Attachment A: Proposed Scenarios for the 2019 Reference System Plan

Acronyms and Abbreviations:

AAEE	Additional Achievable Energy Efficiency
AAPV	Additional Achievable Photovoltaic
ATB	Annual Technology Baseline
BE	Building Electrification
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CEC	California Energy Commission
DER	Distributed Energy Resources
EE	Energy Efficiency
GHG	Greenhouse gas
GW	Gigawatts
GWh	Gigawatt hours
HVAC	Heating, Ventilation, and Air Conditioning
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
MMT	Million Metric Tons
O&M	Operation and Maintenance
OOS	Out-of-State
PEV	Personal Electric Vehicle
PV	Photovoltaic
RA	Resource Adequacy
RSP	Reference System Plan
SB	Senate Bill
TBD	To Be Determined
WECC	Western Electricity Coordinating Council
ZEV	Zero Emission Vehicle

Purpose

The purpose of this document is to propose scenarios for analysis in developing the Reference System Plan for the 2019-20 cycle of the Integrated Resource Planning (IRP) process. By running a capacity expansion model for the California electric sector using a variety of long-term planning assumptions, Commission staff hopes to better understand the economic, policy, and timing-related risks associated with planning California's dynamic and rapidly changing electricity system. This document describes the means by which the supply or demand for electricity may change and quantifies the implications of those changes on the development of the electricity system. This is an important exercise since many of the solutions for achieving the goals for the electricity sector require investments with lead times of five years or more. Identifying these solutions is therefore key to achieving the Commission's objective of achieving GHG reductions and ensuring electric grid reliability at lowest cost while meeting the state's other policy goals.

Background

In the 2017/18 IRP cycle, staff used an optimization model (or capacity expansion model) to produce portfolios of electricity transmission and generation resources that are lowest cost to California ratepayers under a variety of plausible conditions in 2030. In September 2017, staff proposed a single portfolio for use in related planning activities, procurement activities, and near-term actions. The Commission adopted this portfolio as part of the 2017 Reference System Plan in the February 2018 Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans (D.18-02-018).[1] Staff organized the development of scenarios representing plausible conditions in 2030 around three primary questions:

1. **What resources are needed to reduce GHG emissions in the electric sector?** This question was designed to explore the impact of a new GHG planning target on the need for new generation, distributed energy resources (DERs), and transmission.
2. **What is the optimal portfolio of resources under different, alternative futures?** This question was designed to ensure that the portfolio selected by the Commission satisfies all statutory requirements within a range of future conditions.
3. **What investments or actions, if any, should be taken in the short term?** This question was designed to enable the Commission to provide procurement and investment guidance to all regulated entities, as well as other decision makers and market actors in California

In developing portfolios of resources for the 2019/20 Reference System Plan, staff proposes to use these same analytical questions as the starting point. (For a full discussion, see Ch. 4 of the May 2017 Staff Proposal.)[2] Staff also proposes certain updates and modifications to the proposed scenarios as laid out in this document, in order to explore new policy questions and inform the Commission's decision-making.

Framing Study

Commission staff proposes to begin its IRP 2019/20 scenario analysis with a set of framing scenarios in the post-2030-time horizon. The purpose of looking beyond 2030 to 2045 is to begin to understand the potential implications of the Senate Bill (SB) 100 goal of 100 percent of retail electricity sales being supplied by zero-carbon resources by 2045, which will provide useful context for evaluating cases and sensitivities in the 2030 planning period. Furthermore, in looking beyond 2030, staff can begin to

[1] Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K771/209771632.PDF.
[2] Available at: http://www.cpuc.ca.gov/irp_proposal/.

examine the interactions between and across multiple economic sectors that may impact the state's chances of meeting its long-term GHG emission reduction goals. As the Commission Decision (D.18-02-018) setting requirements for the IRP process explains, "our actions with respect to setting GHG targets and planning for emissions reductions in the electricity sector should not be done in isolation," and "there are important interactions between, in particular, the transportation sector and the buildings sector, that can help or hurt the state's chances of meeting its GHG targets in 2030 economy wide."

If other sectors fall short on expected GHG reductions, higher levels of GHG reduction may be needed in the electric sector to achieve statewide goals. Similarly, if the economy experiences higher-than-expected levels of electrification and deeper reductions of GHG emissions in other sectors, it may justify a relaxing of the electric sector GHG reduction target due to the increased load.

Commission staff proposes an analysis of the following scenarios (see Table 1) to examine how GHG reduction performance in other sectors of California's economy influences the performance and cost of the state's electricity sector in 2030 and 2045.

Table 1: Framing scenarios projecting transmission and generation resources in 2045 following three different technology pathways for achieving deep decarbonization. Assumptions and results are derived from CEC's Deep Decarbonization in a High Renewables Future study.[3]

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	What was done in IRP 2017/18[4]
		2045 Framing Scenarios		
2045 High Electrification	Includes aggressive adoption and deployment of GHG mitigation strategies beyond SB350.	Represents the "High Electrification" scenario in CEC's *Deep Decarbonization in a High Renewables Future* study. Achieves 32 MMT by 2030 and 6 million zero-emission vehicles (ZEVs) on the road by 2030, among other targets.	CEC's *Deep Decarbonization in a High Renewables Future* study. PATHWAYS Base Mitigation case.	PATHWAYS 2038 Base Mitigation Case
2045 High Biofuel	Includes biofuels to replace liquid and gaseous fossil fuels with an emphasis on advances, sustainable biofuels excluding corn and sugarcane ethanol.	Represents the "High Biofuels" scenario in CEC's Deep Decarbonization study. Incorporates higher biofuel use, including purpose-grown crops and relatively low number of zero emission vehicles and renewable energy.	CEC's *Deep Decarbonization in a High Renewables Future* study. PATHWAYS High Biofuel case.	PATHWAYS 2038 High Biofuel case.
2045 High Hydrogen	Emphasizes hydrogen as an energy carrier produced from a centralized, grid-connected personal electric vehicle (PEV) electrolysis. It is used in vehicles and as a natural gas replacement in the pipeline.	Represents the "High Biofuels" scenario in CEC's Deep Decarbonization study. Emphasizes a high reliance on fuel cell trucks, less battery electric vehicles, and less renewable energy.	CEC's *Deep Decarbonization in a High Renewables Future* study. PATHWAYS High Hydrogen case.	PATHWAYS 2038 High Hydrogen case

[3] Mahone, Amber, Zachary Subin, Jenya Kahn-Lang, Douglas Allen, Vivian Li, Gerrit De Moor, Nancy Ryan, Snuller Price. 2018. *Updated Results from the California PATHWAYS Model. California Energy Commission*. Publication Number: CEC-500-2018-012

[4] In 2017 staff used the PATHWAYS model to run four different 2038 scenarios, each consistent with 80% reductions in economy-wide GHG emissions by 2050. Scenarios were aligned with the two core GHG cases: 30 MMT or 42 MMT by 2030. Staff observed that the 42 MMT Scenario was roughly on the straight-line path toward the 2050 GHG target and the electric sector's contribution toward the statewide target, though it acknowledged that more analysis of this GHG emissions trajectory was needed.

Proposed Scenarios

The scenarios described in the previous section examine longer term, economy-wide trajectories and provide a framework for understanding the role of the electric sector in meeting California's GHG goals. IRP staff proposes to use the Framing Studies to determine the most important cases and sensitivities to examine in the 2019/20 IRP cycle. This section describes IRP staff's initial recommendations for the cases and sensitivities subject to change based on the results of the post-2030 framing analysis.

Policy Cases

RESOLVE includes optionality to enforce a greenhouse gas (GHG) constraint on California Independent System Operator (CAISO) system-level emissions. The purpose of the core policy cases is to compare the impacts of different GHG planning constraints on portfolio composition, costs, and air pollutants in disadvantaged communities.

These cases will be informed by the CARB-adopted GHG planning target range for the electric sector (30 – 53 MMT by 2030) and results from the 2017/18 Reference System Plan and Preferred System Plan. Staff is proposing the following three policy cases for study in the 2019/20 IRP cycle.

- **46 MMT Case:**[5,6] Equivalent to the 42 MMT case adopted by the Commission as the electric sector 2030 GHG planning target in the 2017 Reference System Plan
- **38 MMT Case**: Represents a mid-point between the electric sector GHG planning target adopted by the Commission and a deeper decarbonization future.
- **30 MMT Case**: Represents a deep decarbonization effort consistent with the low end of CARB's adopted range for the electric sector.

Policy Sensitivities

Separate from the core policy cases, staff proposes to examine how changes to one or more default assumptions regarding technology adoption, technology cost, and grid conditions can impact the least-cost generation and transmission infrastructure for California residents. These specific changes are called "core policy sensitivities" and are intended to help decision makers evaluate:

- o the potential cost to the state of pursuing different resource policies;
- o how these costs change depending on the GHG emissions target; and
- o how costs change depending on different future conditions that may be outside of Commission control.

Three types of sensitivities are discussed in the sensitivities tables:

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[5] Note that the 2019 version of RESOLVE includes several changes to the model to improve both the GHG accounting accuracy and alignment with other state regulatory agencies. For example, the latest version of RESOLVE accounts for 4 MMT CO_2 emissions from California's behind-the-meter combined heat and power facilities, which were not included in RESOLVE during the 2017-18 IRP cycle. This change is consistent with the California Air Resources Board's emissions accounting method and is the rationale for selecting 46 MMT as the GHG target as a policy case in the 2019 proposed scenarios analysis.

[6] If the 46 MMT case does not achieve Senate Bill (SB) 100's legislative mandate of 60% RPS equivalent by 2030, staff proposes to use a 60% RPS constraint rather than 46 MMT as the default case to ensure compliance with the existing policy mandate.

- **Core Sensitivities**: Represent uncertainty around state policies to understand how resource buildouts change in response to variance in technology penetration
- **Resource Cost and Procurement Sensitivities**: Describe changes to the expected cost, availability, and procurement of specific renewable resources to better understand investment risk and buildout robustness under modified conditions
- **Demand Side Studies**: Represent different futures for load forecast and demand-side adoption

The sensitivities described in this work are summarized in Table 2 below for convenience and rapid reference. The sensitivity type and scenario name are shown here. A more detailed explanation of the anticipated data sources, rationale, and precedence within IRP are also provided in Table 3.

Table 2: Summary of the 2019 proposed sensitivity studies to be run in the capacity expansion model for the 2030 timeframe.

Sensitivity Type	Sensitivity Name
2045 Framing Scenarios	2045 High Electrification
	2045 High Biofuel
	2045 High Hydrogen
2030 Core Sensitivities	New Out-of-State Transmission
	Low Net Export Limit
	High Net Export Limit
	High Carbon Price
2030 Resource Cost and Procurement Sensitivities	Low Early OOS Wind
	Aggressive OOS Wind
	Low PV Cost
	High PV Cost
	Low Battery Storage Costs
	High Battery Storage Costs
	High Natural Gas Cost
	Low Natural Gas Cost

Sensitivity Type	Sensitivity Name
2030 Demand Side Studies	Low PEV Load
	High PEV Load
	High PEV Load + High Flexible Charging
	High Building Electrification
	High BTM PV
	Low BTM PV
	Shift Demand Response Optimization
	Economic selection of EE
2030 Special Studies	High Thermal Retention
	Low Thermal Retention
	Low RA Imports
	Low RA Imports and Low Thermal Retention
	60% RPS
	44 MMT
	42 MMT
	40 MMT
	36 MMT
	34 MMT
	32 MMT

The following table provides descriptions of each scenario selected to be run during this IRP cycle.

Table 3: The proposed scenarios are described in the table below. This table includes the proposed sensitivities, data sources, and rationale for each scenario as well as reference to related sensitivity study conducted as part of the scenarios analysis in the previous IRP cycle.

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	Approach in 2017/18 IRP Cycle[7]
		Core Sensitivities		
Transmission to Out-of-State Resources				
Default No New Transmission	Only those OOS resources that can that can be developed utilizing existing transmission are allowed.		Refer to 2019 Inputs and Assumptions proposal	Same
New OOS Transmission	New transmission to OOS resources is allowed	Examines the cost of achieving emissions reductions if interstate transmission dependencies can increase.	Refer to 2019 Inputs and Assumptions proposal	Same
Export Limits				
Default Medium Net Export Limit	Net export increases linearly to 5 GW by 2030	Explores the influence of moderate levels of electricity exports on resource selection.	Repeated value from 2017/18 cycle (source of specific value is TBD)	Same
Low Net Export Limit	Net export limit remains constant at 2 GW through 2030	Examines how low levels of electricity exports influence resource selection	Annual Interregional Information	Same. Also ran "Flex challenged" which combined a low net export constraint (2 GW)

[7] In 2017 staff used the PATHWAYS model to run four different 2038 scenarios, each consistent with 80% reductions in economy-wide GHG emissions by 2050. Scenarios were aligned with the two core GHG cases: 30 MMT or 42 MMT by 2030. Staff observed that the 42 MMT Scenario was roughly on the straight-line path toward the 2050 GHG target and the electric sector's contribution toward the statewide target, though it acknowledged that more analysis of this GHG emissions trajectory was needed.

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	Approach in 2017/18 IRP Cycle[7]
			2017-2018 Transmission Planning Process PowerPoint[8] (2/22/18)	with a minimum gas generation requirement (2 GW)
High Net Export Limit	Net export increases to 8 GW by 2022 and remains constant through 2030	Examines how high levels of electricity exports influence resource selection	Similar value from 2017/18 cycle (source of specific value is TBD)	Same. Also ran a "Flex challenged" which combined a high net export constraint (8 GW MW) with a minimum gas generation requirement (2 GW)
Carbon Price				
Default	Carbon Price remains at Cap-and-Trade allowance price floor (approximately $15/ton in 2018; $29/ton in 2030)			Same
Increased Cost of Carbon	Increased Cost of Carbon ($29/ton in 2018; $88/ton in 2030)	What is the effect of a higher carbon price than the current allowance floor price?	TBD	Same
Resource Cost and Procurement Sensitivities				
Early Out-of-State Wind Procurement				
Default	No early procurement			No early procurement was the default in 2017/18
Low Early OOS Wind	Early (2026) procurement of modest amount of OOS wind	Provides insight regarding the investment risk of low OOS renewable development at earliest reasonable time	(source of specific value is TBD)	Manually added 3,000 MW of WY & NM wind (along with associated transmission to CA) to the portfolio in 2026

[8] https://www.caiso.com/Documents/Presentation_California_ISO_Annual_Interregional_Information_Feb22_2018_revised.pdf

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	Approach in 2017/18 IRP Cycle[7]
High Early OOS Wind	Early (2026) procurement of higher amount of OOS wind	Provides insight regarding the investment risk of aggressive OOS renewable development at earliest reasonable time	Source of specific value is TBD. Suggested 10 GW of OOS is built in 2030 using Annual Technology Baseline (ATB) values	Ran an "unconstrained OOS wind" scenario which allowed optimal amounts of NM and WY wind from 60 GW of available potential
Utility-Scale Solar				
Default	Default Utility scale solar cost			Cost from 2018 IEPR
Low PV Costs	Low PV cost trajectory	Addresses the change in resource mix if solar capital costs are low compared to the default estimation.	Utilize the "High Annual Technology Baseline (ATB)" trajectory, applied to utility-scale PV candidate resource costs.	Same
High PV Costs	High PV cost trajectory	Addresses the change in resource mix if solar capital costs are high compared to the default estimation. Describes "least regrets" solar investment	Utilize the "Low ATB" values, applied to utility-scale PV candidate resource costs.	Same
Battery Storage				
Default	Battery storage costs 2019 I&A			
Low Battery Storage Cost	Battery costs are below reference cost	Illustrates the influence of low battery costs on grid buildout, including the effects of longer lasting batteries or hybrid PV/Battery systems with greater operational flexibility	Uses Lazard's 4.0 electricity generation cost analysis through 2022, with extrapolation thereafter	Similar

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	Approach in 2017/18 IRP Cycle[7]
High Battery Storage Cost	Battery costs are above reference cost	Describes the influence of high battery costs on grid buildout	Lazard's analysis 4.0 to 2022, with extrapolation thereafter	Similar
Natural Gas Cost				
Default	Projected cost of natural gas is moderate for natural gas-fired generators		Long term natural gas projections derived from Natural Gas Intelligence Database	
High Natural Gas Cost	Projected cost of natural gas is high for natural gas-fired generators	Investigates the influence of high natural gas price projections on system costs and future generator resource selection	Same as above	
Low Natural Gas Cost	Projected cost of natural gas is low for natural gas-fired generators	Investigates the influence of low natural gas price projections on system costs and future generator resource selection	Same as above	
		Demand Side Studies		
Transportation Electrification (PEV adoption, no flexible charging)				
Default	Medium PEV load with mid PEV load profile.	Adoption is driven by current state policy and market growth	CEC 2018 IEPR Mid PEV adoption forecast	CEC 2016 IEPR Mid
Low PEV Load	Low PEV load with mid PEV load profile	Explores which resources would be needed if California achieves lower than anticipated levels of EV adoption	CEC 2018 IEPR Low PEV adoption forecast	None
High PEV Load	Consistent with former Governor Brown's goal of	Explores the impact on overall electricity	CEC 2018 IEPR High Demand Forecast	None

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	Approach in 2017/18 IRP Cycle[7]
	5m ZEVs on the road by 2030 with mid PEV load profile	infrastructure associated with achieving the Governor's goal of 5m ZEVs on the road by 2030		
Flexible Charging (PEV adoption with flexible charging)				
Default	Medium load with mid PEV load profile and no flexible charging, except what is already captured in the IEPR load profiles.	Adoption driven by current state policy and market growth	CEC 2018 IEPR Mid PEV adoption forecast	CEC 2016 IEPR Mid
High PEV load + High Flexible Charging	Consistent with the former Governor Brown's goal of 5m ZEVs on the road by 2030 and reflecting a fleet that is highly responsive to charging incentives	Explores the value to the grid of highly flexible PEV charging while also achieving the former Governor Brown's goal of 5m ZEVs on the road by 2030	CEC 2018 IEPR High Demand Forecast; allow the charging shape to be dynamically optimized in RESOLVE's internal production simulation.	None
Building Electrification				
Default Building Electrification	Minimal incremental building electrification measures	What resources would be needed if California does not achieve any new building electrification?	CEC 2018 IEPR	2017-18 IRP incorrectly counted a small amount of BE (~1200 GWh in 2030) from the 2016 IEPR forecast. This "BE" actually represented other forecasted electrification in 2016 IEPR forecast.
High Building Electrification	High building electrification includes significant incremental building electrification	Study the impact on the optimal portfolio of assuming incremental electrification of	CEC 2018 Deep Decarbonization – High Electrification scenario	Used building electrification assumptions from CARB

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	Approach in 2017/18 IRP Cycle[7]
		residential and commercial HVAC and water heating		Scoping Plan Alt 1 (13,000 GWh of BE in 2030)
BTM PV				
Default	2018 IEPR mid demand forecast		2018 IEPR Mid demand forecast (BTM PV), 2018 IEPR Mid AAPV	2016 IEPR mid demand forecast
High BTM PV	High BTM PV forecast	Examines how high levels of baseline BTM PV adoption affects optimal portfolio	2018 IEPR Low demand forecast (BTM PV), 2018 IEPR High AAPV	2016 IEPR low demand forecast
Low BTM PV	Low BTM PV forecast	Examines how low levels of baseline BTM PV adoption affects the optimal portfolio	2018 IEPR High demand forecast (BTM PV), 2018 IEPR Low AAPV	2016 IEPR high demand forecast
Flexible Loads				
Default	Shift Demand Response is not an available candidate resource, Shed Demand Response is	Shift DR not included in due to lack of certainty on viability of resource; Shed DR is available as a candidate resource to see if it is selected to meet system-level needs	*Final Report on Phase 2 Results: 2025 California Demand Response Potential Study*[9] *(for candidate Shed DR)*	Same
Shift Demand Response Optimization	Shift DR optimization	Investigates whether the availability of shift DR as a candidate resource reduces risk and/or cost	Final Report on Phase 2 Results: 2025 California Demand Response Potential Study[10]	Examined as special study.

[9] Lawrence Berkeley National Laboratory, Final Report on Phase 2 Results: 2025 California Demand Response Potential Study (2017). Available at: http://www.cpuc.ca.gov/General.aspx?id=10622

[10] Ibid.

Sensitivity Name	Brief Description	Policy Issue or Rationale	Value and Data Source (if Available)	Approach in 2017/18 IRP Cycle[7]
		across a range of GHG targets		
Energy Efficiency				
Default Energy Efficiency	2018 IEPR Mid AAEE		2018 IEPR Scenario 3 (Mid AAEE)	2017-18 used 2016 IEPR Mid AAEE + savings attributed to AB 802
Economic selection of Energy Efficiency[11]	Energy Efficiency (EE) optimized as candidate resource	Explores economic selection of EE and its impacts on the optimal portfolio	*IRP Technical Analysis: Considerations for Integrating Energy Efficiency into California's Integrated Resource Plan -- Final Draft (2018).*[12]	

[11] Pending budget authorization.
[12] Navigant, IRP Technical Analysis: Considerations for Integrating Energy Efficiency into California's Integrated Resource Plan. September 5, 2018. https://pda.energydataweb.com/api/downloads/2083/Navigant%20IRP%20Technical%20Analysis%20Report-FINAL(clean).pdf

Special 2030 Study Scenarios

Staff also proposes to conduct several special study scenarios that examine the costs and benefits of specific futures outside the context of the core policy cases and sensitivities. Proposed special studies include:

1) **Existing Thermal Generation Retention**: To evaluate the benefits of alternative thermal fleet retention futures aiming to identify the level of thermal generation retention that minimizes ratepayer costs, as required by statute. Staff has identified two additional scenarios which will be studied in addition to the default. These scenarios are described in Table 4.

Table 4: Existing Thermal Generation Retention Sensitivities

Sensitivity Name	Description	Describe Policy Issue Being Answered	Value and Data Source (if Available)	What was done in 2017/18
Thermal Retention				
Default	Retain existing generators when doing so reduces overall system costs. All generators that have announced retirement will be retired in the simulations.	Describes the economically optimal retention of the existing thermal generators.	Fixed O&M costs will be used to estimate the cost of keeping generators available for operation. Data will be derived from WECC.	Economic retention was not explored – High Thermal Retention was the Default assumption.
High Thermal Retention	Retain existing thermal generation unless retirement has been announced.	Explores the costs of retaining all existing thermal generation to maintain their availability as a risk mitigation strategy, hedging against future demand growth, unexpected retirements, or other factors.	Same as above.	Default Assumption
Low Thermal Retention	Incorporate into RESOLVE a low retention schedule.	Explores the costs and benefits of reducing the capacity of existing thermal generation to significantly lower levels than are implied by announced retirements.	Same as above.	A sensitivity in which an additional 12.7 GW of gas generation is assumed to retire by 2030, reducing gas fleet to 13 GW (2017

				Reference System Plan, slide 183),[13] or ~50% of the gas fleet.
Low RA Imports	Lower the capacity of external resources available to meet CAISO peak demand requirements.	Explores the impact of lower RA resource availability outside of CAISO. Reserve margins outside of CAISO may decrease significantly due to impending coal or other resource retirements in the NW and SW, potentially resulting in lower levels of capacity available to Californian during peak periods.	Estimates of current RA contract levels with resources outside of CAISO will inform the contribution of import capacity to the RESOLVE planning reserve margin.	11.3 GW of import capacity was counted towards the CAISO planning reserve margin in all simulations.
Low RA Imports and Low Thermal Retention	Peak capacity "stress test."	Explores a peak capacity "stress test" case in which existing thermal generation in CAISO is retired on an aggressive timeline *and* lower levels of external resources are available to meet CAISO peak requirements.	Same as above.	Same as above.

[13] Available at http://cpuc.ca.gov/irp/proposedrsp/.

2) **Renewable Generation Comparison**: Staff proposes to run a scenario constrained by a 60% renewable portfolio standard to illustrate potentially significant changes in infrastructure development between utilizing a GHG target compared to renewable portfolio standard. Moreover, this study will ensure that a portfolio constrained by the highest GHG-emitting policy case (46 MMT GHG) complies with existing 60% RPS in 2030 as mandated by SB 100.

3) **Cost of Decarbonizing the Electric Sector**: Staff proposes to vary the 2030 GHG constraint across the full spectrum of GHG planning targets used as policy case studies (*e.g.*, set the GHG constraint to 44 MMT, 42 MMT, 40 MMT, 36 MMT, 34 MMT, and 32 MMT in 2030). The purpose of this study is to examine how the optimal portfolio cost and resource buildout changes with incremental decarbonization of the grid, which will be critical information for the Commission and other decision makers in evaluating the appropriate GHG planning target for the electric sector by revealing potential "tipping points" with respect to system cost, resource portfolios, *etc*. These scenarios will be similar to the three core Policy Cases (46 MMT, 38 MMT, and 30 MMT), except policy sensitivities will not be run across them.

(END OF ATTACHMENT A)