Application: A.22-05-002, *et al.*

Exhibit No.: _____

Witness: Brenda Gettig

SUPPLEMENTAL TESTIMONY OF

BRENDA GETTIG – CHAPTER 5B

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 3, 2023

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SUPPLEMENTAL TESTIMONY OF
BRENDA GETTIG
CHAPTER 5B

I. INTRODUCTION

The purpose of my supplemental testimony is to describe the cost effectiveness (CE) analysis for the proposed San Diego Gas & Electric Company (SDG&E) demand response (DR) programs for the program years 2024 through 2027.[1] The analysis follows the 2016 Demand Response Protocols ("the Protocols").[2] SDG&E performed CE analyses for each program individually and for the portfolio. Please note that my supplemental testimony revises some of the underlying cost estimates to align with the costs estimates set forth in the Prepared Direct Testimony of Kenneth Pitsko (Chapter 6B). However, these revisions do not impact SDG&E's CE results. For consistency and accuracy, SDG&E's Demand Response Cost Effectiveness Report (2024-2027) attached hereto as Appendix A has also been updated to reflect the revised figures.

SDG&E reports its CE results using the four tests described in the Protocols: (1) the Total Resource Cost (TRC) test, (2) the Program Administrators Cost (PAC) test, (3) the Ratepayer Impact Measure (RIM) test, and (4) the Participant test (PCT).[3] The inputs to these tests include the net present value of appropriate costs and benefits as specified by the Protocols, discounted over the program cycle. Additional detail on the data inputs used is presented in subsequent sections below. Table BG-1 presents the results for the Capacity Bidding Program (CBP), the Smart Energy Program (SEP), and the overall Portfolio. CBP offers Day Ahead (DA) and Day Of (DO) subprograms, and these were analyzed separately.

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[1] This supplemental testimony is intended to replace and supersede the previous version of my opening testimony relating to program years 2024-2027 (dated May 2, 2022).

[2] 2016 Demand Response Cost Effectiveness Protocols; Resolution E-4788, July 15,2016, Appendix A.

[3] Each of these tests is described in detail in the Commission's Standard Practice Manual: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/energy_programs/cpuc-standard-practice-manual.pdf

Table BG-1: CE Results for 2024 through 2027

	CBP DA	CBP DO	SEP	Portfolio
TRC	0.4	0.4	0.3	0.2
PAC	0.3	0.4	0.2	0.2
RIM	0.3	0.3	0.2	0.2
Participant	1.3	1.3	2.9	2.2

All benefits and costs in the tests are discounted to 2024 dollars. Table BG-2 shows the benefits and costs included in the TRC tests.

Table BG-2: NPV TRC Test Benefits and Costs

	CBP DA	CBP DO	SEP	Portfolio
Benefits	931,699	1,503,492	4,276,128	6,711,319
Costs	2,610,058	4,097,850	16,052,717	27,346,024
Net Benefits	1,678,359)	(2,594,358)	(11,776,589)	(20,634,705)

II. DATA INPUTS AND CALCULATIONS

This section describes the data inputs and calculations used in the CE analysis.

A. The DR Cost Effectiveness Report

The DR Cost Effectiveness Report (DR Calculator) is the Commission approved tool for calculating DR CE. The DR Calculator uses inputs from the Avoided Cost Calculator (ACC). The ACC is the model developed by a third party under contract with the Commission to determine the value of Distributed Energy Resources (DERs).

The DR Calculator was revised for the purposes of this application to accommodate the inputs from the 2021 version of the ACC.[4] Southern California Edison (SCE), on behalf of the electric IOUs, hired Energy and Environmental Economics (E3) in 2021 to update the DR

[4] Resolution E-5150 adopted version the 2021 Electric ACC Model v1b on June 24, 2021. Resolution E-5228 adopted a new version of the ACC in September 2022. At least one party to this proceeding requested that the utilities' cost-effectiveness calculations reflect the updated ACC. For illustrative and comparison purposes, SDG&E provides cost-effectiveness calculations using the updated ACC in Section VI below.

Calculator with inputs from the 2021 version of the ACC. The primary revisions made to the DR Calculator include the following:[5]

1. Updated avoided generation capacity costs.
2. Updated on-peak greenhouse gas (GHG) values and on-peak avoided costs of energy to reflect non zero capacity values rather than vintage TOU periods.
3. Updated Renewable Energy Capacity Planning (RECAP) model availability and dispatchability tables used to calculate A Factor.
4. Other minor revisions to improve functionality

B. Adjustment Factors

The Protocols allow the benefits in the CE calculations to be adjusted by a set of seven adjustment factors, named A through G. The factors are designed to be program specific adjustments to the capacity benefits, energy benefits, and transmission and distribution benefits. Each of the factors is discussed below, along with the values used in the analysis.

1. A Factor

The A Factor adjusts the capacity value according to the availability and dispatchability of the program. The A Factor uses the Renewable Energy Capacity Planning (RECAP) model developed by E3 to estimate loss of load probability.[6] Each DR program has a specified window of time and duration when it can be called upon for load curtailment. Using these parameters, the percentage of time a program can be available when a positive probability of loss of load exists is calculated. If a program event can be called any time there is a positive probability of loss of load, the A Factor for that program would be 100%. Most SDG&E demand response programs have some limitation on when their events can be called, resulting in A Factors below 100%. Table BG-3 presents the calculated A Factors used in the analysis.

[5] A complete description of the updates is provided in: Energy and Environmental Economics, 2022 Demand Response Reporting Template Update Documentation, March 2022.

[6] *See* https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/.

Table BG-3: A Factors for 2024 through 2027

	CBP DA	CBP DO	SEP
Daily hours available to call	1 pm to 9 pm	1 pm to 9 pm	Noon to 9 pm
Event duration (hours)	4	4	4
Maximum hours per year available to call	144	144	80
A Factor	94%	94%	94%

2. B Factor

The B Factor adjusts the capacity value for differences in notification times. The Protocols specify that day-ahead programs shall use a B Factor of 88%, day-of programs that can be called in 30 minutes or less shall use a B Factor of 100%, and day-of programs that require more than 30-minute notification shall use a B Factor of 94%.[7] CBP DA requires day ahead notification, and therefore a B Factor of 88% was used in the analysis. CBP DO requires a 40 minute notification and SEP requires a notification time of two hours. Therefore, both these programs have a B Factor of 94%.

3. C Factor

The C Factor adjusts the capacity value for differences in triggers or the conditions under which a program can be dispatched. The Protocols allow for a C Factor of 100% when the program can be called at the utility's discretion. All of SDG&E's demand response programs can be called at the utility's discretion; therefore, a C Factor of 100% was used for all programs in this analysis.

4. D Factor

The D Factor adjusts the transmission and distribution (T&D) benefits according to a set of four criteria: right time, right place, right certainty, and right availability. SDG&E is not claiming T&D benefits for any of its programs; therefore, a D Factor of 0% was used for all programs in this analysis.

[7] Protocols, p. 33.

5. E Factor

The E Factor adjusts energy benefits to account for the likelihood that demand response events occur when energy prices are at their highest. The on-peak energy price used in the DR Calculator is the average on-peak energy price when the avoided generation capacity value is forecasted to be nonzero. These forecasted prices are averaged over the period 4 p.m. to midnight; however, SDG&E's demand response programs can only be dispatched until 9 p.m. To calculate the E Factor, SDG&E took the ratio of forecasted average energy prices during the dispatch period as compared to the average energy price used in the DR Calculator. The resulting E Factor is 132 percent.

6. F Factor

The F Factor allows additional value for programs that can provide flexible demand response and can meet CAISO's Flexible Resource Adequacy Must Offer Obligation (FRAC-MOO) criteria. The SDG&E programs in this application are not currently designed to meet the FRAC-MOO criteria and therefore SDG&E is not claiming this additional benefit for any of the programs in this analysis.

7. G Factor

The G Factor allows additional value for programs that can provide demand response resources in certain constrained geographical regions. The 2016 Protocols allow SDG&E to use a G Factor of 110%.[8] Therefore, SDG&E used a G Factor of 110% for all programs in this analysis.

C. Treatment of Benefits

The benefits estimated in the analysis include the avoided costs for generation capacity and energy, avoided on-peak greenhouse gas (GHG) emissions, and earned CAISO market revenue. SDG&E did not include benefits for transmission and/or distribution deferrals. Qualitative benefits are discussed in a workpaper attached to this chapter.

1. Capacity Benefits

The forecasted capacity value per kW is estimated in the ACC and adjusted in the DR Calculator by the A, B, C, F and G Factors described above. The forecasted load impacts used are the 50th percentile ex-ante load impacts based on a 1-in-2 weather year, with participation

[8] Protocols, p.34.

adjusted for the portfolio level. Results using the 10th and 90th percentile ex-ante load impacts are presented as sensitivity analyses later in this chapter. The estimation process and results of the ex-ante load impacts is explained in the Prepared Direct Testimony of Lizzette Garcia-Rodriquez (Chapter 4B).

2. Energy and GHG Benefits

Benefits for avoided energy and GHG are estimated using the expected call hours of the programs. The values for on-peak avoided energy and GHG ($ per MWh) are derived from the ACC. The on-peak average energy price is adjusted by the E Factor explained above.

3. CAISO Market Revenue

The programs analyzed are all bid into the day ahead market. SDG&E used the expected number of awards and the average 2021 award price[9] to estimate earned market revenue.

D. Treatment of Costs

1. Allocation of Support Costs

The Protocols state that indirect costs that support a group of programs should be allocated across those programs and included in their respective CE tests. Where SDG&E was able to identify certain costs directly related to specific programs, those costs were included directly. Where costs were known to support a group of programs but exact amounts were unknown, those costs were allocated across programs based on their total program budgets.[10]

SDG&E allocated support costs from the budget categories of Policy and Program Support, ME&O, EM&V and IT. Table BG-4 shows the allocation of these support budgets that were included in the CE tests.

[9] SDG&E escalated the average 2021 award price by 3% annually as a conservative estimate since the average on-peak energy price in the ACC is forecasted to escalate at a higher rate.

[10] Protocols, p. 24.

Table BG-4: Support Costs Included in CE Tests

Program	Policy Support	IT	EM&V	ME&O
CBP DA	51,780	352,318	787,835	43,407
CBP DO	79,210	538,954	1,205,183	66,401
SEP	203,275	5,369,426	3,941,384	2,053,090
Additional Portfolio Costs	95,037	0	0	0
Total	429,302	6,260,698	5,934,402	2,162,898

2. Alignment of Incentives and Signaling Costs

The CE tests include only the portion of the proposed incentive budgets that align with the ex-ante forecasted MWs. Additional incentive budget that is not included in the tests is meant to cover additional growth beyond the forecast used in the analysis. The additional budget not included in the tests will only be used if incremental enrollment and/or performance beyond the forecasted impacts is realized.

Similarly, SDG&E excluded a portion of the proposed signaling costs for SEP from the CE analysis. These costs are for signaling devices during a DR event and are based on the forecasted number of enrolled and connected devices. The additional signaling budget not included in the tests is meant to cover additional enrollment growth or unforeseen price increases not captured in this budget application.

3. Excluded Costs

In addition to incentive and signaling costs explained above, other costs in the proposed budget were not included in the CE tests as they are for activities that do not support the DR programs being analyzed. SDG&E excluded support costs for the Emergency Load Reduction Program (ELRP) as cost effectiveness was waived for this program.[11] Costs for proposed pilots are excluded from the analysis as their ex-ante impacts are uncertain. In addition, SDG&E excluded proposed budget costs for Rates, Rule 32 and Commission Directed Research as these

[11] D.21-12-015, p. 63 and D.21-03-056, p. 29.

activities do not directly support the DR programs analyzed. Table BG-5 summarizes the excluded costs.

Table BG-5: Excluded Costs

Description	Amount Excluded	Reason for Excluding
Incentive budget	5,306,333	The proposed budget allows for growth beyond the forecasted program enrollment and impacts.
Signaling budget	1,570,935	Similar to the incentives, the proposed budget includes an additional amount to allow for growth beyond the forecasted enrollment.
Pilots	27,277,588	Proposed pilots are excluded from the analysis as their ex-ante impacts are uncertain.
Residual costs for sunsetting programs	109,039	These costs are to finalize the closing of BIP, TI and ACS-DO programs in 2024.
Rates and Rule 32	8,355,856	Costs to support dynamic rates and Electric Rule 32 are external to the DR Portfolio.
Commission directed research	800,000	This budget is reserved for Commission research projects which are unknown at this time.
ELRP	80,641,241	Cost effectiveness for ELRP was waived per Decision 21-12-015 and 21-03-0156
Total excluded costs	124,060,992	

4. Additional Costs

The Protocols require all costs supporting the programs to be included in the CE tests, even though they may have been approved in a separate proceeding.[12] SDG&E included costs budgeted for its Demand Response Management System (DRMS) approved in its recent General Rate Case. The DRMS supports the demand response programs and pilots as well as Rule 32.

5. Portfolio Analysis

The portfolio analysis includes all costs and benefits in the individual programs. In addition, the budgeted amount for Emerging Technology was included in the portfolio tests.

[12] Protocols, p. 17.

III. AUTO DEMAND RESPONSE

SDG&E's proposed portfolio for 2024 through 2027 does not include incentives for Auto Demand Response (AutoDR). Therefore, there is no analysis provided showing the impact on cost effectiveness of including the AutoDR incentives.

IV. SENSITIVITY ANALYSIS

The Protocols require sensitivity analyses showing the impact on the TRC resulting from a change in key variables. In particular, the variables specified are the A Factor, the ex-ante load impacts, participant costs and the generation capacity values.[13] Each of these is described below.

A. Sensitivity Analysis of A Factor

To evaluate how sensitive the TRC is to changes in the A Factor, SDG&E used a value of 10% lower than the base case as the low value, and a value of 100% as the high value. Table BG-6 shows there is no significant impact in the TRC resulting from these changes in the A Factor.

Table BG-6: Sensitivity of A Factor on TRC

Program	Base Case		Sensitivity			
	A Factor	TRC	A Factor	TRC	A Factor	TRC
CBP DA	94%	0.4	85%	0.3	100%	0.4
CBP DO	94%	0.4	85%	0.3	100%	0.4
SEP	94%	0.3	85%	0.3	100%	0.3

B. Sensitivity Analysis of Ex-Ante Load Impacts

The protocols specify to use the 10th and 90th percentile values of the load impacts in the sensitivity analysis. The 10^{th} and 90^{th} percentile load impacts for CBP do not change significantly; therefore, the TRC stays the same. For SEP, the impacts range from an average of 4 MW at the 10^{th} percentile to 16 MW at the 90^{th} percentile. Table BG-7 shows the impact on the TRC for SEP when the load impacts vary. As shown, the TRC ranges from 0.1 to 0.5 as the impacts change.

[13] The Protocols also specify sensitivity analysis on the number of years used to amortize capital costs. SDG&E did not amortize costs in this analysis; therefore, the sensitivity on this variable is not applicable.

Table BG-7: Sensitivity of Load Empacts on TRC

Program	50th Percentile (Base Case)1-in-2 Portfolio Ex-Ante Impacts		10% Percentile		90th Percentile	
	Average Sept MW	TRC	Average Sept MW	TRC	Average August MW	TRC
CBP DA	2.4	0.4	No significant change in impacts			
CBP DO	3.7	0.4	No significant change in impacts			
SEP	10	0.3	3.8	0.1	16.3	0.5

C. Sensitivity Analysis of Participant Costs

Participant costs used in the cost effectiveness tests are meant to represent transaction costs, value of service lost, and financial expenditures for equipment or other capital costs related to the program. Since the value of these costs are unknown, the Protocols specify to use a percentage of the value of incentives paid to the participant plus their bill reductions less their capital costs as a proxy for transaction costs plus value of service lost. For most programs, the percentage used for this is 75%. In addition, the low and high values for sensitivity analysis are 50% and 100%. A modification is specified in the Protocols for voluntary AC cycling programs. For these, the base case is 35% and the low and high values for sensitivity analysis are 10% and 60% respectively.[14] Table BG-8 presents the change in TRC as a result of a change in participant costs. As shown, there is only a minor increase in the TRC for CBP DO when participant costs are reduced.

Table BG-8: Sensitivity of Participant Costs on TRC

Program	Base Case		Sensitivity			
	% Used in Proxy	TRC	% Used in Proxy	TRC	% Used in Proxy	TRC
CBP DA	75%	0.4	50%	0.4	100%	0.3
CBP DO	75%	0.4	50%	0.4	100%	0.3
SEP	35%	0.3	10%	0.3	60%	0.2

[14] Protocols, p. 47.

D. Sensitivity Analysis of Generation Capacity Value

For sensitivity tests on the adjusted generation capacity values, the values were lowered and raised by 30%. Table BG-9 shows the results of changes to the TRC for each program when the adjusted generation capacity values are adjusted 30% lower or 30% higher than the values used in the base case analysis.

Table BG-9: Sensitivity of Generation Capacity Value

Program	Base Case TRC	TRC with Adjusted Capacity Value Reduced 30%	TRC with Adjusted Capacity Value Increased 30%
CBP DA	0.4	0.3	0.4
CBP DO	0.4	0.3	0.5
SEP	0.3	0.2	0.3

V. QUALITATIVE ANALYSIS OF NON-ENERGY IMPACTS

The Protocols require a qualitative analysis of social, utility, participant and market non-energy benefits or costs that may result from implementation of the proposed demand response programs, including possible impacts that may not exist. SDG&E has provided an analysis of qualitative benefits and costs of demand response in supporting workpapers.

VI. CE RESULTS FOR 2024-2027 UTILIZING UDPATED ACC

Resolution E-5228 dated September 15, 2022 adopted a new version of the Avoided Cost Calculator. For illustrative and comparison purposes, SDG&E provides in Table BG-10 the benefit cost ratios when the new input values from the 2022 ACC are used. No other inputs in the analysis were changed.

Table: BG-10: Benefit Cost Ratios with 2022 ACC Inputs

	CBP DA	CBP DO	SEP	Portfolio
TRC	1.0	1.0	0.7	0.7
PAC	1.0	1.0	0.6	0.6
RIM	0.9	1.0	0.6	0.6
Participant	1.3	1.3	2.9	2.2

VII. CONCLUSION

This concludes my prepared direct testimony.

VIII. WITNESS QUALIFICATIONS

My name is Brenda Gettig. My business address is 8335 Century Park Court, San Diego, California 92123. I have been employed by SDG&E as a Senior Business Analyst in the Measurement and Evaluation Group for Customer Programs since 2006. My responsibilities include the evaluation and cost effectiveness analysis of SDG&E's demand response and low-income programs. I have a Masters in Economics from the University of California San Diego and a Master of Business Administration from the University of South Florida.

I have previously testified before the California Public Utilities Commission.

APPENDIX A

SDG&E DEMAND RESPONSE COST EFFECTIVENESS REPORT 2024-2027 (REVISED)

The revised report is available at the following link:
SDG&E DEMAND RESPONSE COST EFFECTIVENESS REPORT 2024-2027

APPENDIX B

SDG&E QUALITATIVE ANALYSIS OF NON-ENERGY IMAPCTS 2023-2027

Qualitative Analysis of Non-Energy Impacts
Related to SDG&E Proposed Demand Response Programs for 2023 to 2027

Overview

As required by the Protocols, SDG&E provides this qualitative assessment of non-energy and non-monetary impacts related to its proposed demand response (DR) programs. The discussion addresses potential impacts related to SDG&E's proposed programs of Capacity Bidding (CBP) and AC Saver (ACS)[1] and is not meant to be a comprehensive analysis of impacts related to demand response in general. SDG&E does not quantify the impacts and does not include them in its cost effectiveness analysis. The Protocols require a descriptive analysis of potential impacts (benefits or costs) for four areas: social, utility, participant, and market. Each of these is discussed below.

Social Impacts

Social impacts may include health impacts, environmental impacts, and job creation or loss. The generation capacity avoided costs used in the cost effectiveness analysis include approved estimates of reduced emissions costs. While some research has been done to identify additional air quality benefits related to energy efficiency, no approved estimates are available at this time. Furthermore, the energy saved as a result of SDG&E's CBP and ACS programs is relatively small due to narrow event windows as well as pre-cooling and rebound effects.

SDG&E is unaware of any health or job impacts directly resulting from its programs. Were the CBP and ACS programs to cease operating, it is likely SDG&E staff would be assigned to other areas of operation, and aggregators and contractors working for SDG&E programs would continue working in the industry for other programs or in other capacities. Furthermore, any increase in jobs as a result of SDG&E's programs would potentially be offset by the loss of jobs related to producing additional generation which would be needed if DR programs did not exist.

Utility Impacts

Examples of non-energy impacts for the utility potentially could include changes in the number of customer calls requesting assistance and changes in arrearages or collection costs due to customer bill savings. Due to the relatively small amount of energy saved during event windows and resulting bill savings (assuming energy is saved and not shifted), it is unlikely there is any impact in arrearages or collection costs to the utility as a result of these programs. It is possible, however, there is an increase in customer calls related to program participation. For example, customers may call for additional information on the program , to complain about discomfort due to their air conditioning being cycled, or to opt out of program events. SDG&E does not have data supporting any change in utility costs as a result of operation of its DR programs. These impacts are difficult to quantify, and, even if they exist, likely do not result in a significant impact to the utility.

Participant Impacts

Negative participant impacts can include discomfort from reduced air conditioning, shifting energy intense activities to inconvenient times, and time and hassle related to participating in events. Positive impacts may include feeling good about helping the environment and contributing to corporate sustainability goals. In this section, results from recent customer surveys of ACS and CBP participants are provided to support the discussion.[2]

[1] For 2024 to 2027, SDG&E proposes to replace ACS with Smart Energy Program (SEP).

[2] See Nexant, 2021 Process Evaluation of San Diego Gas and Electric's Demand Response Programs, October 2021. CALMAC Study ID SDG0343.01.

ACS program participants indicated many of them participate for environmental reasons in addition to financial incentives. For example, slightly less than half of ACS participants indicated one reason they participate is to help ensure grid reliability and to help the environment. Program participants also reported negative impacts related to their participation. For example, roughly 15% of ACS participants reported being uncomfortably warm on event days. In addition, approximately 40% of respondents reported they opted out of events due to negative impacts to their normal routines or because they could not leave home due to Covid-19 shelter in place restrictions.

CBP participants also reported they were motivated to participate by contributing to environmental benefits and prevention of rolling blackouts. Many companies promote their social, cultural, and environmental contributions and include participation in DR programs as part of a larger set of corporate sustainability goals. CBP participants also reported a negative impact from multiple consecutive event days where there was no opportunity between down times to return to previous production levels. The high number of events was reported as one of the primary reasons for customer withdrawal from the program.

CBP aggregators reported customer dissatisfaction with events called during periods of mild temperatures. In San Diego, the rationale for dispatch is not always clear to customers because the trigger price does not always correlate to high temperatures in San Diego, and this lack of understanding why events are being called leads to some customers feeling overused and undervalued. Non-participating businesses were also surveyed, and nearly half reported they did not want to join the program because it would impact business operations or customers' comfort.

Market Impacts

Potential impacts suggested in the Protocols such as market power mitigation and market transformation may be developing but have not been evaluated. Potential market impacts associated with DR may include technology and signaling advancements related to enabling technologies and Auto Demand Response (AutoDR); however, SDG&E has proposed sunsetting its AutoDR programs and is not proposing any technology incentives for program years 2024 through 2027.

Conclusion

Non-energy impacts in general are imprecise and difficult to identify and quantify. While a large body of research exists on non-energy impacts resulting from low-income energy efficiency programs, much of it is based on generalized assumptions rather than specific program attribution. A recent assessment of non-energy impacts related to the California Energy Savings Assistance (ESA) Program found that many of the impacts that had been used in cost effectiveness tests for years were not supported by research, overlapped with other benefits, or lacked supporting data to provide a reasonable calculation. While the study made some recommendations for improvement, it acknowledged there was still a high degree of uncertainty in estimating these impacts.[3]

In the sections above, SDG&E presents a discussion of potential non-energy impacts related to its proposed CBP and ACS DR programs. While customer survey responses present some evidence of both positive and negative impacts to participating customers, these impacts cannot be quantified at this time. In addition, social, utility and market impacts resulting from CBP and ACS program operations likely are insubstantial or do not exist.

[3] APPRISE, INC.; California Energy Savings Assistance Program Non-Energy Benefits, January 2021. https://pda.energydataweb.com/api/view/2471/Final%20CA%20ESA%20NEB%20Report%201-25-21_.pdf