization regarding arbitrage opportunities versus grid service or other contractual opportunities. Including diverse business perspectives in the modeling process further ensures that model assumptions are consistent with real-world conditions; modelers especially reliant upon residential markets or standalone storage, for example, will tend to analyze those subjects more deeply. Importantly, including multiple business perspectives also provides a platform to stakeholders who will be directly affected by policy changes – and who could be instrumental in bringing about the desired outcome of such changes. In addition to differences in approach, modelers also chose to assess different scenarios; see Table 7 for the different load profiles and how many different modelers analyzed each.

Figure 1: GHG Impacts of Calibration Runs



[37] This report uses PG&E's generation and distribution marginal costs from the 2017 GRC Phase II filing applied to 2017 weather weightings.

Figure 2: Customer Bill Impacts of Calibration Runs

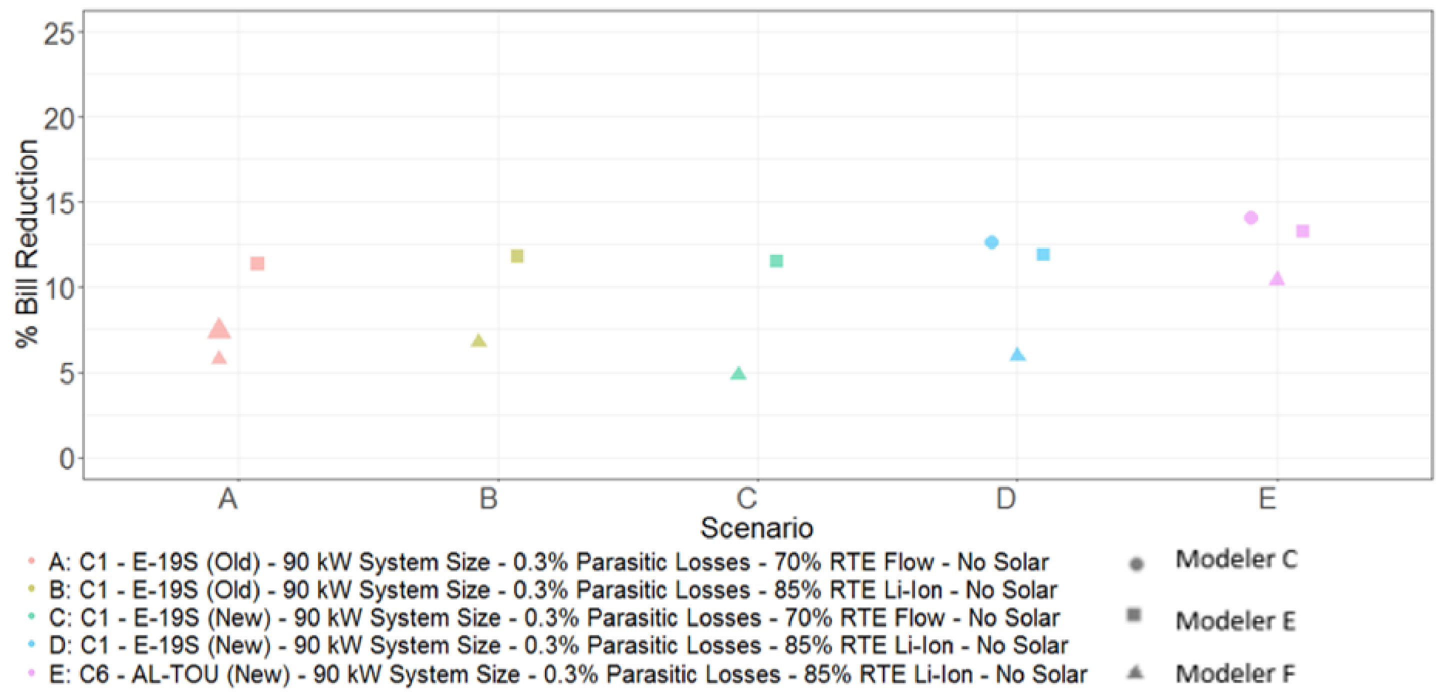
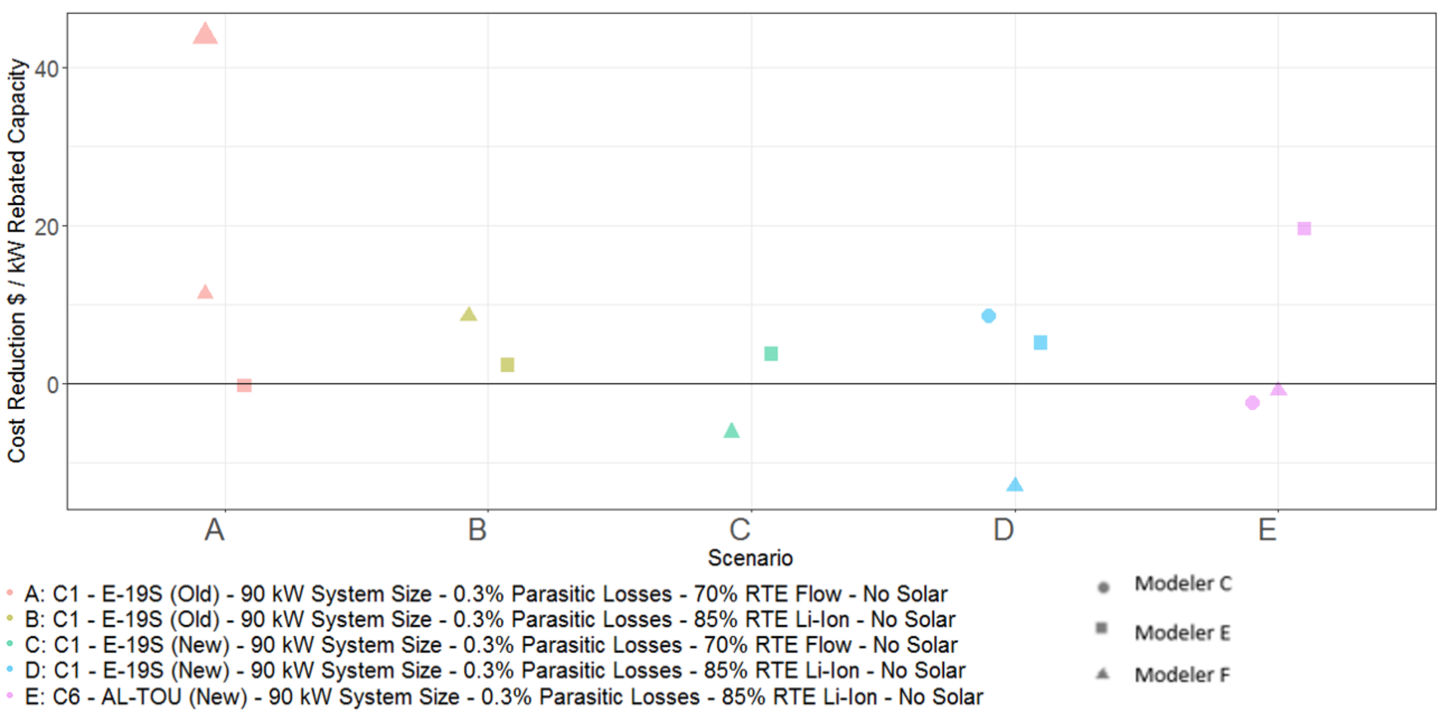


Figure 3: Grid Cost Impacts of Calibration Runs



GHG emissions impact and customer bill impact are the two primary outputs of the Working Group's modeling process. Relative to the baseline of no storage system, reduction in emissions or bills (or both) is desirable. Additional outputs include annual RTE and annual equivalent cycles. To ensure legitimacy when comparing outputs between scenarios or modelers (and the conclusions derived from them), normalization is critical. To that end, the GHG impacts have been expressed as kg of GHGs reduced per kWh of usable storage, while cost impacts have been analyzed on a percentage basis. Note that, throughout this report, a positive value for GHG or cost impacts represents savings (benefit), while negative values represent net increases. Another means of normalization was applied to comparisons involving system size, expressing the metric as the ratio of power rating (kW) to the baseline annual peak demand (kW).

Normalization also addressed the combination of inputs assumed for a given model run. For example, comparing all residential GHG impacts to all commercial GHG impacts may lead to one conclusion initially, but if all commercial model runs assumed different parasitic losses or single-cycle RTE than the residential runs, that initial conclusion may be highly flawed. While such comparisons can be helpful in understanding the data in an aggregate sense, it is often more useful to hold all model inputs (besides the variable of interest) constant when making comparisons to eliminate other sources of variation.

Finally, normalization was applied to enable meaningful comparison between standalone storage system impacts and those of systems paired with solar. Submitted modeling results for storage systems combined with solar included overall cost and GHG impacts in addition to "solar only" (i.e. solar without storage) impacts. To meaningfully compare these impacts with the model results for standalone systems, an adjustment was performed to obtain the impacts solely attributable to the storage system, removing the impacts of solar. First, the overall GHG and cost impacts were calculated for the solar-paired systems; second, the "solar only" impacts were calculated. The final impacts for the storage system – the values used in the analysis – were calculated by subtracting the "solar only" impacts from the overall impacts. Mathematically, the formulas are the following. Cost impacts were normalized as follows:

$$[(\text{Solar and Storage Cost Reduction}) - (\text{Solar Only Cost Reduction})] / (\text{Baseline Costs Without Solar or Storage}) \times 100 \quad (1)$$

GHG impacts were normalized as follows:

$$[(\text{kg Solar and Storage GHG Reduction}) - (\text{kg Solar Only GHG Reduction})] / \text{kWh Usable Storage Capacity} \quad (2)$$

Thus, the reported impacts for a storage system paired with solar reflect the incremental impacts solely attributable to the storage system. The solar system impacts, which were subtracted from the combined impacts to isolate the storage-only impacts, were estimated using the Itron method, calculating solar impact as the product of on-site solar production and marginal GHG signal.

Modeling Results

GHG Impacts

Table 4 is a summary table showing the effect of GHG signal co-optimization on GHG and cost impacts across different scenarios. The GHG reporting metric used here is GHG reduction in kgs (the baseline value - with no storage or solar - minus the GHG emission caused by adding storage to no-solar or solar scenario) and the GHG reductions are normalized further by dividing by the usable storage capacity[38] given in kWh. Negative values mean an increase in that parameter (not desired) and positive values mean a reduction (desired). It can be observed that GHG signal co-optimization gives better GHG impacts compared to No GHG Reduction Solution for all cases.[39] Note that the discussion largely excludes the Charging and Discharging Time Constraints and the No-Charging Time Constraint reduction solutions because their comparisons were less conclusive (see additional sections in the Appendix for impact comparisons of these constraints).

In general, the data indicate that:

- New rates[40] seem to perform better than old rates[41] and Solar Plus Storage seems to perform better than the Storage Only category in terms of GHG impacts[42].
- Within each scenario, the cost savings are not reduced by using GHG signal co-optimization. In fact, the cost savings are enhanced in some cases. GHG signal co-optimization was found to be effective at reducing GHGs overall, but this was not unanimous among all modelers.

Table 4 also gives an overview of the average (aggregated mean) GHG and cost impacts for each category. Each category is further expanded below, with the GHG and cost impacts plotted for unique combinations of load profile, solar size (if any), SCRTE and parasitic losses. Analysis is limited to "apples-to-apples" comparisons where possible; for example, the combinations of customer load profile, solar size (if any), SCRTE, and parasitic losses are held constant between the GHG signal runs and the "no constraints" (No GHG Reduction Solution) runs. The figure shows that in every meaningful comparison, co-optimization leads to equal or better GHG impacts and equal or better cost impacts when compared to the No GHG Reduction Solution scenario. This is generally true for both the average impacts and the percentage of beneficial model runs. The exception is commercial systems paired with solar on new rates; the average GHG impacts are slightly better for the "no constraints" approach, but the co-optimization runs more frequently showed benefits by a decisive margin (85% to 69%). The red bars in Table 4 represent negative values (which means an increase in emissions or costs), whereas the green bars represent positive values (which means a decrease in emissions or costs).

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[38] The 'usable storage capacity' of a storage system mentioned here is the total energy that the system can hold at any given time, usually expressed in kWh. This was obtained by multiplying the battery nominal power capacity in kW with its rated discharge duration in hours.

[39] This result is not surprising; it merely confirms the assumptions on which the GHG Signaling Working Group was formed in the first place. However, a short discussion regarding how a GHG signal impacts residential charging behavior (the simpler case, without demand charges) may be in order. Essentially, if the combination of rate/load profile/solar profile creates an economic incentive to charge a certain amount and discharge a lesser amount (due to RTE) on a certain day, there are generally many hours in which the charging and discharging could occur and have the same rate impact. For example, under new rates, discharging 1 kWh any time between 4PM and 9PM will have the same impact on residential charges, ignoring ITC effects. What the GHG signal does is *choose the highest-GHG hours within 4-9 PM* to discharge (rather than randomly or starting right at 4PM), thus maximizing both the GHG benefit due to displacing high-GHG thermal generation, and the GHG "credit". This discussion implies that the *magnitude* of the GHG signal is almost immaterial, as long as it is strong enough for the storage operation algorithm to rank hours within a TOU period from highest to lowest emissions – and that was indeed found to be the case using the public model.

[40] Throughout this report, the term "new rates" refers to rate plans proposed by the utilities (and in a few cases already in effect) that are subject to TOU schedules substantially different to the conventional TOU rates of the last 30 years. These TOU rates shift the on-peak period much further into the evening hours, thereby better aligning period of high cost with periods of high marginal grid emissions.

[41] The reason for this is that new rates have their peak Time of Use (TOU) periods aligned with the highest marginal GHG emissions, so storage systems operating under new rates are incented to discharge at times when GHG emissions tend to be high. Some new rates also have "Super Off-Peak" (SOP) periods when energy prices (and usually, GHG emissions) are low; storage systems operating under those new rates are also incented to charge when marginal emissions tend to be low.

[42] The reasons that the presence of paired solar tends to improve the GHG performance of a storage system are somewhat different between commercial and residential systems. For commercial customers, the on-site solar creates a "local duck curve" in the customer load, pushing the peak of metered load later in the day just as the grid-scale duck curve pushes the CAISO's net load curve later in the day. This means that storage discharges used for demand charge reduction will tend to align with high-GHG periods (whereas without the paired solar, the peak loads and therefore demand-related storage discharges may occur in the middle of the day when marginal GHGs are lower).
For residential systems, most paired systems apparently take the Investment Tax Credit (ITC), and are therefore operated so as to charge the storage at least 75% from on-site solar – which means charging mid-day (when marginal GHGs are low). And residential load tends to peak in the evening (especially after accounting for the local duck curve effect), so paired systems tend to discharge in the evening when GHG emissions are high.

Table 4: GHG Signal Benefit Comparisons by Scenario

CUSTOMER CLASS	MODEL TYPE INPUT	RETAIL RATE	GHG REDUCTION SOLUTION	MODEL RUNS	% RUNS WITH GHG REDUCTION	MEAN GHG REDUCTION kg/kWH	% RUNS WITH COST REDUCTION	MEAN COST REDUCTION %
Commercial and Industrial	Storage Only	OLD	GHG Signal Co-Optimization	985	23.86	-7.73	99.99	12.53
			No GHG Reduction Solution	153	0	-16.78	97.32	11.45
		NEW	GHG Signal Co-Optimization	792	40.4	-3.63	99.12	21.20
			No GHG Reduction Solution	112	17.86	-10.64	88.68	13.20
	Solar Plus Storage	OLD	GHG Signal Co-Optimization	667	60.12	3.32	100.00	16.08
			No GHG Reduction Solution	148	24.32	-3.45	100.00	13.29
		NEW	GHG Signal Co-Optimization	418	85.41	9.89	100.00	21.30
			No GHG Reduction Solution	176	69.32	10.52	100.00	12.92
Residential	Storage Only	OLD	GHG Signal Co-Optimization	216	3.7	-2.14	33.33	-1.17
			No GHG Reduction Solution	36	0	-2.96	33.33	-1.17
		NEW	GHG Signal Co-Optimization	108	100	21.33	100.00	16.73
			No GHG Reduction Solution	18	22.22	-6.07	100.00	16.73
	Solar Plus Storage	OLD	GHG Signal Co-Optimization	216	58.8	4.57	0.00	-11.27
			No GHG Reduction Solution	36	22.22	-3.48	0.00	-11.27
		NEW	GHG Signal Co-Optimization	243	84.36	14.21	100.00	15.81
			No GHG Reduction Solution	72	72.22	5.08	100.00	14.68

In the context of policy design, important dimensions for comparison include GHG signal co-optimization compared to the lack of a GHG signal for old and new rates, storage with and without solar, and customer class (commercial and residential). Modeling results can be expressed in a manner that examines GHG impacts, customer bill impacts, annual RTE and annual cycling across these dimensions. This section provides analysis and visualizations depicting GHG and cost impacts for all the input combinations (load profile, SCRTE etc.) within subsets of the model runs. Here, the discussion focuses on the subsets about which definitive statements can be made (i.e. all or none of certain types of runs within a subset achieve or fail to achieve benefits). Other sections in the appendices include additional relevant plots not discussed here.

Before delving into the most detailed views of the data, it is helpful to observe broader trends. As mentioned previously, evidence from modeling results suggests that systems paired with solar tend to outperform standalone ones, new rates tend to lead to better impacts than older ones, and GHG signal co-optimization generally achieves greater GHG reductions than instances without a GHG reduction solution. To illustrate how definitive statements can be developed from these observations, while addressing the influences of additional factors, Figure 4 and Figure 5 present the relationship between annual equivalent cycles and GHG impacts for different SCRTEs and GHG reduction solutions, for commercial and residential customers respectively.[43] These depictions focus exclusively on systems **paired with solar** under **new rates** (so they indicate best-case conditions). Figure 4 shows that commercial systems display a positive relationship between cycles and GHG reduction, though the strength of the relationship differs depending on certain conditions. This observation is helpful in determining whether a cycling constraint could be useful in ensuring GHG benefits. Most striking, however, is the observation that 100% of the model runs for commercial systems within this subset lead to both GHG and cost reductions when the SCRTE is set at 85% *and* the system is performing co-optimization with a GHG signal. Next, Figure 5 summarizes the same subset for residential systems. As with commercial systems, the vast majority of model runs for residential systems in this subset indicate both GHG and cost reductions when systems with an SCRTE of 85% perform GHG co-optimization. Subsequent charts focus more deeply on individual input combinations, and it will be shown that an exceptional load profile (R2) could be the reason that these residential systems do not achieve reductions 100% of the time under the specified (best case) conditions. In fact, it should be noted that neither R2 nor R3 are considered to be truly representative load profiles, in the sense that they are not believed to be the type of customers to which energy storage would normally be applied.

[43] We caution that “correlation is not causation” – both annual cycles and GHG reductions could be an *outcome* of other factors. For example, rates or operational modes that emphasize TOU period arbitrage over demand charge mitigation and demand response will tend to incent both more cycling and cycling aligned with GHG emissions; in this example it is not that increased cycling *caused* GHG reductions, but the combination of rate class and operational mode caused both to be high. The displayed regression lines should not be used to infer causality.

Figure 4: Cycles and GHGs for Storage with Solar on New Rates by GHG Reduction Solution and SCRTE (Commercial)[44]

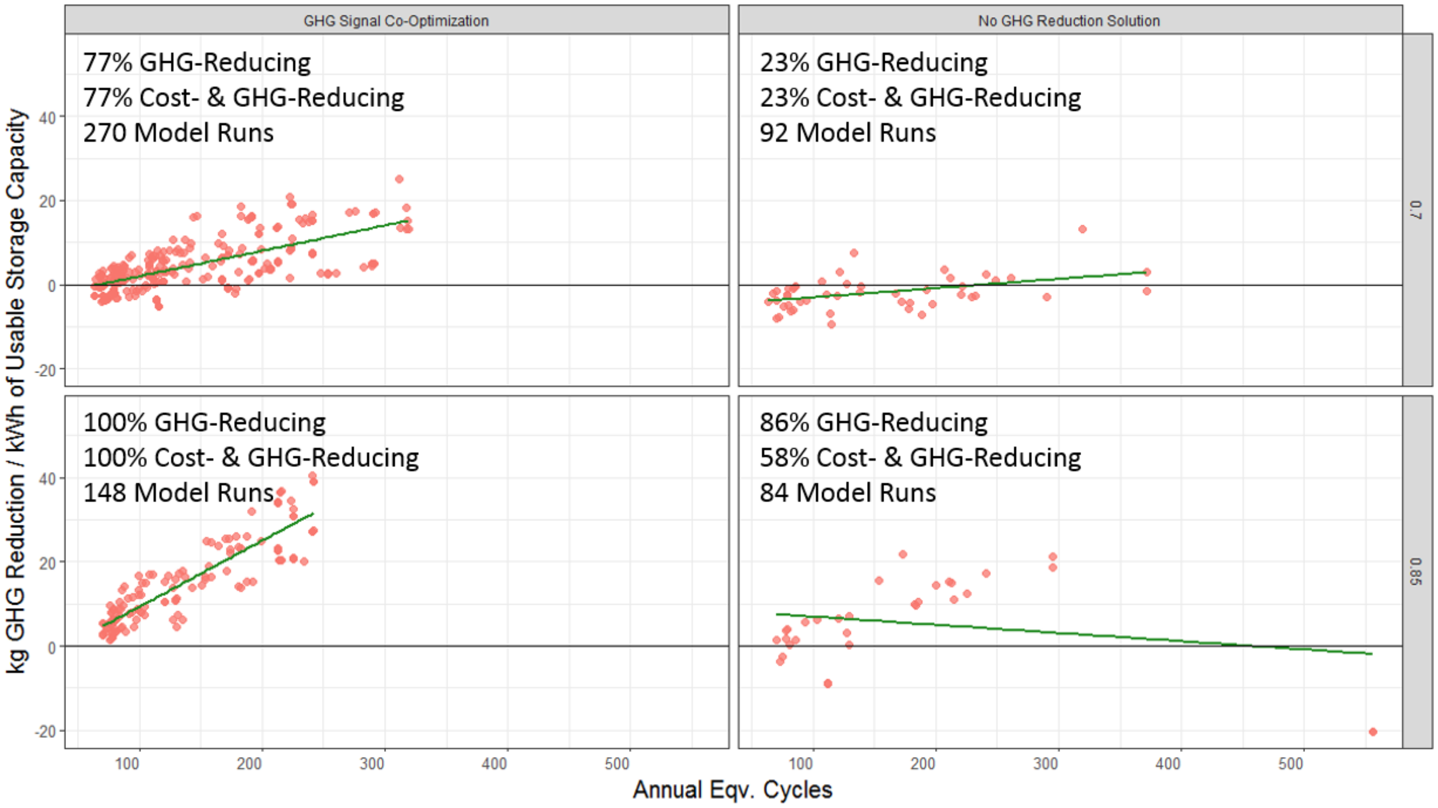
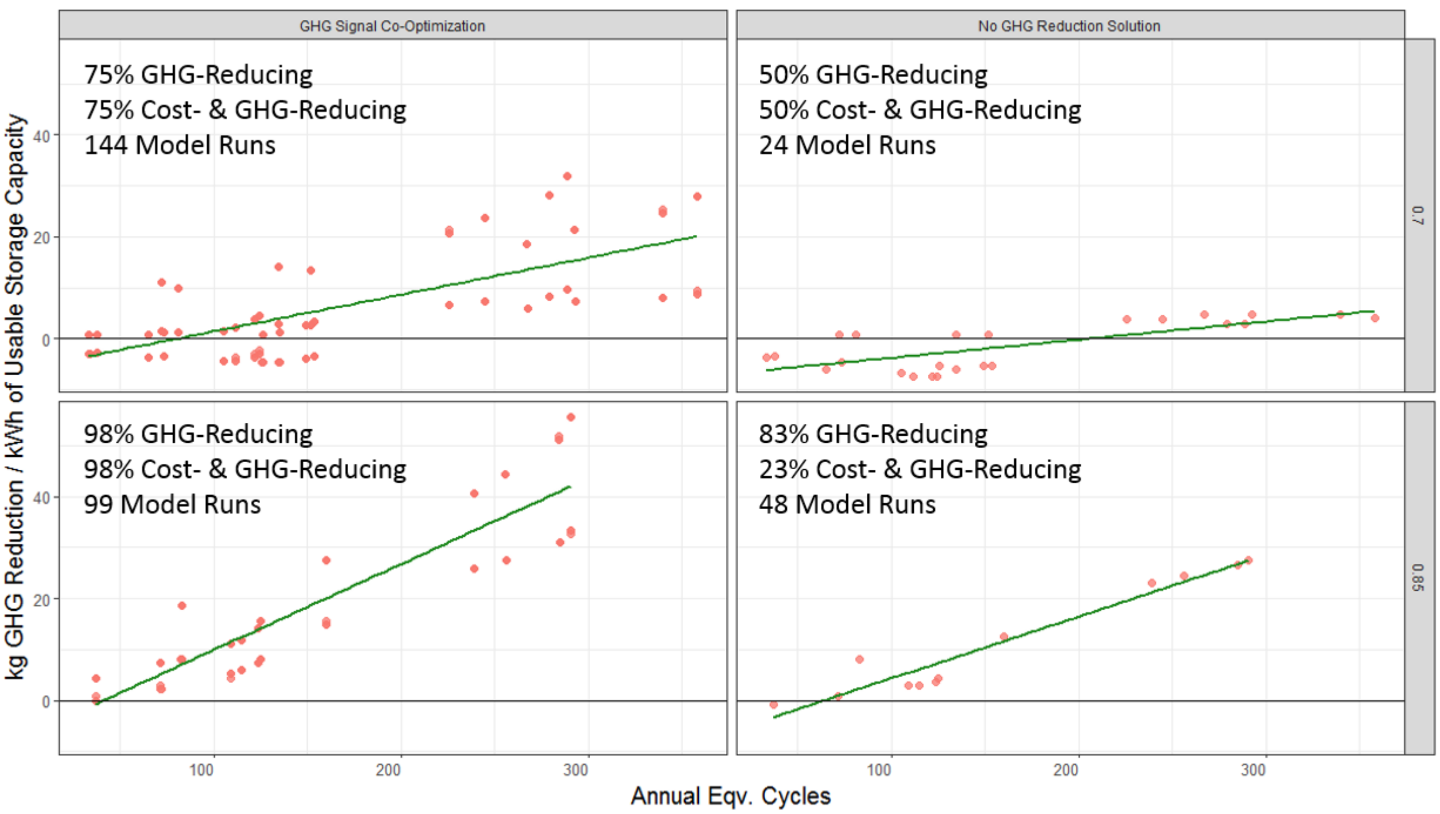


Figure 5: Cycles and GHGs for Storage with Solar on New Rates by GHG Reduction Solution and SCRTE (Residential)[45]



It became apparent upon review of modeling output that, in some situations, a GHG reduction solution such as GHG signal co-optimization is necessary for GHG reductions to be achievable.[46] The x-axis in Figure 6 depicts the average kg GHG reduction per kWh of usable storage capacity for all the input combinations among commercial storage systems **without solar** on **old rates** (so they indicate worst-case conditions). The y-axis contains categories for each of the different input combinations in the following format:

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[44] Note that the total model runs as labeled may not match the number of points shown. This is because not all modelers provided annual equivalent cycles in their results.

[45] Note that the total model runs as labeled may not match the number of points shown. This is because not all modelers provided annual equivalent cycles in their results.

[46] In this context, "achievable" represents provision of value sufficient to justify the purchase and deployment of the storage system.

Load Profile - Solar Size – SCRTE – Parasitic Losses

Each horizontal bar is labeled with the average reduction, followed by the number of model runs in parentheses. Each bar is color-coded according to the percentage of the runs that achieved GHG reduction; deep red corresponds to zero percent, while bright green represents one hundred percent. A pinkish color represents a proportion between zero and fifty percent, while a pale green represents a value above fifty percent but below one hundred percent. White, or something close to white, corresponds to a proportion close to fifty percent. In Figure 6, none of the model runs on the right side of the plot, under “No GHG Reduction Solution,” achieve GHG benefits. It can be said that commercial systems on old rates without solar never be able to achieve GHG reductions without a GHG reduction solution, such as GHG signal co-optimization. Figure 7 is even more decisive; under old rates without solar, residential storage systems with a single-cycle RTE of 70% never achieve GHG reductions. Even among the systems in that subset with a higher single-cycle RTE of 85%, there is never an instance of GHG reduction unless the system is applying a GHG reduction solution such as co-optimization. Among those systems co-optimizing with 85% single-cycle RTE, GHG reductions were only achieved in 11% of the model runs. **These findings suggest that commercial and residential standalone storage systems under old rates should not be incentivized without some sort of GHG reduction solution.**

Figure 6: GHG Impacts of Commercial Standalone Storage Systems on Old Rates

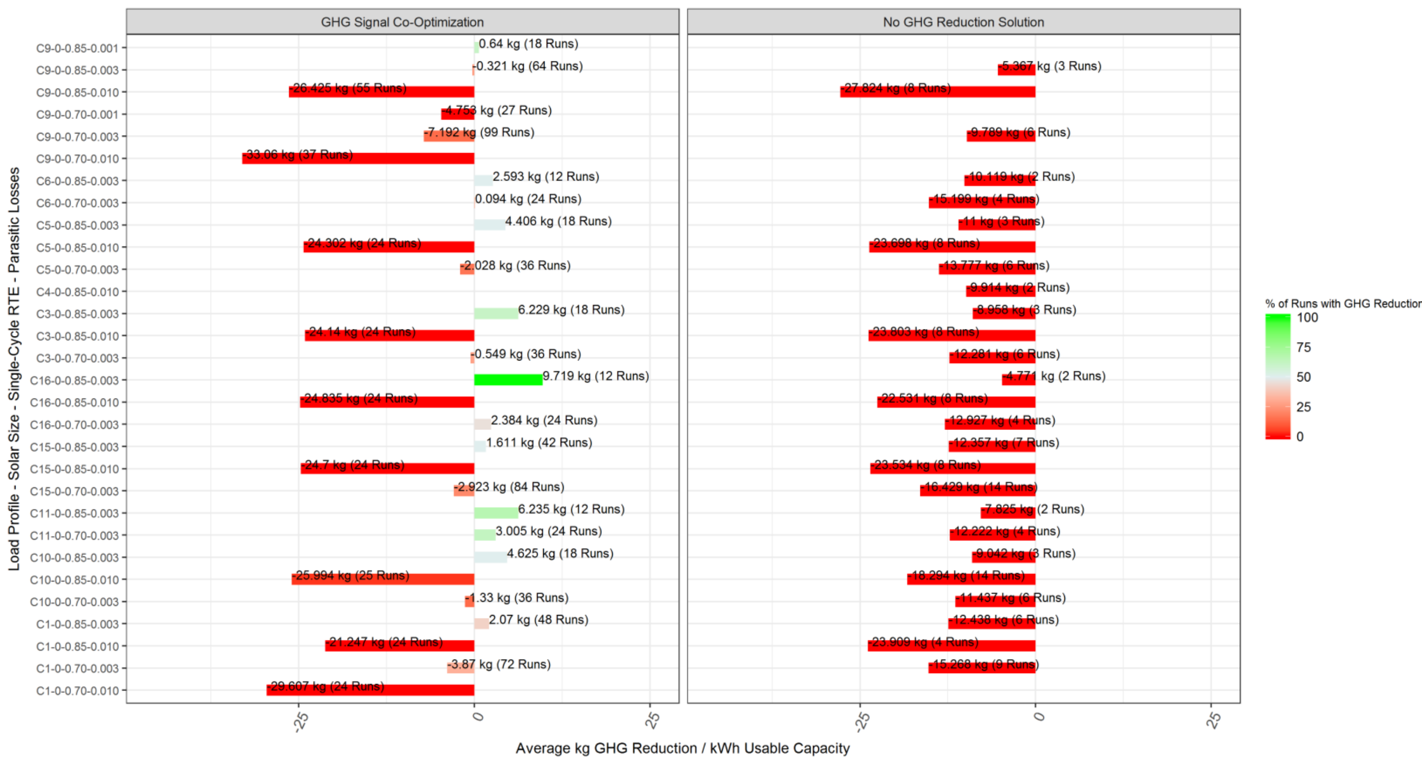
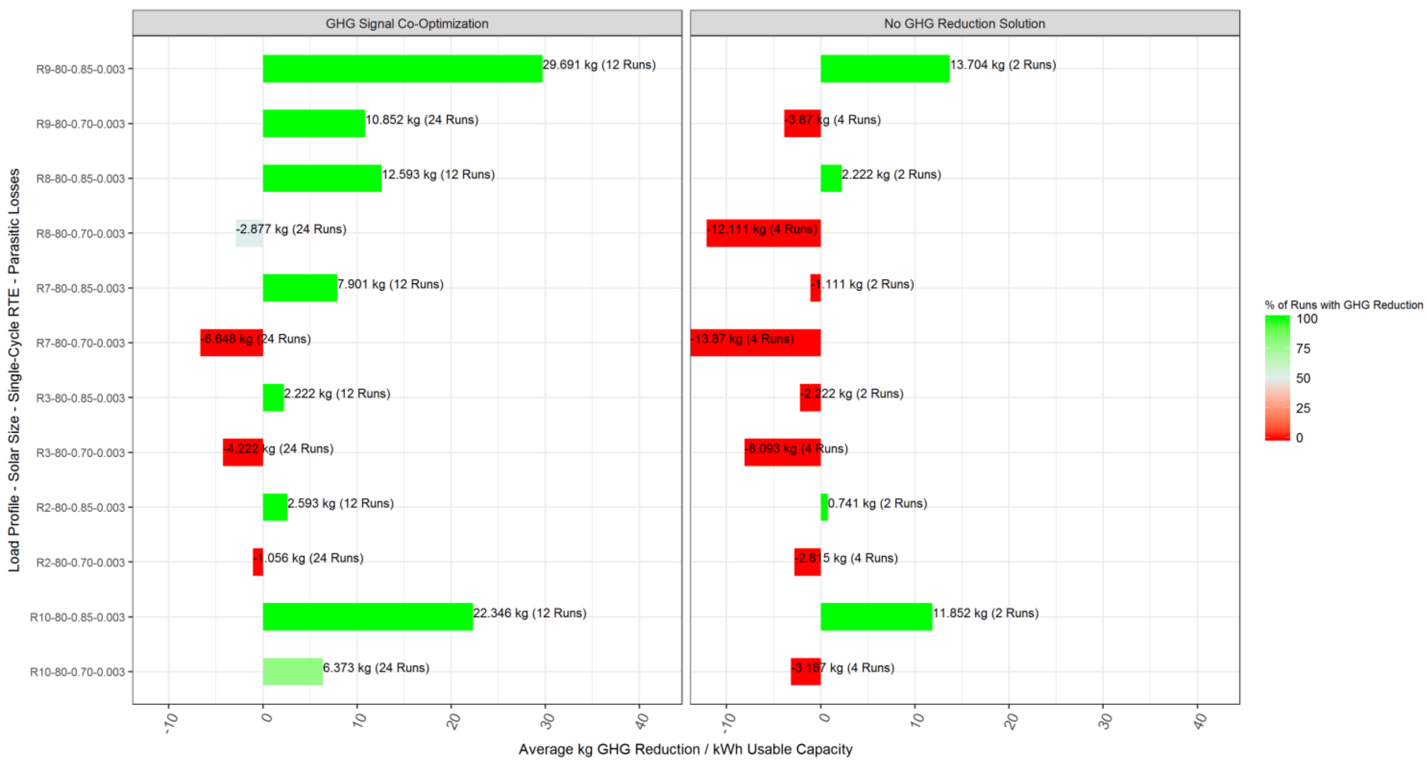


Figure 7: GHG Impacts of Residential Standalone Storage Systems on Old Rates

However, at least for residential systems, there is evidence from model output that old rates can still accommodate GHG benefits when storage is paired with solar (and further assuming the storage system is charged primarily from the solar system.[47]). Figure 8 depicts GHG impact results for residential storage systems, paired with solar, under old rates. From these results, it can be stated that residential systems on old rates with solar must have either a single-cycle RTE of at least 85% or a GHG reduction solution in order to possibly achieve GHG benefits. One hundred percent of the model runs in this subset combining GHG signal co-optimization with a single-cycle RTE of 85% led to GHG benefits. On the other hand, zero percent of the model runs in this subset lacking a GHG reduction solution, with a SCRTE of 70%, led to GHG benefits. These observations could lend support to qualifying and disqualifying factors, respectively, for residential systems paired with solar under old rates.

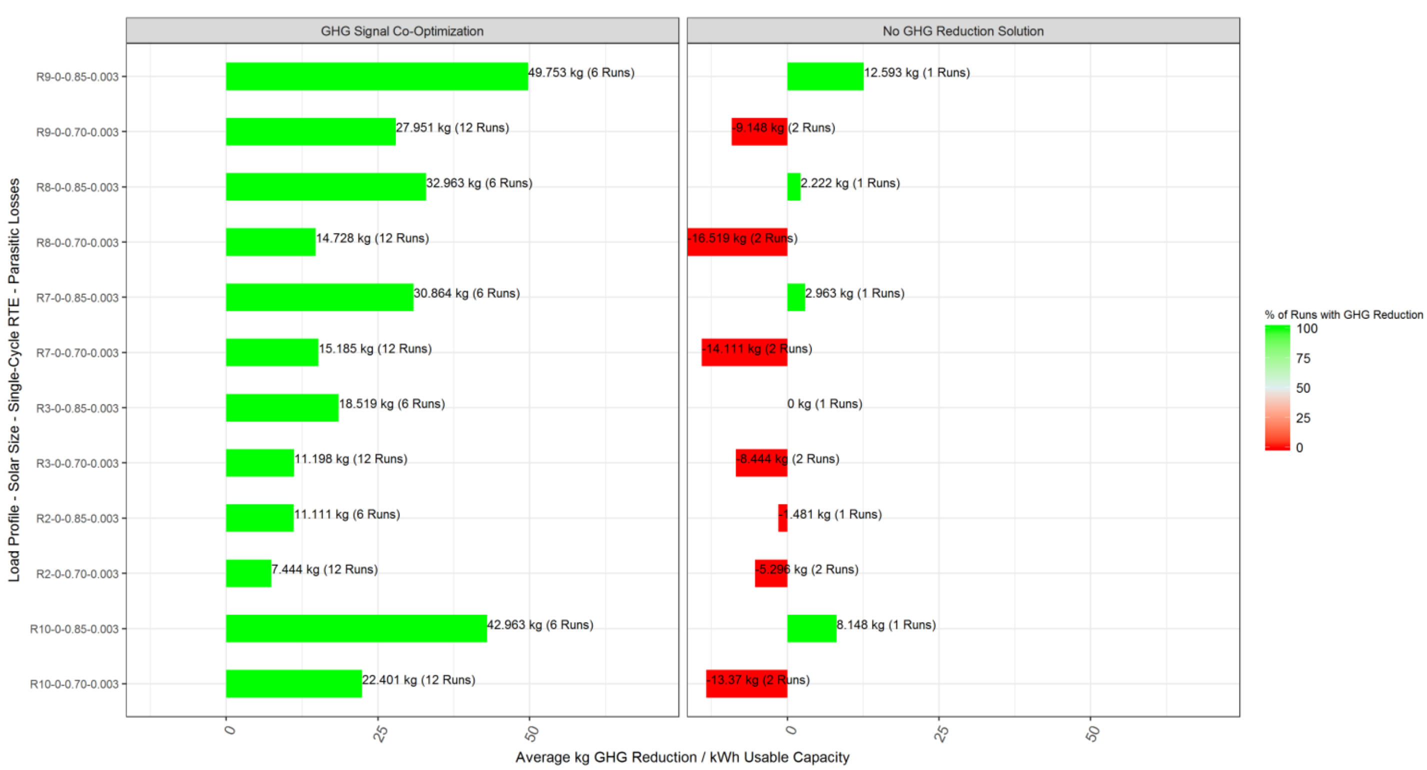
[47] Because solar production hours tend to coincide with times characterized by a low marginal emissions factor on the grid, charging during these times reduces or limits the extent to which the storage system charging increases GHG emissions.

Figure 8: GHG Impacts of Residential Storage Systems with Solar on Old Rates



Switching from old rates to new rates generally improves outcomes. Figure 9 displays the results for all combinations of standalone residential storage systems under new rates. The figure yields a striking observation; according to the model runs, when co-optimizing under new rates, residential standalone systems achieve GHG reduction one hundred percent of the time. In this instance, solar is not necessary. Conversely, without a reduction solution under new rates, residential standalone systems with single-cycle RTE of 70% never achieve GHG reductions.

Figure 9: GHG Impacts of Residential Standalone Storage Systems on New Rates



Just as switching from old rates to new ones generally improves outcomes, so too does pairing storage with solar provided the storage is assumed to charge primarily from the solar system. It has already been shown that adding solar to storage for residential systems under old rates broadens the possibilities of achieving GHG reduction. In addition, there are conditions for commercial systems on new rates, paired with solar, under which GHG reduction is virtually assured, according to the Working Group's model runs. The model runs for this subset of commercial systems always showed GHG reduction when the systems were co-optimizing with SCRTE of 85% (this is the same observation shown previously by Figure 4). It is now clear that the GHG-reducing outcome for these systems was consistent across different load profiles, solar sizes, and parasitic losses, as shown in Figure 10. Examination of load profiles C1, C15, and C16 under these conditions suggests that the benefits generally increased on average as single-cycle RTE and solar size increased (holding other factors constant).

The next plot (Figure 11) depicts the model run results for the best-case scenarios with residential systems, instead of commercial ones. As previously discussed, the model runs for commercial systems on new rates paired with solar always showed GHG reduction when the systems were co-optimizing with a single-cycle RTE of 85%. The same can very nearly be said for residential systems as well (again, this is a more detailed look at the conclusion previously depicted in Figure 5). Under these conditions (co-optimizing and with 85% single-cycle RTE, paired with solar under new rates), the proportion of model runs achieving GHG benefits is 98% rather than 100%. The exception is one combination for one load profile (R2). Again, note that load profiles R2 and R3 would not be considered realistic candidates for solar and storage, according to some of the modelers; they are believed to be less relevant in the analysis. This load profile showed 100% GHG-reducing model runs with a solar size of 100%, single-cycle RTE of 85%, and parasitic losses of 1%. But when the solar size fell to 80% with parasitic losses of 0.3%, not all model runs led to GHG benefits. Still, the evidence is strong that the combination of new rates, pairing with solar, 85% single-cycle RTE, and GHG signal co-optimization is very likely to lead to GHG benefits for both commercial and residential customers under a variety of circumstances.

Figure 10: GHG Impacts of Commercial Storage Systems with Solar on New Rates

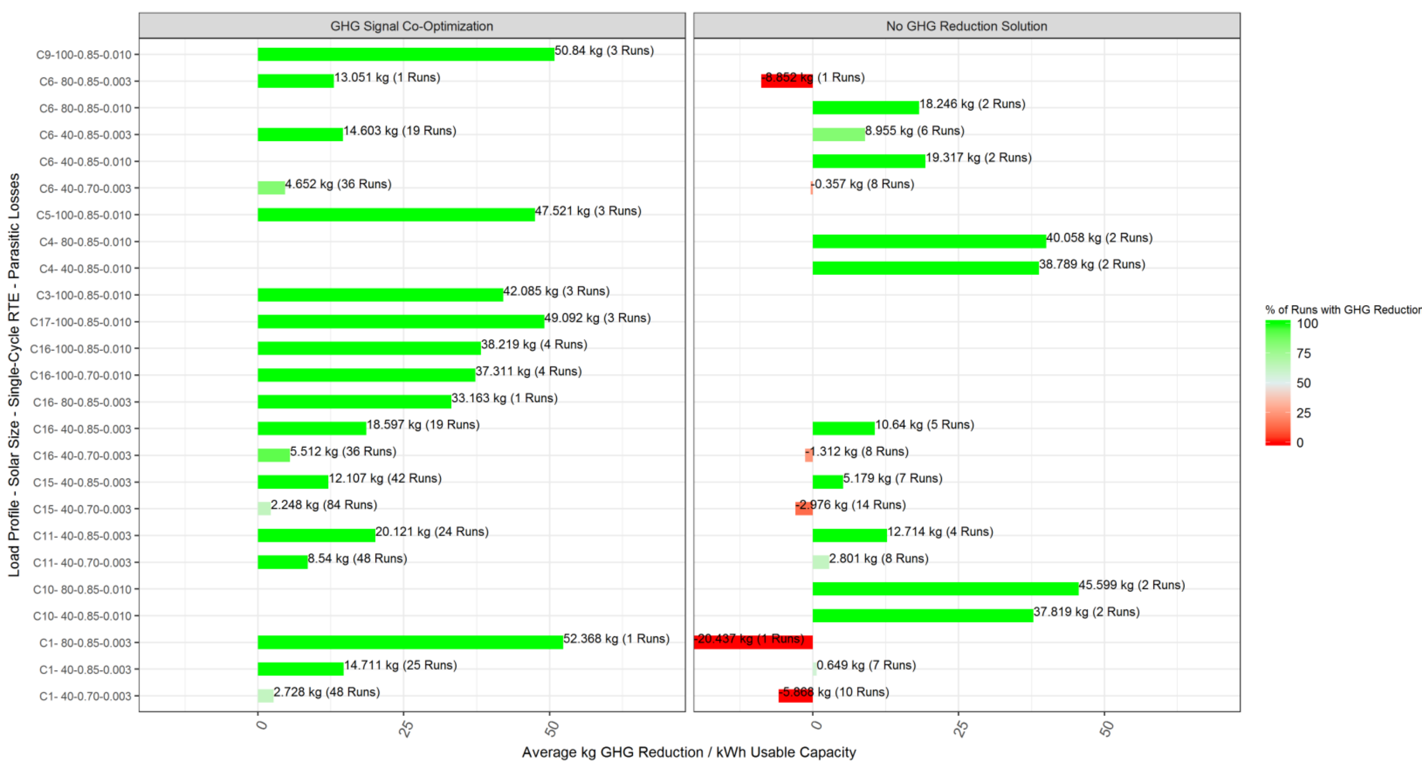
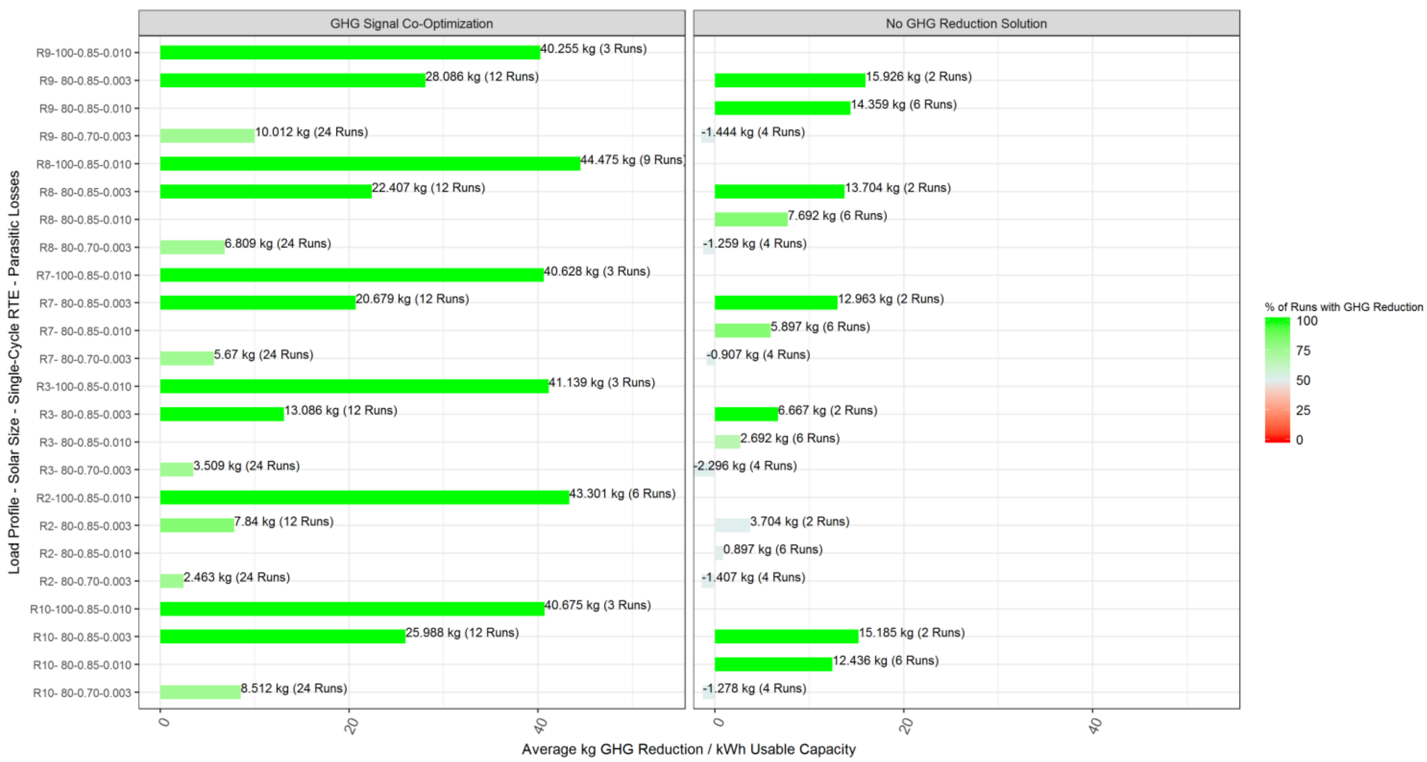


Figure 11: GHG Impacts of Residential Storage Systems with Solar on New Rates



Customer Cost impacts

Modeling results also allow definitive statements to be made about the customer cost impacts from certain subsets of the data. Figure 12 and the following figures follow the same labelling criteria as the above figures shown for GHG impacts, but the horizontal bars now show the average cost impacts calculated as a percent of the baseline (no solar, no storage). Figure 12 shows the cost impacts for residential systems with solar on old rates. It was observed that none of the combinations gave a positive cost impact; that is, all the combinations with or without GHG signal co-optimization increased the customer costs. This particular category was analyzed further to attribute a reason to this behavior and it was found that all these model runs were modeled by a single modeler (the public model), with PG&E's E1 Tier 1 and E1 Tier 3 rates (which were selected to represent tiered, non-TOU rates for all three IOUs). Other modelers had submitted model runs for this category without cost data, so their model runs could not be included in the residential cost impact analysis[48]. Similar results can be observed for residential systems without solar on old rates, but the cost impacts are better in this case (though still negative). Strong conclusions cannot be made because this data represents only one kind of retail rate, but it can be said that the PG&E non-TOU rates hurt customer economics when coupled with storage systems with or without solar[49], and the cost impacts are somewhat better without solar. Residential system on old rates did give some GHG reducing model runs, but seem to increase the customer cost for all model runs.

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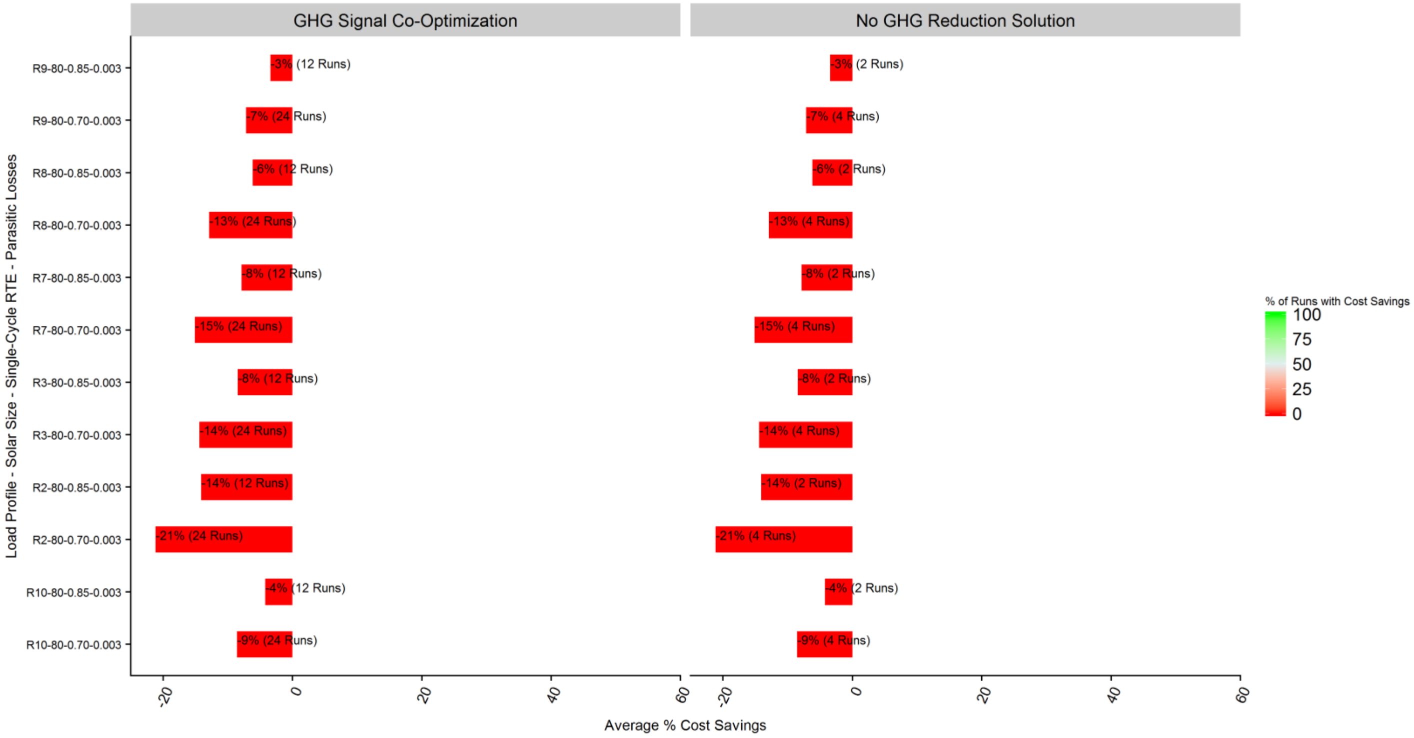
[48] Because residential rates in California do not include demand charges and have fixed TOU periods, the distinction between the different modelers' forecasting methodologies (perfect, neural net-based or historical plus current conditions) is immaterial – the financial impact of a particular charge/discharge cycle is essentially known day-ahead under any of the three forecasting methodologies. Thus, the fact that only the public model was used for this part of the report does not reduce its generality.

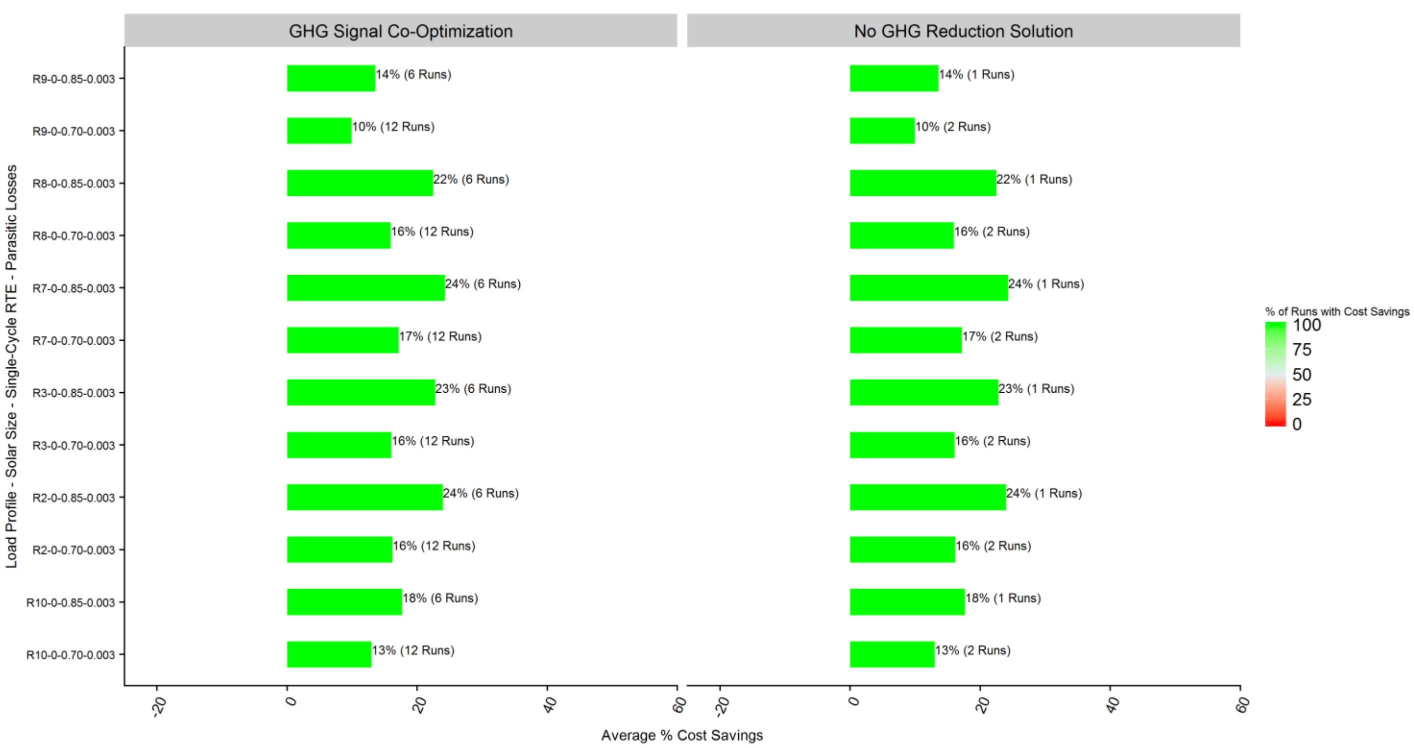
[49] This is hardly surprising – under non-TOU rates a charge/discharge cycle will *always* lose money due to RTE losses, and might even push the customer into a higher tier (an effect that was not modeled). Only the addition of SmartRate (the same as Critical Peak Pricing, or CPP) can salvage an economic benefit, by adding a very strong TOU signal on a limited number of days per year.

Figure 12: Cost Impacts of Residential Storage Systems with Solar on Old Rates



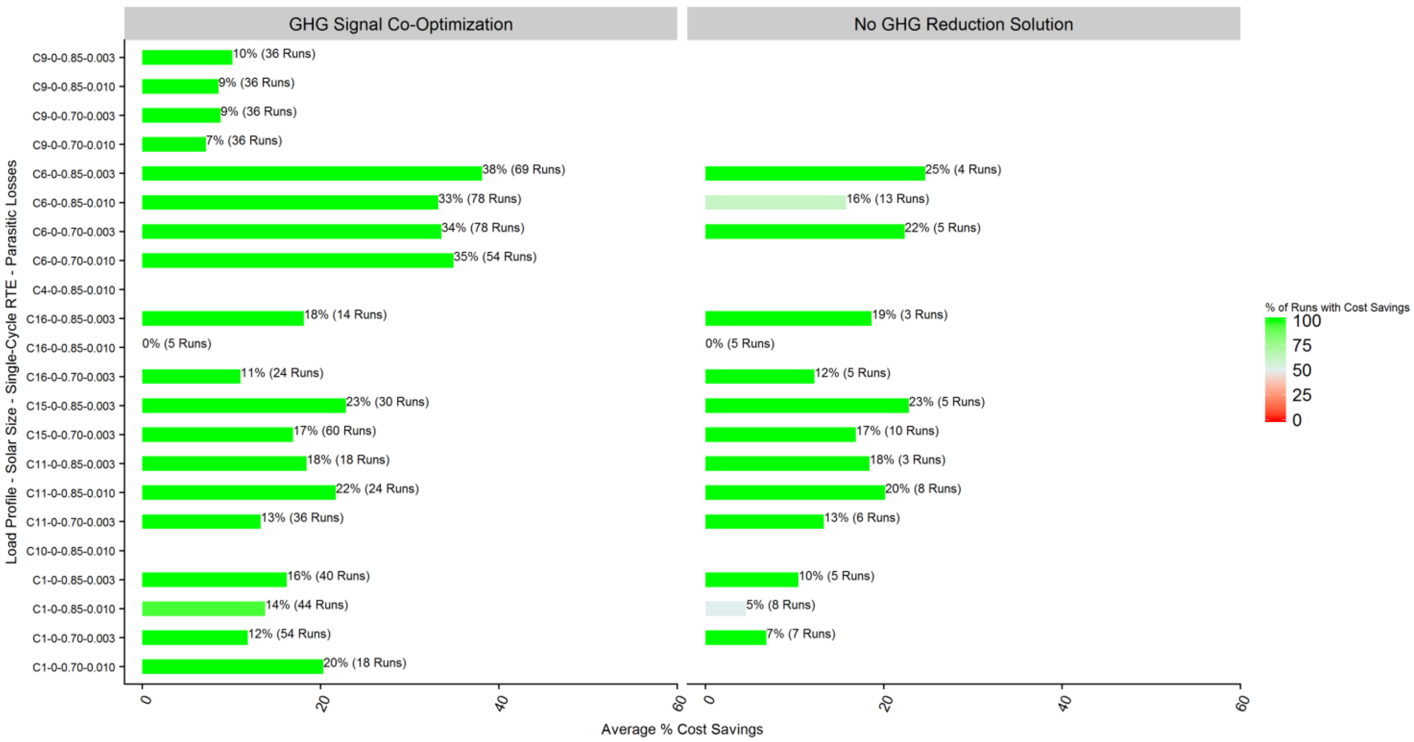
Residential systems subject to new rates give positive cost savings unlike the old rate scenario which was shown in Figure 12 above. This can be seen from Figure 13 below. Residential systems on new rates with and without solar also show the same results; that is, the cost savings are identical with and without GHG signal co-optimization.

Figure 13: Cost Impacts of Residential Standalone Storage Systems on New Rates



Error! Not a valid bookmark self-reference. shows the cost impacts for commercial standalone storage systems on new rates. It can be observed that, for a few load profiles like C1 and C6, the customer cost savings did improve with GHG signal co-optimization compared to No GHG reduction solution. For other load profiles the cost impacts stayed more or less the same, and in no case did the GHG signal co-optimization model runs give lower cost savings than the No GHG reduction input. And we saw earlier that, for this category the GHG impacts were improved by using GHG signal co-optimization. So, it can be concluded that the GHG signal co-optimization method helps in reducing GHG emissions without hurting the customer economics (even improving them in some cases).

Figure 14: Cost Impacts of Commercial Standalone Storage Systems on New Rates



Similar results can be observed for commercial systems on new rates with solar and also for those on old rates with and without solar. All the figures have been included in the appendix (from
Figure 25 to Figure 29).

GHG Emission Reduction Vs Annual Cycles and Annual RTE

Modeling output parameters including annual equivalent storage cycles and annual RTE were analyzed for all the 8 categories mentioned above. It was found that both generally have a positive correlation with GHG savings but the correlation with annual RTE is much stronger than with annual cycles. To see the impact of SCRTE (an input parameter), graphs of GHG reductions in kg per kWh of usable storage capacity were plotted against annual cycles and annual RTE and were categorized based on the input SCRTE. The blue model runs in the figures represent a higher SCRTE of 0.85 whereas the red/pinkish model runs represent a lower SCRTE of 0.7. The blue trend line shown is the least square error linear regression line fitted to the data. The linear regression line is plotted here for displaying the general trend, not for concluding anything directly from it. This is because these model runs include data from different modelers applying different techniques for cost and GHG reduction, so some variation in the data is expected. So, some extreme data points have the potential to skew the trend line, but the trend line can give an understanding of the data where different modelers agree with each other on the results.

Annual Cycles

Figure 15 below compares GHG reduction (measured in kg per kWh of usable ESS[50] capacity) of commercial **standalone** storage systems on **old rates** (the worst-case scenarios) to the number of annual equivalent storage cycles they achieved. The chart on the left depicts systems with No GHG reduction solution while the chart on the right shows model runs utilizing GHG signal co-optimization. As was observed in the GHG impact graphs above, it is clear from this figure that commercial storage systems without solar on old rates were unable to achieve GHG savings in any of the model runs without GHG signal co-optimization. Here it can be seen that GHG signal co-optimization helps increase GHG savings from commercial standalone storage systems on old rates regardless of SCRTE. The text in the top left corners of both the columns shows the % of model runs in each category which showed positive GHG reduction and the total model runs submitted in that category. So, for example, 0.0% of 153 model runs showed a positive GHG reduction for commercial standalone storage systems on old rates with No GHG reduction solution. The black dotted horizontal line is the GHG impact division line- the model runs above it show a net decrease in GHG emissions whereas the model runs below it show a net increase; that is, the model runs above the line are beneficial for GHGs.

[50] Energy storage system

Figure 15: GHG Reduction kg/kWh vs Annual Cycles for Commercial Standalone Storage on Old Rates

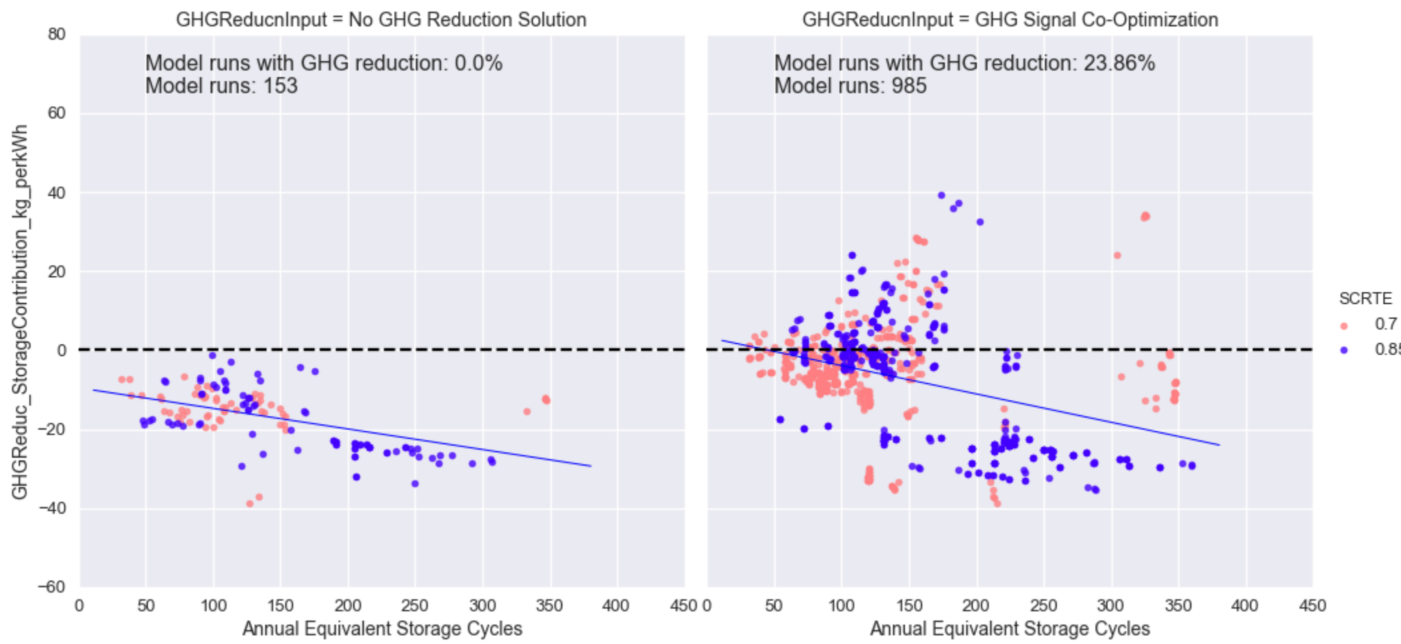


Figure 16 shows the same graph, but for commercial **standalone** systems on **new rates**. With new rates, the No GHG reduction solution gives better GHG impacts compared to old rates, but even for this case the GHG signal co-optimization performs better. Also, the shift in annual cycles from old rates (ranging from 50 to 300) to new rates (ranging from 100 to 450) can be clearly observed. This can be due to the fact that the new rates happen to align their load peak periods well with the GHG marginal emissions peak period compared to old rates and so the GHG optimization algorithm finds more intersecting time slots to charge and discharge thereby cycling more. Thus, a causation between annual cycles and GHG reduction cannot be established as such, because better GHG impacts and increased annual cycles can both be a function of some other input parameter like the new rates as seen here. So, no conclusion can be made about the requirement of an annual cycling constraint.

Figure 16: GHG reduction kg/kWh vs Annual Cycles for Commercial Standalone Storage on New rates

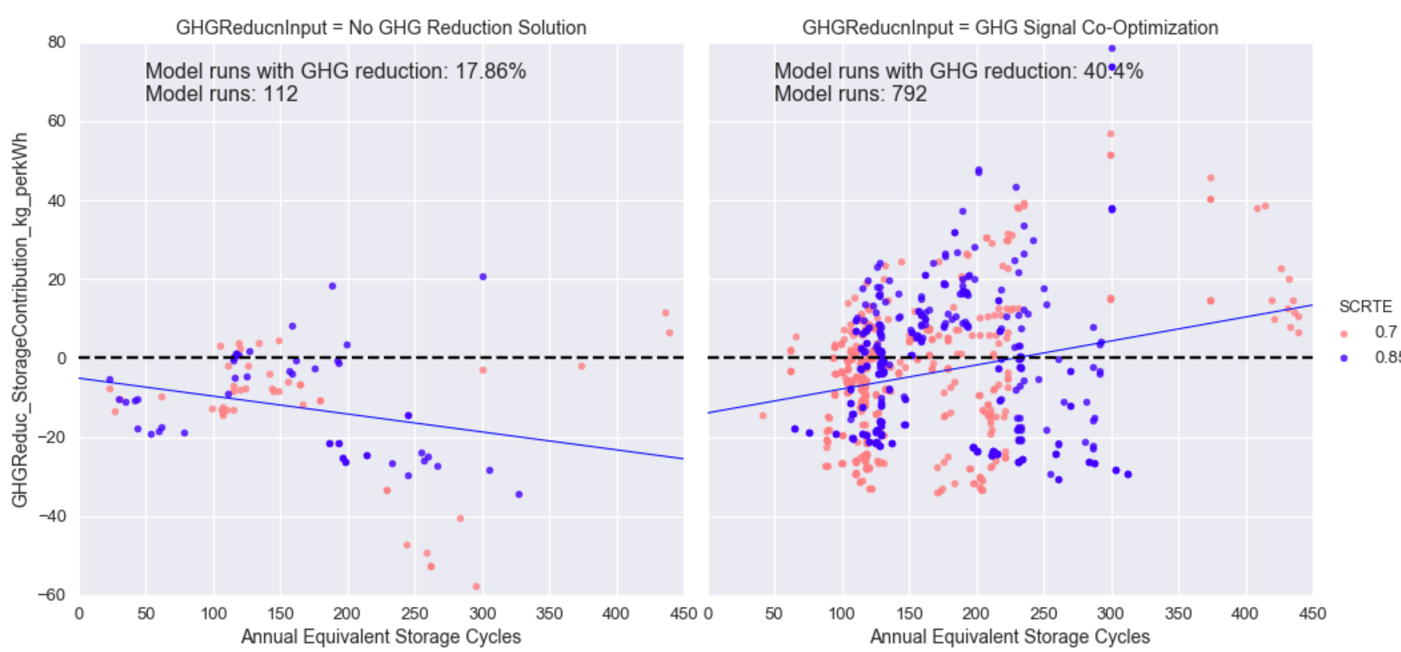


Figure 17 shows that adding solar to commercial storage on new rates improves the performance further, provided the storage system is charged primarily from the solar system, and GHG signal co-optimization still performs better than the No GHG reduction solution. Also, the No GHG reduction solution performs the best with solar and new rates. And from Figure 17 it is also clear how SCRTE helps improve the GHG reductions; that is, higher SCRTE gives higher GHG reductions in kg/kWh. And if Figure 17 is compared to its counterpart on old rates (refer Figure 30) the same shift in annual cycles range can be observed as observed for Figure 15 and Figure 16. All the graphs can be found in the appendix (Figure 30 to Figure 33). **So, for commercial storage systems, adding solar on new rates with GHG signal co-optimization gives best GHG impacts but if new rates are not possible in near future, at least GHG signal co-optimization should be used with or without solar (though pairing with solar gives much better results)**.

Figure 17: GHG reduction kg/kWh vs Annual Cycles for Commercial Storage with Solar on New rates

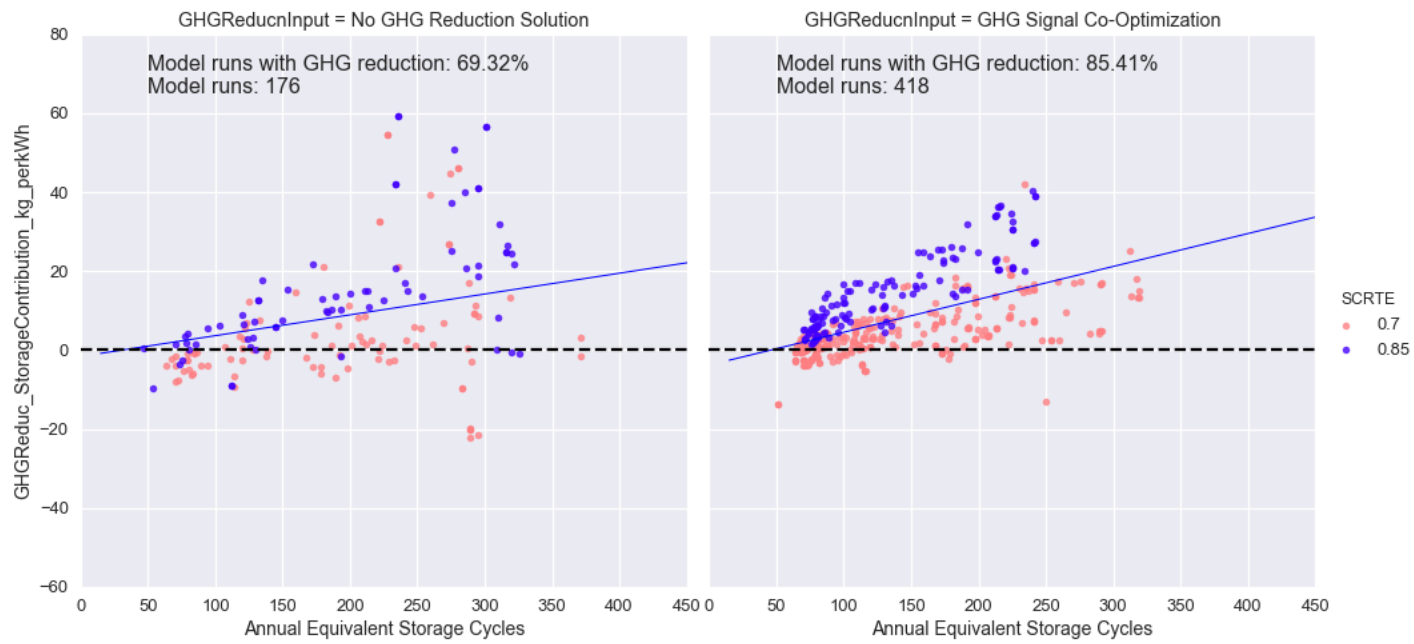


Figure 18 shows similar results for residential storage systems with solar on old rates. It can be clearly seen that No GHG reduction solution does not give positive GHG reduction if the SCRTE is 0.7. **So, if GHG reduction is desired for residential solar plus storage systems on old rates, it is advisable to use a higher SCRTE of 0.85 or greater.** Or, if a higher SCRTE is not possible (for example, flow or lead acid battery), then the system should use GHG signal co-optimization, as can be observed from the right column chart of Figure 18. Thus, it can be concluded that GHG signal co-optimization helps even lower SCRTE systems achieve GHG reduction. Also, a combination of GHG signal co-optimization, pairing with solar and higher SCRTE of 0.85 or greater almost guarantees GHG reduction for residential systems even with old rates as can be observed from the right-side chart of Figure 18.

Figure 18: GHG reduction kg/kWh vs Annual Cycles for Residential Storage with Solar on Old rates

Annual RTE

Figure 19 and Figure 20 below show GHG reduction in kg per kWh of usable storage capacity against the annual RTE for Commercial storage systems paired with solar on new rates and residential standalone storage systems on new rates respectively. These **clearly display the positive correlation between GHG savings and annual RTE**. One more thing which becomes clear through these graphs is **that annual RTE is strongly and positively correlated with SCRTE- that means the higher the SCRTE, the higher will be the annual RTE and thereby higher will be the GHG savings**[51].

[51] We need not caveat this result with "correlation is not causation" as we did for cycling – SCRTE is an *input*, not an *output*, and it is clear that for a given load shape, rate and storage control algorithm, a storage system with a lower SCRTE will have to charge more for a given discharge amount and will therefore generate at least as much GHGs as one with a higher SCRTE – and it will generate more GHGs unless the additional charging kWhs occur only when marginal GHGs are zero.

Figure 20 shows how GHG signal co-optimization gives GHG savings 100% of the time on new rates, irrespective of the SCRTE against the No GHG reduction solution which gives GHG reduction 22.22% of the times, that too only with a higher SCRTE of 0.85. When solar was added to Figure 20 (refer Figure 39 in the appendix) scenario, the No GHG reduction solution and GHG signal co-optimization achieved GHG reductions 72.22% and 84.36% of the times respectively. And the No GHG reduction solution had model runs with a lower SCRTE of 0.7 giving positive GHG reduction which was not the case without solar. Figure 20 also shows how the GHG signal co-optimization makes all the model runs give higher GHG reductions and also pulls the lower 0.7 SCRTE model runs above zero when compared to the No GHG reduction solution. So, GHG signal co-optimization can be used for residential storage systems with and without solar to achieve GHG savings. But if it is not possible to use GHG signal co-optimization for residential storage systems, they should at least be paired with solar, or have a higher SCRTE of 0.85, or both.

Annual RTE was found to have a strong correlation with GHG savings among all other parameters, but annual RTE in itself is an output parameter (and as such it does not have a direct causal relationship with GHG impacts), so it made more sense to check what input parameters affect annual RTE the most. A linear regression model (Figure 40) using least squares model was fitted to the data and it was found that SCRTE and parasitic load (in kW) when used as independent input parameters explain about 95.3% (the R^2 value of regression) variation in the dependent parameter- annual RTE. This means that annual RTE is highly dependent on these two input parameters, and the coefficients of regression were found to be 0.9113 and -12.0616 for SCRTE and parasitic load respectively. And since these parameters affect the annual RTE to a great extent, they also affect the GHG savings. **More particularly, as SCRTE increases and/or parasitic loss decreases, GHG savings go up. And since SCRTE is the parameter which can be controlled more actively, it makes sense to mandate high SCRTE systems in order to achieve higher GHG reductions for 1. all residential systems and 2. commercial systems paired with solar without GHG reduction solution. This fact is corroborated through almost all the figures shown in the modeling results**. In addition, it was found that every model run, which gave an annual RTE of less than 0.466, showed an increase in GHG emissions. So, there is a minimum value below which it is not possible to achieve any GHG reduction (as per the modeling results), but no value of annual RTE was found above which GHG reduction is guaranteed.

Figure 19: GHG Reduction kg/kWh vs Annual RTE for Commercial Storage with Solar on New Rates

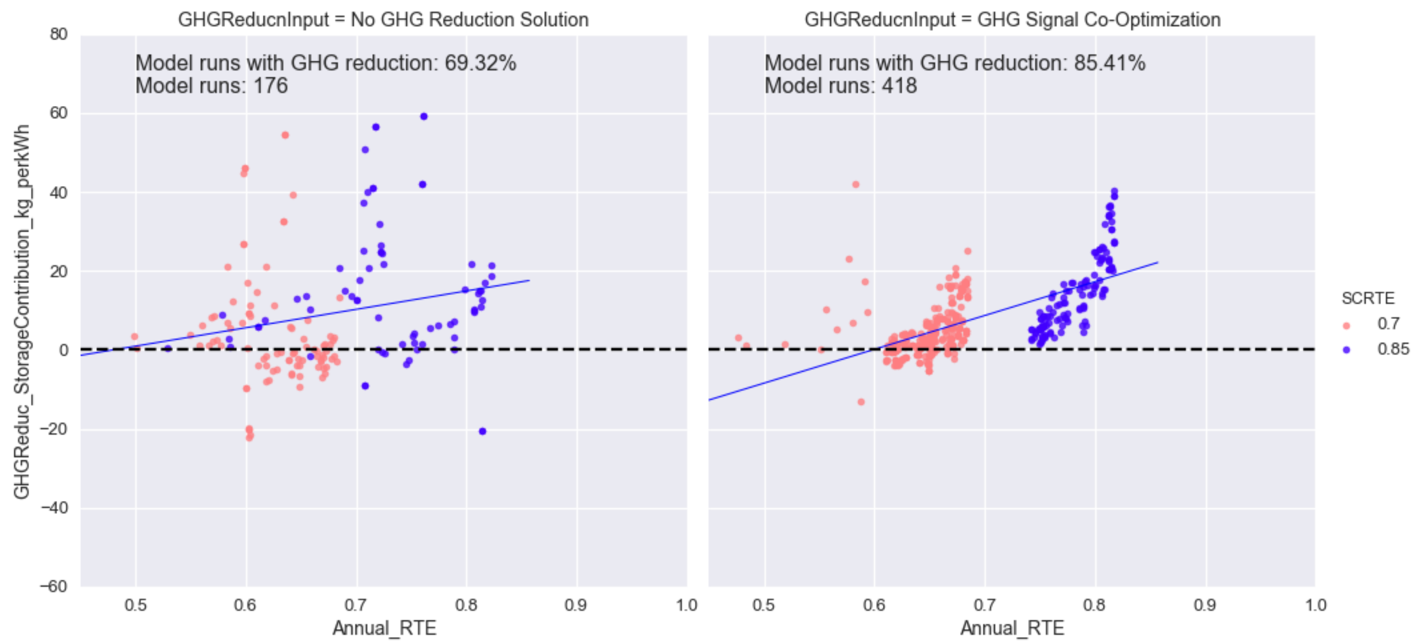


Figure 20: GHG Reduction kg/kWh vs Annual RTE for Residential Standalone Storage on New Rates

Key Takeaways

Overall, submitted data from the Working Group's modeling runs suggest several key takeaways that can help drive GHG-reducing operation of energy storage systems.

1. Residential energy storage systems **under old rates:**
   a. **When paired with solar**, are helped by the GHG signal to achieve GHG benefits[52] in the majority of cases irrespective of SCRTE, but a combination of utilizing the GHG signal and a higher SCRTE of 85% guarantees GHG reduction. Without the GHG signal, a higher SCRTE of 85% increases the chances of achieving GHG reduction but does not guarantee it.
   b. **Without solar**, appear highly unlikely to reduce GHGs.
2. Residential energy storage systems **under new rates:**
   a. **When paired with solar with SCRTE of 85%,** almost always achieve GHG benefits with or without the GHG signal, but even lower SCRTE (here 70%) systems can reduce GHGs in the majority of cases when GHG signal is utilized.
   b. **Without solar**, appear to always reduce both GHGs and customer bills when performing GHG signal co-optimization, regardless of SCRTE. But without the GHG signal, a higher SCRTE of 85% or above is required to achieve GHG reduction.

[52] Assuming the storage system is charged primarily, if not exclusively from the solar system

3. Commercial energy storage systems **under old rates:**
    a. **With solar**, when performing GHG signal co-optimization with 85% SCRTE, achieved GHG reduction 82% of the time (compared to 49% with a lower SCRTE of 70%). Without the GHG signal, the model runs achieved GHG reduction only 24% of the time regardless of SCRTE.
    b. **Without solar,** appear highly unlikely to reduce GHGs.
4. Commercial energy storage systems **under new rates:**
    a. **With solar and performing GHG signal co-optimization,** give GHG reduction 85% of the time regardless of SCRTE and 100% of the time with 85% SCRTE. Without a GHG signal, GHG reduction was achieved 69% of the time irrespective of SCRTE, but with a higher SCRTE of 85% the proportion increased to 86%.
    b. **Without solar**, while benefiting from co-optimization, are generally are unlikely to reduce GHGs (40% of commercial standalone model runs reduced GHGs when performing co-optimization under newer rates, regardless of SCRTE; the frequency increased modestly to 44% when a constraint of 85% SCRTE was added).

Appendix B: Load profile, Retail Rates and Modeler Summary

Table 5: Commercial Load Profile Summary Table

Master Index	Location	Utility	Annual Total kWh	Max Peak kW	Site Description
C1	East Bay	PG&E	978,487	520	Light Industrial, less BTM PV
C3	CZ 9	SCE	2,570,742	686	Office
C4	ClimZone 4	PG&E	3,766,149	735	Office
C5	CZ 8	SCE	2,150,156	436	Food Processor
C6	CZ 7	SDG&E	763,917	489	Manufacturing
C9	Los Angeles	SCE	2,680,057	500	Grocery
C10	Los Angeles	SCE	7,285,730	1,698	Industrial
C11	San Diego	SDG&E	971,347	548	Office
C15		PG&E	11,232,025	6,240	Small-Medium
C16		PG&E	28,681,525	16,200	Medium-Large
C17	South Bay	PG&E	1,099,205	404	High School w/ Summer School

Table 6: Residential Load Profile Summary Table

Master Index	Location	Utility	Annual total kWh	Max Peak kW	Site Description
R2	Long Beach	SCE	2,082	1	Household
R3	Coulterville	PG&E	4,700	4	Has well pump (runs all December)
R7	Albany	PG&E	8,872	5	Household with PHEV, Level 1?
R8	Crockett	PG&E	10,652	8	Household with EV, Level 2 charger
R9	Central Valley	PG&E	21,112	11	Household with lots of AC
R10	Central Valley	PG&E	15,838	8	Household with lots of AC

Table 7: Scenarios by Modeler

Load Profile	Model Type	Modeler					
		A	B	C	D	E	F
C1	Solar Plus Storage			X	X	X	X
	Storage Only		X	X	X	X	X
C10	Solar Plus Storage	X				X	
	Storage Only	X	X		X	X	
C11	Solar Plus Storage					X	
	Storage Only		X			X	
C15	Solar Plus Storage					X	
	Storage Only		X			X	
C16	Solar Plus Storage				X	X	X
	Storage Only		X		X	X	X
C17	Solar Plus Storage				X		
C3	Solar Plus Storage				X	X	
	Storage Only		X			X	
C4	Solar Plus Storage	X					
	Storage Only	X					
C5	Solar Plus Storage				X	X	
	Storage Only		X			X	
C6	Solar Plus Storage	X		X	X	X	X
	Storage Only	X	X	X	X	X	X
C9	Solar Plus Storage				X	X	
	Storage Only		X	X		X	
R10	Solar Plus Storage	X			X	X	
	Storage Only					X	
R2	Solar Plus Storage	X			X	X	

Table 8: Load Profile and Retail Rates Modeled for Commercial & Industrial (Number of Model Runs)

	LOAD PROFILE MASTER INDEX										
RETAIL RATES BY UTILITIES	C1	C10	C11	C15	C16	C17	C3	C4	C5	C6	C9
PGE_A-1-STORAGE (NEW)	62										
PGE_A-6 (OLD)	60			36							
PGE_A-6 PDP (OLD)	54										
PGE_E-19R (NEW)	2										
PGE_E-19S (NEW)	193			54	114			2		6	
PGE_E-19S (OLD)	76			54	54			2			
PGE_E-19S PDP (NEW)	54			54	54						
PGE_E-19S PDP (OLD)	54			54	54						
PGE_E-19S-R (NEW)	56			27	41	3	3	4	3		3
PGE_E-19S-R (OLD)	39			27	27			4			
PGE_E-19-TOU (OLD)	73										
PGE_E-19-TOU-NOPDP (OLD)	24										
PGE_TOU-8-B (OLD)					36						
SCE_TOU-8-B (OLD)		92		54			90		90		163
SCE_TOU-8-B-CPP (OLD)		54		54			54		54		125
SCE_TOU-8-B-R (OLD)		31		27			27		27		27
SCE_TOU-8-RTP (OLD)		54		54			54		54		132
SCE_TOU-8D (NEW)		2									72
SCE_TOU-8E (NEW)		4									72
SCE_TOU8A (OLD)		8									
SDGE_AL-TOU (NEW)			90	54						266	
SDGE_AL-TOU (NEW) with DA CAISO			54	54							
SDGE_AL-TOU (OLD)			54	54						54	
SDGE_AL-TOU-CP2 (NEW)			54	54						126	
SDGE_AL-TOU-CP2 (OLD)			54	54						54	
SDGE_DG-R-S (NEW)			27	27						63	

Table 9: Load Profile and Retail Rates Modeled for Residential (Number of Model Runs)

	LOAD PROFILE MASTER INDEX					
RETAIL RATES BY UTILITIES	R10	R2	R3	R7	R8	R9
PGE_E-1 Tier 1 (OLD)		54	54	54	54	
PGE_E-1 Tier 1 SmartRate (OLD)		54	54	54	54	
PGE_E-1 Tier 3 (OLD)	54					54
PGE_E-1 Tier 3 SmartRate (OLD)	54					54
PGE_EV-A (NEW)	58	58	58	58	58	58
PGE_TOU B (NEW)	1	1	1	1	1	1
PV self supply (NEW)	1	1	1	1	1	1
SCE_TOU D (NEW)	1	1	1	1	1	1
SDGE_DR SES (NEW)	28	31	28	28	34	28
SDGE_EV (NEW)	1	1	1	1	1	1

Appendix C: Summary of GHG and Cost Impacts

Figure 21: Commercial and Industrial: Summary of GHG and Cost Impacts for Different Scenarios

CUSTOMER CLASS	MODEL TYPE INPUT	RETAIL RATE	GHG REDUCTION SOLUTION	SCRTE	MODEL RUNS	% RUNS WITH GHG REDUCTION	MEAN GHG REDUCTION kg/kWh	% RUNS WITH COST REDUCTION	MEAN COST REDUCTION %
Commercial and Industrial	Storage Only	OLD	GHG Signal Co-Optimization	0.7	523.00	21.03	-6.32	100.00	11.19
Commercial and Industrial	Storage Only	OLD	GHG Signal Co-Optimization	0.85	462.00	27.06	-9.33	99.78	14.05
Commercial and Industrial	Storage Only	OLD	No GHG Reduction Solution	0.7	61.00	0.00	-14.56	100.00	10.05
Commercial and Industrial	Storage Only	OLD	No GHG Reduction Solution	0.85	92.00	0.00	-18.24	95.45	12.42
Commercial and Industrial	Storage Only	NEW	GHG Signal Co-Optimization	0.7	398.00	37.19	-4.39	100.00	19.74
Commercial and Industrial	Storage Only	NEW	GHG Signal Co-Optimization	0.85	394.00	43.65	-2.86	98.22	22.68
Commercial and Industrial	Storage Only	NEW	No GHG Reduction Solution	0.7	44.00	15.91	-13.23	100.00	12.70
Commercial and Industrial	Storage Only	NEW	No GHG Reduction Solution	0.85	68.00	19.12	-8.97	80.65	13.56
Commercial and Industrial	Solar Plus Storage	OLD	GHG Signal Co-Optimization	0.7	445.00	49.21	1.57	100.00	15.84
Commercial and Industrial	Solar Plus Storage	OLD	GHG Signal Co-Optimization	0.85	222.00	81.98	6.84	100.00	16.57
Commercial and Industrial	Solar Plus Storage	OLD	No GHG Reduction Solution	0.7	89.00	10.11	-5.52	100.00	13.55
Commercial and Industrial	Solar Plus Storage	OLD	No GHG Reduction Solution	0.85	59.00	45.76	-0.32	100.00	12.83
Commercial and Industrial	Solar Plus Storage	NEW	GHG Signal Co-Optimization	0.7	270.00	77.41	4.91	100.00	20.20
Commercial and Industrial	Solar Plus Storage	NEW	GHG Signal Co-Optimization	0.85	148.00	100.00	18.99	100.00	23.31
Commercial and Industrial	Solar Plus Storage	NEW	No GHG Reduction Solution	0.7	92.00	52.17	4.32	100.00	13.27
Commercial and Industrial	Solar Plus Storage	NEW	No GHG Reduction Solution	0.85	84.00	88.10	17.31	100.00	12.49

Figure 22: Residential: Summary of GHG and Cost impacts for Different Scenarios

CUSTOMER CLASS	MODEL TYPE INPUT	RETAIL RATE	GHG REDUCTION SOLUTION	SCRTE	MODEL RUNS	% RUNS WITH GHG REDUCTION	MEAN GHG REDUCTION kg/kWh	% RUNS WITH COST REDUCTION	MEAN COST REDUCTION %
Residential	Storage Only	OLD	GHG Signal Co-Optimization	0.7	144.00	0.00	-2.17	33.33	-1.21
Residential	Storage Only	OLD	GHG Signal Co-Optimization	0.85	72.00	11.11	-2.08	33.33	-1.09
Residential	Storage Only	OLD	No GHG Reduction Solution	0.7	24.00	0.00	-2.99	33.33	-1.21
Residential	Storage Only	OLD	No GHG Reduction Solution	0.85	12.00	0.00	-2.90	33.33	-1.09
Residential	Storage Only	NEW	GHG Signal Co-Optimization	0.7	72.00	100.00	16.48	100.00	14.70
Residential	Storage Only	NEW	GHG Signal Co-Optimization	0.85	36.00	100.00	31.03	100.00	20.78
Residential	Storage Only	NEW	No GHG Reduction Solution	0.7	12.00	0.00	-11.15	100.00	14.70
Residential	Storage Only	NEW	No GHG Reduction Solution	0.85	6.00	66.67	4.07	100.00	20.78
Residential	Solar Plus Storage	OLD	GHG Signal Co-Optimization	0.7	144.00	38.19	0.40	0.00	-13.21
Residential	Solar Plus Storage	OLD	GHG Signal Co-Optimization	0.85	72.00	100.00	12.89	0.00	-7.37
Residential	Solar Plus Storage	OLD	No GHG Reduction Solution	0.7	24.00	0.00	-7.32	0.00	-13.21
Residential	Solar Plus Storage	OLD	No GHG Reduction Solution	0.85	12.00	66.67	4.20	0.00	-7.37
Residential	Solar Plus Storage	NEW	GHG Signal Co-Optimization	0.7	144.00	75.00	6.16	100.00	12.20
Residential	Solar Plus Storage	NEW	GHG Signal Co-Optimization	0.85	99.00	97.98	25.91	100.00	21.06
Residential	Solar Plus Storage	NEW	No GHG Reduction Solution	0.7	24.00	50.00	-1.43	100.00	12.18
Residential	Solar Plus Storage	NEW	No GHG Reduction Solution	0.85	48.00	83.33	8.34	100.00	19.68

GHG impacts

Figure 23: GHG Impacts of Commercial Storage Systems with Solar on Old Rates

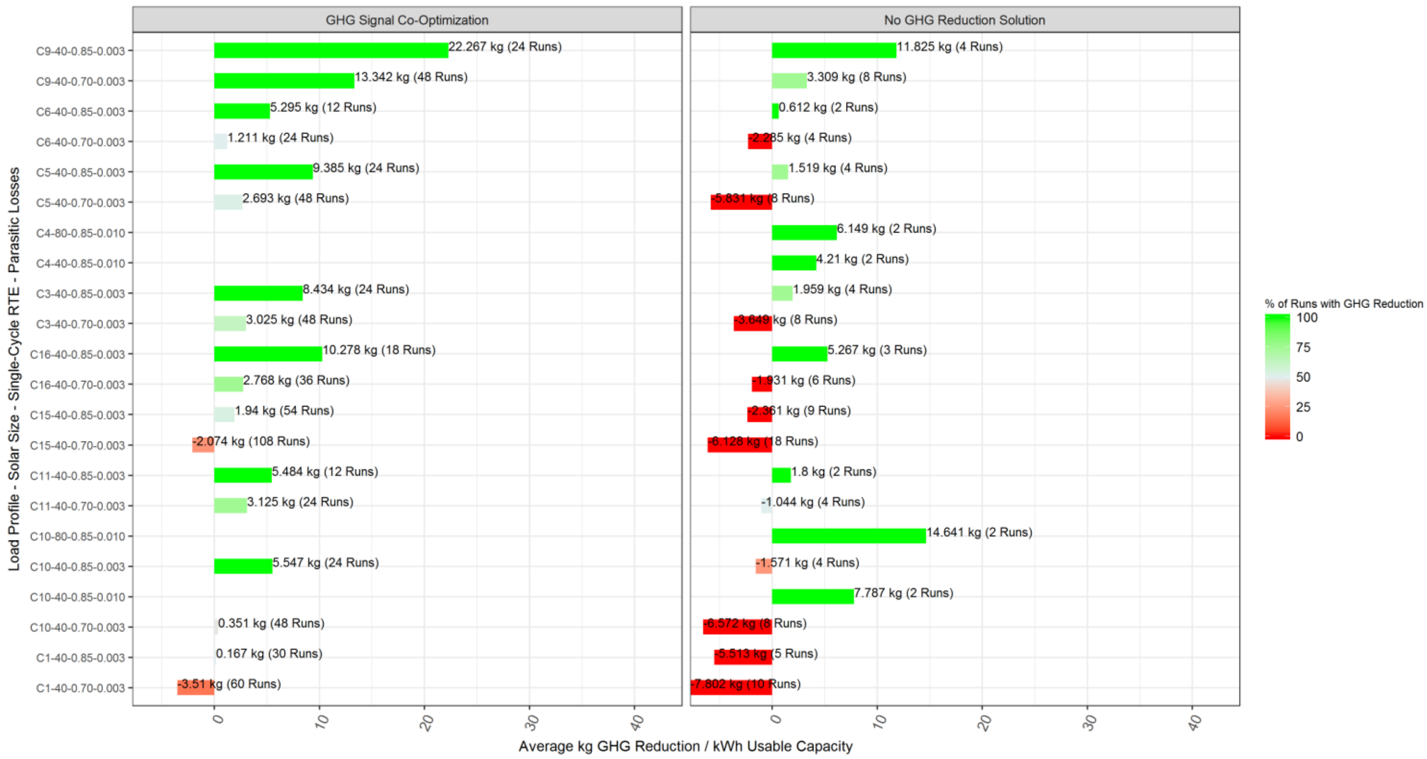
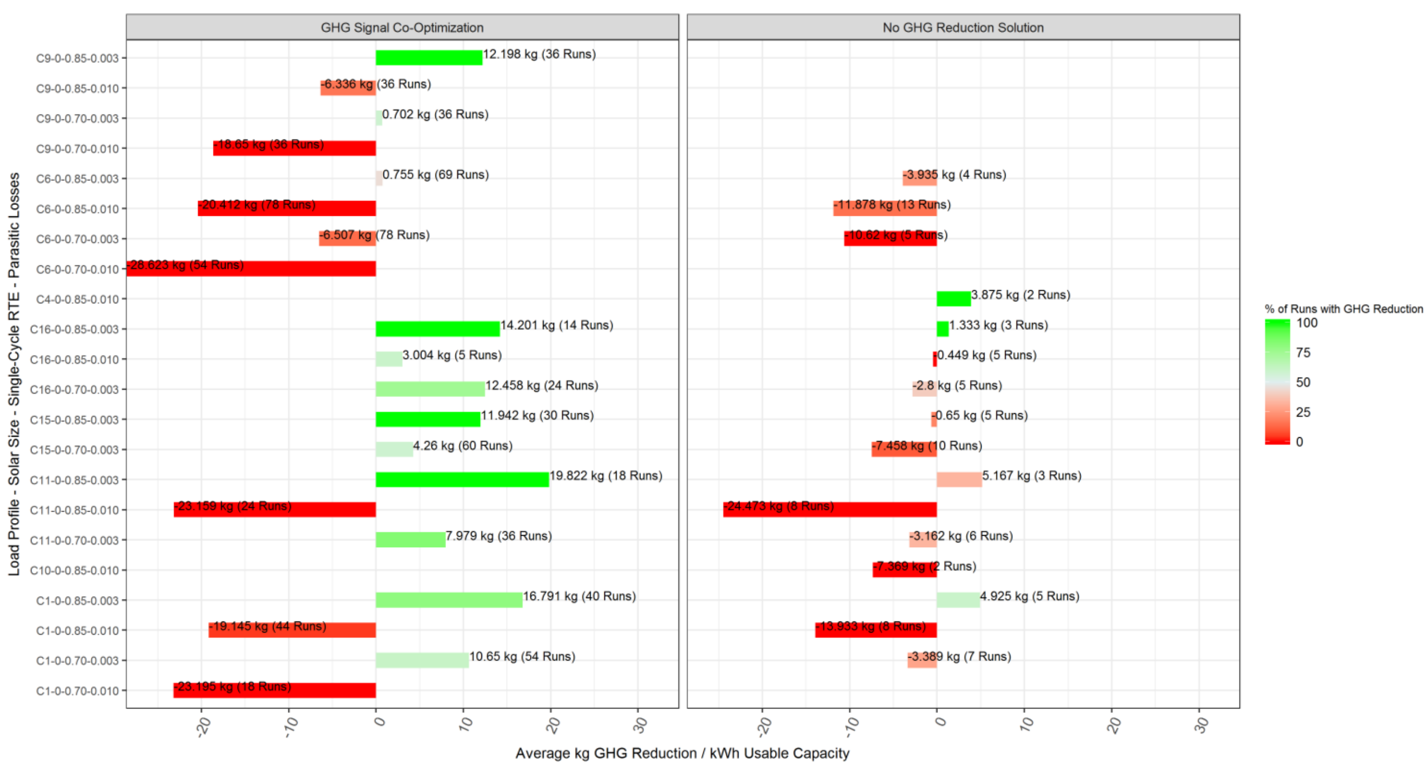


Figure 24: GHG Impacts of Commercial Standalone Storage Systems on New Rates



Cost Impacts

Figure 25: Cost Impacts of Commercial Storage Systems on Old Rates

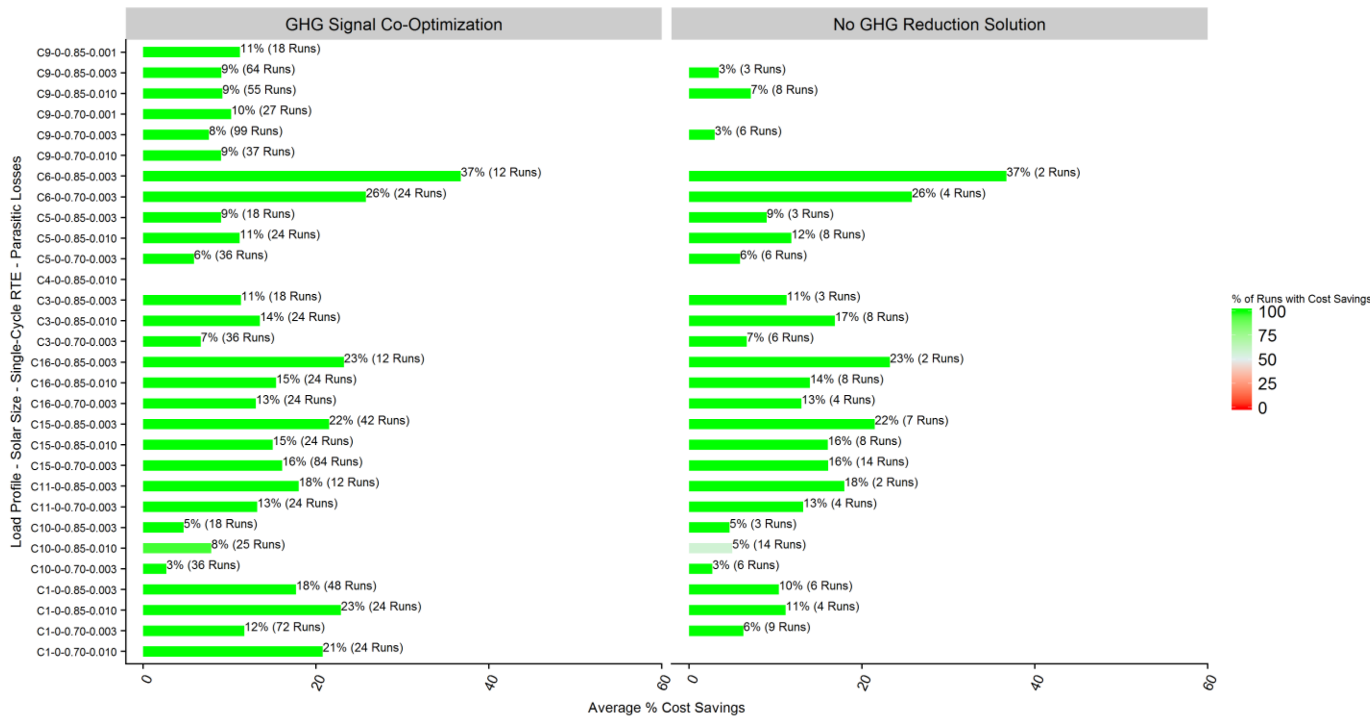


Figure 26: Cost Impacts of Commercial Storage Systems with Solar on Old Rates

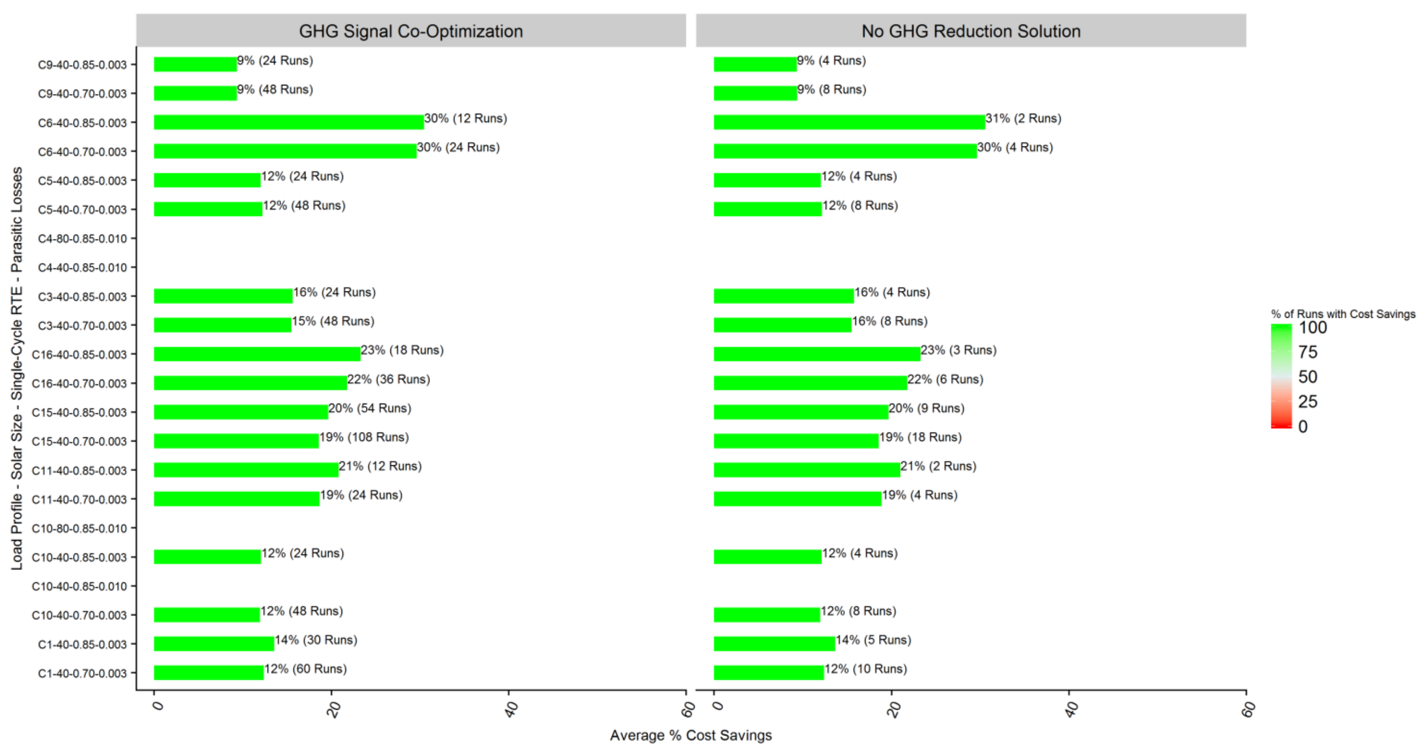


Figure 27: Cost Impacts of Residential Standalone Storage Systems on Old Rates

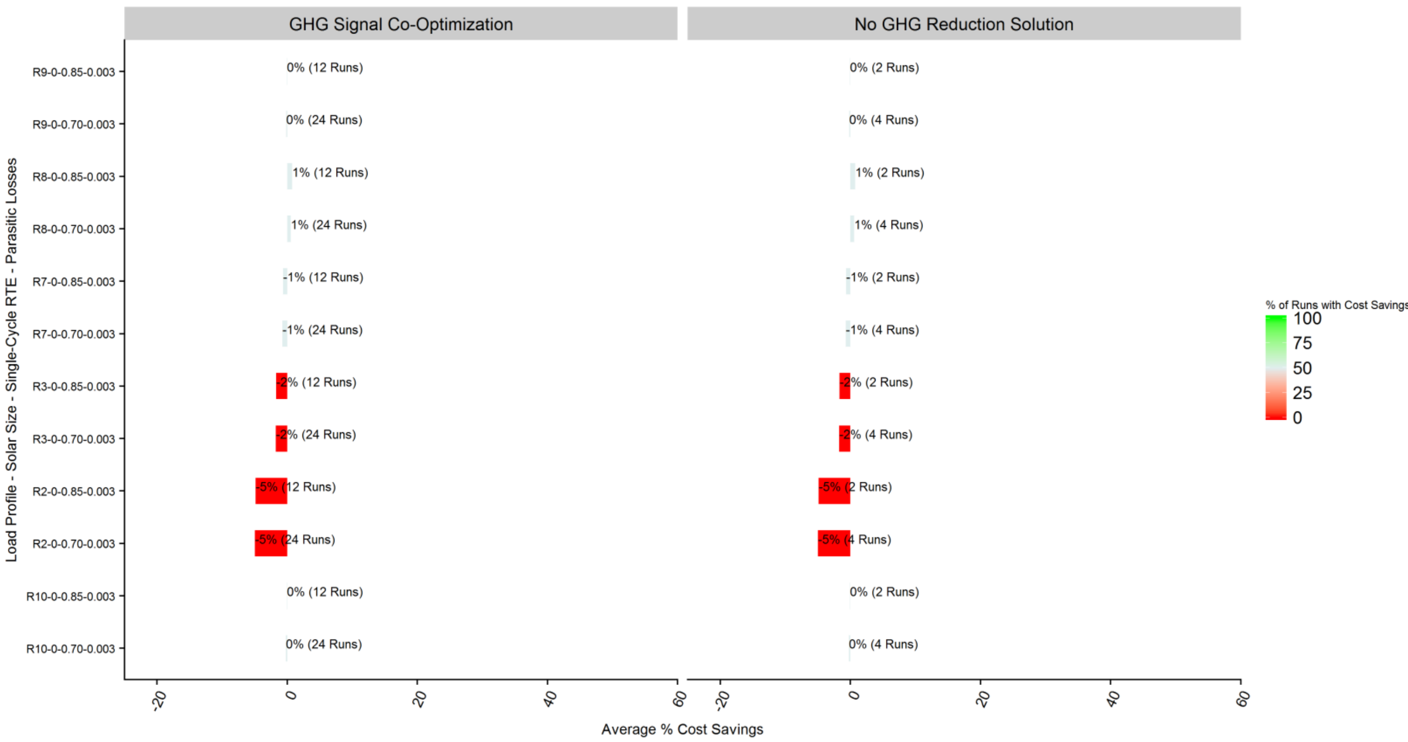


Figure 28: Cost Impacts of Commercial Storage Systems with Solar on New Rates

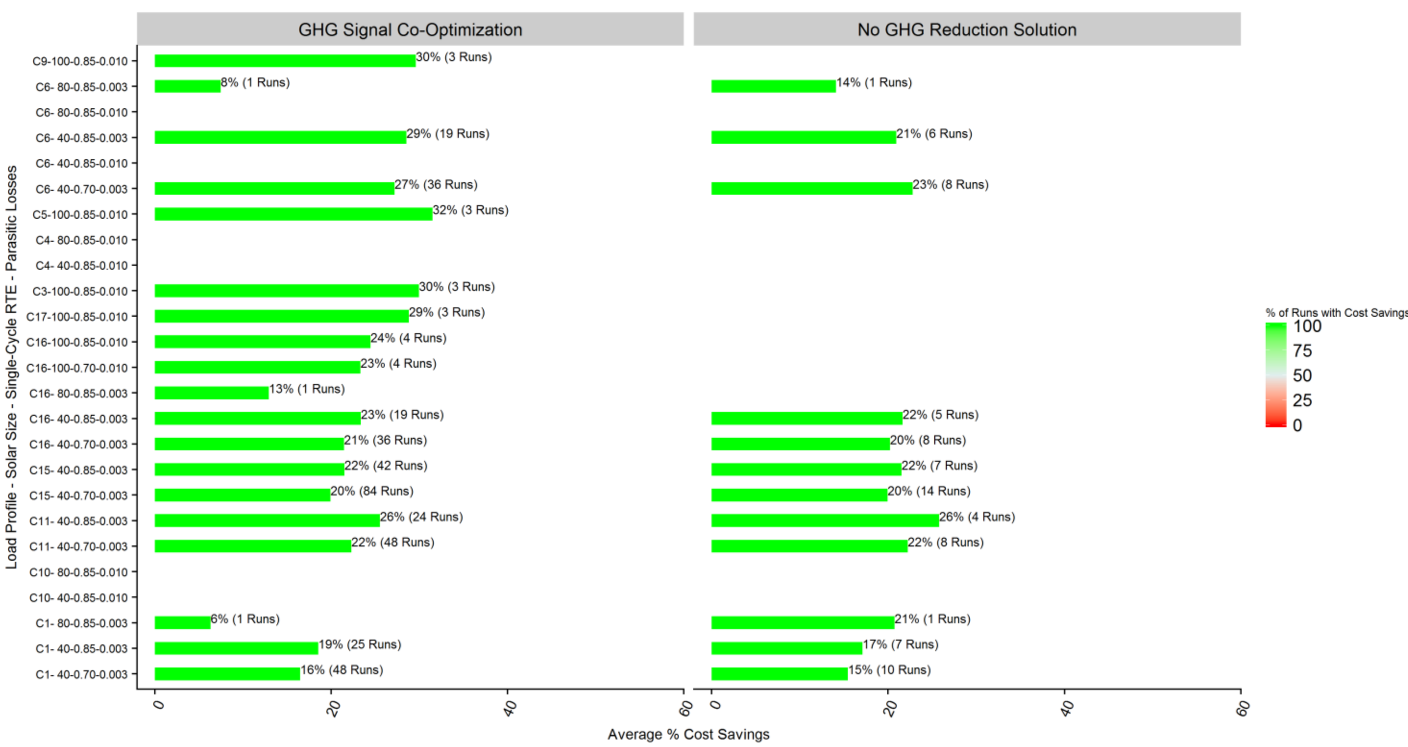
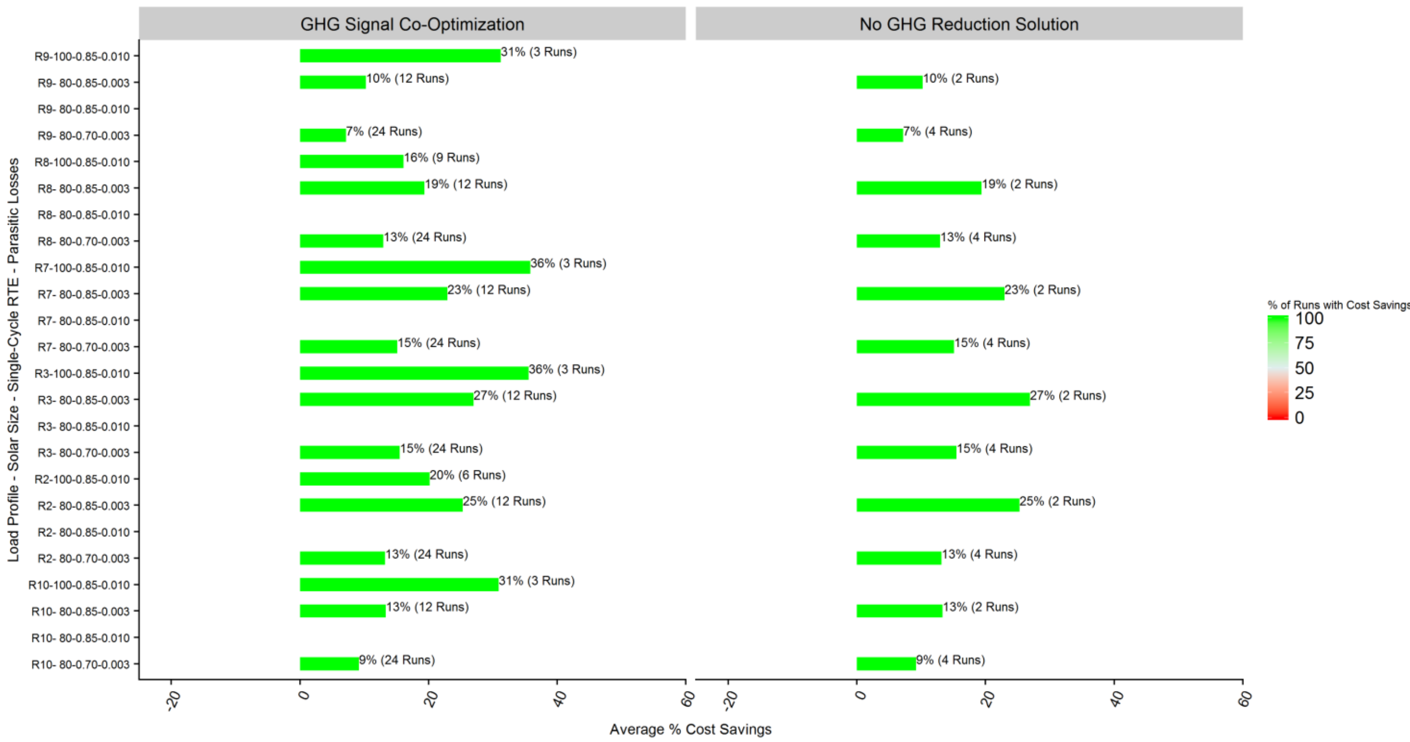


Figure 29: Cost Impacts of Residential Storage Systems with Solar on New Rates



Appendix D: Annual Cycles

Figure 30: GHG Reduction kg/kWh vs Annual Cycles for Commercial Storage with Solar on Old rates

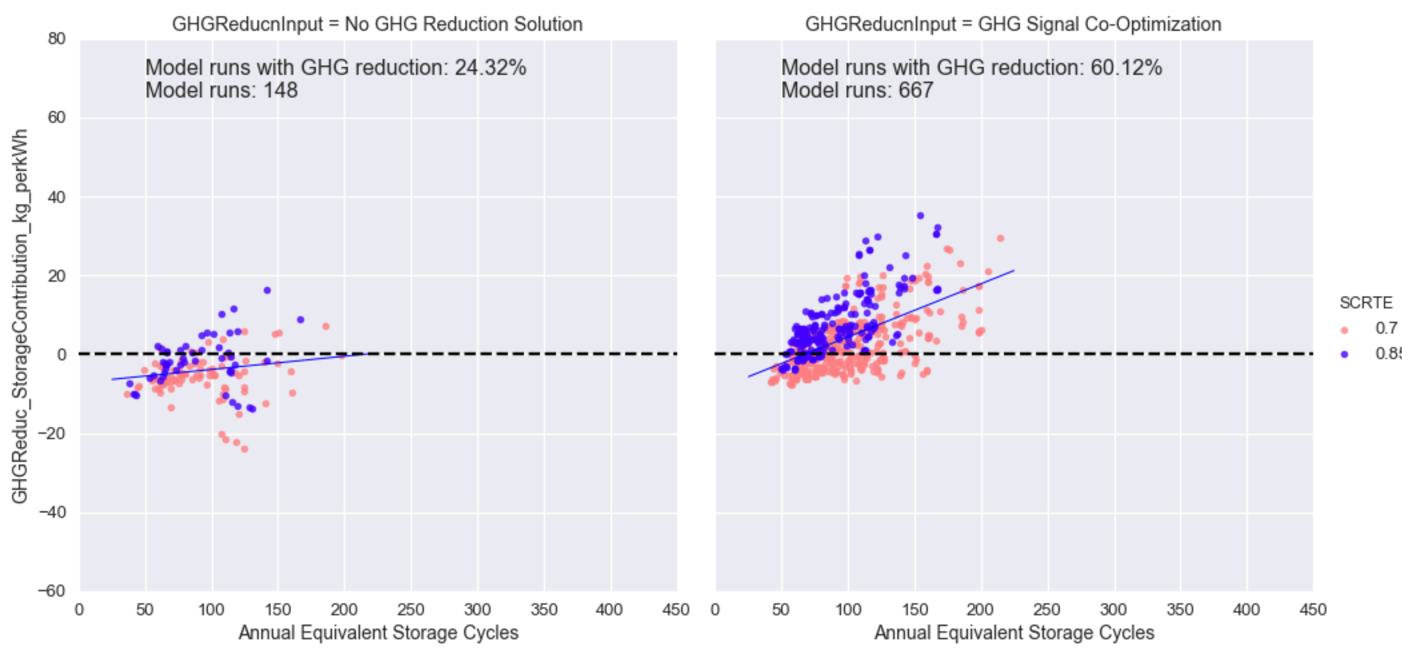


Figure 31: GHG Reduction kg/kWh vs Annual Cycles for Residential Standalone Storage on Old Rates

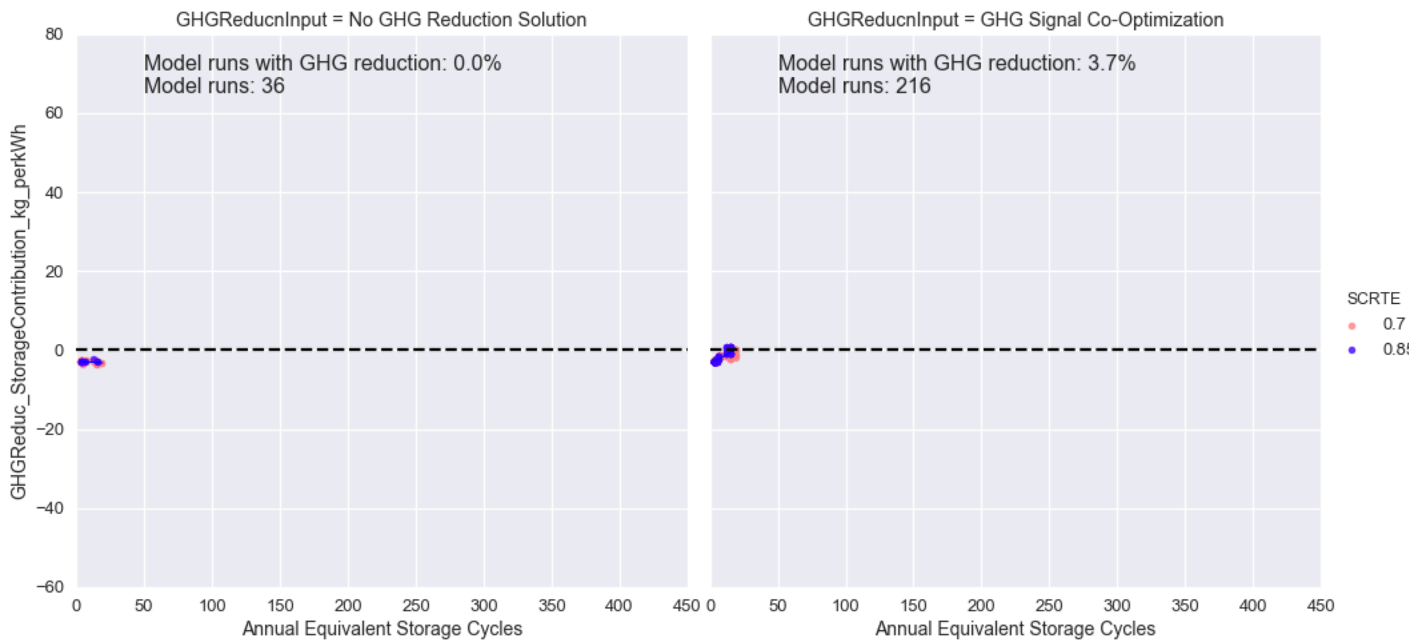


Figure 32: GHG Reduction kg/kWh vs Annual Cycles for Residential Standalone Storage on New Rates

Figure 33: GHG Reduction kg/kWh vs Annual Cycles for Residential Storage with Solar on New Rates

Appendix E: Annual RTE

Figure 34: GHG Reduction kg/kWh vs Annual RTE for Commercial Standalone Storage on Old Rates

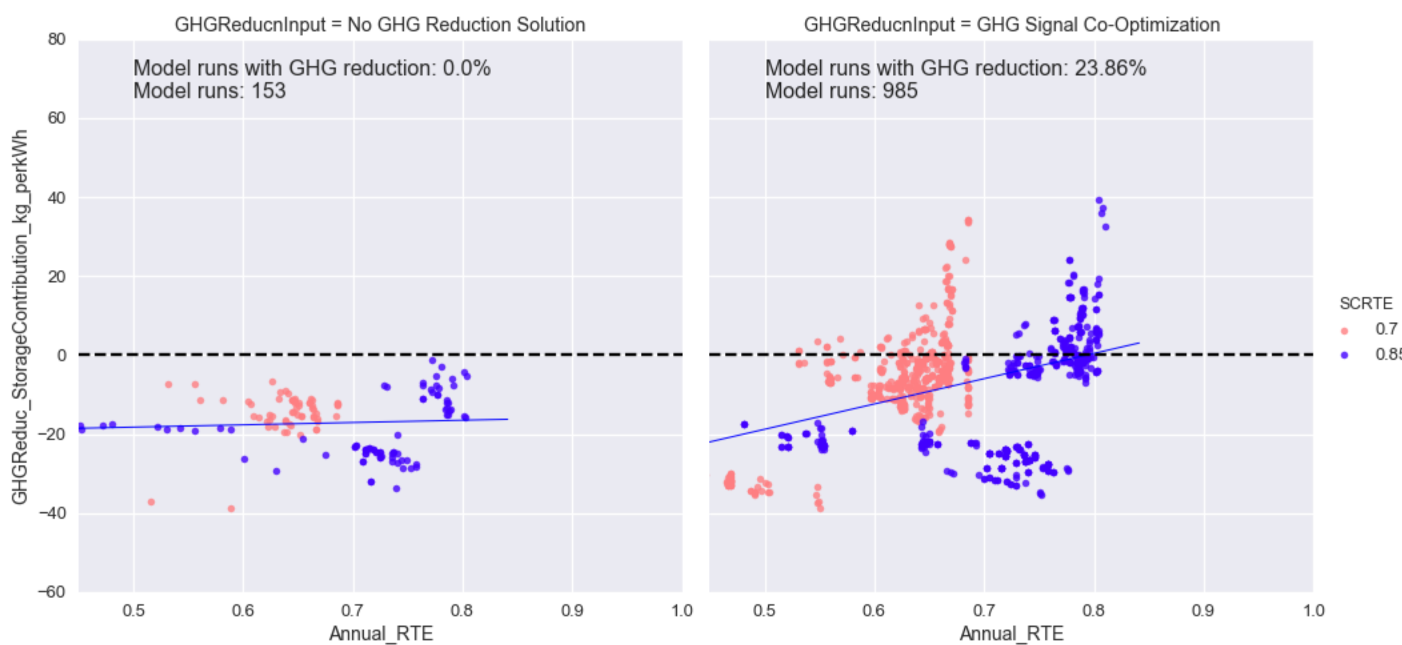


Figure 35: GHG Reduction kg/kWh vs Annual RTE for Commercial Standalone Storage on New Rates

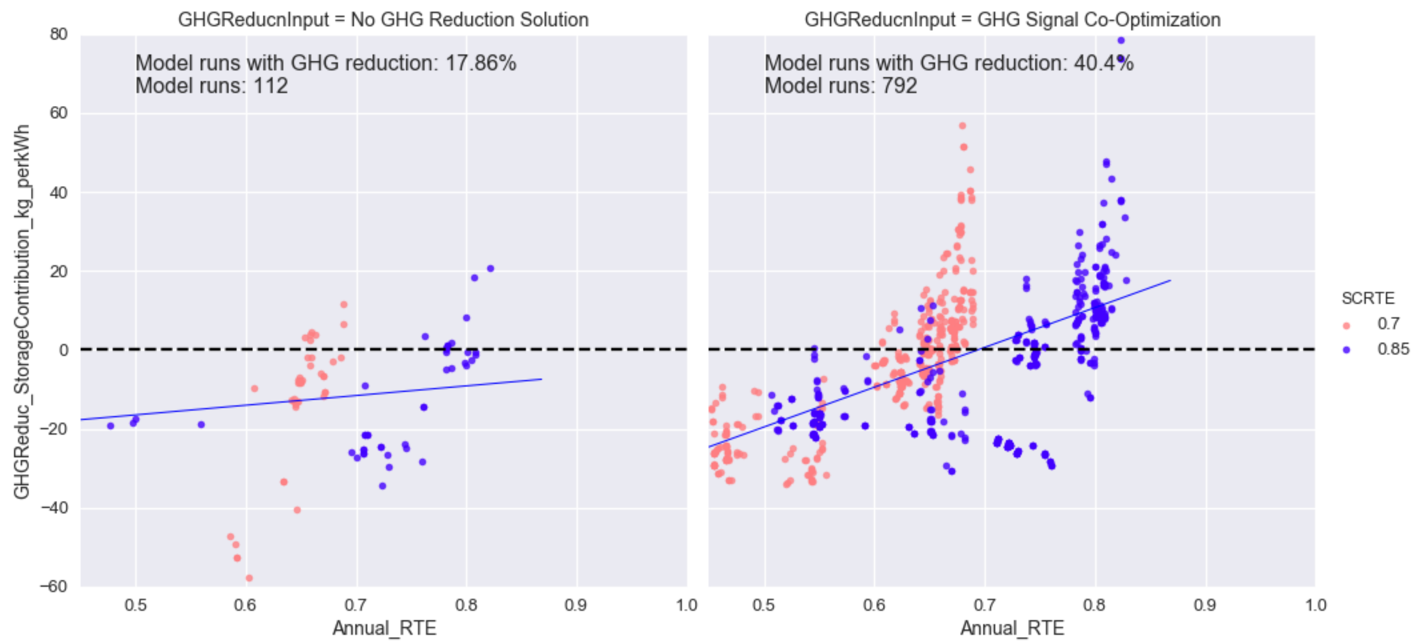


Figure 36: GHG Reduction kg/kWh vs Annual RTE for Commercial Storage with Solar on Old Rates

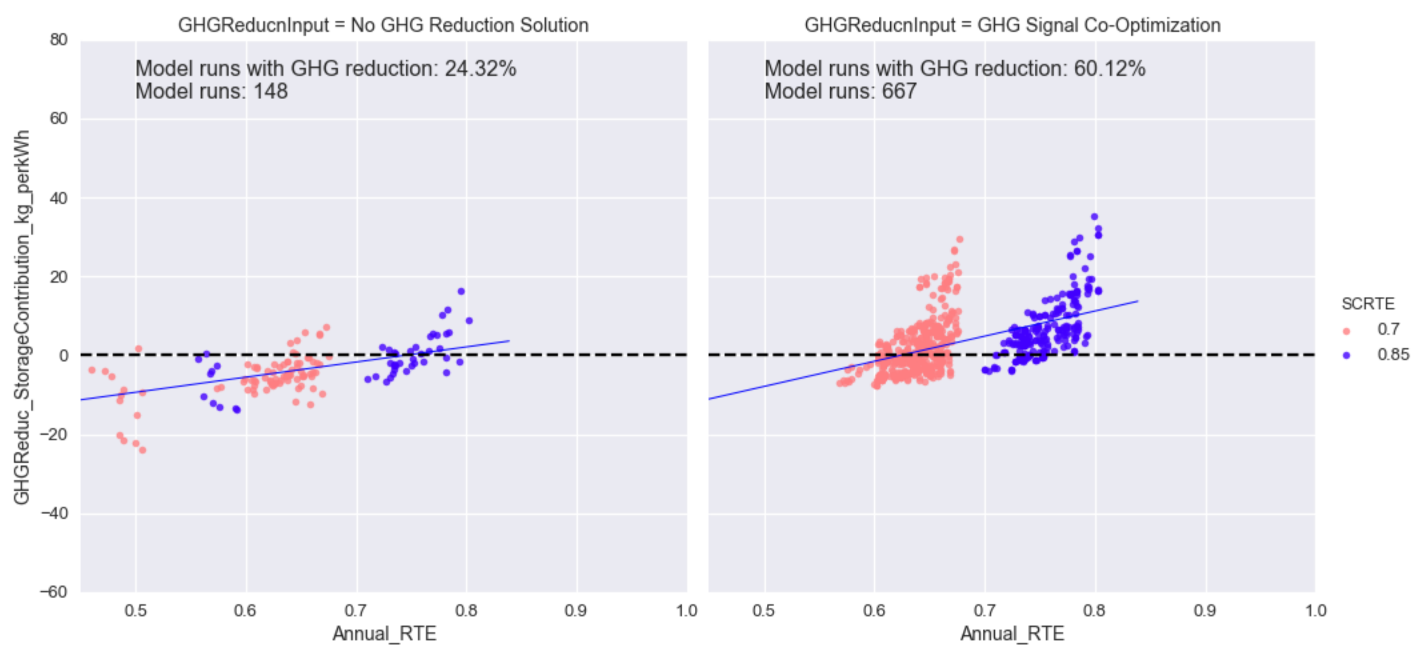


Figure 37: GHG Reduction kg/kWh vs Annual RTE for Residential Standalone Storage on Old Rates

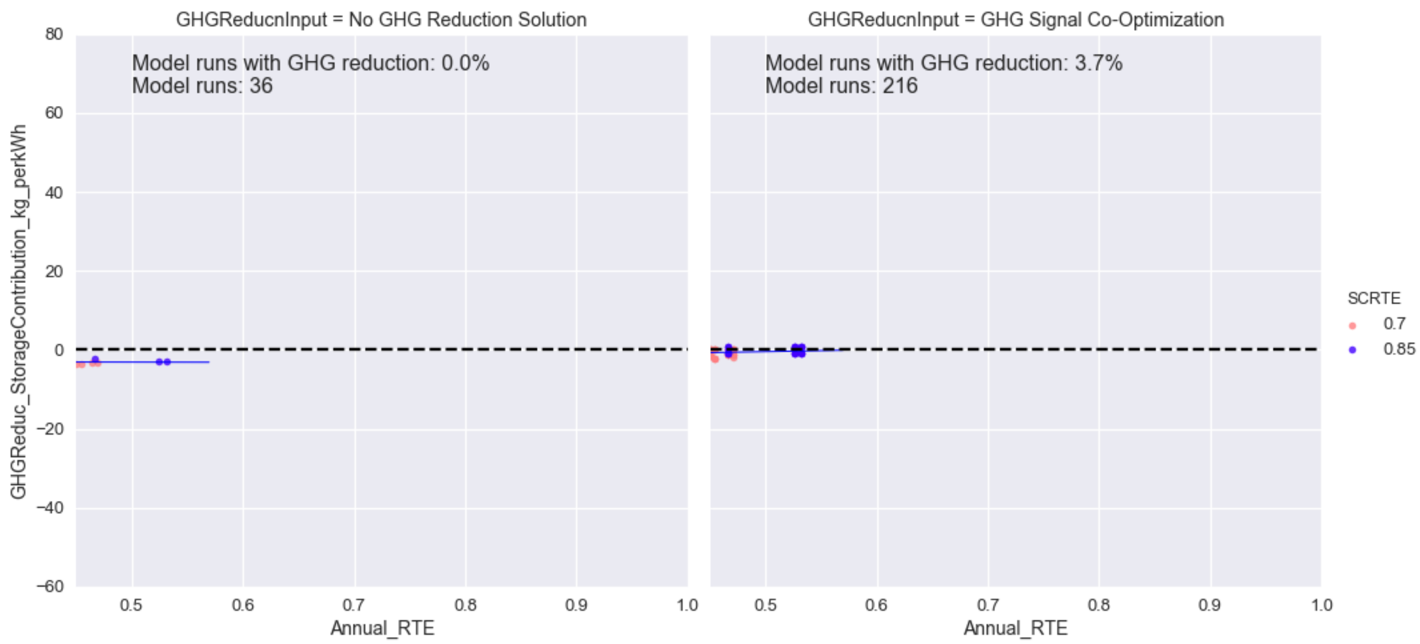


Figure 38: GHG Reduction kg/kWh vs Annual RTE for Residential Storage with Solar on Old Rates

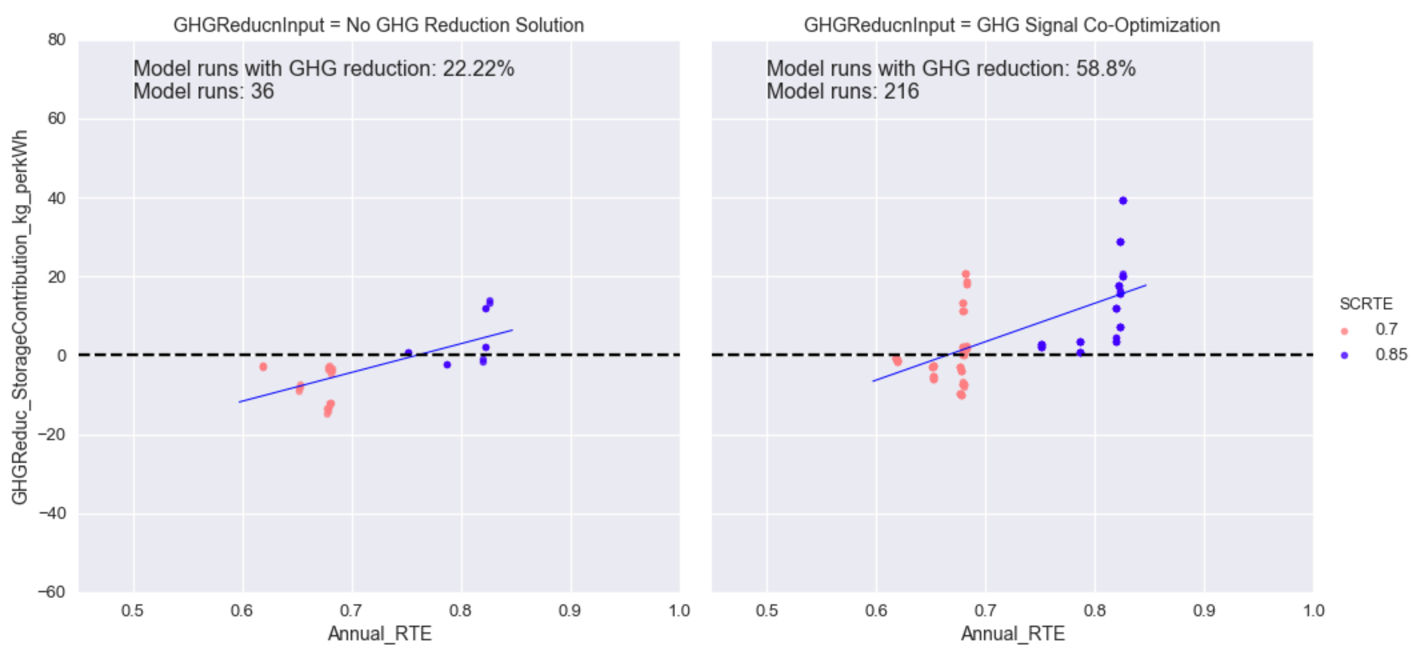


Figure 39: GHG Reduction kg/kWh vs Annual RTE for Residential Storage with Solar on New Rates

Figure 40: Linear Regression between - Annual RTE and SCRTE, Parasitic Load

Dep. Variable:	Annual_RTE	**R-squared:**	0.953
Model:	OLS	**Adj. R-squared:**	0.953
Method:	Least Squares	**F-statistic:**	5.128e+04
Date:	Mon, 21 May 2018	**Prob (F-statistic):**	0.00
Time:	12:05:33	**Log-Likelihood:**	2618.8
No. Observations:	5068	**AIC:**	-5234.
Df Residuals:	5066	**BIC:**	-5221.

	coef	**std err**	**t**	**P>|t|**	**[0.025**	**0.975]**
Single_Cycle_RTE_Input	0.9113	0.005	170.641	0.000	0.901	0.922
Parasitic_Storage_Load_Input	-12.0616	0.915	-13.184	0.000	-13.855	-10.268

Appendix F: Annual Cycles and Annual RTE Summary Statistics

Figure 41: Average Annual Cycles for GHG and Cost Reducing Model Runs

CUSTOMER CLASS	MODEL TYPE INPUT	RETAIL RATE	ANNUAL CYCLE MEAN			
			MODEL RUNS WITH GHG SAVINGS		MODEL RUNS WITH COST SAVINGS	
			GHG SIGNAL CO-OPTIMIZATION	NO GHG REDUCTION SOLUTION	GHG SIGNAL CO-OPTIMIZATION	NO GHG REDUCTION SOLUTION
Commercial & Industrial	Storage Only	OLD	125.41	NA	141.06	146.42
		NEW	180.55	184.13	164.92	165.72
	Solar Plus Storage	OLD	101.71	103.91	91.91	91.34
		NEW	148.36	210.46	139.44	198.37
Residential	Storage Only	OLD	14.57	NA	13.07	13.08
		NEW	228.83	266.78	228.83	228.83
	Solar Plus Storage	OLD	199.69	181.73	NA	NA
		NEW	176.40	199.58	162.87	162.86

Figure 42: Average Annual RTE for GHG and Cost Reducing Model Runs

CUSTOMER CLASS	MODEL TYPE INPUT	RETAIL RATE	ANNUAL RTE MEAN			
			MODEL RUNS WITH GHG SAVINGS		MODEL RUNS WITH COST SAVINGS	
			GHG SIGNAL CO-OPTIMIZATION	NO GHG REDUCTION	GHG SIGNAL CO-OPTIMIZATION	NO GHG REDUCTION SOLUTION
Commercial and Industrial	Storage Only	OLD	0.72	NA	0.67	0.68
		NEW	0.73	0.74	0.66	0.66
	Solar Plus Storage	OLD	0.7	0.72	0.68	0.64
		NEW	0.7	0.68	0.69	0.67
Residential	Storage Only	OLD	0.51	NA	0.41	0.41
		NEW	0.72	0.83	0.72	0.72
	Solar Plus Storage	OLD	0.75	0.81	NA	NA
		NEW	0.72	0.74	0.71	0.71

Table 10: Average Annual Equivalent Cycles by Reduction Solution, Rate, Model Type, and Customer Class

Reduction Solution	Rates	Model Type	All Model Runs		GHG- and Cost-Reducing	
			C & I	Residential	C & I	Residential
GHG Signal Co-Optimization	New	Solar Plus Storage	139.44	162.87	148.36	176.40
		Storage Only	164.92	228.83	180.55	228.83
	Old	Solar Plus Storage	91.91	174.79	101.71	N/A
		Storage Only	141.06	7.01	125.41	14.57

No GHG Reduction Solution	New	Solar Plus Storage	198.37	162.86	210.46	199.58
		Storage Only	165.72	228.83	184.13	266.78
	Old	Solar Plus Storage	91.34	174.83	103.91	N/A
		Storage Only	146.42	7.02	N/A	N/A

Table 11: Average Annual RTE by Reduction Solution, Rate, Model Type, and Customer Class

Reduction Solution	Rates	Model Type	All Model Runs		GHG- and Cost-Reducing	
			C & I	Residential	C & I	Residential
GHG Signal Co-Optimization	New	Solar Plus Storage	0.69	0.71	0.70	0.72
		Storage Only	0.66	0.72	0.73	0.72
	Old	Solar Plus Storage	0.68	0.71	0.70	N/A
		Storage Only	0.67	0.16	0.72	0.51
No GHG Reduction Solution	New	Solar Plus Storage	0.67	0.71	0.68	0.74
		Storage Only	0.66	0.72	0.74	0.83
	Old	Solar Plus Storage	0.64	0.71	0.72	N/A
		Storage Only	0.68	0.16	N/A	N/A

Appendix G: Effect of Charge Constraints on GHG Emissions

Table 12: Effect of Charge Constraints on GHG Emissions by Load Profile: Modelers B, D, and F

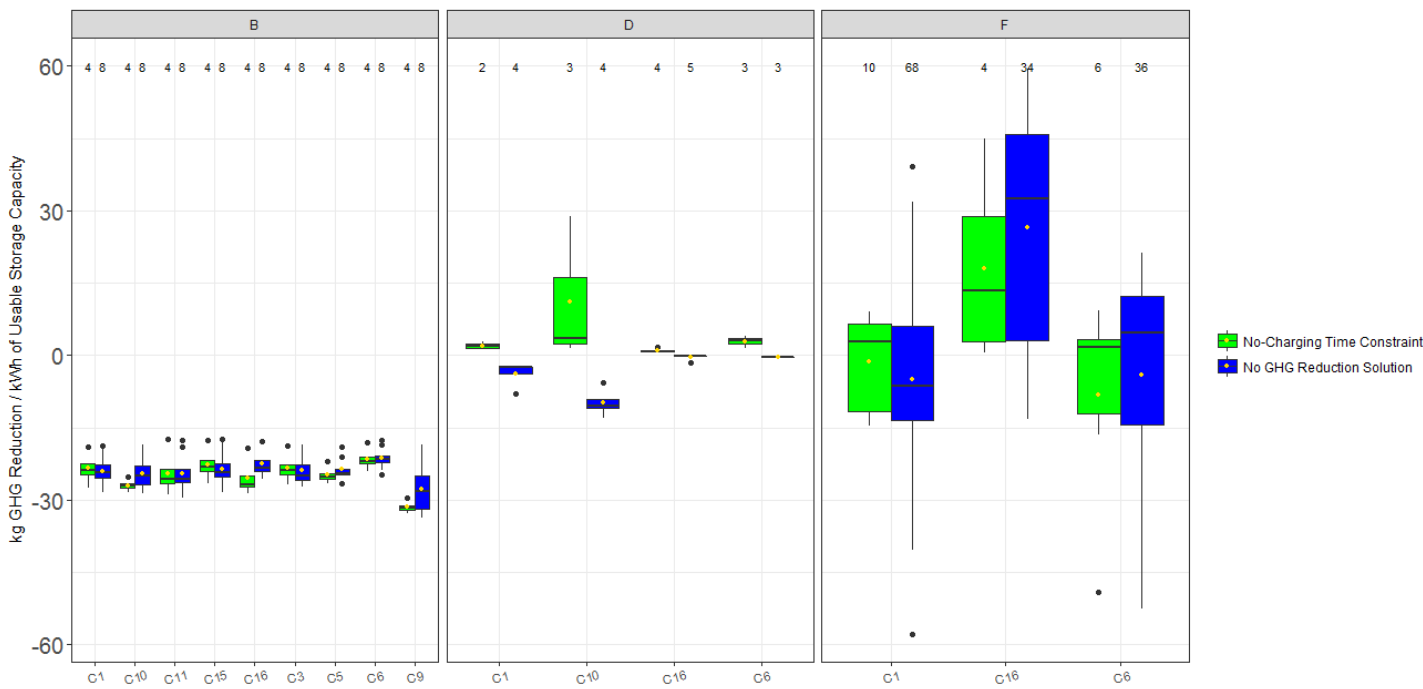
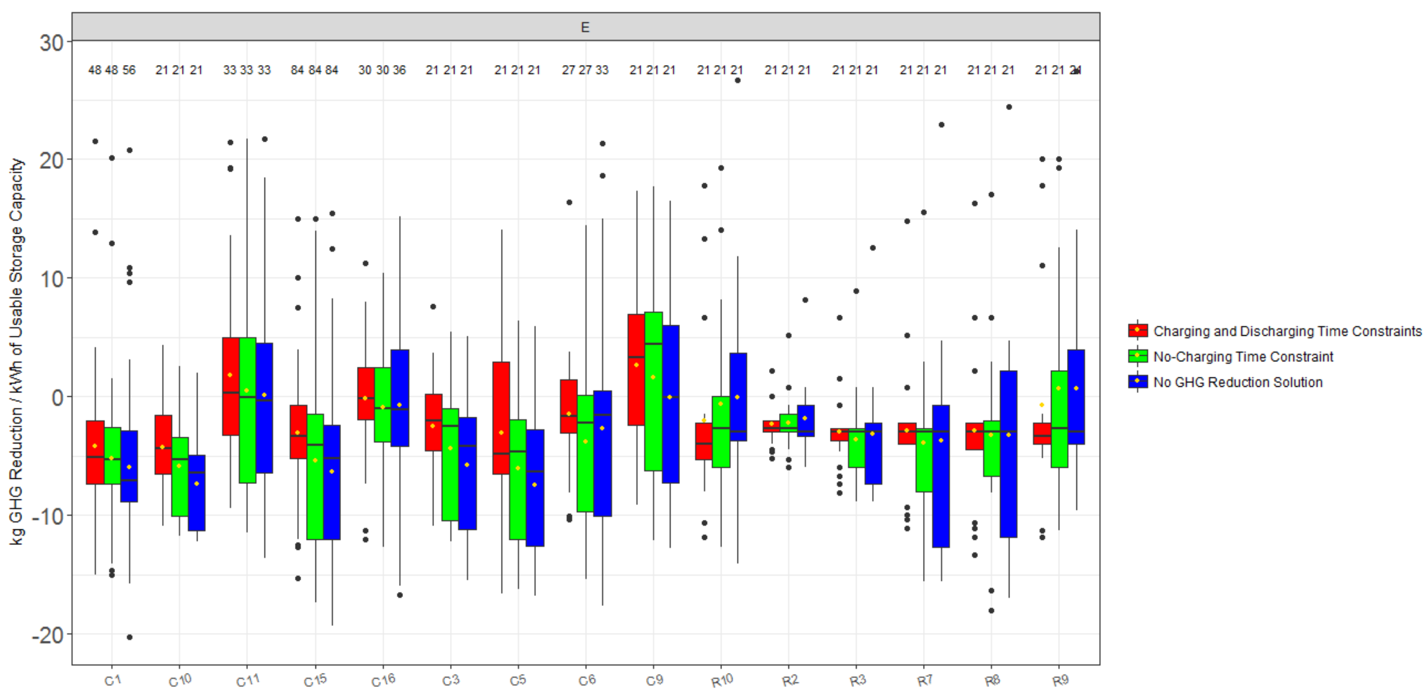


Table 13: Effect of Charge Constraints on GHG Emissions by Load Profile: Modeler E



Appendix H: CALSSA Modeling to Support Solar Credit Proposal

			Solar			Solar Plus Storage			Capital Recovery (Years)	
Profile	Utility	Pre-Solar Bill	PV-kW	Solar Investment	Solar Bill Reduction	ESS (PV-kW/ESS-kW/ESS-kWh)	S+S Invest-ment	S+S Bill Reduction	Solar Pay-back	S+S Pay-back
C1	PGE	221,994	390	682,500	107,226	260/130/260	509,486	89,294	6.3	5.7
C1	SCE	172,103	390	682,500	81,421	260/130/260	518,051	74,195	8.4	7
C1	SDGE	304,552	390	682,500	168,609	260/130/260	516,466	136,079	4.0	3.7
C6	PGE	205,385	305	533,750	71,957	203/100/200	405,632	62,681	7.4	6.5
C6	SCE	185,478	305	533,750	67,926	203/100/200	410,182	68,006	7.8	6.7
C6	SDGE	316,152	305	533,750	152,288	203/100/200	410,203	134,551	3.4	3.0
C9	PGE	508,501	1000	1,470,000	221,496	720/360/720	1,152,000	218,811	6.6	5.2
C9	SCE	333,577	1000	1,470,000	98,619	720/360/720	1,180,796	115,637	19.9	19
C9	SDGE	560,090	1000	1,470,000	181,506	720/360/720	1,180,796	199,869	8.2	5.9
C10	PGE	1,230,155	1000	1,470,000	221,393	1000/500/1000	1,655,148	288,197	6.6	5.7
C10	SCE	915,499	1000	1,470,000	151,551	1000/500/1000	1,698,678	200,815	10.0	8.7
C10	SDGE	1,514,180	1000	1,470,000	248,973	1000/500/1000	1,677,140	356,470	5.8	4.7

Appendix I: Better Energies Modeling to Support Solar Credit Proposal

Table 14: Better Energies Customer 1

PV	360
ES kW	90
ES kWh	120
PV $/W	2
ES $/kWh	800
PV Price	$720,000.00
ES Price	$96,000.00
PV ITC	$(216,000.00)
ES ITC + SGIP	$(54,480.00)
PV net cost	$504,000.00
ES net cost	$41,520.00

Table 15: Better Energies SCE GS-2 Old Tariffs and New Tariffs

Old Tariffs

	Old bill	New Bill	Savings
NBC	18,238	9,353	8,885
Energy	36,708	-	36,708
Demand	50,988	16,152	34,836
PV Savings			45,593
ES Savings			34,836
Solar only simple return			9%
PV+ES simple return			15%

New Tariffs

	Old bill	New Bill	Savings
NBC	18,238	8,708	9,530
Energy	36,838	17,069	19,769
Demand	44,395	12,005	32,390
PV Savings			29,299
ES Savings			32,390
Solar only simple return			6%
PV+ES simple return			11%

Table 16: Better Energies Customer 2

PV	569
ES kW	114

ES kWh	324
PV $/W	2
ES $/kWh	800
PV Price	$1,138,000.00
ES Price	$259,200.00
PV ITC	$(341,400.00)
ES ITC + SGIP	$(147,096.00)
PV net cost	$796,600.00
ES net cost	$112,104.00

Table 17: Better Energies PG&E E-19 Old Tariffs and New Tariffs

Old Tariffs

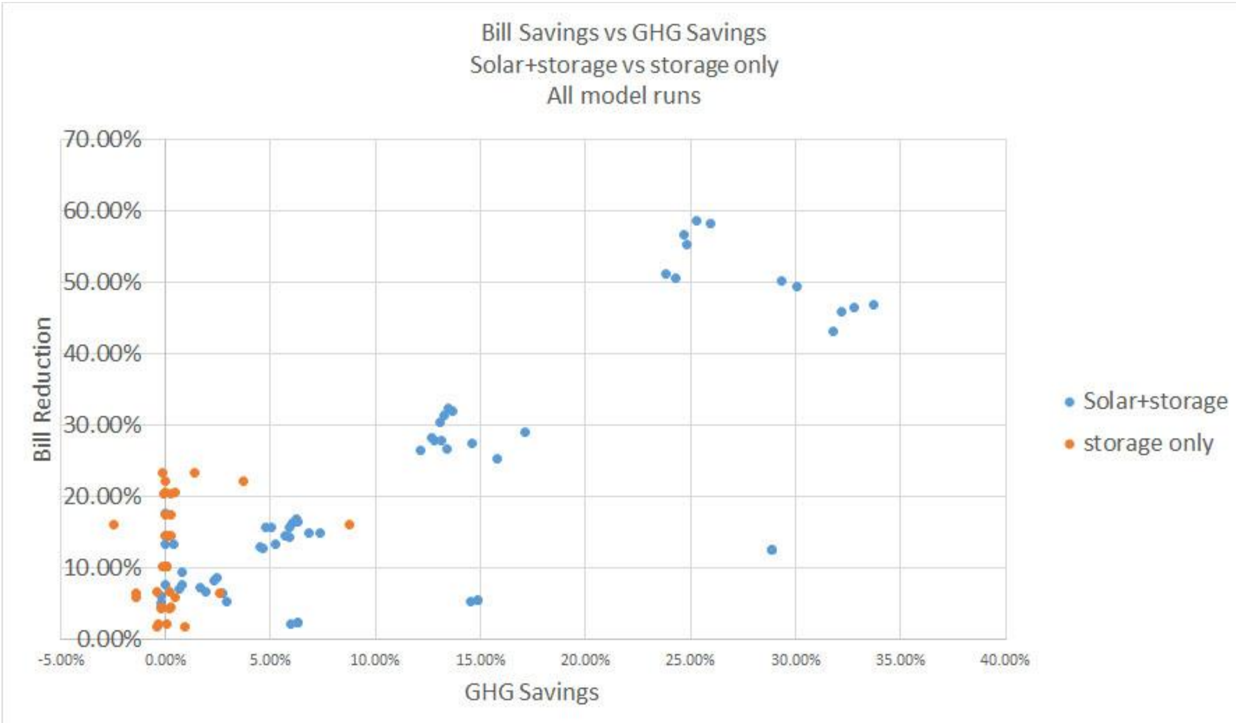
	Old bill	New Bill	Savings
NBC	69,128	50,302	18,826
Energy	218,260	163,720	54,540
Demand	147,480	76,342	71,138
PV Savings			73,366
ES Savings			71,138
Solar only simple return			9%
PV+ES simple return			16%

New Tariffs

	Old bill	New Bill	Savings
NBC	69,128	50,064	19,064
Energy	222,211	190,104	32,107
Demand	133,637	79,716	53,921
PV Savings			51,171
ES Savings			53,921
Solar only simple return			6%
PV+ES simple return			12%

Appendix J: CPS Analysis

Figure 43: Corrected Cost Savings vs GHG Reduction Storage Only



Summary

1. 98 model runs including storage only and solar + storage. Blue dots clearly show substantial cost and GHG savings. Original slide produced by AESC had Bill Reductions and GHG Savings swapped.

Figure 44: Cost: Commercial and Industrial Solar Only Vs Solar + Storage Savings Old Rates Vs New Rates

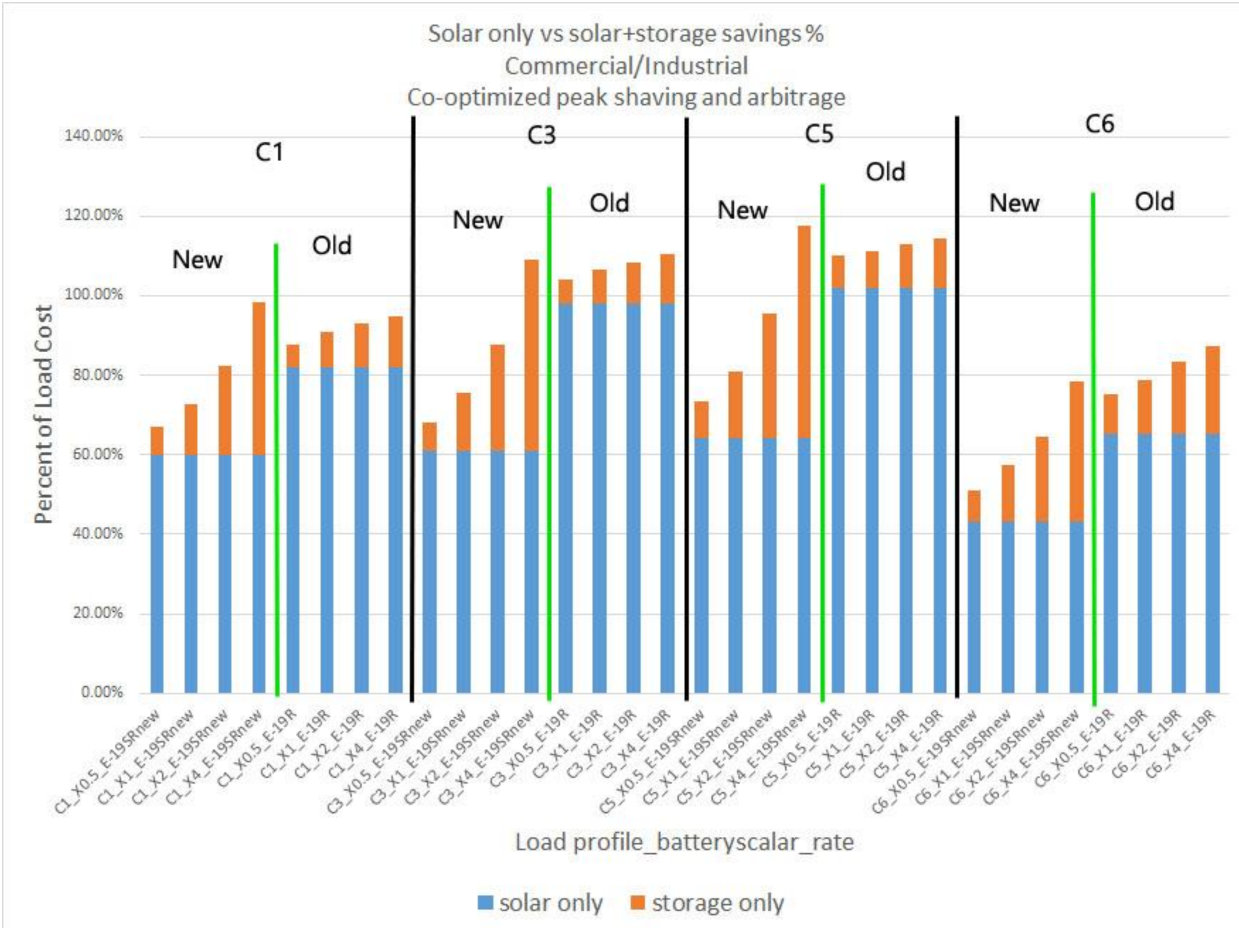
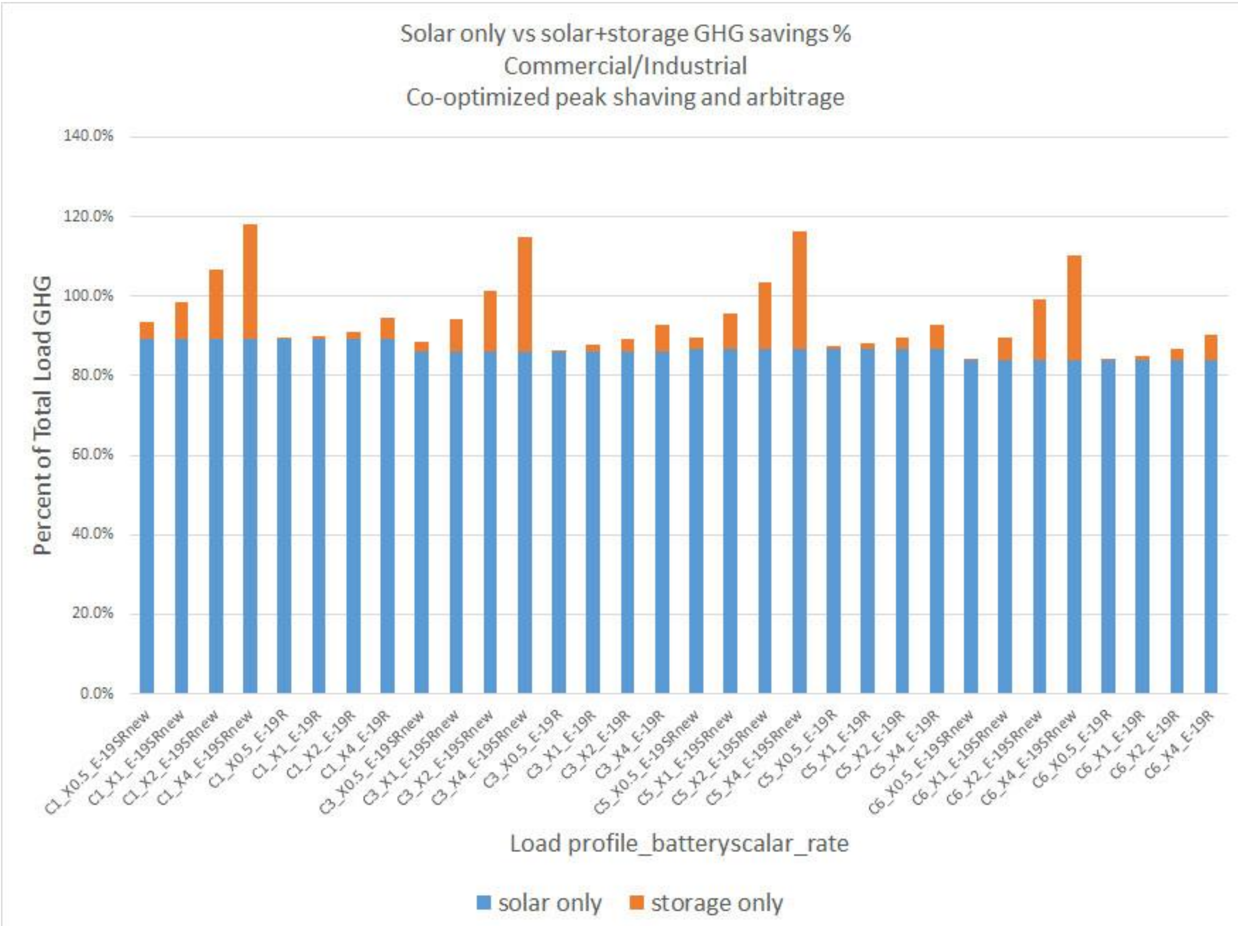


Figure 45: GHG: Commercial and Industrial Solar Only Vs Solar + Storage Savings Old Rates Vs New Rates



Summary

1. Charts depicts 4 representative commercial/industrial loads, including light and medium manufacturing, offices, and food processing.
2. These charts compare the current E-19R PG&E rate and the new E-19R (E-19SRnew) rate coming in 2019.
3. Chart shows co-optimized peak shaving and arbitrage.
    a. Peak shaving is conservative, using forecasting instead of perfect foresight
    b. Arbitrage has priority
    c. Primary optimization is best cost savings

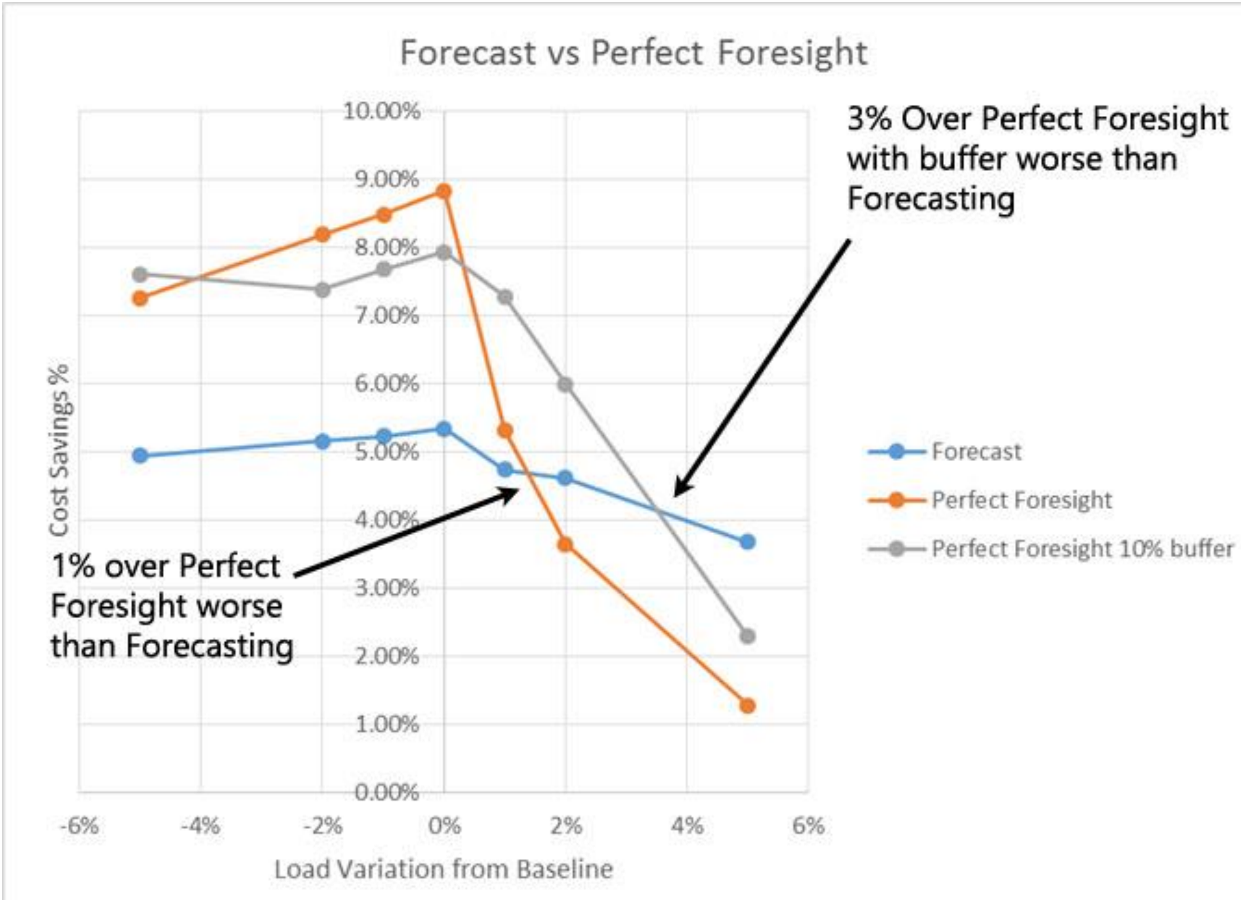
Conclusions

1. The value of solar alone is reduced with the new rates by 20%-40%.
2. Adding storage gives back some of the value lost.
3. Larger storage greatly increases the GHG savings and cost savings
    a. Based on the size of the storage system
    b. Larger systems up to 4X provide greater value with new rates compared to current rates due to arbitrage.

Notes

1. Solar was sized to generate solar power over the year equal to the load use over the year.
2. From left to right the first 4 are 0.5x,1x,2x and 4x storage size for the new E-19R rate
    a. Size of storage 1X=peak power of solar*1 hour
3. The next 4 are the current E-19R rate - same list of storage sizes.
4. The titles are at the bottom with the storage sizes as well as rates in the title.

Figure 46: Forecasting Vs Perfect Foresight Sensitivity Study



Summary

1. Chart depicts model runs comparing peak shaving using Forecasting vs Perfect Foresight. Many commercial modeling tools use Perfect Foresight to predict cost savings, which we feel are very unlikely to be achieved in real systems operation.
2. Perfect Foresight model sets up to 4 different peak shaving thresholds per month, a different threshold for each rate period, to maximize savings.
3. Forecasting in this model uses only one peak shaving value for the entire year.
4. Perfect Foresight is extremely sensitive to increase in loads. 1% in load increase destroys cost savings, virtually certain to happen in real life.
5. Adding a buffer can soften this sensitivity at an overall decrease in cost savings.

Conclusions

1. Caution should be exercised in evaluating cost savings models. Some commercially available models are unreasonably optimistic in cost savings analysis with peak shaving.

Notes

1. C9 Load Case
2. 390kw Inverter
3. 870kwh Storage
4. No solar – storage only
5. 85% RTE
6. 0.3% Parasitic Losses
7. TOU8B rate
8. Vary load profile +/- up to 5%
9. All other parameters identical

10. Simulate variability in load (real life)

Figure 47: Residential Cycling Impact on GHG Reduction 20 kWh Storage

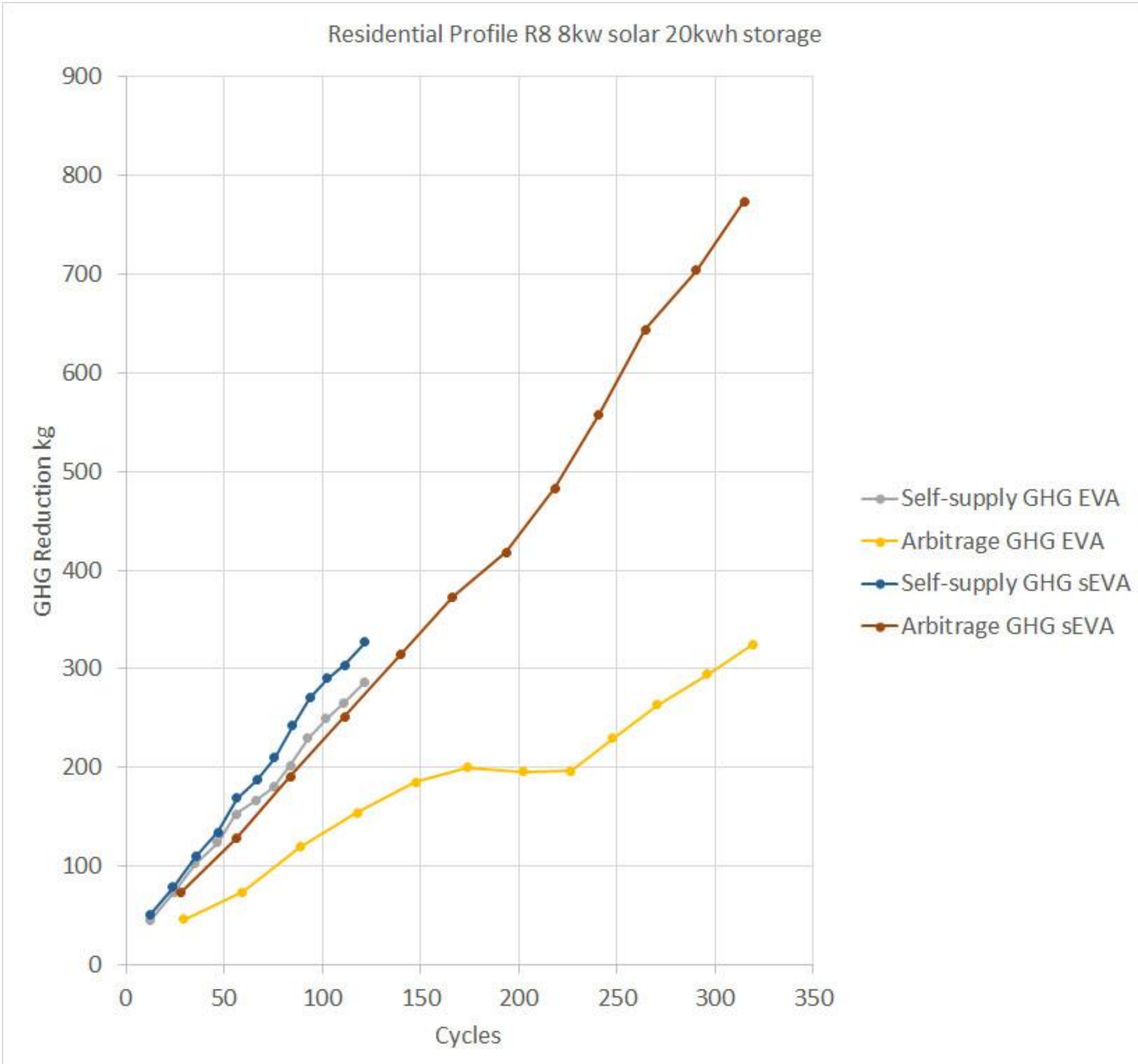


Figure 48: Residential Cycling Impact on Cost Reduction 20 kWh Storage

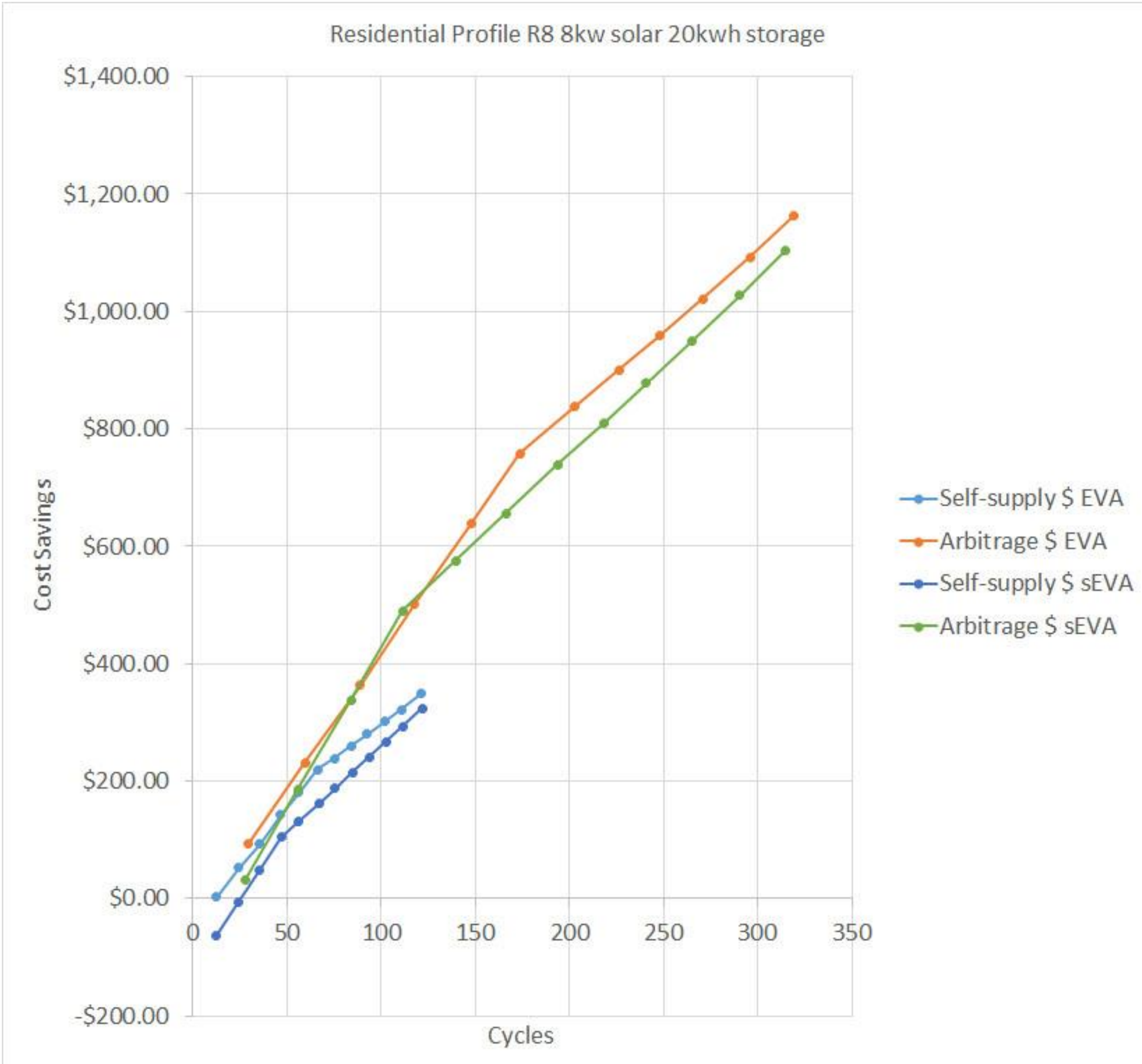


Figure 49: Residential Cycling Impact on GHG Reduction 13.5 kWh Storage

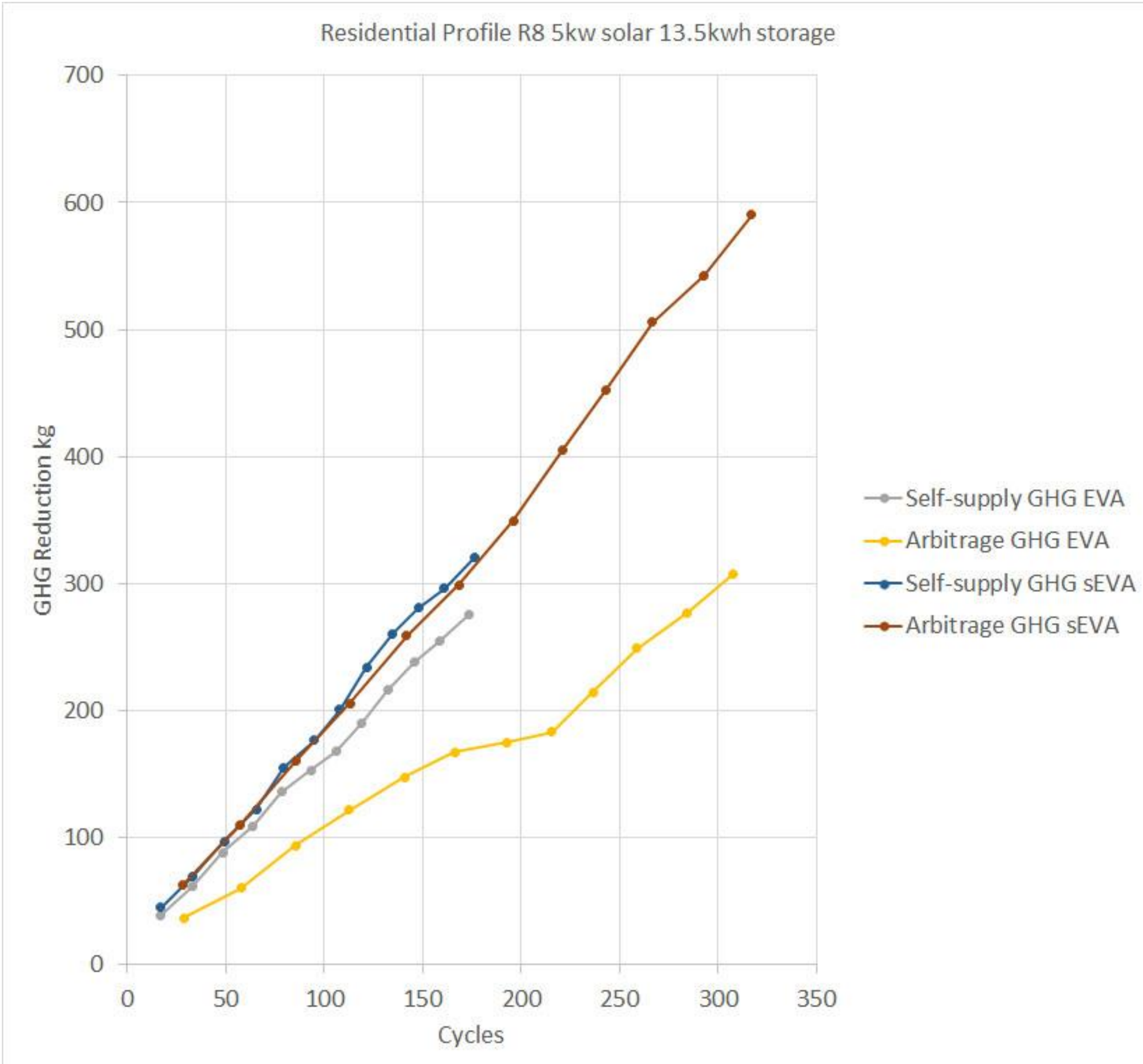
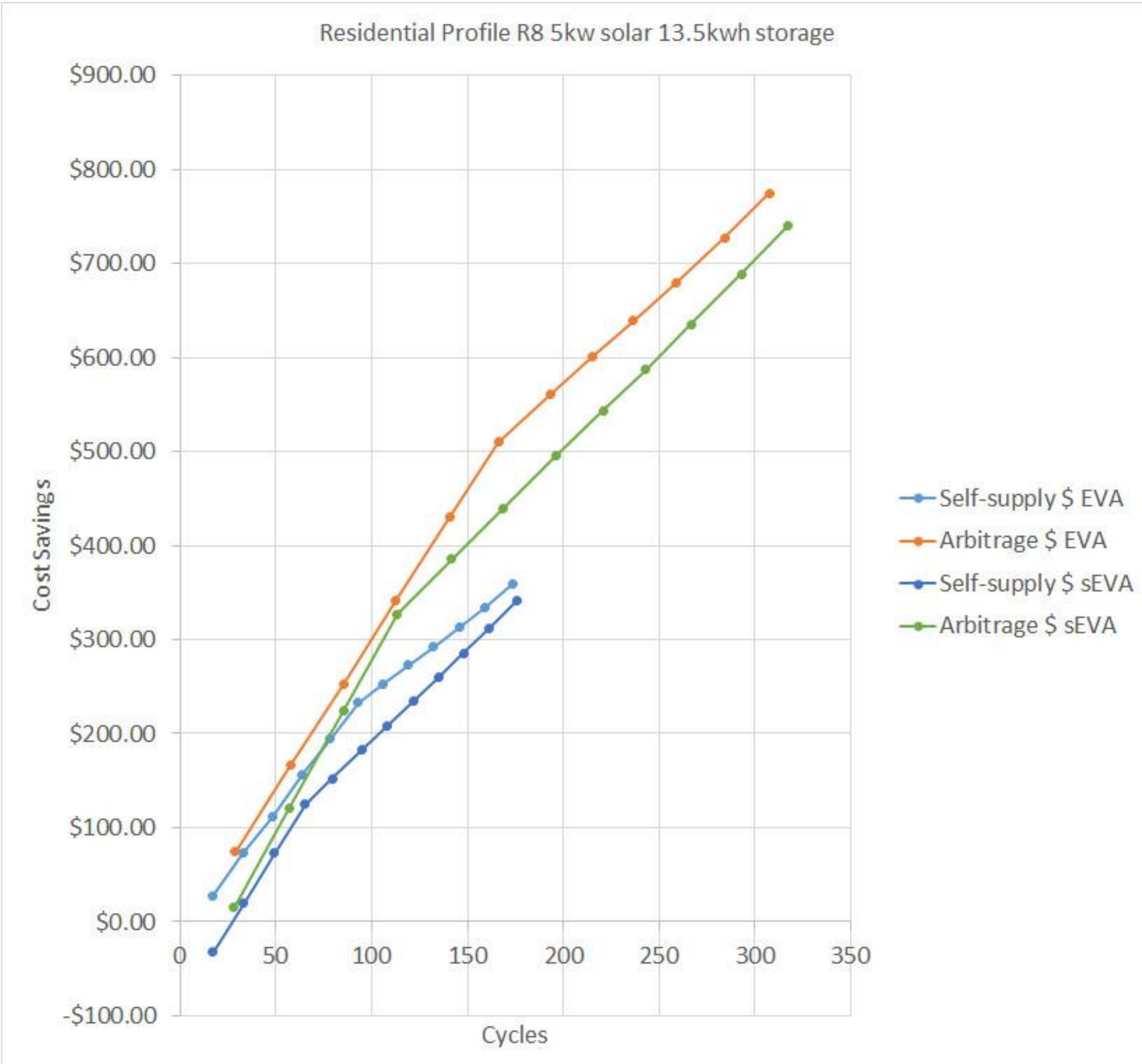


Figure 50: Residential Cycling Impact on Cost Reduction 13.5 kWh Storage



Summary

1. Current 50 cycles requirement for residential solar + storage has minimal impact on cost and GHG savings. Less than $100 in cost savings per year. Less than 150kg GHG savings per year.
2. Increasing to 100 cycles per year doubles both cost & GHG savings.

Conclusions

1. Increasing cycling to 100 cycles/year doubles cost savings to customer and doubles GHG savings

Notes

1. Fig 4 & 6 show GHG savings vs Cycles. Fig 5 & 7 show Cost Savings. Fig 4 &5 are Custom Power Solar Radian 8kw/20kwh systems. Fig 6&7 are Tesla Powerwalls.
2. This chart also compares current EVA rate with sEVA rate, a new rate available next year in PG&E available to all customers with solar + storage.
3. In self-supply mode, loads only are supplied with energy from storage, typically after solar periods.
4. In Arbitrage mode, loads are supplied first, then excess power is sent back to grid during peak rate periods.
5. All systems energy storage power is charged ONLY from solar power.
6. Each dot from left to right represents 1 month of cycling with daily cycling, starting in June, and adding one month, stepping both forward and backward in time.

7. For emergency backup use, retaining a portion of energy in the storage is advisable. Self-supply mode usually has 50% capacity remaining after peak rate periods even with max cycling. Arbitrage modes above have 0% capacity remaining, so if emergency backup is to be allocated discharge should be limited to amount desired to retain for backup use.

Figure 51: GHG Savings from EV Use 1

Models by: **Custom Power Solar** R8_EVA_8kw_20kwh_v63_5_18_18.xlsx
Load year 2017

Solar Data OAKLAND METROPOLITAN ARPT, CA

Annual

	sEVA	EVA			EBCE FIT
Cost	$2,358.15	$2,189.39	$0.00	$0.00	
Cost Est. with Solar	-$331.85	-$1,460.64	$0.00	$0.00	$1,495.82
Cost Est. with Solar+Storage	-$1,435.71	-$2,505.33	$0.00	$0.00	**$2,629.08**
Improvement over solar only	**46.81%**	**47.72%**	**0.00%**	**0.00%**	
Cost Advantage batteries	**$1,103.86**	**$1,044.69**	**$0.00**	**$0.00**	
Difference vs optimized rate		**45.36%**	**0.00%**	**0.00%**	
Total Value Solar+Storage	**$3,793.86**	**$4,694.71**	**$0.00**	**$0.00**	
Optimized Rate					

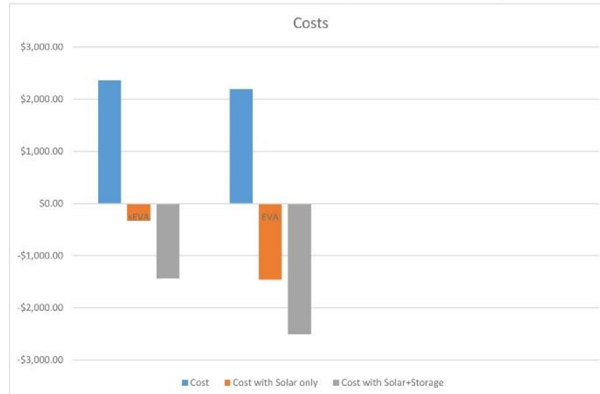
Total usage	**10,657 kwh**		**8.00 kw Battery**
Total solar	**13,850 kwh**		**8.00 kw AC Solar**
Surplus	**3,193 kwh**		**20.00 kwh Battery**
Percent solar vs usage	**130.0%**		**84.9% RTE**
GHG savings	**4,549 kgs/CO2**	**np15**	**GHG Data**
GHG savings battery alone	**774 kgs/CO2**		**6,296 kwh Battery use**
Annual percent dispatchable	**45.5%**		**8.62% % of Life used**

Annual Demand Charges

	sEVA	EVA			Max Demand
Cost	$0.00	$0.00	$0.00	$0.00	8.08
Cost Est. with Solar	$0.00	$0.00	$0.00	$0.00	8.08
Cost Est. with Solar+Storage	$0.00	$0.00	$0.00	$0.00	8.03

Annual Energy Charges

	sEVA	EVA		
Cost	$2,358.15	$2,189.39	$0.00	$0.00
Cost Est. with Solar	-$331.85	-$1,460.64	$0.00	$0.00
Cost Est. with Solar+Storage	-$1,435.71	-$2,505.33	$0.00	$0.00
Grid Charge	0 kwh			
Grid Charge	0 days			



			GHG Value Adder	
EV Use	**35.0**	**mi/day**	**$65**	**$/mT**
EV Charge	**3190.6**	**kwh**	**$50.28**	**GHG Savings Battery alone**
EV Gas Savings	**$1,701.64**		**$2,189.39**	**Baseline rate cost**
EV GHG savings	**3786.1**	**kg**	**($1,435.71)**	**Optimized rate final cost**
Total GHG Savings	**8,335**	**kg**	**$3,675.38**	**Total Savings**
Net GHG savings	**4,848**	**kg**		
GHG Load Only	**-3,487**	**kg**		

Figure 52: GHG Savings from EV Use 2

Models by: **Custom Power Solar** R8_EVA_5kw_13p5kwh_v63_5_15_18.xlsx
Load year 2017

Solar Data OAKLAND METROPOLITAN ARPT, CA

Annual

	sEVA	EVA			EBCE FIT
Cost	$2,358.15	$2,189.39	$0.00	$0.00	
Cost Est. with Solar	$676.90	-$91.88	$0.00	$0.00	$934.89
Cost Est. with Solar+Storage	-$63.02	-$674.77	$0.00	$0.00	**$1,705.23**
Improvement over solar only	**31.38%**	**26.62%**	**0.00%**	**0.00%**	
Cost Advantage batteries	**$739.92**	**$582.89**	**$0.00**	**$0.00**	
Difference vs optimized rate		**25.94%**	**0.00%**	**0.00%**	
Total Value Solar+Storage	**$2,421.17**	**$2,864.15**	**$0.00**	**$0.00**	
Optimized Rate					

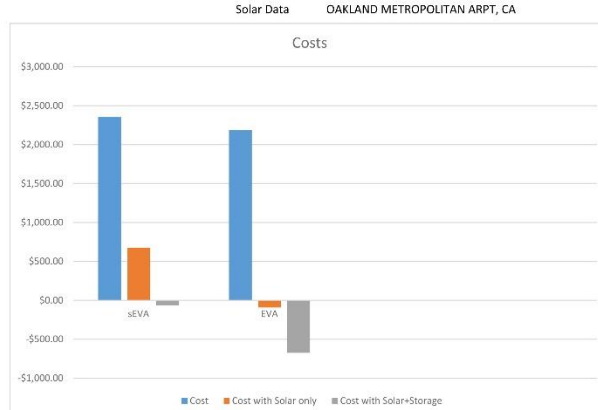
Total usage	**10,657 kwh**		**3.38 kw Battery**
Total solar	**8,656 kwh**		**5.00 kw AC Solar**
Surplus	**-2,000 kwh**		**13.50 kwh Battery**
Percent solar vs usage	**81.2%**		**84.9% RTE**
GHG savings	**2,950 kgs/CO2**	**np15**	**GHG Data**
GHG savings battery alone	**590 kgs/CO2**		**4,280 kwh Battery use**
Annual percent dispatchable	**49.4%**		**8.69% % of Life used**

Annual Demand Charges

	sEVA	EVA			Max Demand
Cost	$0.00	$0.00	$0.00	$0.00	8.08
Cost Est. with Solar	$0.00	$0.00	$0.00	$0.00	8.08
Cost Est. with Solar+Storage	$0.00	$0.00	$0.00	$0.00	8.02

Annual Energy Charges

	sEVA	EVA		
Cost	$2,358.15	$2,189.39	$0.00	$0.00
Cost Est. with Solar	$676.90	-$91.88	$0.00	$0.00
Cost Est. with Solar+Storage	-$63.02	-$674.77	$0.00	$0.00
Grid Charge	0 kwh			
Grid Charge	0 days			



			GHG Value Adder	
EV Use	**35.0**	**mi/day**	**$65**	**$/mT**
EV Charge	**3190.6**	**kwh**	**$38.37**	**GHG Savings Battery alone**
EV Gas Savings	**$1,701.64**		**$2,189.39**	**Baseline rate cost**
EV GHG savings	**3786.1**	**kg**	**($63.02)**	**Optimized rate final cost**
Total GHG Savings	**6,736**	**kg**	**$2,290.77**	**Total Savings**
Net GHG savings	**3,249**	**kg**		
GHG Load Only	**-3,487**	**kg**		

Summary

1. A typical residential system with an EV DOUBLES the GHG savings of the solar + storage system alone. In examples above, 2950 to 4549kg/year GHG savings augmented by additional 3786kg EV GHG savings.

Conclusions

1. Encouraging EV adoption charged by solar + storage systems will accelerate GHG reductions

Notes

1. All miles driven by EV charged from home system.
2. GHG savings calculated by:
3. Number of total miles driven by vehicle per year divided by 30mpg = number of equivalent gallons of gasoline use avoided. Multiply gallons used by 1gal = 8.9kg GHG emitted.

Appendix K: SGIP Statutory and Current Program Requirements Relevant to GHGs

Energy Division's September 2010 Staff Proposal calculated the minimum roundtrip efficiency that would be required to avoid GHG emissions and arrived at 67.9%, but recommended minimum a conservative roundtrip efficiency of 70%. In D.11-09-015 the Commission approved storage for SGIP participation but did not comment on the minimum roundtrip efficiency requirement. Following the decision, the SGIP program administrators filed Advice Letter (AL) PG&E 3253-G/3940-E to revise the SGIP Handbook to reflect the changes ordered by the Commission including a proposed requiring a minimum roundtrip efficiency of 67.9%. The California Energy Storage Association (CESA) appealed the disposition letter. Addressing that appeal, the Commission issued Resolution E-4519 accepting CESA's proposed 5% differential in line loss factors between peak and off-peak, decreasing the minimum roundtrip efficiency needed to qualify for SGIP from 67.9 to 63.5%.

Decision 15-11-027 adopted a minimum round-trip efficiency of 66.5% over ten years of operations to qualify for SGIP, equivalent to a first-year round-trip efficiency of 69.6%[53]. This was based on operating margin emission factors, build margin emission factors, line losses, and performance degradation parameters.

The current Self-Generation Incentive Program Handbook, December 18, 2017, states that the purpose of the SGIP is to contribute to Greenhouse Gas (GHG) emission reductions, demand reductions and reduced customer electricity purchases, resulting in the electric system reliability through improved transmission and distribution system utilization; as well as market transformation for distributed energy resource (DER) technologies. In conformance to D.15-11-027, it states that energy storage systems must maintain a round trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5%, assuming a 1% annual degradation rate. While not purely intended to ensure GHG reduction, it also states the following requirements;

- Commercial systems are required to discharge a minimum of 130 full discharges per year.
- Residential systems are required to discharge a minimum of 52 full discharges per year.
- To be considered paired with and charging from on-site renewables, energy storage systems must either be claiming the Investment Tax Credit (ITC) or, if not claiming the ITC, charge a minimum of 75% from the on-site renewable generator.

[53] D.15-11-027 pg 33

Appendix L: 2016 SGIP Storage Impact Evaluation findings

A key finding in Itron's 2016 SGIP Advanced Energy Storage Impact Evaluation, August 31, 2017, was that "GHG impacts for both PBI and non-PBI non-residential projects are positive, reflecting increased emissions. The magnitude and the sign of GHG impacts is dependent on the timing of AES charging and discharging. During 2016, non-residential SGIP Advanced Energy Storage projects increased GHG emissions by 726 metric tons of CO2."[54,55]

Additional relevant findings in the Itron report were:

- The mean observed RTE was 44% for non-PBI projects and 74% for PBI projects over the 2016 evaluation period. The 2016 SGIP Handbook requires a first-year RTE of 69.6% and a ten-year lifetime average RTE of 66.5% for program eligibility. PBI projects met this requirement during the evaluation period but non-PBI projects did not.
- SGIP AES projects represented a combination of standalone projects and projects either co-located or paired directly with solar PV systems. We found that during 2016 there was no discernable difference in performance between non-residential AES systems paired with PV and standalone AES projects. The data indicated that non-residential AES projects paired with PV were not prioritizing charging from PV. This suggests that storage developers do not see value in maximizing PV self-consumption given current retail rates and Net-Energy Metering (NEM) tariffs.
- The mean capacity factor was 2.3% for non-PBI projects and 8.1% for PBI projects and the mean observed RTE was 44% for non-PBI projects and 74% for PBI projects over the entire evaluation period. The SGIP Handbook requires that PBI projects achieve an AES capacity factor of at least 10%, 520 hours over the course of each year, to receive full payment. Non-PBI projects are not required to meet a 10% capacity factor.[56]
- The evaluation team observed significant standby losses and parasitic loads associated with system cooling, communications, and other power electronic loads when examining non-PBI system data. While these low-power charge events were generally small at the 15-minute level, over the course of year, the impacts can become substantial, especially for a system that is under-utilized.
- SGIP non-residential projects are generally discharging during peak and partial peak tariff periods when retail energy rates are higher. However, a significant percentage of non-PBI and PBI storage projects are also discharging during off peak tariff hours. This behavior suggests that although storage systems are being utilized for some TOU arbitrage, this might not be the main explanation of dispatch behavior.

[54] "This greenhouse gas emission impact analysis is limited to emissions from grid-scale gas power plants. CO2 emissions were the only greenhouse gas modeled in this study. Throughout this report the terms 'Greenhouse Gas' and 'CO2' are used interchangeably. Note that energy storage system capacity factor requirement is not explicitly an operational requirement in the current Self-Generation Incentive Program." Ibid.

[55] Itron assessed the GHG emissions impact of SGIP AES projects by developing a dataset of marginal power plant GHG emission rates for each 15-minute interval in 2016.

Simulation of Proposed GHG-Reduction Solutions with Open-Source Energy Storage Model

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I. BACKGROUND

The Self-Generation Incentive Program (SGIP) working group established by the California Public Utilities Commission (CPUC) was tasked with developing "a proposal for a greenhouse gas signal and enforcement mechanism for energy storage systems participating in the Self-Generation Incentive Program to ensure these projects reduce greenhouse gas [GHG] emissions." In its first meeting, the Working Group highlighted modeling the effectiveness and economic impact of potential GHG-reduction solutions as its primary method of identifying preferred solutions. However, the initially-proposed modeling process relied heavily on the use of behind-the-meter storage technology companies' proprietary and confidential dispatch modeling software, which posed challenges for the Working Group's ability to identify discrepancies in modeling methodology and results, and come to consensus.

To address this concern, several stakeholders proposed using an open-source energy storage model (OSESMO). Unlike the proprietary models, OSESMO's methodology could be shared with the Working Group and with the Commission, including its source code being freely available on GitHub[57]. In addition, unlike the proprietary model results, which could only be shared with the Working Group and Commission after being aggregated and anonymized, OSESMO's result outputs could be published and presented individually. This meant that the public-model results could be shared with proprietary modelers, allowing for comparison and validation without proprietary results needing to be shared with the group.

OSESMO's fast runtime and programmatic design allowed it to be used to model many more scenarios (consisting of residential or commercial/industrial load profiles, retail rates, storage hardware parameters, and storage dispatch approaches) than the proprietary models, and it therefore became a de-facto benchmark with which the proprietary model results were compared.

II. METHODOLOGY

A. Overview

OSESMO was intended to offer similar sophistication to the software used by energy storage technology providers for pre-sales modeling and real-time storage dispatch. It is also seemingly quite similar in structure to the E3 RESTORE model[58] used in the 2016 SGIP Impact Report, as well as to the EPRI StorageVET model[59]. Most significantly, unlike a spreadsheet-based model or a rules-based storage dispatch model, OSESMO's approach is based on mathematical optimization, a field of mathematics and computer science. Optimization algorithms are used to solve large and complex problems where the objective is to minimize or maximize a function, often subject to a number of constraints.

In this case, the dispatch (charge/discharge) behavior of customer-sited energy storage systems can be simulated with an optimization-based model where the objective is to minimize the customer's monthly bill. The primary advantage of optimization-based storage control over rules-based storage control is the ability to effectively provide value across multiple, often competing, economic value streams, such as demand charge reduction and time-of-use energy charge arbitrage. In the case of OSESMO's usage by the SGIP GHG Working Group, an optimization-based model structure also offers the ability to co-optimize between customer bill savings and GHG reduction, which opens the possibility of emissions reduction with little to no impact on the storage system's ability to provide other economic value streams. This optimization-based structure was also leveraged in the creation of the Non-Economic Solar Self-Supply dispatch algorithm, which encourages solar self-consumption even when uneconomic, such as for residential solar-plus-storage customers on a non-TOU rate. The Solar Self-Supply algorithm allows the system to respond to infrequent economic signals, such as SmartRate critical peak pricing events, as well as to an economic GHG signal.

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[57] R. Mann et al, 2018. "OSESMO: Open Source Energy Storage Model". *GitHub*, github.com/RyanCMann/OSESMO.
[58] Energy + Environmental Economics (E3). "RESTORE: Energy Storage Dispatch Model". ethree.com/tools/restore-energy-storage-dispatch-model.
[59] Electric Power Research Institute (EPRI). "Storage Value Estimation Tool (StorageVET)". storagevet.com

OSESMO uses a well-established mathematical optimization technique known as linear programming that allows large problems to be solved quickly. In this case, OSESMO is capable of finding the optimal charge-discharge dispatch strategy for all 15-minute time intervals in the year 2017 in under 10 seconds. This makes it possible to perform thousands of model runs, evaluating the impact of the proposed GHG reduction solutions for all combinations of a large number of inputs, across a representative set of load profiles and retail rates.

It's important to note that OSESMO does not perform load forecasting, as production storage-dispatch software does, instead assuming perfect knowledge of historical load. Load forecast accuracy affects the operation of energy storage when performing demand charge reduction; more accurate forecasting increases the amount of savings achieved and decreases the need for unnecessary battery cycling. Thus, results for commercial & industrial customers are less representative of actual storage system behavior than results for residential customers, and should be compared to results from other modelers whose dispatch-simulation software includes load forecasts.

B. Cost Function

OSESMO simultaneously co-optimizes the customer's retail energy and demand charges, carbon emissions (for GHG Signal model runs), as well as unnecessary battery cycling and degradation. This is formulated mathematically as follows:

$$
\begin{gathered}
\text{minimize} \sum_{t=1}^{N} (c_{energy}(t) + c_{carbon}(t)) * (P_{ES,in}(t) - P_{ES,out}(t)) * \Delta t + \\
\left(\frac{\eta_{charge} * c_{cycle}}{2 * S_{ES}}\right) * P_{ES,in}(t) * \Delta t + \\
\left(\frac{c_{cycle}}{\eta_{discharge} * 2 * S_{ES}}\right) * P_{ES,out}(t) * \Delta t + \\
0 * E(t) + \\
c_{demand,NC} * P_{max,NC} + \\
c_{demand,CPK} * P_{max,CPK} + \\
c_{demand,CPP} * P_{max,CPP}
\end{gathered}
$$

Variable	Definition	Units
$c_{energy}(t)$	Volumetric energy rate.	\$/kWh
$c_{carbon}(t)$	Dynamic emissions-based economic signal. Equal to marginal emissions (metric tons CO_2/MWh) * carbon adder (\$/metric ton) * (1 MWh/1000 kWh).	\$/kWh
$P_{load}(t)$	Original customer load.	kW
Δt	Model timestep length.	hours
η_{charge}	Single-cycle charging efficiency of the battery.	%
c_{cycle}	Degradation cost per battery charge-discharge cycle.	\$/cycle
S_{ES}	Nameplate energy capacity of the battery.	kWh
$P_{ES,in}(t)$	Power used to charge the battery.	kW
$\eta_{discharge}$	Single-cycle discharging efficiency of the battery.	%
$P_{ES,out}(t)$	Power discharged from the battery.	kW
$E(t)$	Energy level of the battery, analogous to state-of-charge.	kWh
$c_{demand,NC}$	Noncoincident maximum demand charge rate.	\$/kW
$P_{max,NC}$	Noncoincident maximum monthly demand.	kW
$c_{demand,CPK}$	Coincident peak demand charge rate.	\$/kW
$P_{max,CPK}$	Coincident peak maximum monthly demand.	kW
$c_{demand,CPP}$	Coincident part-peak demand charge rate.	\$/kW

$P_{max,CPP}$	Coincident part-peak maximum monthly demand.	kW

The objective function to be minimized represents the total variable customer cost over the set time horizon. This cost has a number of components:

1. The net customer demand in each timestep (gross customer demand, minus power produced by solar if applicable, plus power consumed/generated by the battery, is multiplied by the volumetric energy rate.
2. The emissions impact in each timestep, equal to the net customer demand multiplied by the forecasted or real-time carbon emissions rate, is multiplied by a carbon price.
3. The battery has a limited cycle life (assumed 10 years of daily cycling until the battery is degraded to 80% of its original capacity), so all power going into or out of the battery incurs a cost on the value of the asset. Note that this cycling penalty only applies to lithium-ion batteries; flow batteries do not experience this cycling-related degradation.
4. Depending on the rate structure, the customer may pay a noncoincident demand charge that is based on the highest 15-minute demand in each month (regardless of the time of day). The customer may also pay up to two additional coincident demand charges: one based on the highest 15-minute demand occurring during peak hours, and another based on the highest 15-minute demand occurring during part-peak hours. Some tariffs only have a single coincident peak or part-peak demand charge, some only have noncoincident demand charges, and some do not have any demand charges.
5. There is no cost associated with the energy level of the battery, but it must be included as a decision variable with an associated cost of $0 in order to be included in the constraint equations. This cost could be changed to a negative value to give the model a preference for high states of charge (to prepare for demand-response events).

C. Constraints

The behavior of the storage system is also subject to a number of constraints. Some of these constraints are representations of physical limitations on the battery's dispatch (for instance, it cannot be more than 100% full or less than 0% full), whereas others are operational requirements, such as the need to charge from solar to receive the Investment Tax Credit.

1. The difference in the energy level of the battery between timesteps is equal to charging power minus discharging power, multiplied by the timestep length, with an efficiency penalty on both battery charge and discharge. This constraint applies for Timestep 1 through Timestep (N-1).

$$E(t+1) = E(t) + [\eta_{charge} * P_{ES,in}(t) - \frac{1}{\eta_{discharge}} * P_{ES,out}(t)] * \Delta t$$

2. Power flowing into or out of the battery must be less than or equal to the rated power of the battery (or battery inverter), and greater than 0 kW. Power flowing into the battery includes both power from the PV system and power from the grid.

$$0 \leq P_{ES,in}(t) \leq P_{ES,max}$$
$$0 \leq P_{ES,out}(t) \leq P_{ES,max}$$

3. The energy level of the battery cannot be below 0 kWh, or above the nameplate energy capacity of the battery.

$$0 \leq E(t) \leq S_{ES}$$

4. The state of charge/energy level of the battery is set to 30% (0.3 * S_{ES}) at the beginning and end of the year. The optimization algorithm will most likely discharge the battery as much as possible in the final timesteps of the time horizon to minimize the customer's bill, a "greedy" dispatch action that would not be seen during continuous operation with an infinite time horizon. To create more realistic charge/discharge profiles, the time horizon (here, a calendar-month billing period) is "padded" with extra days at the end to ensure that the final energy levels are as close as possible to the values that would be seen during continuous operation. The initial state of charge in all months after the first is set based on the state of charge and charging/discharging power in the final unpadded timestep from the prior month to ensure continuity.

$$E(0) = 0.3 * S_{ES}$$
$$E(N) = 0.3 * S_{ES}$$

5. To mathematically represent demand charges while keeping a linear-program optimization format (including a maximum() function in the cost-function would make the problem nonlinear), an upper bound on net demand is set as a decision variable, and then a constraint is added to ensure that net demand in all timesteps is less than the optimally-set upper bound. If there is on-site PV generating electricity, net load includes the solar system's output in addition to the original customer load and the storage's charge/discharge power.

$$P_{load}(t) - P_{PV}(t) + P_{ES,in}(t) - P_{ES,out}(t) \leq P_{max,NC}$$

6. The above equation applies to the noncoincident demand charge, which applies to all timesteps in the month. The coincident peak demand charge below applies only to timesteps that fall during peak TOU periods.

$$P_{load}(t \in \text{peak periods}) - P_{PV}(t \in \text{peak periods}) + P_{ES,in}(t \in \text{peak periods}) - P_{ES,out}(t \in \text{peak periods}) \leq P_{max,peak}$$

7. The coincident part-peak demand charge below applies only to timesteps that fall during part-peak TOU periods.

$$P_{load}(t \in \text{part} - \text{peak periods}) - P_{PV}(t \in \text{part} - \text{peak periods}) + P_{ES,in}(t \in \text{part} - \text{peak periods}) - P_{ES,out}(t \in \text{part} - \text{peak periods}) \leq P_{max,part-peak}$$

8. If the solar plus storage system is claiming the Investment Tax Credit for the storage system, it must be charged at least 75% from solar. However, the ITC amount is prorated by the amount of energy entering into the battery that comes from solar (ex. a storage system charged 90% from solar receives 90% of the ITC). As a result, the optimal amount of solar charging is likely higher than the minimum requirement of 75%, and likely very close to 100%. For simplicity, this formulation of the constraint requires the storage system to charge 100% from solar.

$$P_{ES,in}(t) \leq P_{PV}(t)$$

9. In its response to Stem's Petition for Modification to the SGIP round-trip efficiency requirement, PG&E suggested a set of constraints on charging and discharging times as a proposed method for reducing greenhouse gas emissions associated with storage dispatch. Specifically, at least 50% of total charging would need to occur between 9:00 am and 2:00 pm (the Charging Time Constraint), and at least 50% of total discharging would need to occur between 4:00 pm and 9:00 pm (the Discharging Time Constraint). Charging would also not be allowed to occur between 4:00 pm and 9:00 pm (the No-Charging Time Constraint).

Derivation of Charging Time Constraint in standard linear form $Ax \leq b$:

$$\frac{\sum_{t=1}^{N} P_{ES,in}(t \in \{9:00\ am - 2:00\ pm\}) * \Delta t}{\sum_{t=1}^{N} P_{ES,in}(t) * \Delta t} \geq 0.5$$

$$\sum_{t=1}^{N} P_{ES,in}(t \in \{9:00\ am - 2:00\ pm\}) * \Delta t \geq 0.5 * \sum_{t=1}^{N} P_{ES,in}(t) * \Delta t$$

$$0 \geq 0.5 * \sum_{t=1}^{N} P_{ES,in}(t) * \Delta t - \sum_{t=1}^{N} P_{ES,in}(t \in \{9:00\ am - 2:00\ pm\}) * \Delta t$$

$$0.5 * \sum_{t=1}^{N} P_{ES,in}(t) * \Delta t - \sum_{t=1}^{N} P_{ES,in}(t \in \{9:00\ am - 2:00\ pm\}) * \Delta t \leq 0$$

The Discharging Time Constraint is identical in structure to the Charging Time Constraint:

$$\frac{\sum_{t=1}^{N} P_{ES,out}(t \in \{4:00\ pm - 9:00\ pm\}) * \Delta t}{\sum_{t=1}^{N} P_{ES,out}(t) * \Delta t} \geq 0.5$$

The No-Charging Time Constraint sets charging to zero between 4:00 pm and 9:00 pm:

$$P_{ES,in}(t \in \{4:00\ pm - 9:00\ pm\}) = 0$$

10. The GHG emissions solutions (No-Charging Time Constraint, Charging and Discharging Time Constraints, GHG Signal Co-Optimization) can be supplemented with a requirement that the storage systems also obey an annual equivalent cycling constraint.

$$\sum_{t=1}^{N} \left(\frac{\eta_{charge}}{2 * S_{ES}}\right) * P_{ES,in}(t) * \Delta t + \left(\frac{1}{\eta_{discharge} * 2 * S_{ES}}\right) * P_{ES,out}(t) * \Delta t \geq SGIP\ Annual\ Cycling\ Requirement$$

11. If there is a no-export restriction, net load must be greater than or equal to zero. This applies to storage-only systems only, because solar-plus-storage systems are allowed to export to the grid per Net Energy Metering rules. (NEM rules also specify that solar-plus-storage systems cannot export more to the grid than the solar system would have exported in the absence of storage. This constraint was not modeled, but was not likely to have been violated by ITC-compliant systems.)

$$P_{load}(t) + P_{ES,in}(t) - P_{ES,out}(t) \geq 0$$

D. Non-Economic Solar Self-Supply Mode

The economic-dispatch model above can be modified to encourage solar self-supply even when it is not economically beneficial, such as for residential solar-plus-storage customers on a non-time-of-use rate who wish to self-consume solar as much as possible.

For this mode, the objective function provided to the linear-programming optimization algorithm is the same as in the economic-dispatch model above, but with a new term:

$$\sum_{t=1}^{N} c_{self-supply} * \left(P_{PV}(t) - P_{ES,in}(t)\right) * \Delta t$$

This additional cost term serves as a strong incentive for the storage system to minimize power produced by the solar PV system that is not stored in the battery. However, because PV production $P_{PV}(t)$ is not controllable (not a decision variable), this can be simplified to adding a cost term of

$$\sum_{t=1}^{N} -c_{self-supply} * P_{ES,in}(t) * \Delta t$$

A value of $1 is currently used for $c_{self-supply}$. This can be thought of as a $1.00/kWh incentive to charge the storage system.

This new cost-function term alone is not sufficient to ensure that the solar-plus-storage system is self-consuming from solar, and not simply charging and discharging to and from the grid. Two additional constraints must also be added:

1. First, an additional constraint is needed to ensure that the storage system only charges from excess solar. This can be achieved by creating a new vector with the excess solar production. This excess solar vector $P_{Excess\ PV}(t)$ is equal to $P_{PV}(t) - P_{Load}(t)$, with all negative values set to 0 kW. Then, power entering the storage system can be set less than or equal to excess solar production.

$$P_{ES,in}(t) \leq P_{Excess\ PV}(t)$$

2. Second, a constraint needs to be added to ensure that the storage system only discharges when net load is positive, which means that the solar PV system is not fully meeting the customer load. This helps to ensure that the storage system does not discharge to the grid in addition to the solar system's export, or charge and discharge simultaneously (which is physically impossible).

This can be represented similarly to the constraint above with the creation of a positive net load vector $P_{Positive\ Net\ Load}(t)$ is equal to $P_{Load}(t) - P_{PV}(t)$, with all negative values set to 0 kW. Then, power exiting the storage system can be set less than or equal to positive net load.

$$P_{ES,out}(t) \leq P_{Positive\ Net\ Load}(t)$$

III. INPUTS, SENSITIVITIES, AND GHG SOLUTIONS MODELED

A. Load Profiles

Publicly-sharable load profile data was provided by members of the SGIP working group, and was processed into a standard format that could be used by all modelers. The most substantial of these processing steps involved remapping data collected prior to 2017 in order to approximate 2017 profiles. This was achieved by using CAISO net load data for 2017 and the original data year, and ranking days in each month based on total statewide net load. Then, customer-level data was reordered to match CAISO data, such that customer load is highest on days from 2017 when total state net load is also highest, such as during heat waves. Load data was also step-interpolated to 15-minute time resolution, if not originally available in that form.

A summary of load profiles selected for use by the Working Group appears below:

Customer Class	Data Source	Location	Description	Data Year(s)
Residential	Custom Power Solar	Albany	Residential with EV	2017
Residential	Custom Power Solar	Crockett	Residential with EV	2017
Residential	PG&E	Central Valley	Non-CARE	2015
Residential	PG&E	Central Valley	CARE	2015
Commercial & Industrial	Avalon	East Bay	Light Industrial	2015-2016
Commercial & Industrial	Stem	Southern CA	Office	2017

Commercial & Industrial	Stem	Southern CA	Food Processing	2017
Commercial & Industrial	Stem	San Diego	Manufacturing	2017
Commercial & Industrial	EnerNOC	Los Angeles	Grocery	2012
Commercial & Industrial	EnerNOC	Los Angeles	Industrial	2012
Commercial & Industrial	EnerNOC	San Diego	Office	2012
Commercial & Industrial	PG&E	Northern CA	Small-Medium Business	2011-2012
Commercial & Industrial	PG&E	Northern CA	Medium-Large Business	2011-2012

B. Solar PV Production Profiles

Solar PV production data were taken from the California Solar Initiative's Distributed Generation Statistics database[60], which includes 15-minute interval data collected by Itron for a subset of CSI program participants. The most recent CSI interval data available were collected in 2016, meaning that a similar remapping process to the one described above for load profile data was necessary to approximate 2017 solar production data. Here, CAISO utility-scale solar production data from 2017 and the original data year were used to rank and reorder days in each month based on total statewide solar production.

One residential and one commercial & industrial solar production profile was chosen for each of the three California investor-owned utility service territories. Profiles were selected based on data completeness, as well as recency of system installation. As a result, they may not be representative of typical azimuths, tilts, or capacity factors of PV systems in their corresponding California utility's service territory.

Some other modelers involved in the SGIP Working Group used typical meteorological year (TMY) hourly solar data from NREL PVWatts[61], as opposed to the re-ordered measured solar production data used here. While TMY profiles are not synchronized with heat waves and other meteorological effects that also affect customer load, we do not believe that their use would bias others' modeling results significantly.

When modeling, solar data were rescaled to offset a set percentage of annual customer load. Residential solar PV systems were sized to offset 80% of annual customer energy consumption, and commercial & industrial PV systems were sized to offset 40% of annual energy consumption.

Metadata and summary statistics for the solar PV production data are available below:

Customer Class	**CSI Application #**	**System Size (kW-DC)**	**Azimuth**	**Tilt**	**Capacity Factor**
Residential	PGE-CSI-25632	7.6	180°	30°	13.3%
Residential	SCE-CSI-07211	3.6	180°	30°	18.7%
Residential	SD-CSI-04810	3.4	180°	30°	19.6%
Commercial & Industrial	PGE-CSI-16803	45.1	220°	20°	17.3%
Commercial & Industrial	SCE-CSI-08338	20	180°	10°	16.7%
Commercial & Industrial	SD-CSI-00087	33.6	0°	15°	10.7%

C. Retail Electricity Rates

[60] California Distributed Generation Statistics. "CSI 15-Minute Interval Data". californiadgstats.ca.gov/downloads/.

[61] National Renewable Energy Lab (NREL). "PVWatts Calculator". pvwatts.nrel.gov/pvwatts.php.

A set of representative retail electricity rates were selected based on popularity and rate structure diversity, including both historical rates from 2016 and 2017, currently active rates, and proposed rates from PG&E's 2017 General Rate Case. The Working Group also chose to model a single hypothetical commercial & industrial rate combining SDG&E AL-TOU's demand charges with day-ahead wholesale energy rates in place of time-of-use EECC generation rates. This rate mimics SDG&E's pilot Grid Integration Rate, which was discontinued at the end of 2017.

In the table below, the designations (NEW) and (OLD) refer to the timing of TOU periods. NEW rates are those with a peak period from 4:00 PM to 9:00 PM; OLD rates have an earlier peak period. Many of the NEW rates also feature a Super-Off-Peak period during spring months, meant to encourage the shifting of load towards times of likely solar curtailment.

The E-1 tiered residential rate does not have time-dependent energy rates or demand charges, and is therefore non-economic for energy storage. It was included because many SGIP-incented residential storage systems are on this rate (or similar rates in other IOU territories), and are used primary for battery backup in the event of outages. The E-1 tiers were simplified for modeling purposes: the Tier 1 rate was used for all consumption by the Custom Power Solar load profiles, and the Tier 3 rate was used for all consumption by the Central Valley load profiles.

The SmartRate, Peak Day Pricing (PDP) and Critical Peak Pricing (CPP) rates feature reduced energy or demand rates relative to their base rates, in exchange for significantly increased peak-period energy charges on specific days when loads and temperatures are particularly high. SmartRate/PDP/CPP events are called a day in advance; for this effort they were modeled as being called on the days when they occurred in 2017, which varied by utility.

Besides SmartRate, PDP, and CPP, there are several other utility demand response programs, such as the Base Interruptible Program (BIP) and the Capacity Bidding Program (CBP), which were not modeled due to their complexity. California energy storage systems also commonly participate in the Demand Response Auction Mechanism (DRAM) and SCE's Local Capacity Requirements (LCR), but these programs were not modeled due to a lack of publicly available information about event times, event frequency, and incentives for participation.

All modeled retail rates are listed below:

Customer Class	**Utility**	**Rate Name**	**Effective Date**
Residential	PG&E	E-1 (OLD)	2017-01-01
Residential	PG&E	E-1 with SmartRate (OLD)	2017-01-01
Residential	PG&E	EV-A (NEW)	Proposed - 2017 GRC Phase II
Residential	SDG&E	DR-SES (NEW)	2017-12-01
Commercial & Industrial	PG&E	A1-STORAGE (NEW)	Proposed - 2017 GRC Phase II
Commercial & Industrial	PG&E	A-6 (OLD)	2017-03-01
Commercial & Industrial	PG&E	A-6 with PDP (OLD)	2017-03-01
Commercial & Industrial	PG&E	E-19S (OLD)	2017-03-01
Commercial & Industrial	PG&E	E-19S (NEW)	Proposed - 2017 GRC Phase II
Commercial & Industrial	PG&E	E-19S with PDP (OLD)	2017-03-01
Commercial & Industrial	PG&E	E-19S with PDP (NEW)	Proposed - 2017 GRC Phase II
Commercial & Industrial	PG&E	E-19S Option R (OLD)	2017-03-01
Commercial & Industrial	PG&E	E-19S Option R (NEW)	Proposed - 2017 GRC Phase II
Commercial & Industrial	SCE	TOU-8P Option B (OLD)	2018-01-01
Commercial & Industrial	SCE	TOU-8P with CPP (OLD)	2018-01-01

Commercial & Industrial	SCE	TOU-8P Option R (OLD)	2018-01-01
Commercial & Industrial	SCE	TOU-8P RTP (OLD)	2018-01-01
Commercial & Industrial	SDG&E	AL-TOU (OLD)	2016-08-01
Commercial & Industrial	SDG&E	AL-TOU (NEW)	2018-01-01
Commercial & Industrial	SDG&E	AL-TOU-CP2 (OLD)	2016-08-01
Commercial & Industrial	SDG&E	AL-TOU-CP2 (NEW)	2018-01-01
Commercial & Industrial	SDG&E	AL-TOU with DA CAISO (NEW)	Hypothetical Rate
Commercial & Industrial	SDG&E	DG-R (NEW)	2018-01-01

A subset of these rates (DR-SES, E-19S Option R, TOU-8P Option R, DG-R) is only applicable to customers with eligible renewable on-site generation. These rates were only applied for solar-plus-storage modeling runs, and not for storage-only modeling runs.

These electricity rates were mapped to the selected customer load profiles as follows:

Customer Class	**Load Profile**	**Modeled Retail Rates**
Residential	Custom Power Solar Albany	E-1 (Tier 1), E-1 (Tier 1) with SmartRate, EV-A, DR-SES
Residential	Custom Power Solar Crockett	E-1 (Tier 1), E-1 (Tier 1) with SmartRate, EV-A, DR-SES
Residential	PG&E Central Valley Non-CARE	E-1 (Tier 3), E-1 (Tier 3) with SmartRate, EV-A, DR-SES
Residential	PG&E Central Valley CARE	E-1 (Tier 3), E-1 (Tier 3) with SmartRate, EV-A, DR-SES
Commercial & Industrial	Avalon East Bay Industrial	E-19S (OLD & NEW), E-19S PDP (OLD & NEW), E-19S Option R (OLD & NEW), A-1-STORAGE (NEW), A-6 (OLD), A-6 PDP (OLD)
Commercial & Industrial	Stem SCE Office	TOU-8-B, TOU-8-CPP, TOU-8-RTP, TOU-8-R
Commercial & Industrial	Stem SCE Food Processing	TOU-8-B, TOU-8-CPP, TOU-8-RTP, TOU-8-R
Commercial & Industrial	Stem San Diego Manufacturing	AL-TOU (OLD & NEW), AL-TOU-CP2 (OLD & NEW), DG-R
Commercial & Industrial	EnerNOC Los Angeles Grocery	TOU-8-B, TOU-8-CPP, TOU-8-RTP, TOU-8-R
Commercial & Industrial	EnerNOC Los Angeles Industrial	TOU-8-B, TOU-8-CPP, TOU-8-RTP, TOU-8-R
Commercial & Industrial	EnerNOC San Diego Office	AL-TOU (OLD & NEW), AL-TOU-CP2 (OLD & NEW), AL-TOU (NEW) with DA CAISO, DG-R
Commercial & Industrial	PG&E Small-Medium Business	E-19S (OLD & NEW), E-19S PDP (OLD & NEW), E-19S Option R (OLD & NEW), TOU-8-B, TOU-8-CPP, TOU-8-RTP, TOU-8-R, AL-TOU (OLD & NEW), AL-TOU-CP2 (OLD & NEW), AL-TOU (NEW) with DA CAISO, DG-R

Commercial & Industrial	PG&E Medium-Large Business	E-19S (OLD & NEW), E-19S PDP (OLD & NEW), E-19S Option R (OLD & NEW)

D. Storage Parameters

Lithium-ion batteries were simulated with round-trip efficiencies of 70% and 85%, and flow batteries were simulated with a round-trip efficiency of 70%. Based on input provided by working group members, parasitic losses such as electronics and HVAC were assumed to be equal to 0.3% of the storage system's rated power. For instance, a storage system with a size of 100 kW would be modeled as having a constant parasitic loss value of 0.3 kW. It's important to note that parasitic losses were not accounted for in the storage dispatch equations, but instead are added after the optimization has been solved; battery parasitic loads were assumed to be drawing from grid power instead of from the battery, and therefore not impacting storage state of charge.

Residential storage systems were sized at 5 kW based on the specifications of the Tesla Powerwall, which makes up the majority of residential storage systems that have received the SGIP incentive. Commercial & industrial storage systems were sized based on a simple financial metric, meant to emulate the sizing decision-making process made by storage technology companies and their customers. A range of system sizes proportional to the customer load was modeled, and the largest system size with a simple payback time (upfront capital cost divided by Year 1 savings, not including SGIP or ITC incentives) less than or equal to 8 years was selected. Battery capital costs are based on per-kWh values from Lazard's Levelized Cost of Storage reports[62]. Residential lithium-ion systems were modeled as having a duration of 2.7 hours, and commercial & industrial systems were modeled as having a duration of 2 hours, based on the durations most commonly seen among SGIP participants. Flow battery systems were modeled as having a duration of 3 hours, based on input from Avalon Battery.

Storage Type	Round-Trip Efficiency (%)	Parasitic Losses (% of Power Rating)	Cost per kWh	Lifetime
Lithium-ion Battery	70%, 85%	0.3%	$960/kWh (Residential), $681.50/kWh (C&I)	10 years
Flow Battery	70%	0.3%	$941.88/kWh	20 years

E. GHG Emissions Rates

GHG emissions data were used by the model for two separate purposes: as a forecast signal used to inform the systems' charge-discharge dispatch behavior, and as an evaluation signal used to measure the systems' GHG impact. The emissions-rate evaluation signal is based on Real-Time Five-Minute wholesale energy market prices. This evaluation signal can also be passed in to the model as a forecast signal, representing a perfect-forecast upper bound on the storage system's ability to reduce emissions. Alternatively, the model can also use WattTime's public day-ahead forecast as an emissions forecast signal input, representing a lower bound on the storage system's ability to reduce emissions given an imperfect forecast. An operational storage system would likely be capable of leveraging a rolling emissions forecast, where current and near-future emissions rates can be predicted with high accuracy, and emissions rates further in the future can be predicted with accuracy closer to that of a day-ahead forecast.

F. GHG Reduction Solutions

Several GHG-reduction solutions were modeled to evaluate proposed approaches suggested by Working Group stakeholders:

GHG Reduction Solution	Description
No GHG Reduction Solution	Base case – storage system is dispatched purely for customer bill reduction.
No-Charging Time Constraint	The storage system is not allowed to charge between 4:00 pm and 9:00 pm.
Charging and Discharging Time Constraints	In addition to the No-Charging Time Constraint above, at least 50% of charging must occur between 9:00 am and 2:00 pm, and at least 50% of discharging must occur between 4:00 pm and 9:00 pm.

[62] Lazard. "Lazard's Levelized Cost of Storage Analysis – Version 3.0". lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf.

GHG Signal Co-Optimization	The storage system is dispatched to minimize a combination of customer energy-bill costs and a dynamic emissions-rate economic signal equal to the grid emissions rate multiplied by a carbon adder.

The GHG Signal Co-Optimization solution was modeled in a number of variants. As discussed above, the emissions forecast signal had two variants: a Real-Time signal representing perfect foresight of marginal GHG emissions rates, and a Day-Ahead forecast signal. The Day-Ahead forecast signal, provided by WattTime, was a simple, publicly sharable forecast based on information that would have been available from CAISO as of 11:00 pm on the previous day. It represents a lower bound on GHG signal forecast accuracy, just as the Real-Time signal represents an upper bound on forecast accuracy.

Emissions Forecast Signal	**Description**
Real-Time Signal	Perfect forecast of emissions-rate evaluation signal.
Day-Ahead WattTime Signal	Forecast of emissions rates based on day-ahead wholesale prices, time of day, hydrological season, and current emissions forecast error.

In addition, three different carbon prices were modeled. As detailed in the Methodology section, these Carbon Adder values were used as multipliers to the emissions rate forecast signal, and the resulting economic signal was combined with the retail energy rate:

Carbon Adder Value	**Description**
$1/metric ton	Arbitrarily low carbon adder.
$15/metric ton	Based on current cap-and-trade market price.
$65/metric ton	Based on the current cap-and-trade price ceiling.

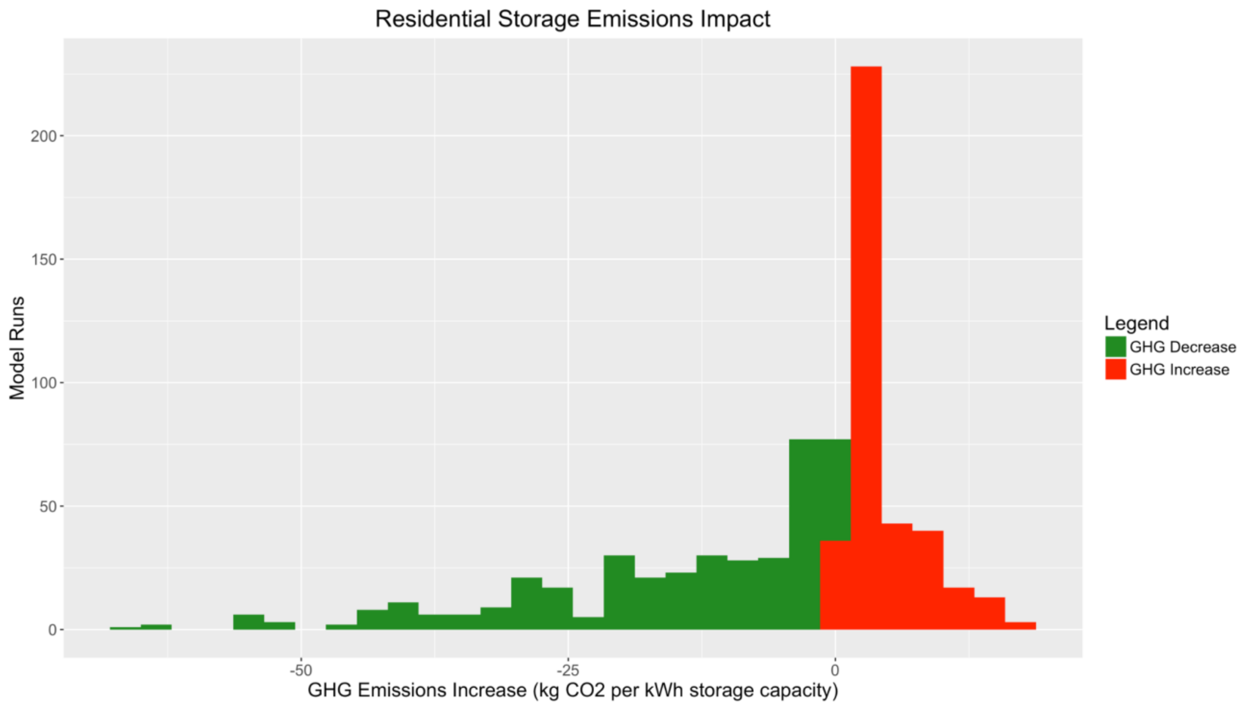
IV. RESULTS

Modeling results can be viewed interactively using the OSESMO Results Viewer.[63] The model output data can be filtered and compared, as in the results presented below, by selecting input values in the sidebar panel of the Results Viewer. Emissions impact data are visualized as a histogram of annual GHG emissions increase in kg CO_2 per kWh of usable storage capacity. Emissions-increasing model runs are colored in red, and emissions-decreasing model runs are colored in green. The full model-results dataset can also be downloaded as a CSV spreadsheet to be used in additional analysis if desired.

A. Residential Storage Modeling Results

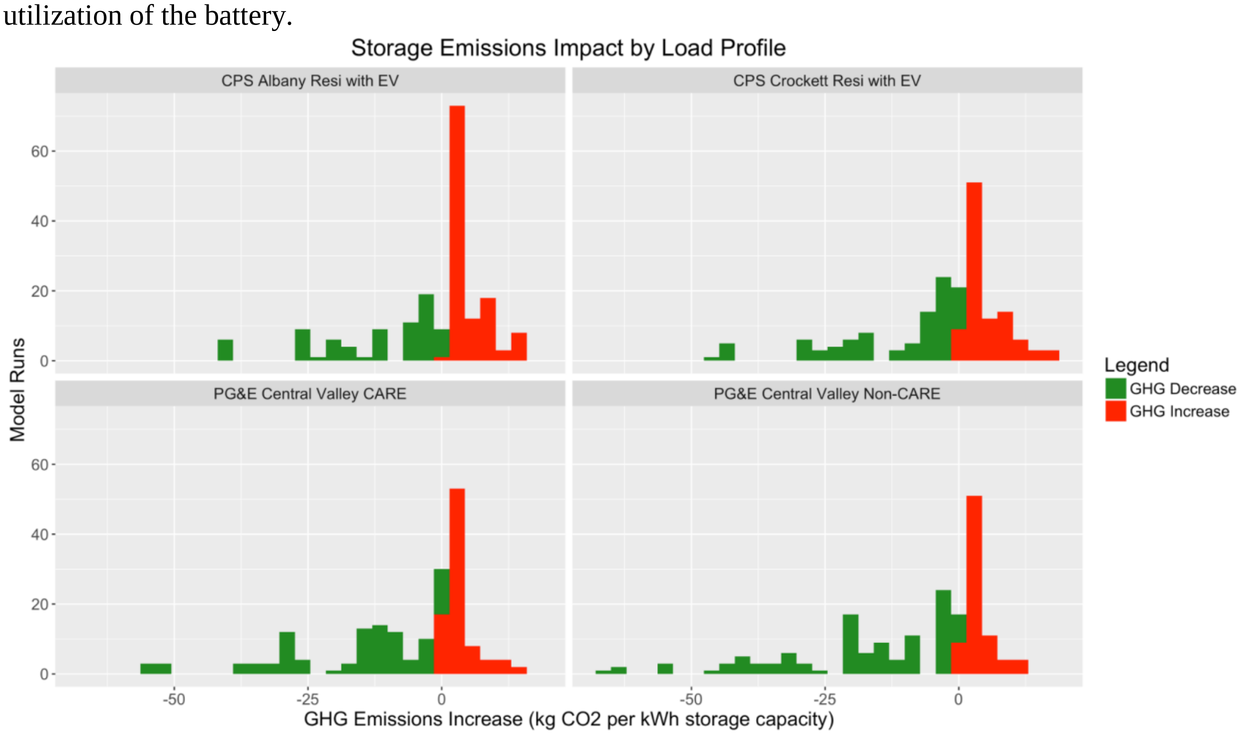
In total, 756 residential modeling runs were performed, representing all combinations of the residential inputs listed above. A distribution of GHG impacts across all residential model runs can be seen below.

[63] R. Mann et al, 2018. "OSESMO Results Viewer". *shinyapps.io by RStudio*, osesmo.shinyapps.io/osesmo_results_viewer.



1) Impact of Load Profile and Rate Inputs

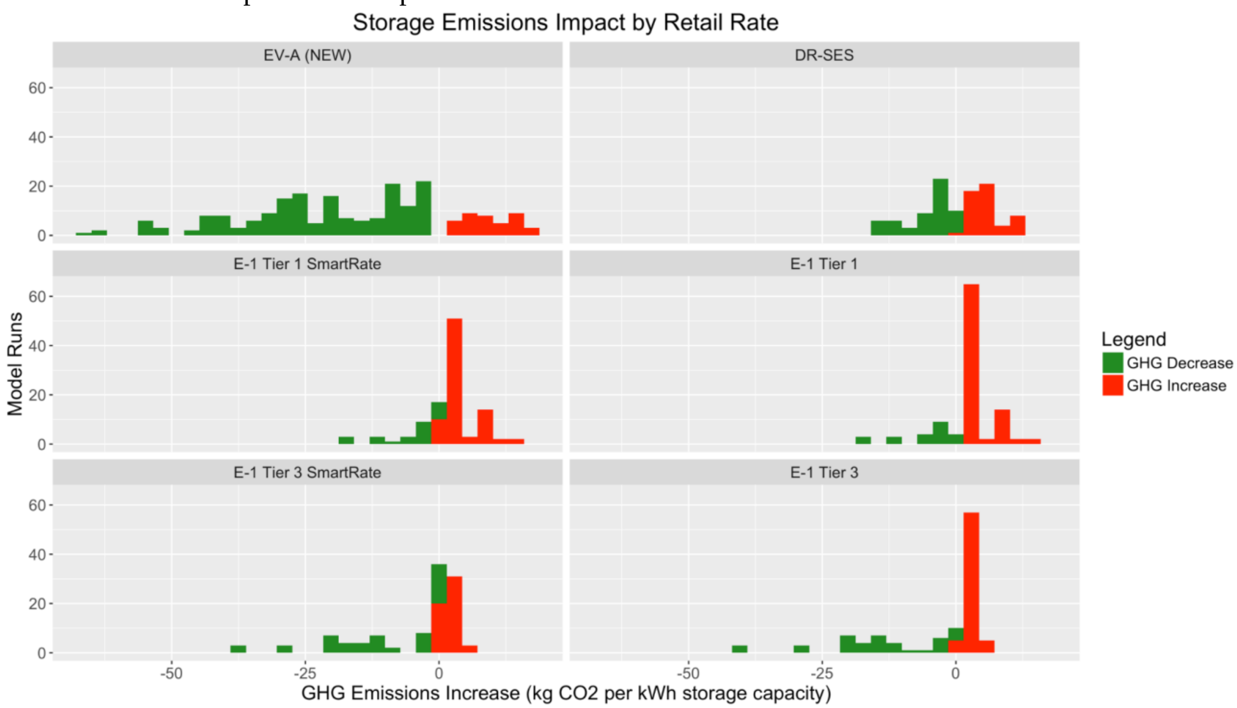
There is little difference in GHG impact between residential load profiles, although storage systems associated with the Central Valley PG&E profiles appear to have a lower GHG impact (fewer GHG-increasing model runs, and more GHG-reducing model runs) than the other profiles. This may be because the original load profiles have greater energy consumption during high-emissions peak-TOU-rate hours, and greater energy consumption in general, leading to greater utilization of the battery.



The impact of retail rates on GHG emissions is somewhat more significant. As the results below show, the majority of model runs with the PG&E E-1 tiered rate input cause an annual increase in GHG emissions. The majority of systems on the SDG&E DR-SES rate reduce GHG emissions, but there are a still a significant number of GHG-increasing systems on that rate.

The addition of the SmartRate critical peak pricing program to the E-1 rate results in a small decrease in annual GHG emissions impact. These SmartRate events (between 9 and 15 per year) tend to be fairly well-correlated with times of high marginal emissions, so this financial incentive to avoid charging and encourage discharging during SmartRate events improves emissions impacts slightly. Note that the impact on marginal generation, distribution, and transmission capacity costs from SmartRate and other similar programs may be much greater than the modest impact on GHG emissions shown here. While not detailed in this report, preliminary investigations using capacity costs provided by PG&E showed significant beneficial impacts on marginal costs from SmartRate, especially for Divisions where marginal distribution costs are higher than average.

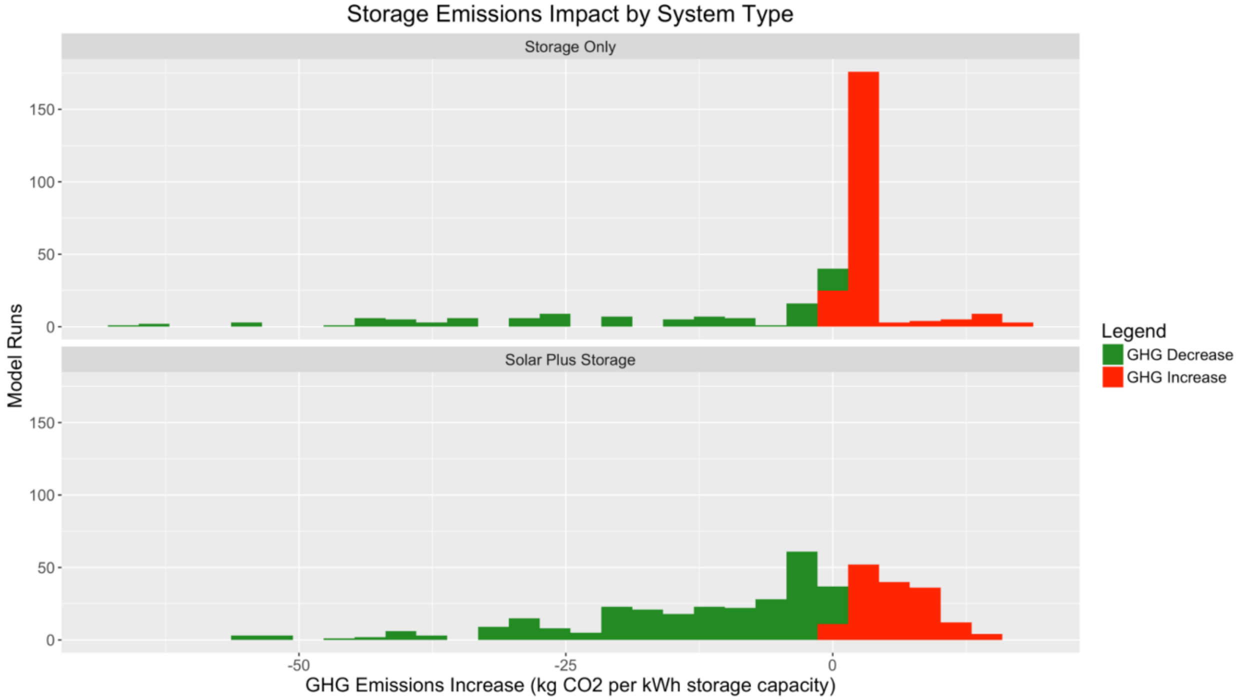
Finally, the vast majority of storage systems on the proposed PG&E EV-A rate reduce emissions, with very few model runs reporting emissions increases. This TOU rate is effective in decreasing the magnitude of emissions increases, or increasing the magnitude of emissions decreases, because the rate's low-price (off-peak or super-off-peak) hours tend to fall during low-emissions-rate times, and high-price peak hours tend to be correlated with high-emissions times. Moreover, the EV-A rate has sufficient differential between on-peak and off-peak costs to incent daily cycling, even in the winter. Newer TOU rates, with mid-day super-off-peak periods and later on-peak periods, are more effective in this regard than older TOU rates with higher mid-day prices and lower evening prices, as long as there is a sufficiently-large differential between peak and off-peak rates.



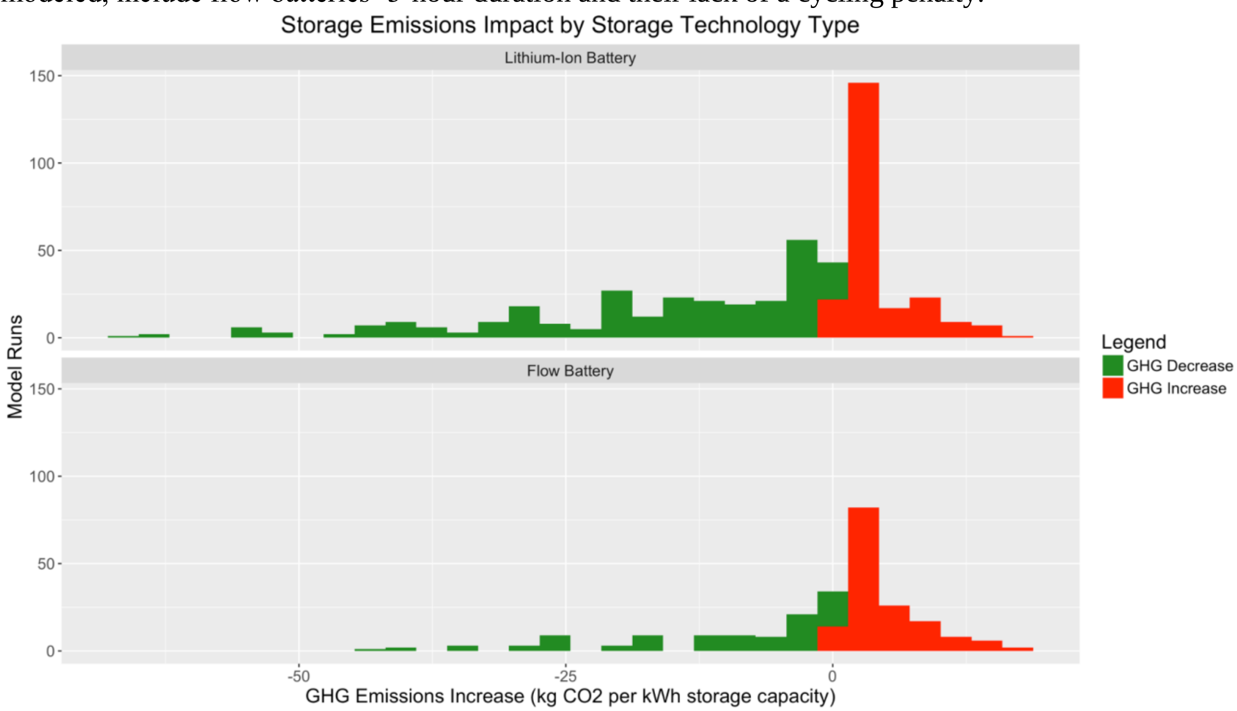
2) Impact of Solar and Storage Parameter Sensitivities

Residential solar-plus-storage systems appear to be more likely to reduce GHG emissions than storage-only systems. Note that storage-only and solar-plus-storage GHG emissions impacts are both evaluated using the same methodology: the storage system's charge-discharge profile is multiplied by the marginal emissions rate in each timestep, and then these emissions impacts in each timestep are totaled to calculate annual GHG impact. Under this approach, the GHG emissions impact of the PV system itself is not included as part of the solar-plus-storage emissions impact. This also means that when storage systems charge "from solar" to receive the Investment Tax Credit, this charging is assigned the marginal grid emissions rate at that time, and not the solar's 0-tons-per-kWh emissions rate. No adjustments are made to account for the avoided transmission and distribution losses associated with charging from paired solar as opposed to charging from the grid.

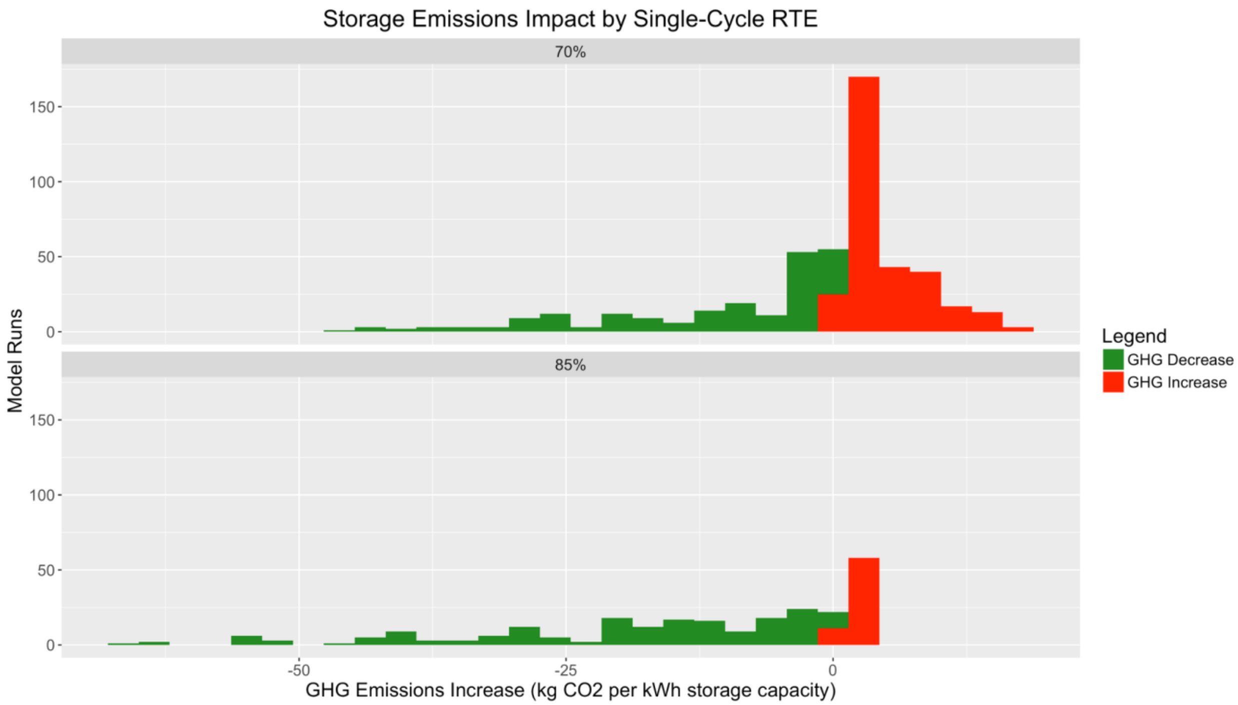
Solar-plus-storage systems tend to be associated with lower emissions because they are charging primarily in the middle of the day, when the solar PV system is producing. These times also happen to line up with times when utility-scale solar and other rooftop solar systems are producing, and systemwide net load (along with marginal GHG emissions rates) tends to be lowest.



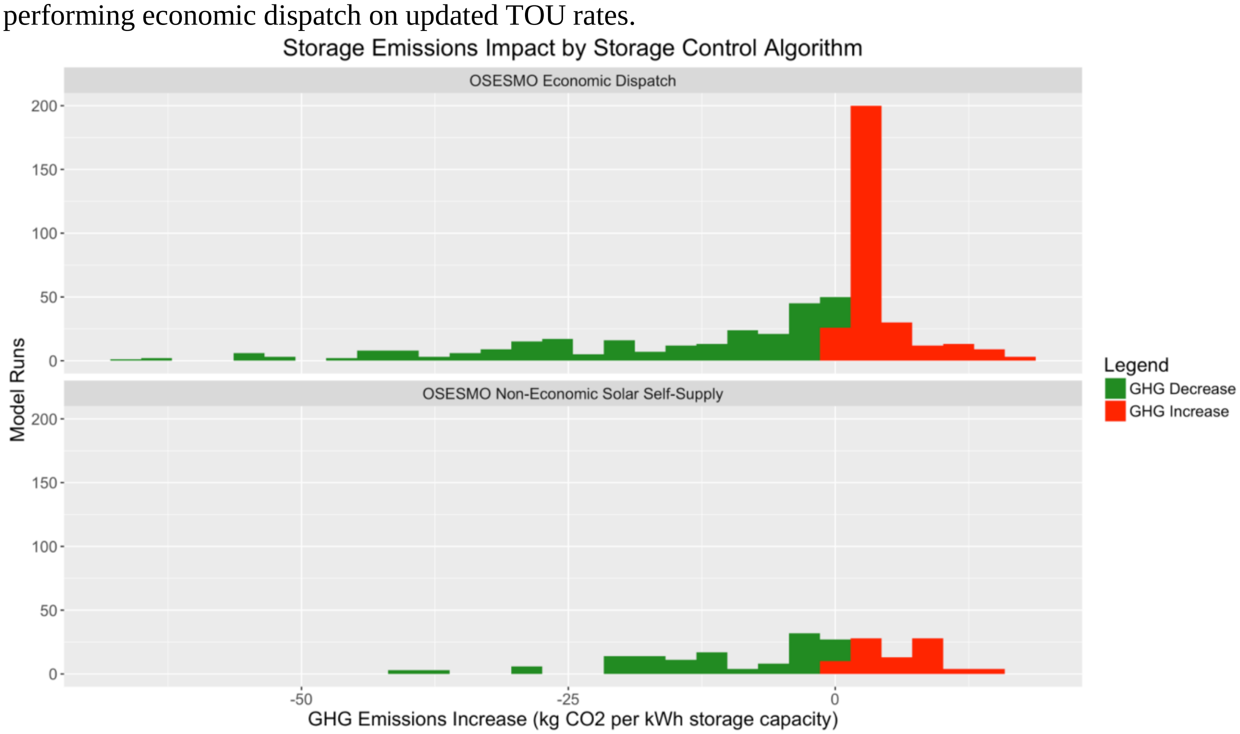
As modeled, lithium-ion battery storage systems are associated with slightly lower GHG emissions than flow batteries. This is primarily due to the use of both 85% and 70% single-cycle round-trip efficiency values for lithium-ion batteries versus a 70% round-trip efficiency value for flow batteries. Other differences between the two technologies, as modeled, include flow batteries' 3-hour duration and their lack of a cycling penalty.



All other things being equal, systems with a lower single-cycle RTE are associated with higher emissions rates. With 85% single-cycle RTE, the majority (73%) of modeled residential storage systems reduced emissions. With 70% single-cycle RTE, only about 40% of modeled storage systems reduced emissions.



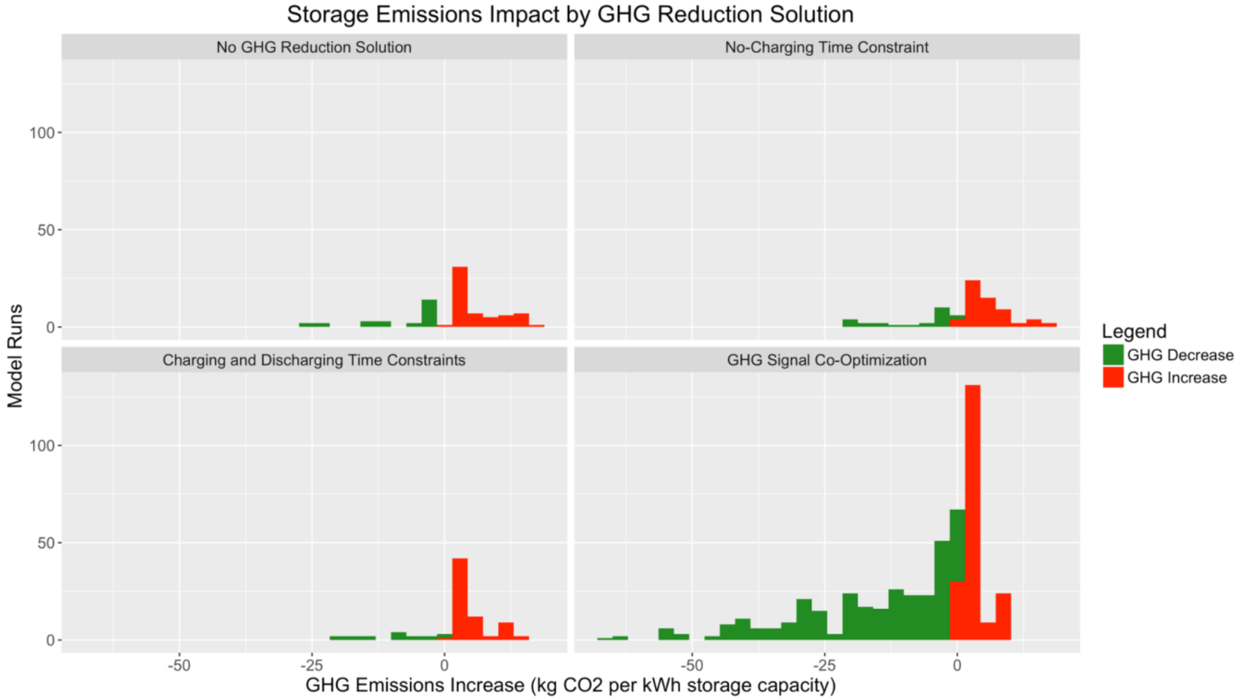
Another interesting comparison for residential storage systems is between the default Economic Dispatch storage control algorithm and the augmented Non-Economic Solar Self-Supply algorithm. The Solar Self-Supply algorithm only applies to solar-plus-storage systems on a non-TOU rate, such as the PG&E E-1 tiered rate, where the customer is performing non-economic solar self-consumption. Even though the systems are not responding to time-of-use rates, their charging during solar peak hours and discharging during evening hours results in a similar GHG impact to systems performing economic dispatch on updated TOU rates.



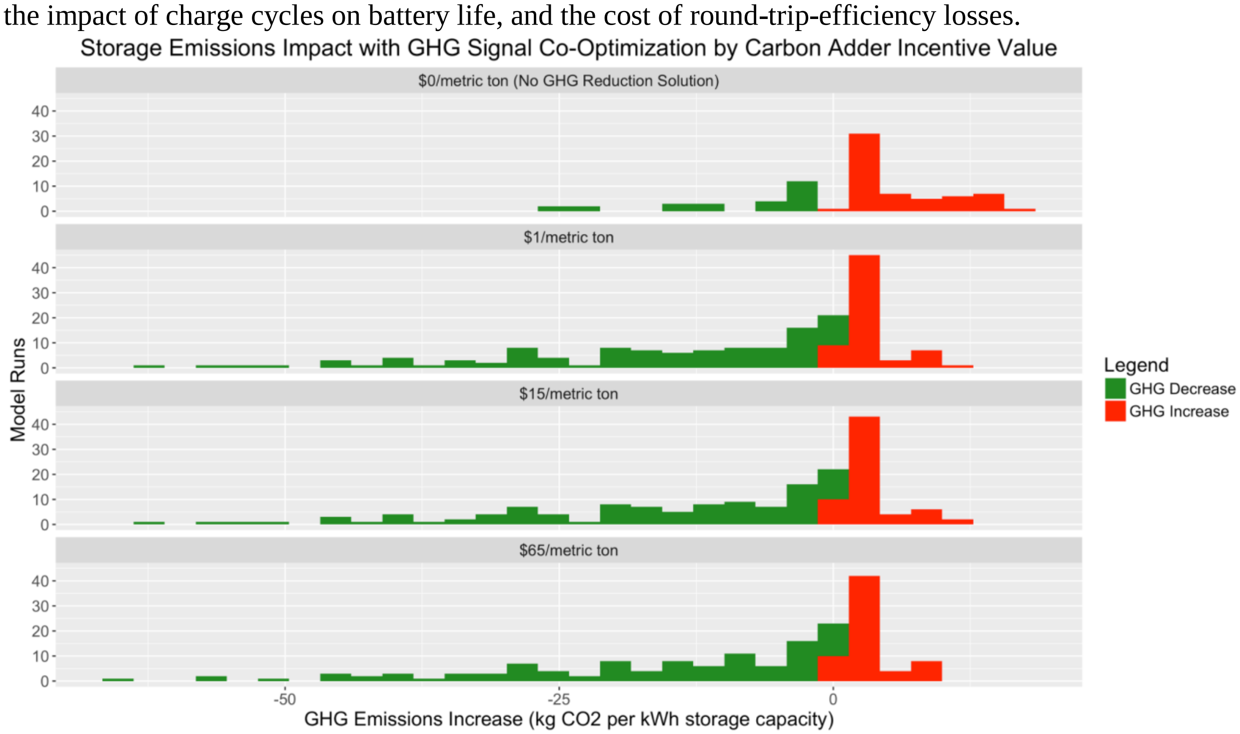
3) Impact of GHG Solutions

There is a noticeable difference in GHG emissions impacts among the four modeled GHG Solutions. Compared to the No GHG Emissions base-case, both the No-Charging Time Constraint and the Charging and Discharging Time Constraints are minimally effective in reducing emissions. On the other hand, GHG Signal Co-Optimization has a significant impact on GHG emissions relative to the base case. However, a sizable fraction of model runs under the GHG

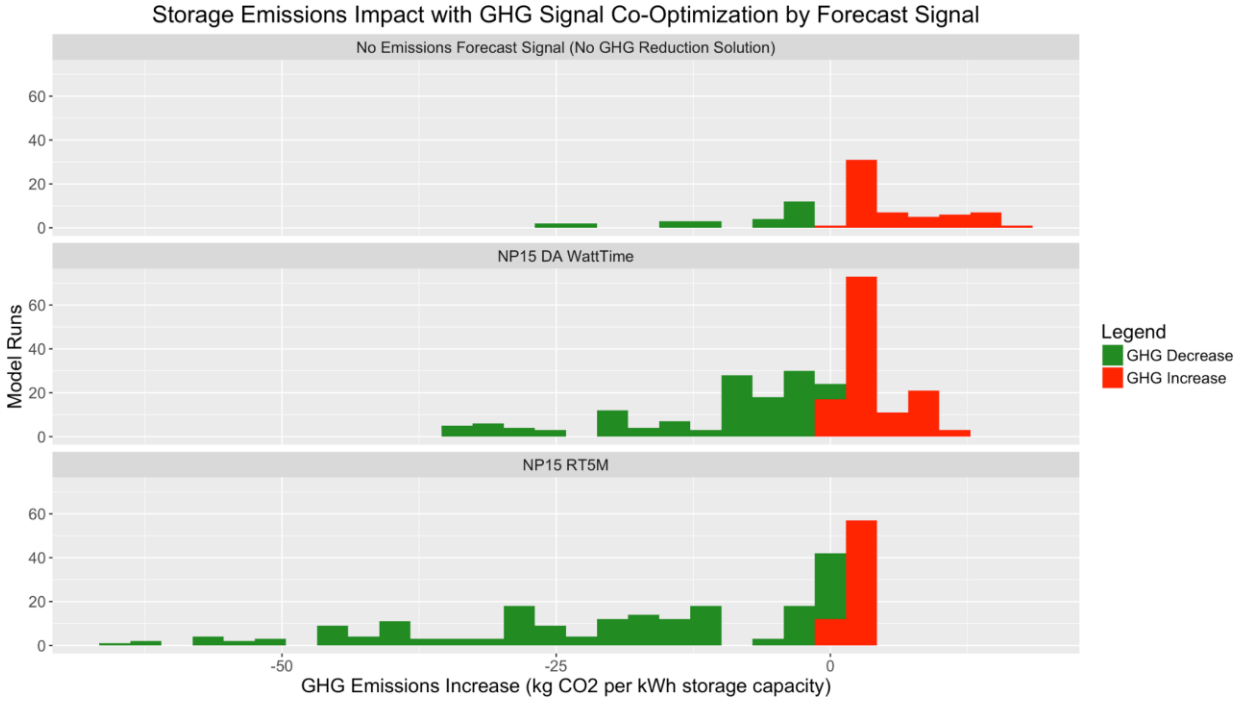
Signal Co-Optimization case are still increasing emissions. These GHG-increasing systems are primarily storage systems on tiered rates that do not cycle frequently, and therefore are not significantly affected by the GHG signal.



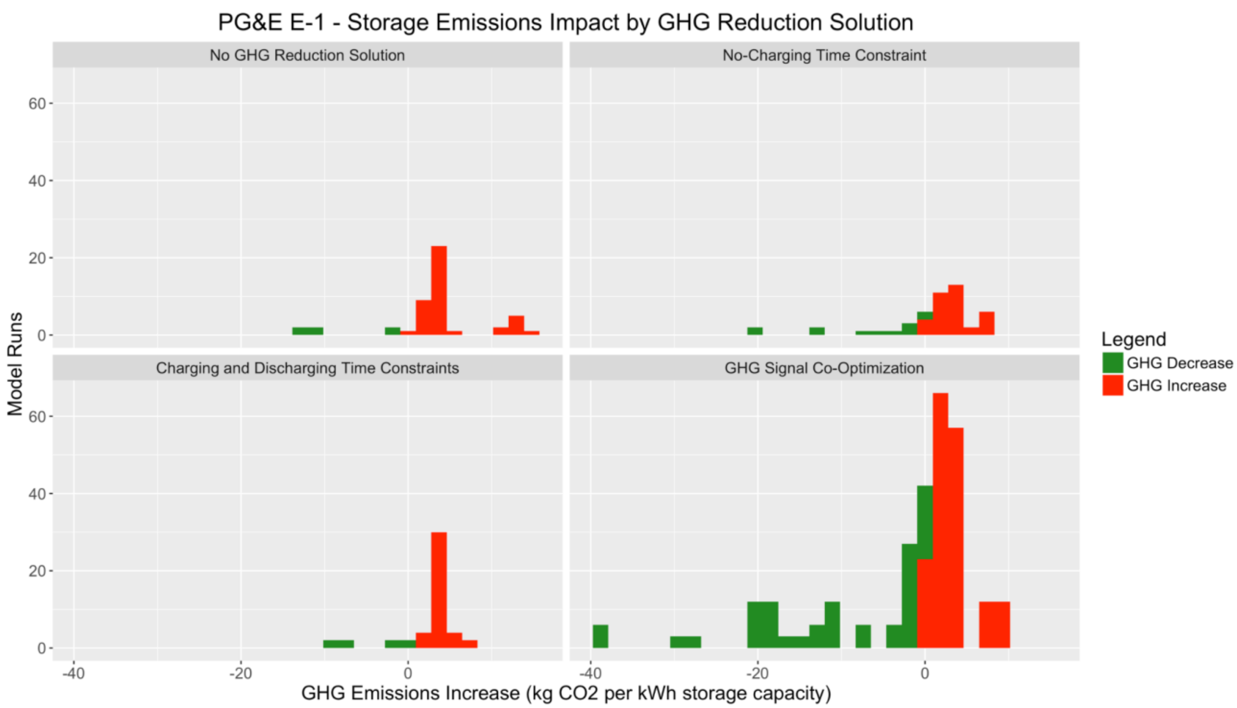
One interesting finding when looking at GHG Signal Co-Optimization cases is that the magnitude of the carbon adder used to convert GHG rates into an economic signal ($1/metric ton, $15/metric ton, or $65/metric ton) has little impact on its effectiveness at reducing emissions. This may be because the main impact of GHG Signal Co-Optimization is to change the storage system's charge/discharge timing, rather than the amount of charging and discharging. On residential rates, the addition of a GHG signal encourages the storage system to charge during the lowest-emissions time periods of a particular off-peak TOU period, and to discharge during the highest-emissions time periods of a particular on-peak TOU period. Much higher carbon adders might be necessary to change the amount of charging/discharging, given the impact of charge cycles on battery life, and the cost of round-trip-efficiency losses.



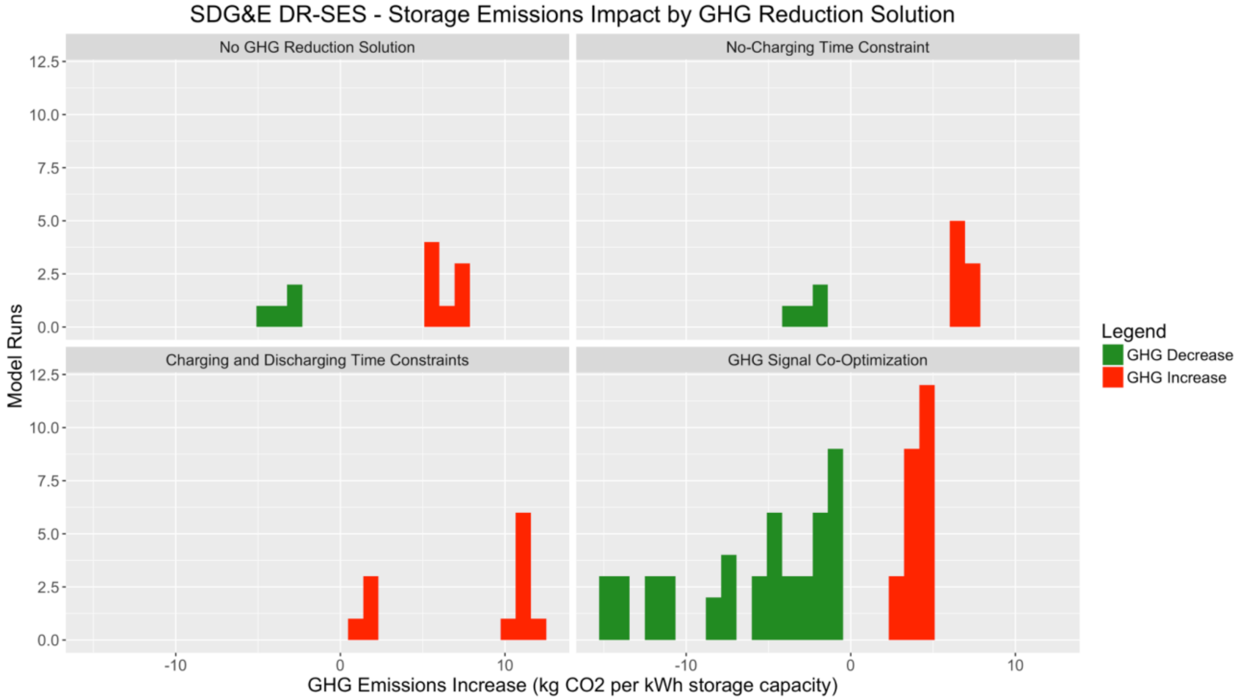
Another item to note is that although there is some difference between the perfect-information Real-Time Five-Minute emissions signal and the imperfect Day-Ahead WattTime-public-model emissions signal, the day-ahead GHG forecast signal is still effective at reducing emissions. It should be noted that this day-ahead forecast represents a lower bound on forecast accuracy, because an operational storage system would be able to receive a rolling forecast that can predict emissions rates for the next few hours more accurately than the prior day's day-ahead forecast.



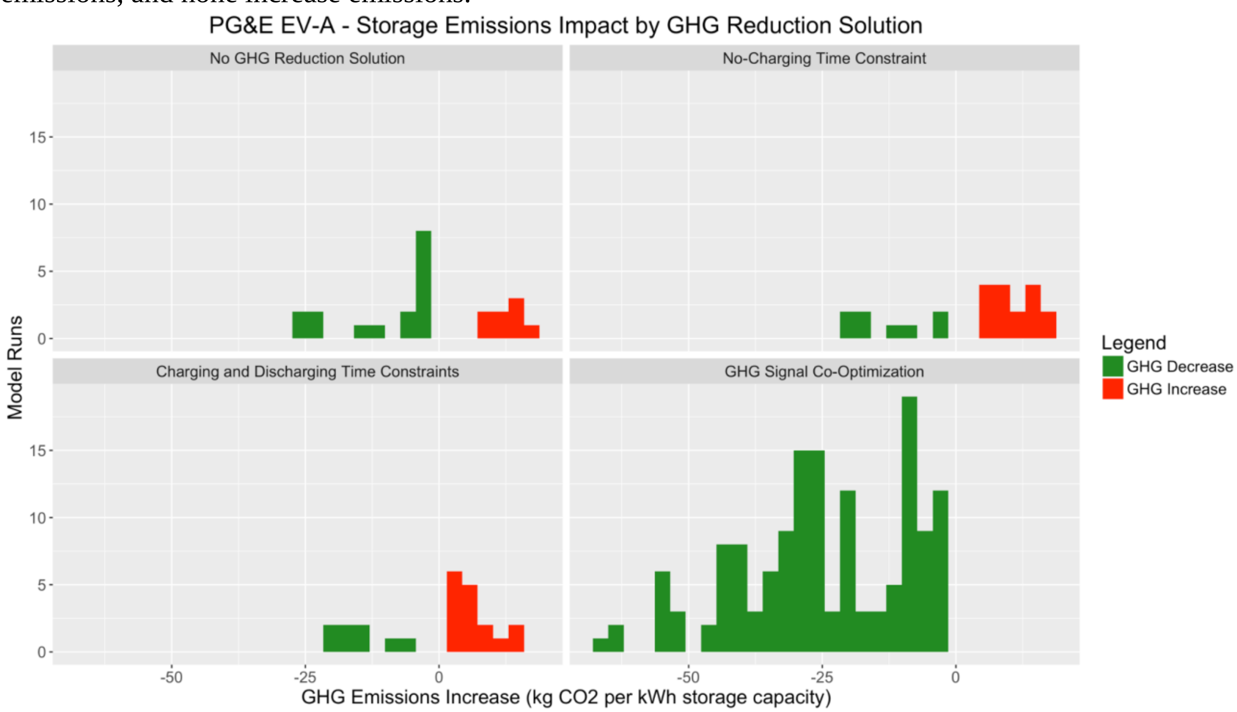
GHG emissions impacts can also be visualized with combinations of residential retail rates and GHG Reduction Solutions. On the PG&E E-1 rate, the majority of model runs are associated with increased GHG emissions. This is true even with GHG Signal Co-Optimization, although co-optimization does help reduce emissions in many cases. Note that the results below include both the standard version of PG&E E-1 as well as E-1 with SmartRate.



Under the SDG&E DR-SES rate, the majority of model runs under the No GHG Solution base case and the Time-Constraint cases result in increased emissions. However, the majority of DR-SES model runs with GHG Signal Co-Optimization reduce emissions.

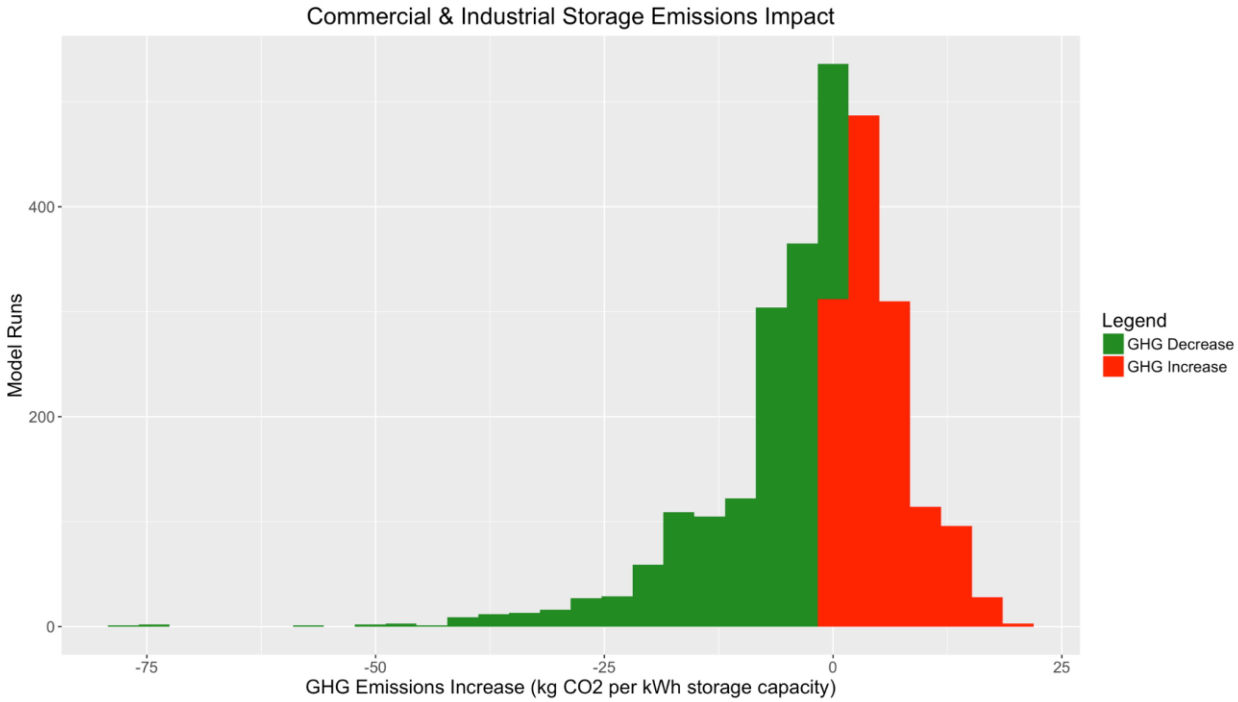


Finally, under the PG&E EV-A rate, the majority of model runs are associated with reduced emissions even for the No GHG Reduction Solution base case. Furthermore, when the GHG Signal is added, all of the model runs reduce emissions, and none increase emissions.



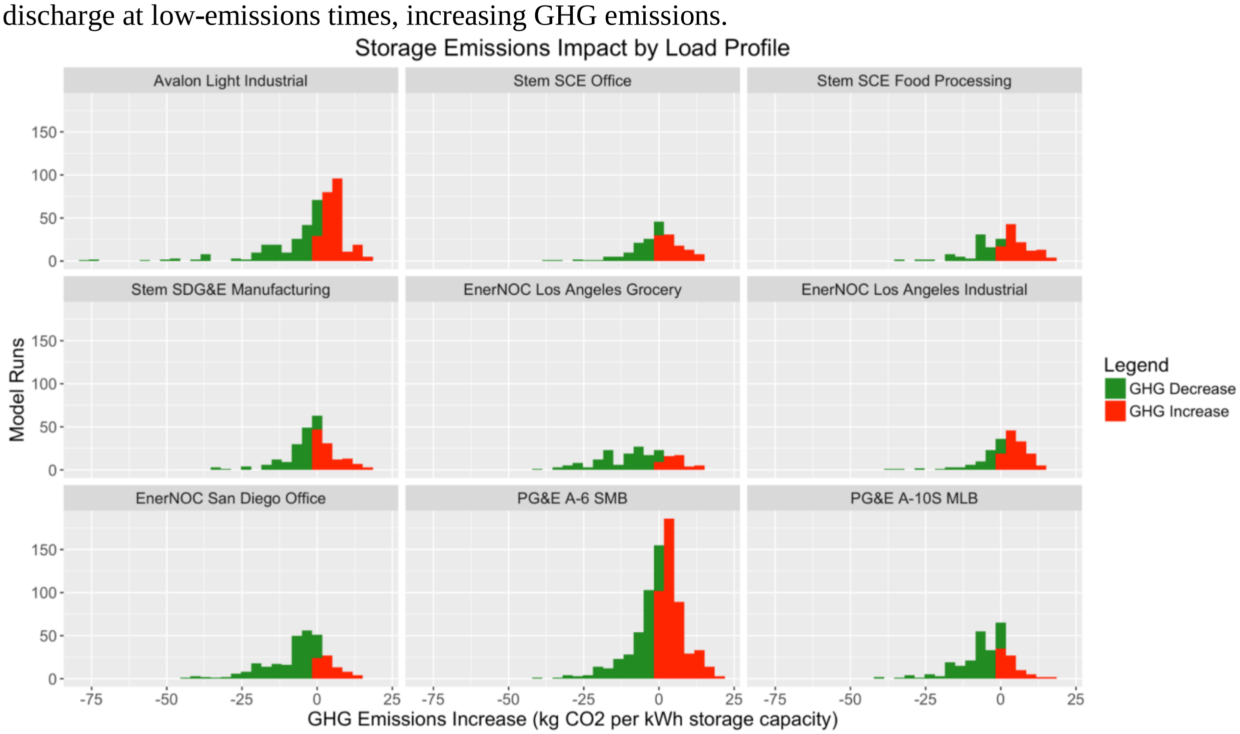
B. Commercial & Industrial Storage Modeling Results

First, 1447 model runs were performed to determine the best storage system size for each combination of load profile, system type (storage-only versus solar-plus-storage), storage type (lithium-ion vs. flow battery), and retail rate. Only the No GHG Solution base case was modeled when determining sizing. Then, 2754 model runs were performed using the selected system sizes, to evaluate the impact of the three GHG solutions. A distribution of GHG impacts across all commercial & industrial model runs for the selected storage sizes can be seen below.



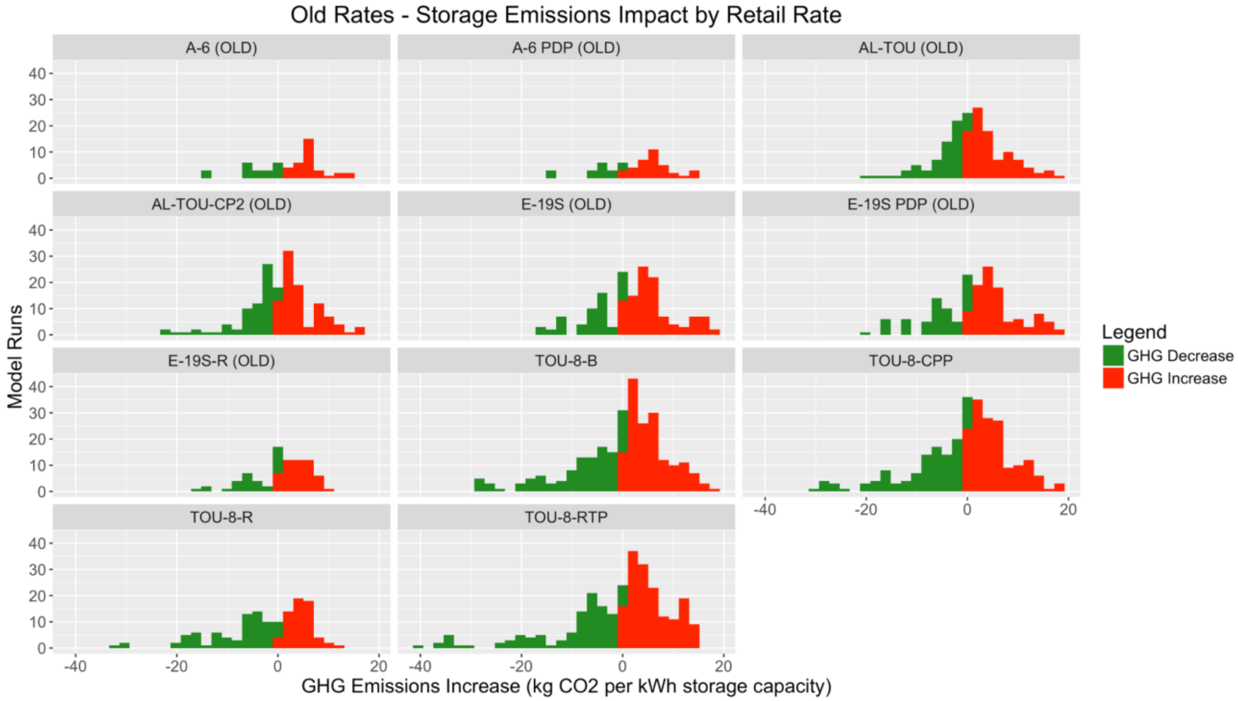
1) Impact of Load Profile and Rate Inputs

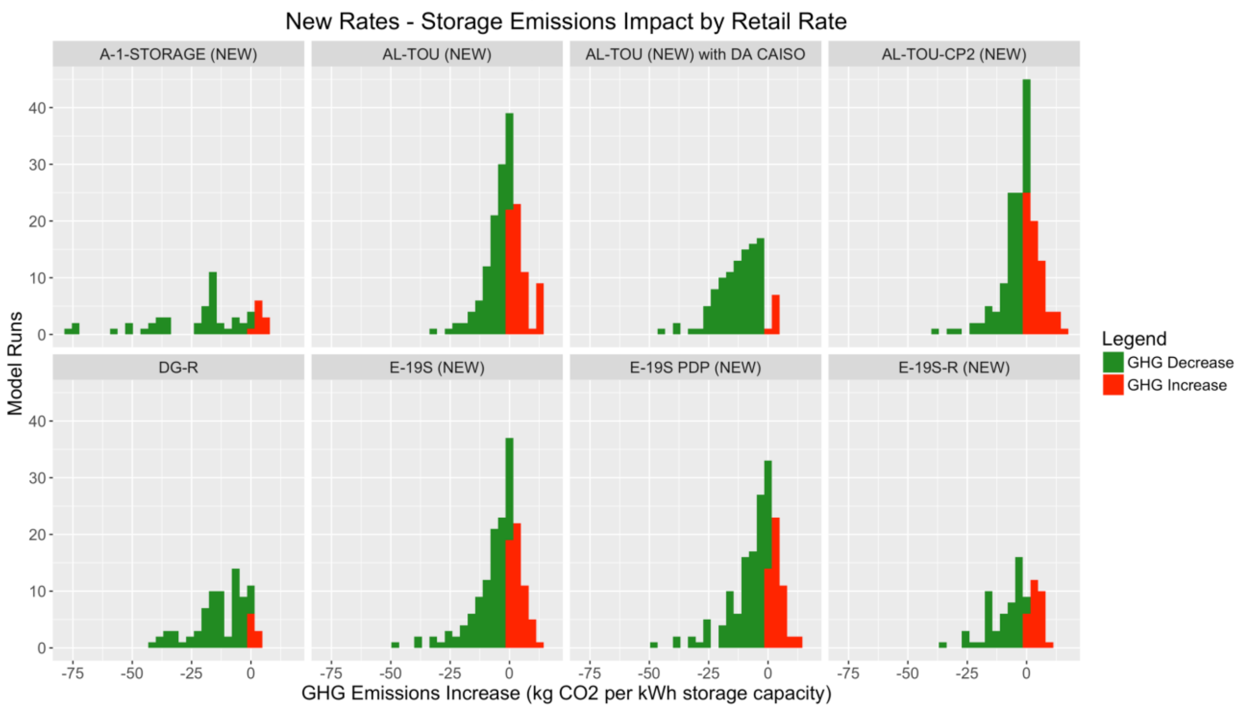
There is substantially more diversity in GHG impacts between load profiles for commercial & industrial load profiles compared to residential load profiles. This is likely due to the existence of a noncoincident demand-charge value stream that encourages reducing the customer's maximum demand. If the customer's maximum demand tends to fall during high-emissions evening peak hours, the storage system will frequently be discharging during these periods and reducing GHG emissions. Conversely, if the site's maximum demand falls during mid-day hours, the storage system will tend to discharge at low-emissions times, increasing GHG emissions.



As with residential storage systems, retail rates significantly influence commercial & industrial storage systems' GHG impacts. Generally, new rates with updated TOU periods are associated with lower GHG emissions than older rates.

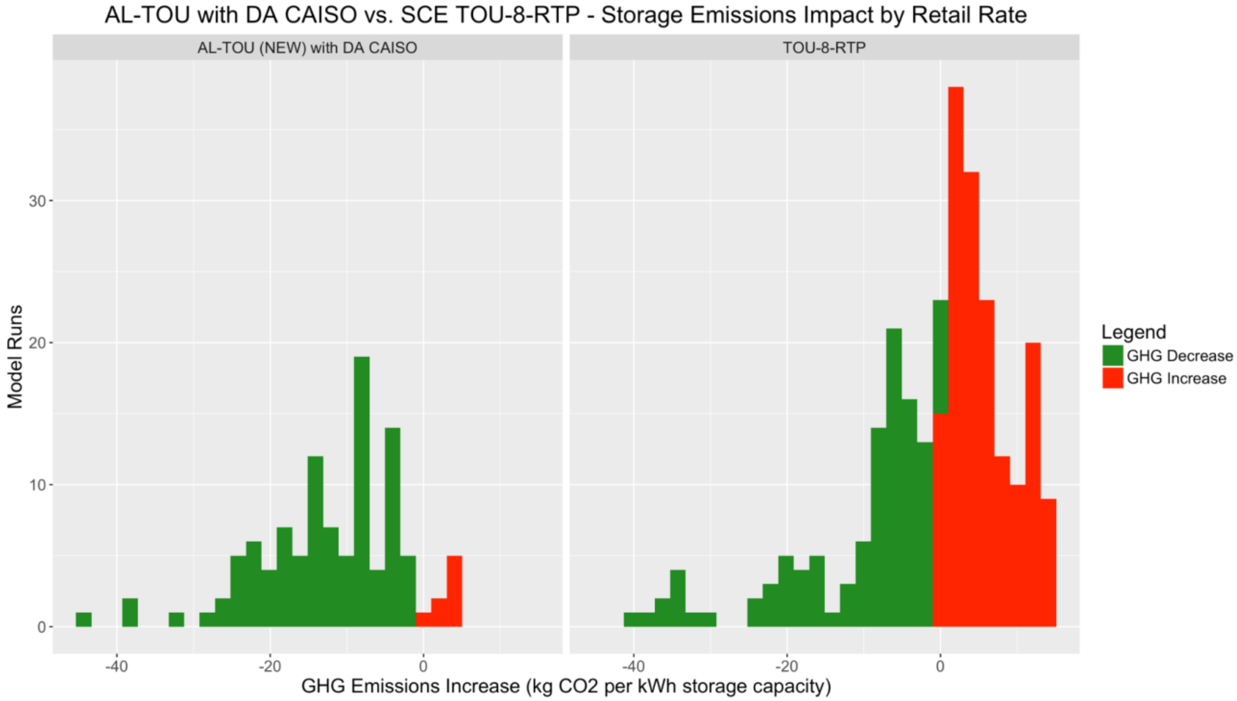
Systems on Option R rates (which are exclusive to customers with solar) tend to have lower emissions than their default-rate counterparts; however, this result is likely primarily associated with ITC-compliant midday solar charging by solar-plus-storage systems, as opposed to the rate structure itself. Critical Peak Pricing and Peak Day Pricing rates only have a very slight impact on GHG emissions, likely because these events occurred only 3-15 times in 2017 (depending on the utility). Much as with the residential SmartRate, CPP and PDP rates appear to have a more significant beneficial impact on utility marginal capacity costs.





One interesting point of comparison can be drawn between SCE's current TOU-8-RTP (OLD) rate, and the hypothetical SDG&E AL-TOU with Day Ahead CAISO (NEW) rate structure. The SCE TOU-8-RTP (OLD) rate modeled is the current version of the rate, and not the proposed rate from the SCE General Rate Case. Much like some of the older TOU rates, its daily price profile does not match up with current net demand, wholesale price, and marginal emissions rate profiles.

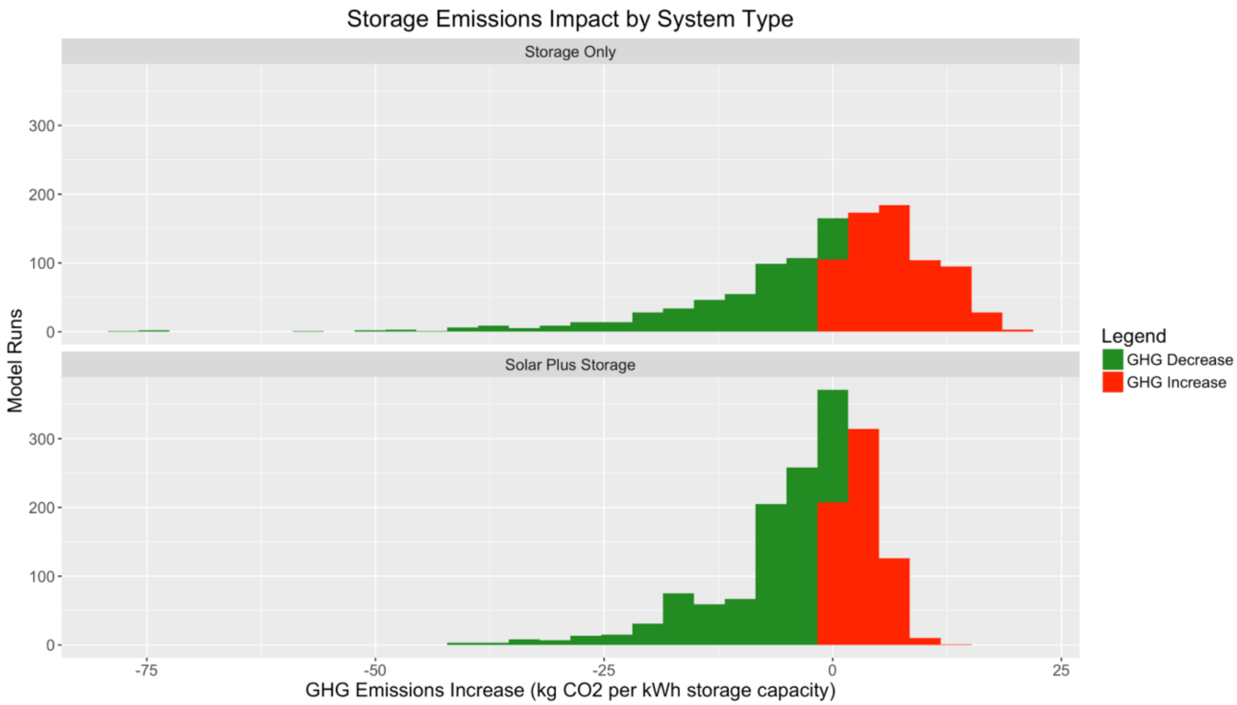
In addition, this “real-time pricing” rate is based on the previous day’s maximum temperature, and so it is only reflective of grid conditions when temperatures and system-level demand are similar to the prior day’s. On the other hand, the hypothetical AL-TOU with Day-Ahead CAISO rate directly reflects (predicted) grid conditions, and therefore does not feature this misalignment. As a result, the difference in GHG impacts between the two rates is dramatic.



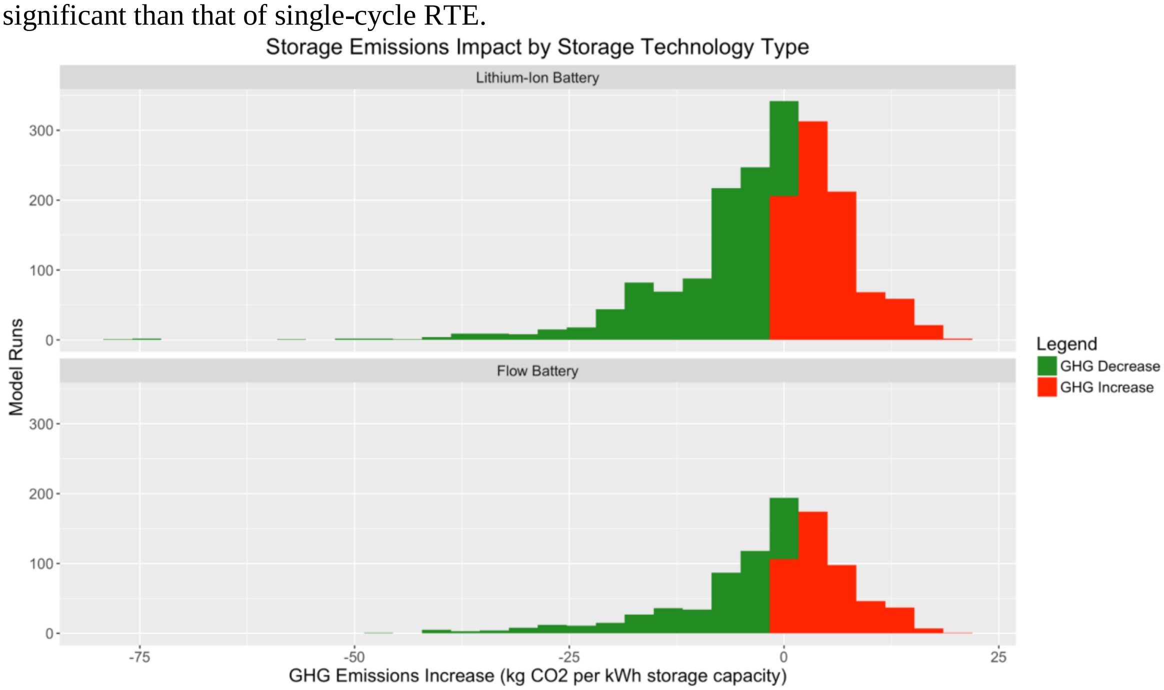
2) Impact of Storage Parameter Sensitivities

As with the residential models, commercial & industrial solar-plus-storage systems appear to be more likely to reduce GHG emissions than storage-only systems, because they tend to charge during low-emissions mid-day hours. It’s worth noting that this shift in charging patterns between standalone-storage and solar-plus-storage is primarily attributable to the Investment Tax Credit’s requirement that charging occur during solar production hours.

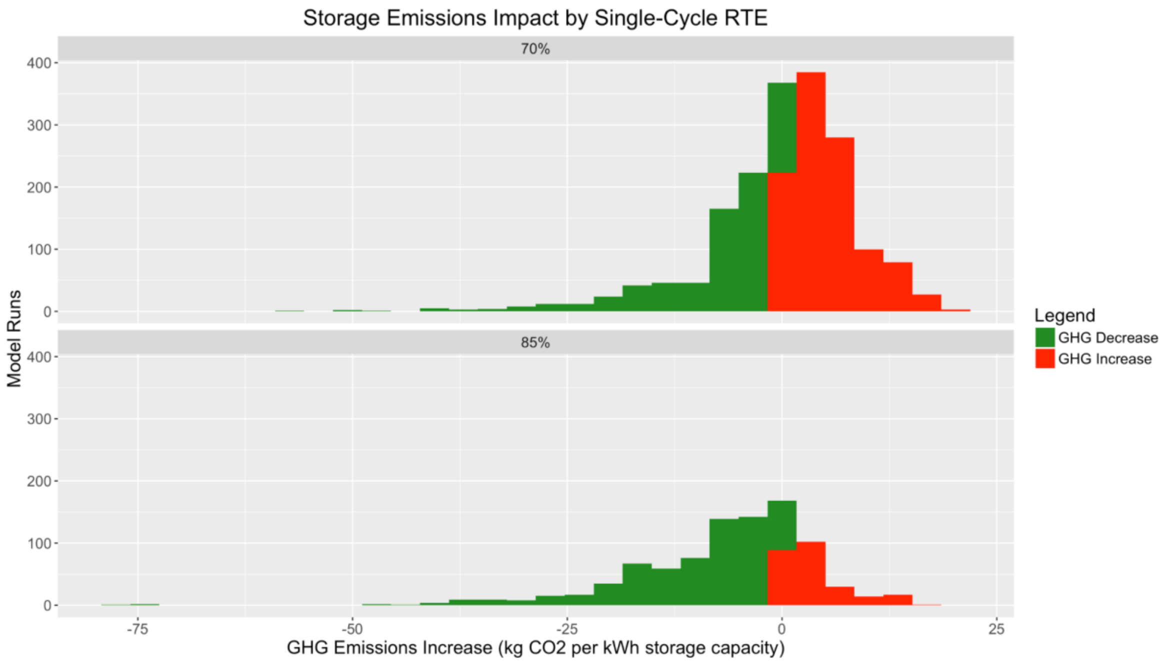
However, not all solar-plus-storage projects claim the ITC. Retrofits of existing solar projects with storage, and MUSH (municipal, university, school, hospital/nonprofit)-owned projects, may not be ITC-eligible. Such non-ITC solar-plus-storage projects would still be likely to have their maximum net demand occur later in the day, and noncoincident demand-charge reduction would therefore be primarily focused on high-emissions evening hours. As a result, they would be likely to see lower GHG emissions relative to standalone storage with the same load profile, but may be less GHG-reducing than solar-plus-storage systems that do claim the ITC and charge at least 75% from solar. In this modeling effort, all solar-plus-storage systems were assumed to be claiming the ITC and charging 100% from solar.



As modeled, lithium-ion battery storage systems are associated with slightly lower GHG emissions than flow batteries. Lithium-ion batteries were modeled with both 85% and 70% single-cycle round-trip efficiency values, but flow batteries were all modeled with 70% RTE. Flow batteries were also modeled as having a longer duration, and no cycling penalty. In addition, flow batteries have a slightly larger per-kWh cost, so it's possible that smaller storage systems were selected based on the 8-year-simple-payback methodology. However, these additional differences are likely to be less significant than that of single-cycle RTE.

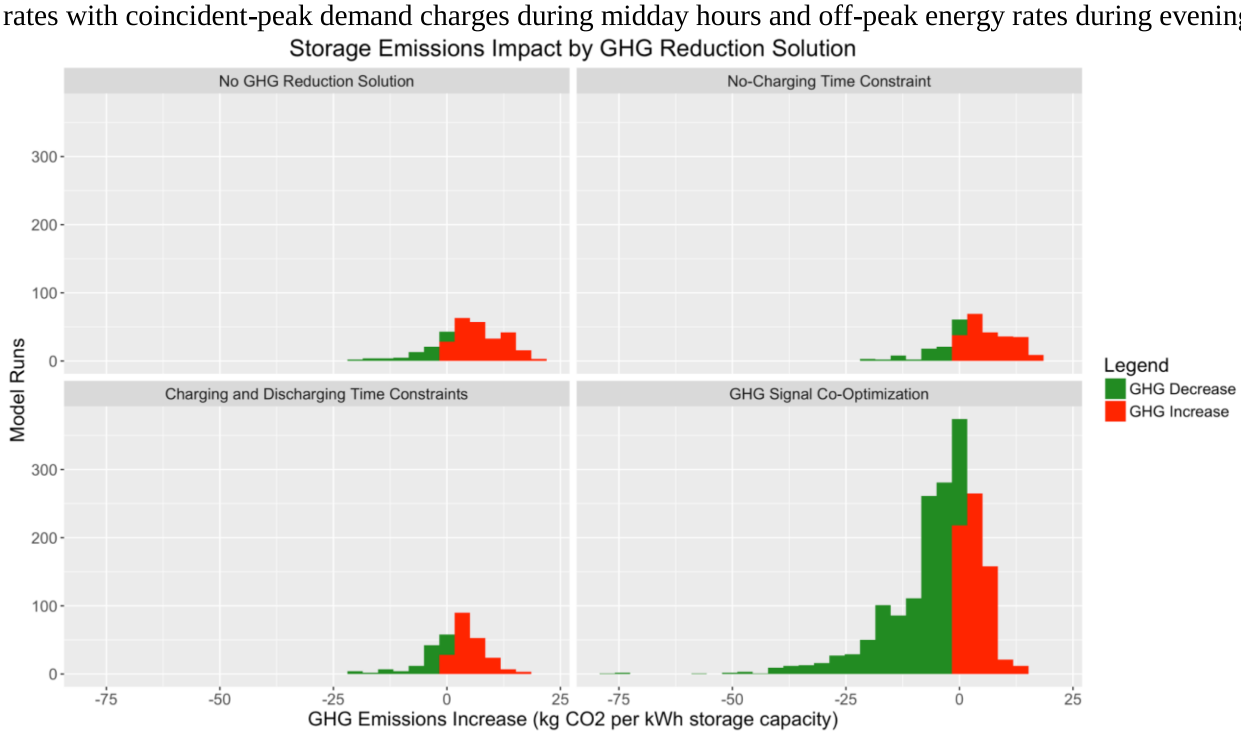


All other things being equal, systems with a lower single-cycle RTE are associated with higher emissions rates.

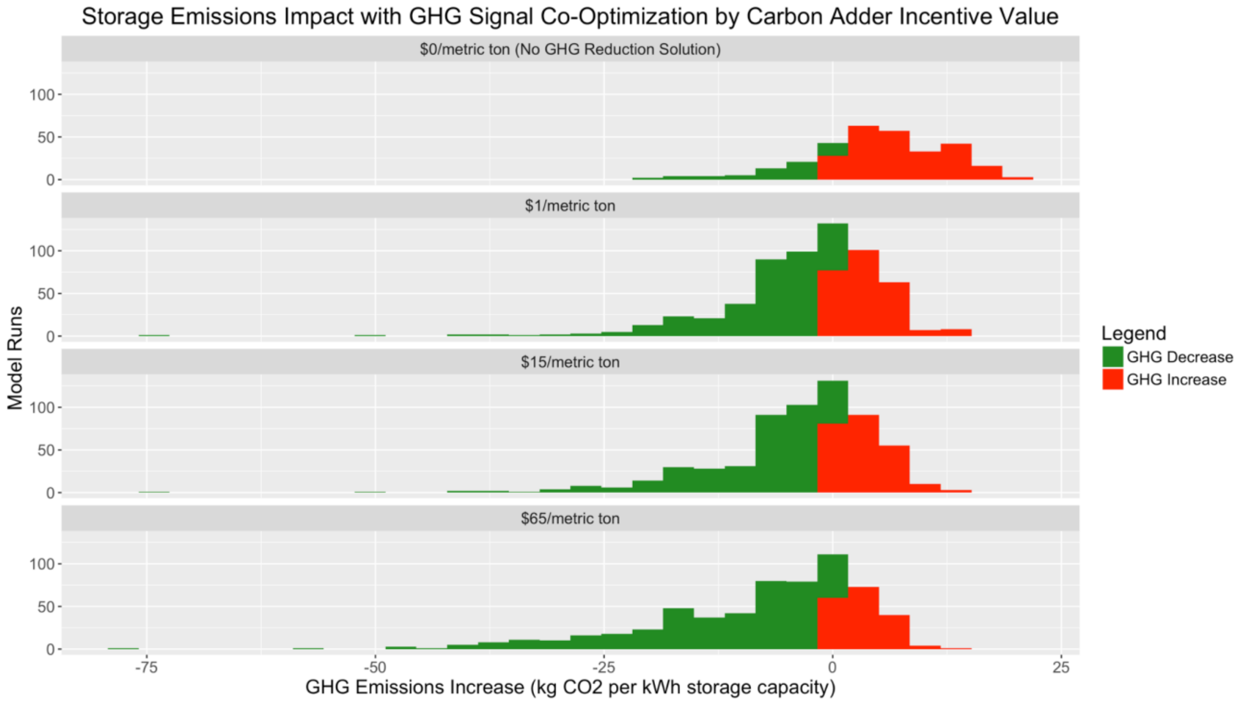


3) Impact of GHG Solutions

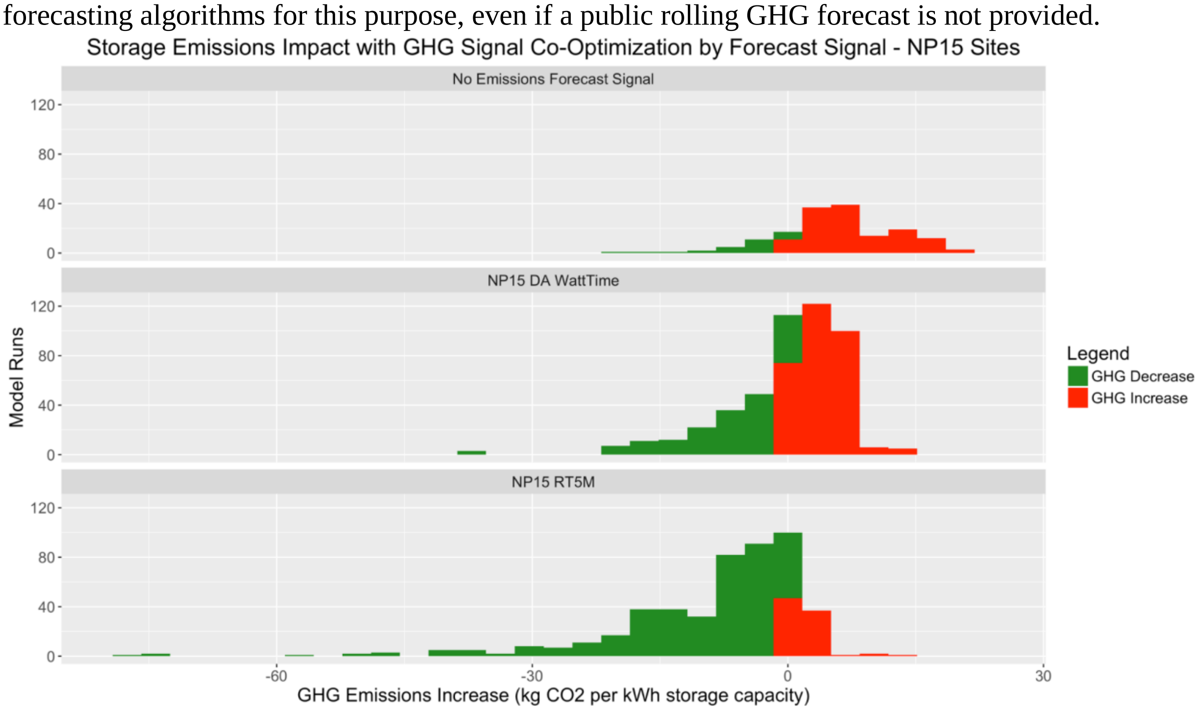
There is a noticeable difference in GHG emissions impacts among the four modeled GHG Solutions. Compared to the No GHG Emissions base-case, both the No-Charging Time Constraint and the Charging and Discharging Time Constraints are minimally effective in reducing emissions. On the other hand, GHG Signal Co-Optimization has a significant impact on GHG emissions relative to the base case. However, a large fraction of model runs under the GHG Signal Co-Optimization case are still increasing emissions. These GHG-increasing systems include commercial & industrial sites with noncoincident maximum demands that do not fall during high-GHG hours, or systems on older TOU rates with coincident-peak demand charges during midday hours and off-peak energy rates during evening hours.

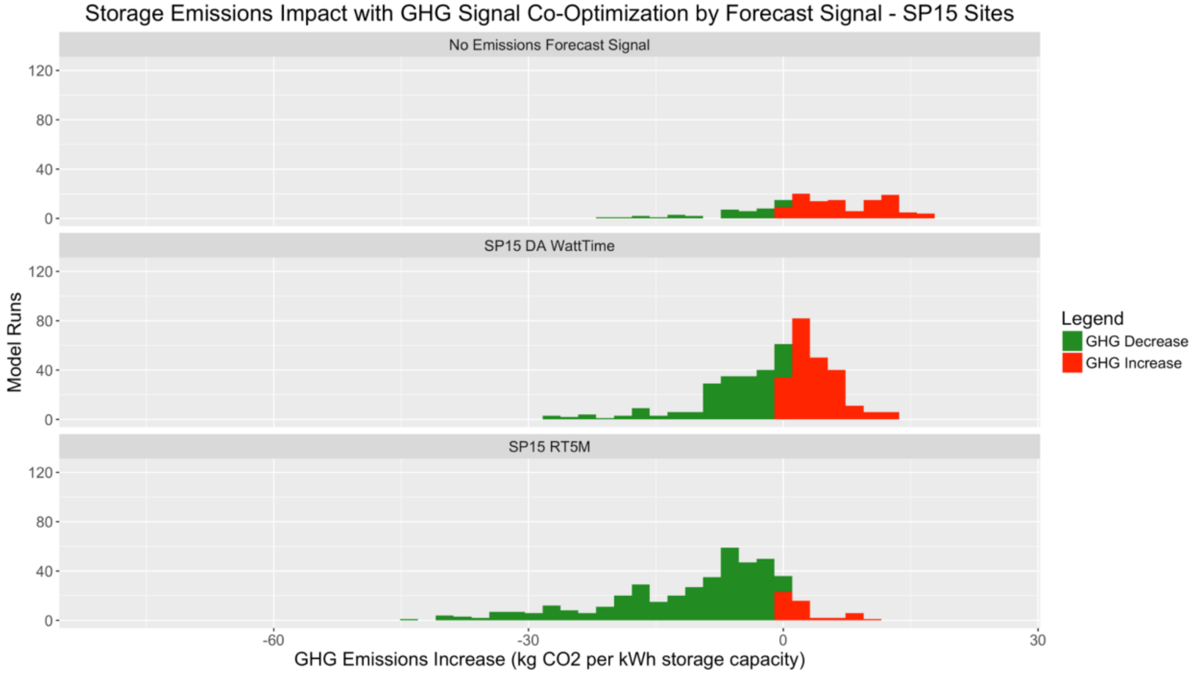


In contrast to the residential model runs, the magnitude of the carbon adder used to convert GHG rates into an economic signal ($1/metric ton, $15/metric ton, or $65/metric ton) has a small but noticeable impact on its effectiveness at reducing emissions. This may be because commercial & industrial rates have a more complex structure with multiple energy and demand charges. Residential storage charge/discharge patterns have a tendency to change as soon as a nonzero GHG-based economic signal is added to TOU energy rates, but then do not change significantly as the magnitude of the carbon adder is increased. By contrast, nonresidential storage charge/discharge patterns may change less when a small nonzero emissions signal is added, but continue to see incremental changes as the adder value is increased.

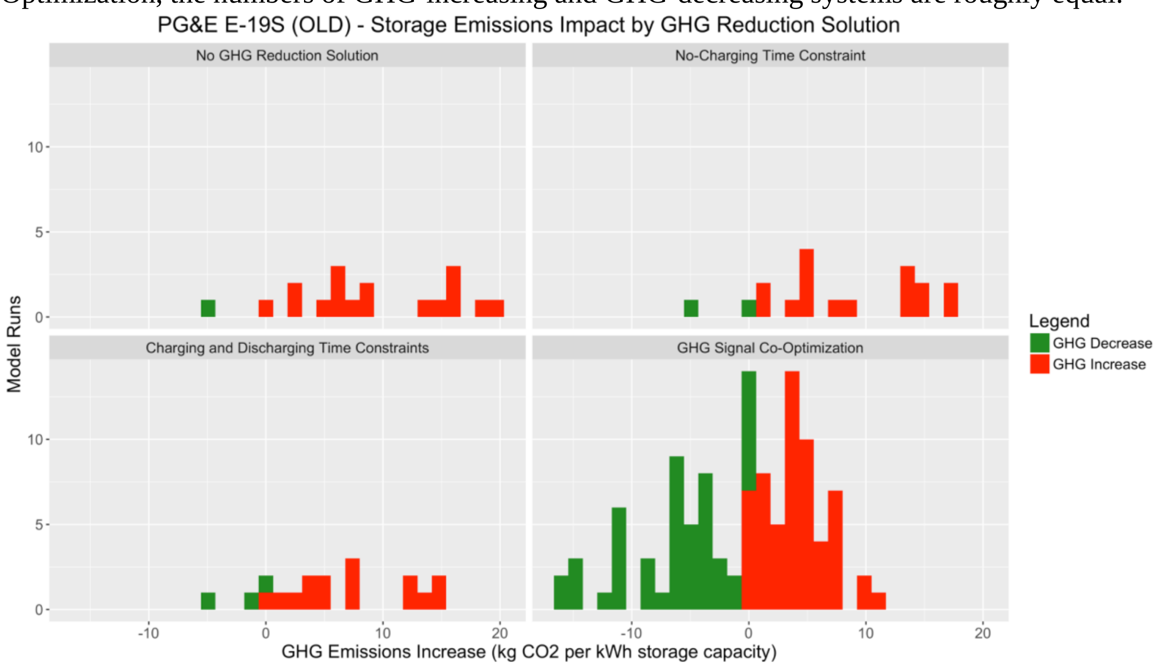


There is also a noticeable difference between GHG impacts using the perfect-information Real-Time Five-Minute emissions signal and the imperfect day-ahead WattTime-public-model emissions signal, although the day-ahead GHG forecast signal is still effective at reducing emissions relative to the base case. A rolling forecast that can accurately predict near-term GHG emissions impacts more accurately than the prior day's day-ahead forecast is likely to be more effective at reducing emissions. Storage technology companies may be able to leverage their sophisticated load-forecasting algorithms for this purpose, even if a public rolling GHG forecast is not provided.

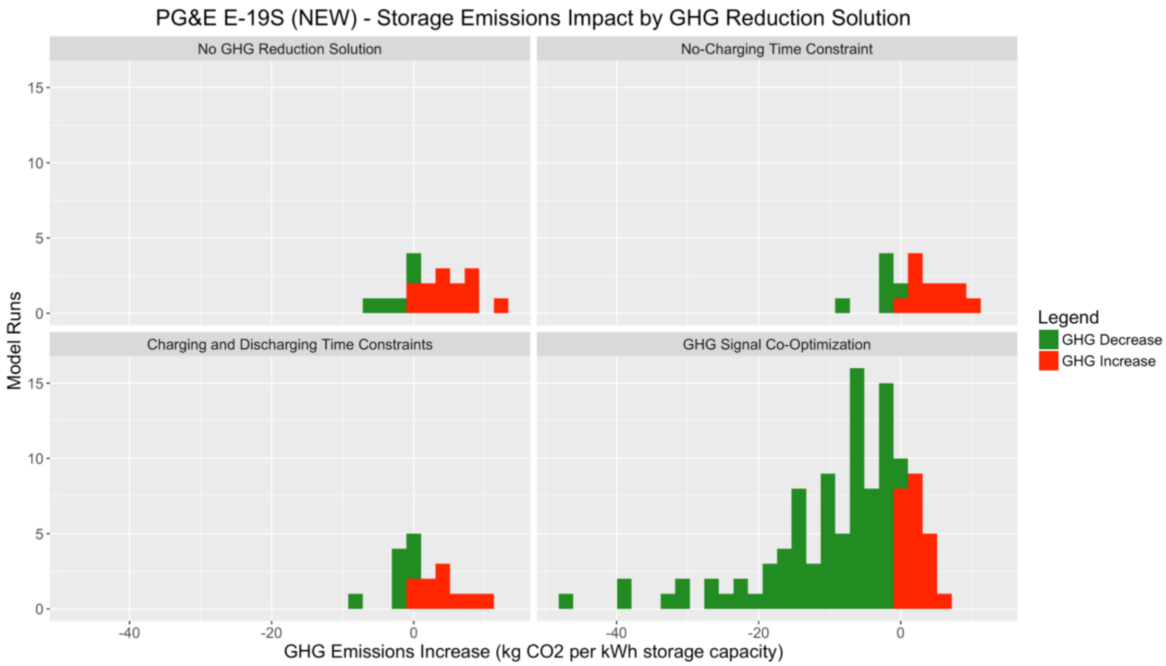




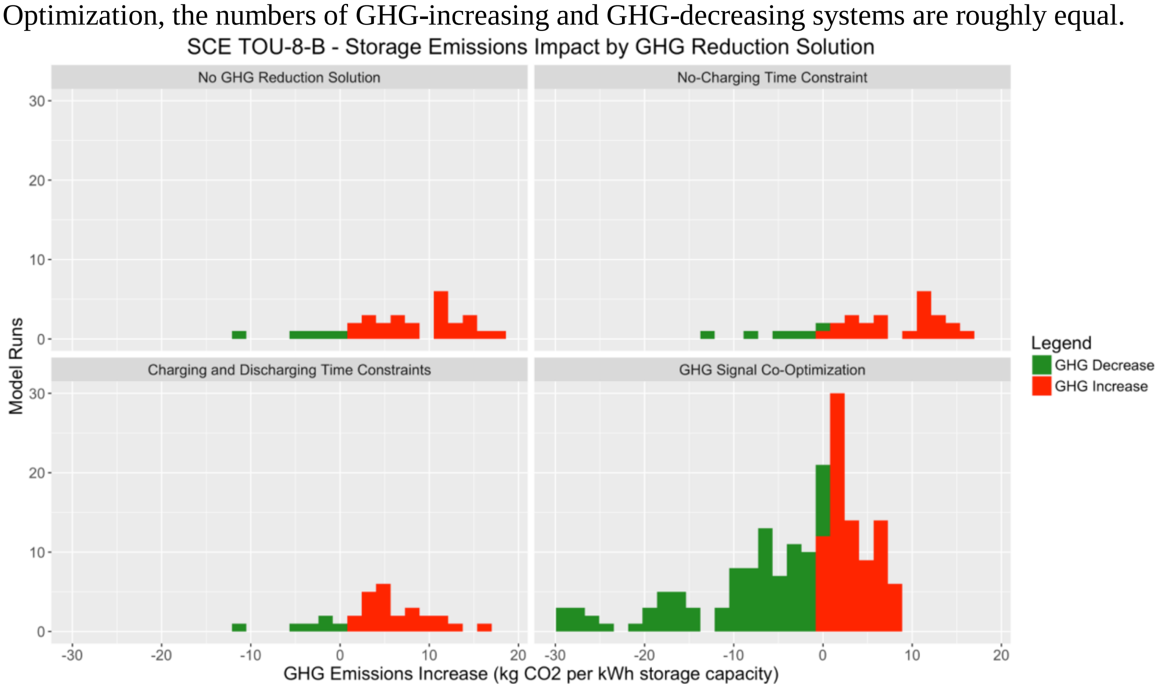
Finally, GHG emissions impacts can be visualized with combinations of commercial & industrial retail rates and GHG Reduction Solutions. For example, on the current PG&E E-19S (OLD) rate, the vast majority of model runs are associated with increased GHG emissions in the No GHG Solution and time-constraints cases. With GHG Signal Co-Optimization, the numbers of GHG-increasing and GHG-decreasing systems are roughly equal.



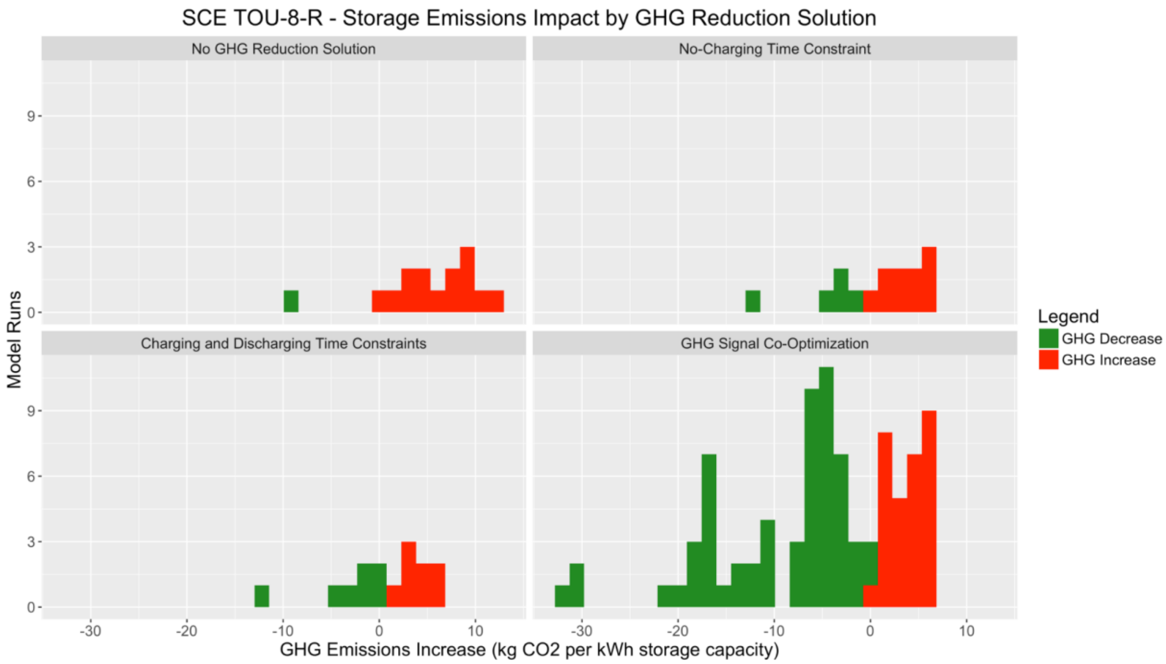
On the proposed PG&E E-19S (NEW) rate, the majority of model runs still show an increase in GHG emissions in the No GHG Solution case. However, after adding GHG Signal Co-Optimization, the majority of modeled storage systems are GHG-decreasing.



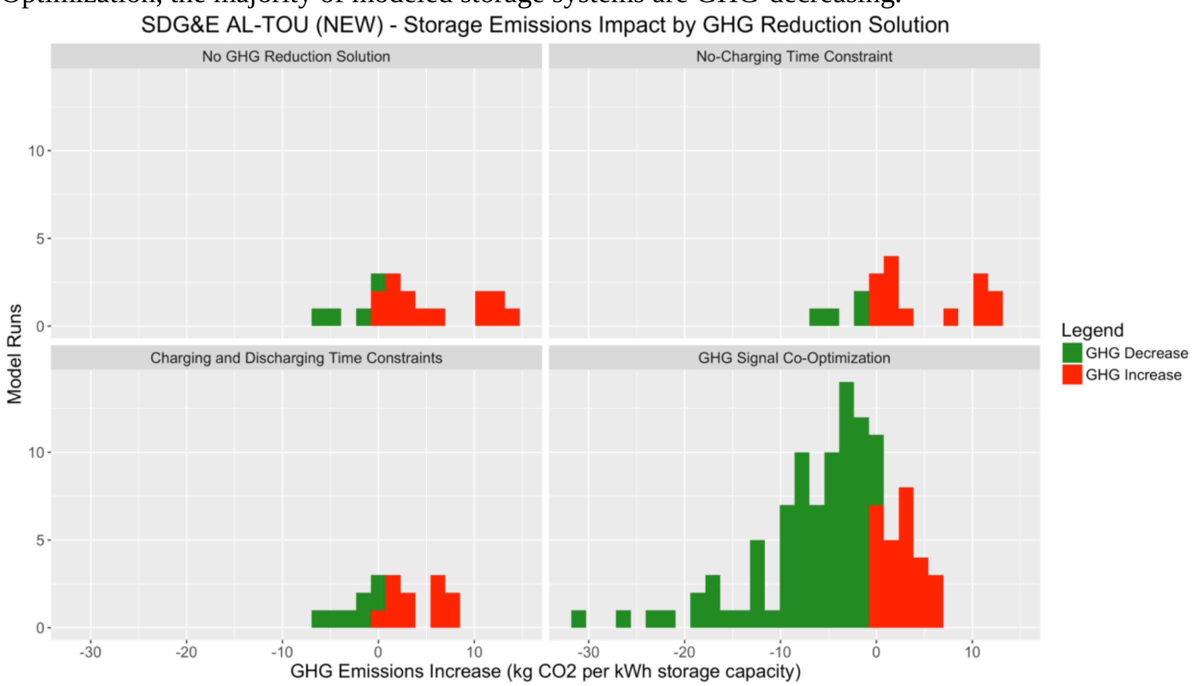
On the SCE TOU-8-B (OLD) rate, the majority of modeled systems are GHG-increasing. With GHG Signal Co-Optimization, the numbers of GHG-increasing and GHG-decreasing systems are roughly equal.



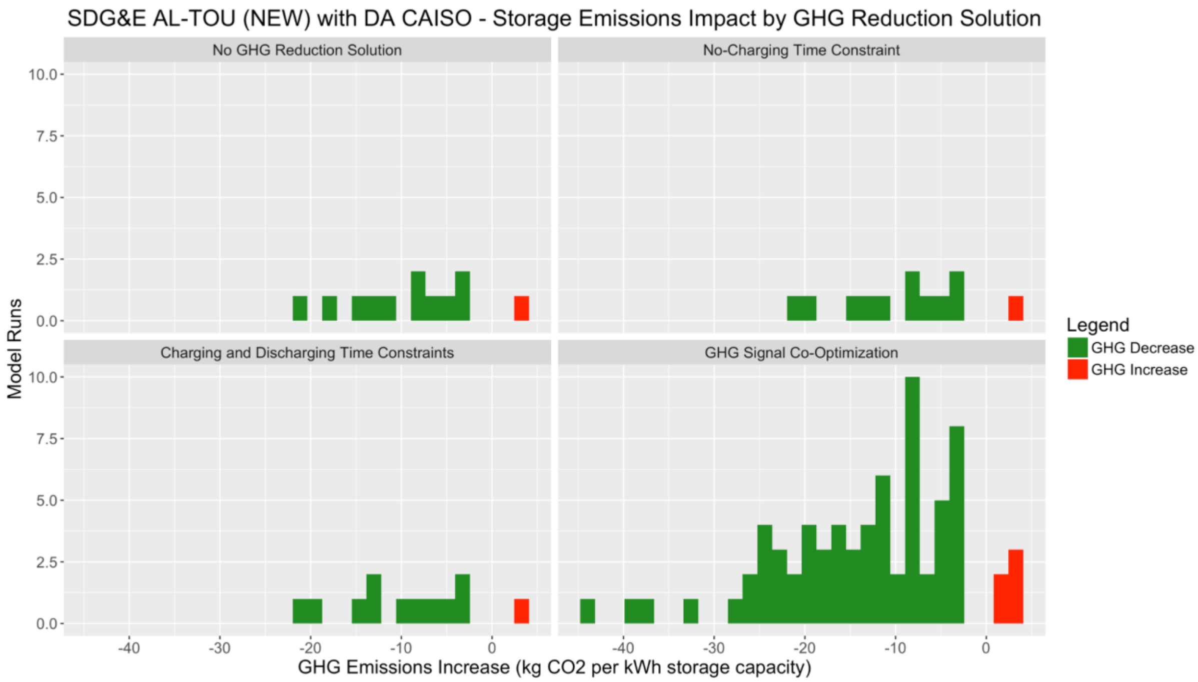
On the SCE TOU-8-R (OLD) rate (only for customers with PV), the majority of model runs still show an increase in GHG emissions in the No GHG Solution case. However, with GHG Signal Co-Optimization, the majority of modeled storage systems are GHG-decreasing. On this particular rate, the time-constrained cases do show more GHG reduction than the base case, though not nearly as much as the GHG Signal Co-Optimization cases.



On the SDG&E AL-TOU (NEW) rate, a slight majority of model runs are GHG-increasing. After adding GHG Signal Co-Optimization, the majority of modeled storage systems are GHG-decreasing.



On the hypothetical SDG&E AL-TOU rate featuring Day-Ahead CAISO energy prices in place of the EECC TOU energy rates, nearly all modeled systems are GHG-reducing, across all four GHG Solutions. This is because the Day-Ahead CAISO energy prices are very similar to the WattTime Day-Ahead GHG emissions forecast.



V. CONCLUSIONS

The results above allow a number of conclusions to be drawn to help inform the Working Group's recommended modifications to SGIP eligibility requirements and incentive structures:

First, the results suggest that out-of-date retail rate structures that are poorly aligned with real-time grid conditions and GHG emissions are a key driver of behind-the-meter energy storage system's tendency to increase emissions.

For residential storage systems, this includes the use of non-time-of-use tiered rates, as well as TOU periods featuring high energy rates during peak solar-production hours and lower energy rates during high-emissions evening hours. Recent and upcoming TOU rates are better aligned with average daily cost and emissions profiles, and modeling results suggest that storage systems operating to minimize bills for customers on these rates are more successful at reducing GHG emissions, especially when paired with solar and taking the ITC.

For commercial & industrial customers, older rates also tend to feature out-of-date TOU periods, as well as a greater emphasis on of noncoincident demand charges. If the customer's maximum demand occurs during low-emissions mid-day hours (which is common for commercial & industrial customers, but uncommon among residential customers), storage systems will be strongly incentivized to discharge during those hours, and will potentially charge during evening hours at high emissions rates if energy rates are low during these times. Updated commercial & industrial rates feature higher energy costs during evening hours and low Super-Off-Peak energy costs during mid-day hours in the spring. These newer rates also typically feature a shift towards coincident-peak and part-peak demand charges, which encourages a greater portion of demand-capping to occur during system-peak hours as opposed to during customer-peak hours. Both of these factors in the new rates (updated TOU periods, and a shift from noncoincident to coincident demand charges) affect storage operations so as to reduce GHG emissions compared to the older rates.

However, these new rates do not universally cause optimally-dispatched energy storage systems to reduce GHG emissions while minimizing customer costs. This suggests that there may be additional need to achieve better alignment between economic incentives and grid conditions through the use of a GHG signal. TOU rate structures are frequently too coarse of an economic signal to guarantee that storage systems are reducing emissions. Plots of retail energy rates and marginal emissions frequently revealed periods of high grid emissions that occur after the 4:00 pm - 9:00 pm peak period found in the newest TOU rates, or system-wide curtailment events lasting an hour or less that occur during part-peak TOU hours.

Although the SGIP Working Group decided that rate-design topics were out-of-scope with respect to its program-modification recommendations, many participants expressed hope that the group's modeling findings could help inform the direction of future retail rate structures. For example, the hypothetical version of SDG&E AL-TOU (NEW) featuring day-ahead wholesale energy prices achieved a degree of consistent GHG emissions reduction not found using any of the current or proposed retail rates. These modeling results support the idea that it would be beneficial for some form of real-time pricing to be available as an option to both residential and non-residential customers, as was suggested by some participants at the December 2017 CPUC Rate Design Forum. Similar results could be achieved with a GHG signal, but would require a substantially higher carbon-adder value than the values considered here to provide a comparably-strong economic signal.

In the absence of such rates, additional GHG Solution measures can be taken to ensure that SGIP storage systems are less likely to increase GHG emissions. Of the solutions modeled, the use of a GHG emissions signal was significantly more effective than the addition of constraints on storage charging and discharging times. In addition, this economic signal is less likely to impact storage's ability to provide customer bill-reduction and grid services than operational constraints would.

Modeling results suggested that the carbon adder incentive value (here, $1/metric ton, $15/metric ton, or $65/metric ton) chosen as a multiplier to the dynamic carbon-emissions signal did not have a noticeable impact on the degree of storage GHG reduction for residential storage systems, but had a small impact on commercial & industrial energy storage systems' GHG reduction.

In addition, there was an appreciable difference between GHG emissions reduction achieved using a perfect-forecast Real-Time Five-Minute emissions signal, relative to the Day-Ahead Hourly emissions forecast calculated using a public model contributed by WattTime. Operational storage systems may be able to use a more accurate emissions forecast than the current version of the WattTime public model by developing their own emissions forecast (for instance, using their own load-forecasting algorithm trained on historical real-time emissions data) or using a proprietary rolling emissions forecast provided by WattTime or another third party.

Storage systems charging from solar to receive the Investment Tax Credit typically have lower GHG impacts than storage-only systems without this economic incentive to charge during mid-day, typically low-emissions-rate hours. (Solar-plus-storage systems not performing ITC solar self-consumption do exist, but were not modeled here.) However, some ITC-compliant solar-plus storage systems did increase emissions. This suggests that some combination of retail-rate, storage-parameter, and cycling requirements could be necessary in addition to ITC compliance to achieve reasonable certainty that storage systems are decreasing GHG emissions, if emissions impact is not measured or incentivized directly for these systems.

All other things being equal, storage systems with high single-cycle round-trip efficiency reduce emissions more (or increase emissions less) than lower-SCRTE storage systems. However, low-SCRTE storage systems are still capable of reducing emissions, and high-SCRTE storage systems can increase emissions.

Parasitic storage losses from auxiliary loads such as HVAC and electronics also appear to be a significant driver of storage GHG emissions. It is not clear whether approach used in this modeling effort (0.3% of storage rated power) is a sufficiently accurate representation of parasitic loads. A more realistic model might use different parasitic load values depending on whether the storage system is inactive or charging/discharging, whether the system is located indoors or outdoors, and ambient temperature at the customer site.

The SGIP program features storage cycling incentives for systems receiving Performance-Based Incentives, and also monitors the related operational-RTE and capacity-factor metrics. Modified incentives or constraints related to these metrics were not exhaustively modeled, but results suggest that low-cycling residential systems have among the poorest GHG performance, whereas more active residential systems (those on high-differential TOU rates, or solar-plus-storage systems performing solar self-consumption) are much more likely to be reducing GHG emissions. By contrast, there are fewer low-cycling commercial & industrial energy storage systems, and cycling requirements may actually increase GHG emissions if not combined with updated retail rates and/or a GHG signal, while accelerating battery degradation.

The operational-RTE metric used in the SGIP program represents a combination of single-cycle round-trip efficiency, parasitic losses, and storage cycling. These are all important explanatory factors for storage systems' GHG emissions impact, but cannot solely be used to determine a system's GHG impact in the absence of information about the marginal grid emissions rates at which storage systems charge and discharge.

This modeling effort did not include the impact of demand response programs such as the Base Interruptible Program (BIP), Capacity Bidding Program (CBP), Demand Response Auction Mechanism (DRAM), or Local Capacity Requirements (LCR), which storage systems commonly participate in. However, results for residential systems participating in SmartRate, and commercial & industrial systems participating in Peak Day Pricing (PDP) or Critical Peak Pricing (CPP), suggest that participation in DR programs with infrequent events has a minimal GHG impact. Participation in DR programs with infrequent events can still have a significant impact on utility marginal costs (generation energy and capacity, and distribution capacity), because capacity costs tend to be concentrated in a small number of hours per year. Although not modeled here, DR programs with frequently-called events could meaningfully reduce GHG impact, as long as storage systems do not begin charging immediately after a DR event, when marginal emissions rates are usually still high.

Given that GHG emissions reduction by storage systems is primarily achieved by charging during low- or zero-emissions times, as opposed to discharging during high-emissions times, it seems plausible that the forthcoming ESDER 3 CAISO load-shift product, which will incentivize storage systems to charge during times of renewables curtailment, could have a GHG-reducing impact similar to or exceeding that of the GHG emissions signal modeled here.

VI. RECOMMENDATIONS

Because this modeling effort represents the contributions of multiple Working Group stakeholders, this work paper does not include any specific proposed reforms or recommendations to ensure that SGIP-funded storage achieves the program's intended GHG-reduction objectives.