SOUTHERN CALIFORNIA EDISON®

(U 338-E)

2025 GRC
A.23-05-010

Workpapers

SCE-02 Vol.06
Grid Modernization, Grid Technology, and Energy Storage

May 2023

2025 General Rate Case
Index of Workpapers
SCE-02 Vol. 06 - Grid Modernization, Grid Technology, and Energy Storage

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(U 338-E)

2025 General Rate Case

A. 23-05-

Workpapers

SCE-02 Grid Activities
Volume 6 - Grid Modernization, Grid Technology, and Energy Storage
Grid Modernization - T&D Deployment Readiness

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	Grid Modernization - T&D Deployment Readiness
Witness:	Mark Esguerra

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	169	156
Non-Labor	150	1,435
Other	0	0
Total	318	1,591

Due to rounding, totals may not tie to individual items.

Description of Activity:
T&D deployment readiness - Include non-labor cost related to consultant contracts that support organizational change management functions for the grid modernization deployments

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	Grid Modernization - T&D Deployment Readiness
Witness:	Mark Esguerra

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	29	44	187	155	169
Non-Labor	1,469	863	1,218	1,045	150
Other	0	0	0	0	0
Total	**1,498**	**907**	**1,405**	**1,200**	**318**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	133	0.32	292	0.47	312	0.69
Non-Labor	(1,333)	0.87	(222)	0.41	(279)	0.60
Other	0	0.00	0	0.00	0	0.00
Total	**(1,199)**	**N/A**	**71**	**N/A**	**32**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	162	7	170	13	139	56	117	67
Non-Labor	597	448	804	468	819	406	949	447
Other	0	0	0	0	0	0	0	0
Total	**759**	**N/A**	**974**	**N/A**	**957**	**N/A**	**1,066**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	169	169	169
Non-Labor	150	150	150
Other	0	0	0
Total	**318**	**318**	**318**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	150	157	156
Non-Labor	544	1,402	1,435
Other	0	0	0
Total	**694**	**1,559**	**1,591**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	Grid Modernization - T&D Deployment Readiness
Witness:	Mark Esguerra

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor	29	44	187	155	169	150	157	156	Itemized	156	(12)
Non-Labor	1,469	863	1,218	1,045	150	544	1,402	1,435	Itemized	1,435	1,285
Other											
Total	1,498	907	1,405	1,200	318	694	1,559	1,591		1,591	1,273

Due to rounding, totals may not tie to individual items.

Analysis of Forecasting Methods
Itemized Forecast: Itemized Forecast Method

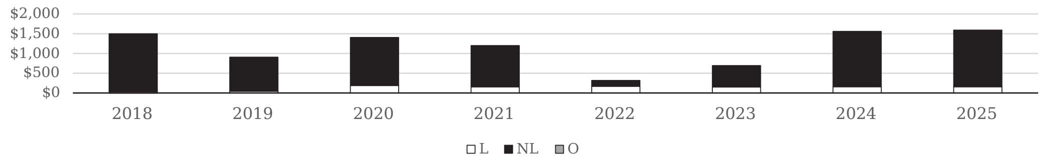
Other Forecast Methods not Selected
Last Recorded Year: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.
Linear Trending: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.
Averaging: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility's control, an average of recorded-expenses is appropriate. For this activity the Averaging method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Averaging method is not appropriate.

2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	Grid Modernization - T&D Deployment Readiness
Witness:	Mark Esguerra

Recorded/Adj. 2018-2022 / Forecast 2023-2025



Cost Type		Recorded/Adj. 2018	2019	2020	2021	2022	Forecast 2023	2024	2025
Recorded / Forecast	Labor	29	44	187	155	169	150	157	156
	Non-Labor	1,469	863	1,218	1,045	150	544	1,402	1,435
	Other	0	0	0	0	0	0	0	0
	Total	**1,498**	**907**	**1,405**	**1,200**	**318**	**694**	**1,559**	**1,591**

Labor	Prior Year Total	29	44	187	155	169	150	157
	Change	15	143	(32)	14	(19)	8	(1)
	Total	**44**	**187**	**155**	**169**	**150**	**157**	**156**

Non-Labor	Prior Year Total	1,469	863	1,218	1,045	150	544	1,402
	Change	(606)	355	(173)	(895)	395	858	33
	Total	**863**	**1,218**	**1,045**	**150**	**544**	**1,402**	**1,435**

Other	Prior Year Total	0	0	0	0	0	0	0
	Change	0	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total Change	Prior Year Total	1,498	907	1,405	1,200	318	694	1,559
	Change	(591)	498	(205)	(881)	375	865	32
	Total	**907**	**1,405**	**1,200**	**318**	**694**	**1,559**	**1,591**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	Grid Modernization - T&D Deployment Readiness
Witness:	Mark Esguerra

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	29	44	187	155	169	150	157	156
	Non-Labor	1,469	863	1,218	1,045	150	544	1,402	1,435
	Other	0	0	0	0	0	0	0	0
	Total	**1,498**	**907**	**1,405**	**1,200**	**318**	**694**	**1,559**	**1,591**

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

Workpaper Title:

T&D Deployment Readiness Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity T&D Deployment Readiness
Project: T&D Deployment Readiness

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025
O&M:									
SCE Labor	O&M	29	44	187	155	169	150	157	156
Vendor Contract	O&M	1,469	863	1,218	1,045	150	544	1,402	1,435
Software/Hardware/Data Center License Incl. SaaS/Cloud	O&M	-	-	-		-	-	-	-
OCM Training / PMO	O&M	-	-	-	-	-	-	-	-
Other	O&M	-	-	-	-	-	-	-	-
Total O&M:		**1,498**	**907**	**1,405**	**1,200**	**318**	**694**	**1,559**	**1,591**

Key Assumptions:
1. SCE employees will project manage the T&D Deployment Readiness effort.
2. Contractors will perform the OCM activities.
3. The scope of the OCM activities has been estimated based on the scope of the various T&D Automation projects.

Sensitivity: Internal

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2025 General Rate Case

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Workpapers

SCE-02 Grid Activities
Volume 6 - Grid Modernization, Grid Technology, and Energy Storage
IT Project Support

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	IT Project Support
Witness:	Michael Schulte

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	760	1,574
Non-Labor	1,935	3,379
Other	0	0
Total	**2,695**	**4,952**

Due to rounding, totals may not tie to individual items.

Description of Activity:
IT Project Support Activities - Includes the cost of labor, materials used, and expenses for activities to support grid modernization and other related programs. Includes related costs such as: transportation expenses; meals, traveling, lodging, and incidental expenses; and division overhead.

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	IT Project Support
Witness:	Michael Schulte

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	2,868	923	787	913	760
Non-Labor	2,757	2,650	3,440	2,514	1,935
Other	6	0	0	0	0
Total	**5,632**	**3,573**	**4,227**	**3,427**	**2,695**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	767	0.03	684	0.31	(862)	0.54
Non-Labor	(381)	0.98	1,252	0.41	1,768	0.27
Other	0	0.00	0	0.00	(5)	0.50
Total	**385**	**N/A**	**1,935**	**N/A**	**901**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	837	77	820	67	846	73	1,250	812
Non-Labor	2,224	289	2,629	620	2,635	537	2,659	483
Other	0	0	0	0	0	0	1	3
Total	**3,061**	**N/A**	**3,450**	**N/A**	**3,480**	**N/A**	**3,911**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	760	760	760
Non-Labor	1,935	1,935	1,935
Other	0	0	0
Total	**2,695**	**2,695**	**2,695**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	1,389	6,210	1,574
Non-Labor	2,464	2,354	3,379
Other	0	0	0
Total	**3,854**	**8,564**	**4,952**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	IT Project Support
Witness:	Michael Schulte

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor	2,868	923	787	913	760	1,389	6,210	1,574	Itemized	1,574	814
Non-Labor	2,757	2,650	3,440	2,514	1,935	2,464	2,354	3,379	Itemized	3,379	1,444
Other	6								Itemized		
Total	5,632	3,573	4,227	3,427	2,695	3,854	8,564	4,952		4,952	2,257

Due to rounding, totals may not tie to individual items.

Analysis of Forecasting Methods
Itemized Forecast: Itemized Forecast Method

Other Forecast Methods not Selected
Last Recorded Year: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.
Linear Trending: In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.
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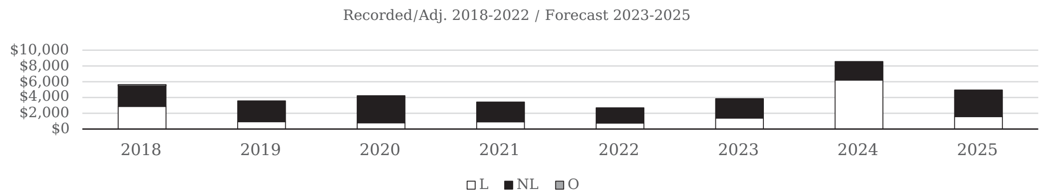
2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	IT Project Support
Witness:	Michael Schulte



Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	2,868	923	787	913	760	1,389	6,210	1,574
	Non-Labor	2,757	2,650	3,440	2,514	1,935	2,464	2,354	3,379
	Other	6	0	0	0	0	0	0	0
	Total	**5,632**	**3,573**	**4,227**	**3,427**	**2,695**	**3,854**	**8,564**	**4,952**

Labor	Prior Year Total	2,868	923	787	913	760	1,389	6,210
	Change	(1,946)	(136)	127	(153)	629	4,821	(4,636)
	Total	**923**	**787**	**913**	**760**	**1,389**	**6,210**	**1,574**

Non-Labor	Prior Year Total	2,757	2,650	3,440	2,514	1,935	2,464	2,354
	Change	(107)	790	(926)	(579)	530	(110)	1,024
	Total	**2,650**	**3,440**	**2,514**	**1,935**	**2,464**	**2,354**	**3,379**

Other	Prior Year Total	6	0	0	0	0	0	0
	Change	(6)	0	0	0	0	0	0
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total Change	Prior Year Total	5,632	3,573	4,227	3,427	2,695	3,854	8,564
	Change	(2,059)	654	(800)	(732)	1,159	4,710	(3,612)
	Total	**3,573**	**4,227**	**3,427**	**2,695**	**3,854**	**8,564**	**4,952**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Modernization
Activity:	IT Project Support
Witness:	Michael Schulte

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	2,868	923	787	913	760	1,389	6,210	1,574
	Non-Labor	2,757	2,650	3,440	2,514	1,935	2,464	2,354	3,379
	Other	6	0	0	0	0	0	0	0
	Total	5,632	3,573	4,227	3,427	2,695	3,854	8,564	4,952

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

Workpaper Title:

IT Project Support Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity IT Project Support
Project: IT Project Support

$000 in Thousands — **Cost Estimation Sheet**

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025
O&M:									
SCE Labor	O&M	2,903	940	802	916	754	1,389	6,210	1,574
Vendor Contract	O&M	1,655	1,683	2,402	1,958	1,828	2,464	2,354	3,379
Software/Hardware/Data Center License Incl. SaaS/Cloud	O&M	518	7	7	3	3	-	-	-
OCM Training / PMO	O&M	-	-	-	-		-	-	-
Other	O&M	556	942	1,017	549	110	-	-	-
Total O&M:		**5,632**	**3,573**	**4,227**	**3,427**	**2,695**	**3,854**	**8,564**	**4,952**

Key Assumptions:
1. IT Project Support covers three main areas: OCM, Training and Operational Readiness
2. Training will be delivered by contractors and be project managed by SCE personnel
3. OCM will be performed by contractors and will be project managed by SCE personnel
4. Operational readiness will be performed by a vendor
5. SCE Labor includes seat time for T&D personnel receiving training on GMS. Seat time has been estimated based users impacted by the various releases on the GMS deployment schedule

Sensitivity: Internal

Workpaper Title:

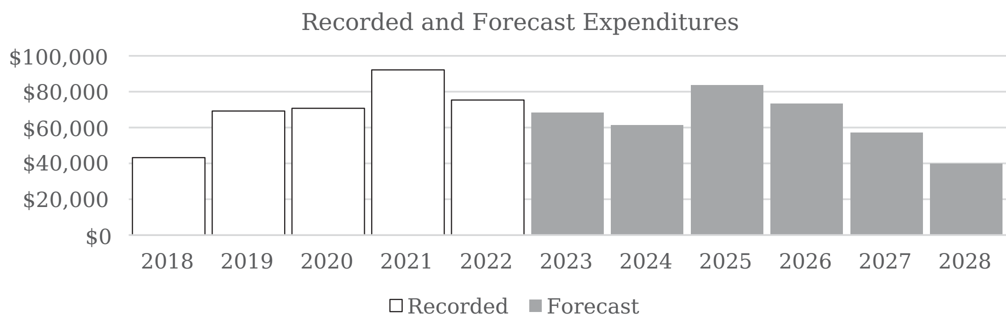
Engineering and Planning and Software Tools Capital Workpaper

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-02 Grid Activities
Volume: 6 - Grid Modernization, Grid Technology, and Energy Storage

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures	43,216	69,215	70,732	92,167	75,348	68,181	61,409	83,633	73,446	57,226	39,907
Total Expenditures					350,678						383,801

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Engineering and Planning Software Tools	35,232	22,350	24,787	19,269	13,754	9,717	125,109
Grid Management System	32,949	39,059	58,846	54,177	43,473	30,190	258,693
GRC Total	68,181	61,409	83,633	73,446	57,226	39,907	383,801

Workpaper Title:

Capital Details by WBS for GCM

Southern California Edison
2025 GRC Capital Workpapers

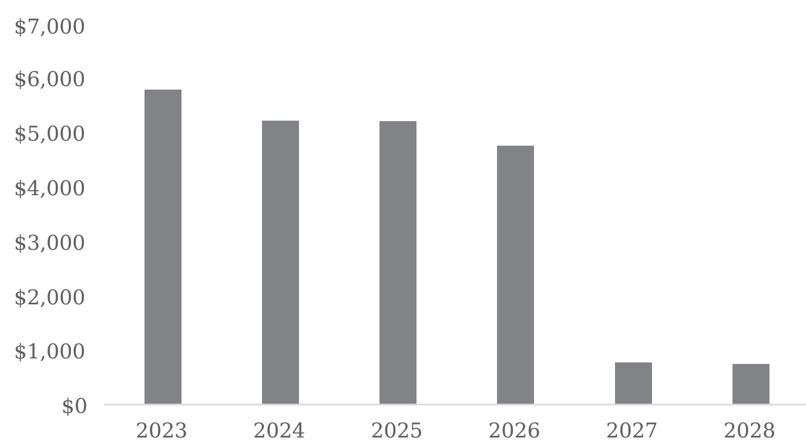
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Engineering and Planning Software Tools
1. Witness:	Michael Schulte
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	522
5. Pin:	7963
6. CWBS Element:	CIT00OPNS000521
CWBS Description:	Grid Connectivity Model
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	5,807	5,230	5,225	4,768	771	745	22,548

Due to rounding, totals may not tie to individual items.



Workpaper Title:

GCM Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Engineering and Planning Software Tools
Project: Grid Connectivity Model
CWBS Element: CIT-00-OP-NS-000521

Nominal $000 in Thousands — **Cost Estimation Sheet**

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital	512	405	429	274	330	367	383	307	280	45	43	3,375
Vendor Contract	Capital	3,859	8,786	6,617	5,065	5,610	5,411	4,816	4,894	4,466	723	699	50,945
Software License COTS	Capital	1	185	0	122	0							307
Hardware and Data Center (App, DB, SAN,VM)	Capital	-	-	-	-								-
Cloud (SaaS)	Capital	-	-	-	-								-
Other	Capital	114	520	582	(425)	69	29	31	25	22	4	4	975
Total Capital:		**4,485**	**9,896**	**7,628**	**5,036**	**6,009**	**5,807**	**5,230**	**5,225**	**4,768**	**771**	**745**	**55,602**

Key Assumptions:
1. GCM architecture will not require any major changes through 2028.
2. Project managment overhead is constant.
3. No further licensesing or infrastructure is required.
4. Vendor contract rate remains constant.

Sensitivity: Internal

Workpaper Title:

Capital Details by WBS for GAA

Southern California Edison
2025 GRC Capital Workpapers

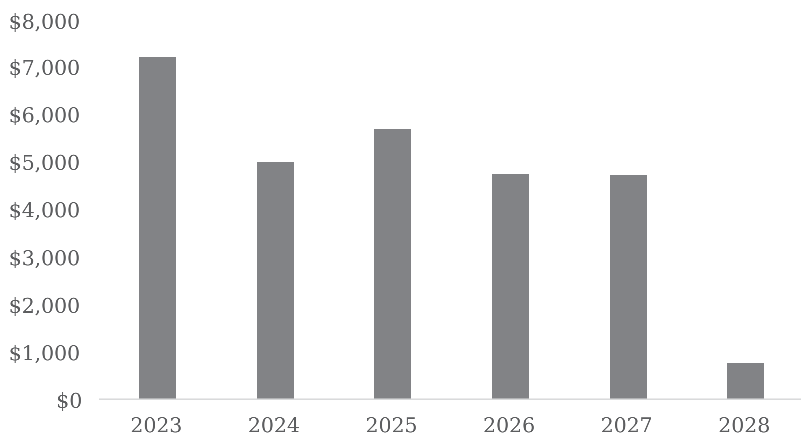
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Engineering and Planning Software Tools
1. Witness:	Michael Schulte
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	465
5. Pin:	7963
6. CWBS Element:	CIT00SDPM000247
CWBS Description:	Grid Analytics Applications
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	7,226	5,002	5,703	4,750	4,728	762	28,170

Due to rounding, totals may not tie to individual items.



Workpaper Title:

GAA Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Engineering and Planning Software Tools
Project: Grid Analytics Application
CWBS Element: CIT-00-SD-PM-000247

Nominal $000 in Thousands — **Cost Estimation Sheet**

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital	540	400	416	272	237	273	219	200	167	166	27	2,917
Vendor Contract	Capital	8,529	6,340	6,607	6,487	5,555	6,915	4,752	5,474	4,560	4,538	731	60,488
Software License COTS	Capital	1	-	0	0	0	-	-	-	-	-	-	1
Hardware and Data Center (App, DB, SAN,VM)	Capital	-	-	-	-	-	-	-	-	-	-		-
Cloud (SaaS)	Capital	-	-	-	-		-	-	-	-	-	-	-
Other	Capital	280	162	1,360	(1,169)	67	38	31	28	23	23	4	846
Total Capital:		**9,350**	**6,902**	**8,383**	**5,589**	**5,859**	**7,226**	**5,002**	**5,703**	**4,750**	**4,728**	**762**	**64,252**

Key Assumptions:
1. GAT architecture will not require any major changes through 2028.
2. Project managment overhead is constant.
3. No further licensesing or infrastructure is required.
4. Vendor contract rate remains consistent.
5. SCE labor resources would remain consistent.

Sensitivity: Internal

Workpaper Title:

Capital Details by WBS for LTPT-SMT

Southern California Edison
2025 GRC Capital Workpapers

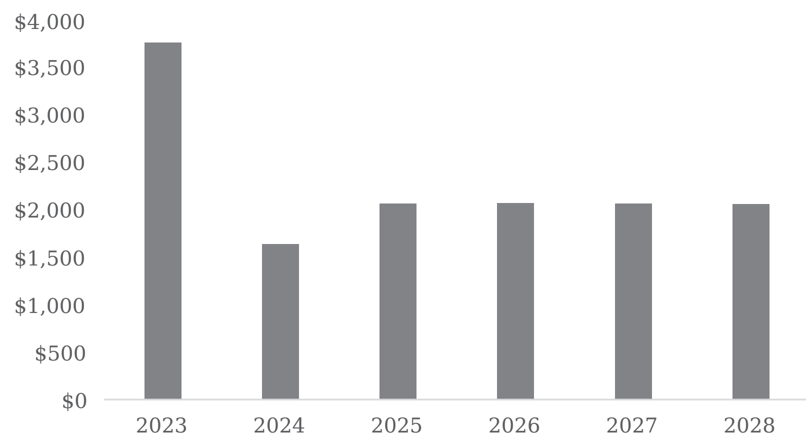
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Engineering and Planning Software Tools
1. Witness:	Michael Schulte
2. Asset type:	5YR SWA
3. In-Service date:	12\1\2028
4. RO Model ID:	699
5. Pin:	3896
6. CWBS Element:	CIT00DMDM000263
CWBS Description:	Long Term Planning Tool
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	3,766	1,638	2,068	2,072	2,068	2,063	13,675

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Engineering and Planning Software Tools

1. Witness:	Michael Schulte
2. Asset type:	5YR SWA
3. In-Service date:	12\1\2031
4. RO Model ID:	700
5. Pin:	3896
6. CWBS Element:	CIT00DMDM000264
CWBS Description:	System Modelling Tool
7. SRIIM Eligible:	No

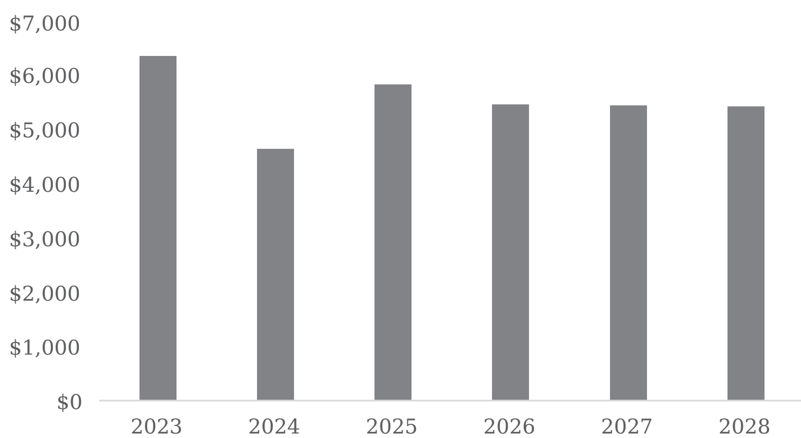
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	6,369	4,651	5,847	5,473	5,456	5,439

2023 - 2028 Total
33,236

Due to rounding, totals may not tie to individual items.



Workpaper Title:

LTPT-SMT Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Engineering and Planning Software Tools
Project: Long Term Planning Tool and System Modeling Tool
CWBS Element: CIT-00-DM-DM-000-263 & CIT-00-DM-DM-000-264

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital	374	497	483	362	318	508	526	545	564	583	595	5,354
Vendor Contract	Capital	6,589	6,583	5,202	6,240	5,148	9,219	5,717	7,179	6,933	6,891	6,856	72,556
Software License COTS	Capital	1	-	100	1,221	542	363		143				2,370
Hardware and Data Center (App, DB, SAN,VM)	Capital	-	-	-	-								-
Cloud (SaaS)	Capital	-	-	-	-								-
Other	Capital	234	1,430	412	(387)	(3)	45	46	47	49	50	52	1,974
Total Capital:		**7,198**	**8,509**	**6,196**	**7,436**	**6,004**	**10,135**	**6,289**	**7,915**	**7,545**	**7,525**	**7,502**	**82,254**

Key Assumptions:
1. SCE labor resources remain constant.
2. Contract costs based on current contract rates and estimated future scope.
3. Other - includes the overhead costs such as procurement services.
4. Software costs are based on current market estimates.

Sensitivity: Internal

Workpaper Title:

Capital Details by WBS for DRPEP

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Engineering and Planning Software Tools

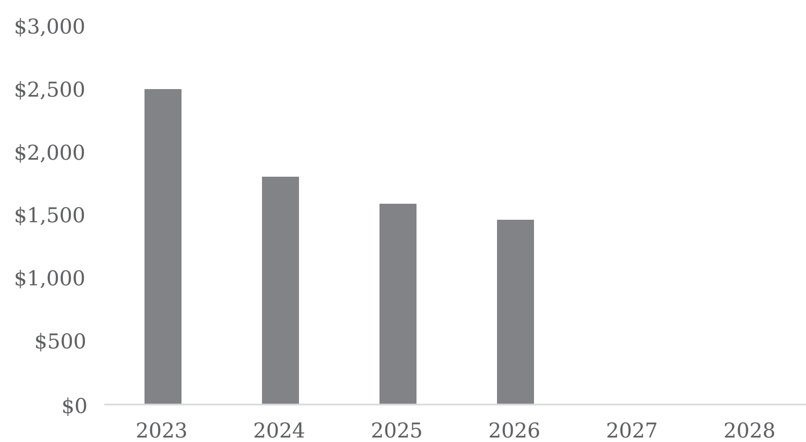
1. Witness:	Michael Schulte
2. Asset type:	5YR SWA
3. In-Service date:	1\1\2027
4. RO Model ID:	701
5. Pin:	3896
6. CWBS Element:	CIT00DMDM000265
CWBS Description:	DRP External Portal
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	2,491	1,798	1,586	1,459	0	0	7,334

Due to rounding, totals may not tie to individual items.



Workpaper Title:

DRPEP Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Engineering and Planning Software Tools
Project: DRP External Portal
CWBS Element: CIT-00-DM-DM-000265

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital		205	216	254	190	280	300	320	150	-	-	1,916
Vendor Contract	Capital		1,416	1,001	2,495	2,409	2,021	1,428	1,151	699	-	-	12,619
Software License COTS	Capital		-	(0)	366	0	-	30		600	-		996
Hardware and Data Center (App, DB, SAN,VM)	Capital		-	-	-		150		75		-		225
Cloud (SaaS)	Capital		-	-	-								-
Other	Capital		64	102	49	(56)	40	40	40	10	-	-	289
Total Capital:		**-**	**1,686**	**1,319**	**3,163**	**2,543**	**2,491**	**1,798**	**1,586**	**1,459**	**-**	**-**	**16,045**

Key Assumptions:
1. Workload estimate based on 2021 and 2022 trending from CPUC requirements. Vendor cost estimates are based on current contracts.
2. Infrastructure additions and upgrades for on-prem infrastructure built as of EOY 2021.
3. ArcGIS Named User License (5-year cycle due in 2026).
4. Project ramps down in mid 2026.

Workpaper Title:

Capital Details by WBS for GIPT

Southern California Edison
2025 GRC Capital Workpapers

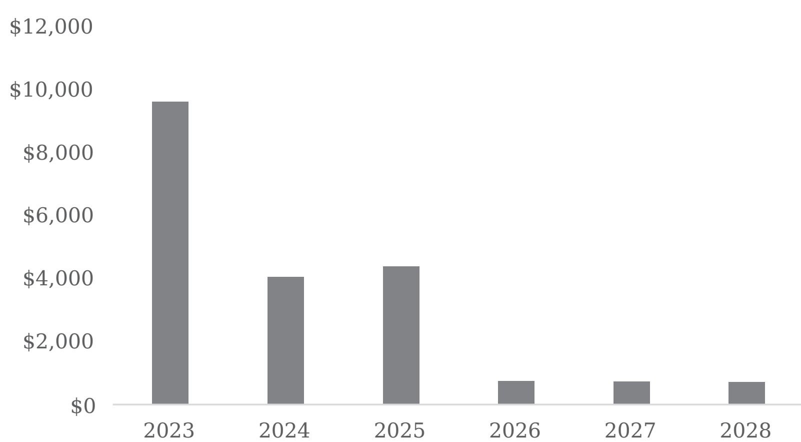
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Engineering and Planning Software Tools
1. Witness:	Michael Schulte
2. Asset type:	5YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	521
5. Pin:	7963
6. CWBS Element:	CIT00OPNS000520
CWBS Description:	Grid Interconnection Processing Tool
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	9,574	4,031	4,358	746	730	708	20,146

Due to rounding, totals may not tie to individual items.



Workpaper Title:

GIPT Capital Workpaper

Business Planning Group:	System Augmentation
Business Planning Element:	Grid Modernization
GRC Activity	Engineering and Planning Software Tools
Project:	Grid Interconnection Processing Tool
CWBS Element:	CIT-00-OP-NS-000520

Nominal $000 in Thousands — **Cost Estimation Sheet**

All GIPT (GIPT/CI/DER DM) Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital	348	466	370	227	264	280	323	203	200	200	200	3,082
Vendor Contract	Capital	2,866	8,499	5,914	2,838	4,024	6,593	3,557	4,005	430	414	392	39,530
Software License COTS	Capital	1	-	(0)	0	(0)	1,500	-	-	-	-	-	1,501
Hardware and Data Center (App, DB, SAN,VM)	Capital	-	-	-	-	-	1,100	-	-	-	-	-	1,100
Cloud (SaaS)	Capital	-	-	-	-	-	21	80	96	96	96	96	485
Other	Capital	242	1,040	(706)	174	508	80	71	55	20	20	20	1,525
Total Capital:		**3,457**	**10,006**	**5,578**	**3,239**	**4,796**	**9,574**	**4,031**	**4,358**	**746**	**730**	**708**	**47,223**

Key Assumptions:
1. GIPT IT project managment resource requirements to remain stable.
2. Vendor contracts estimated based on current contract totals for Pega Development, code reviews and infrastructure support.
3. Common Intake RFP will be issued in 1Q 2023 and vendor selected in 2Q 2023.
4. License and cloud costs are based on similar current rmarket pricing.
5. Hardware set up basic considerations for Dev, System Test and Prod with 5 Servers (1, 2 and 2 respectively).

Workpaper Title:

Capital Details by WBS for ADMS and DERMS

Southern California Edison
2025 GRC Capital Workpapers

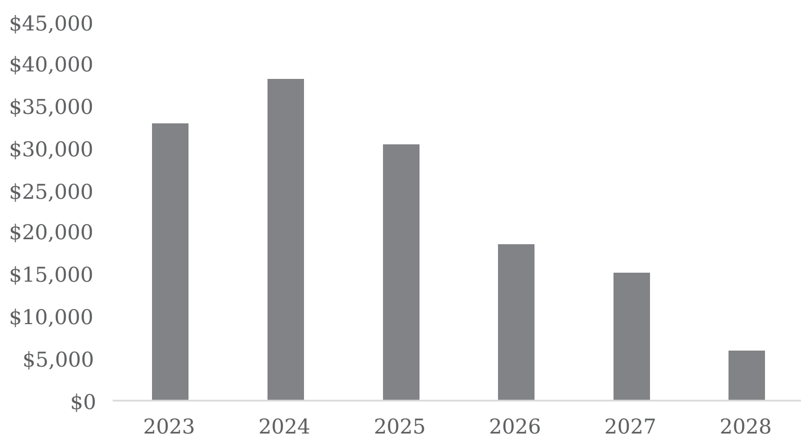
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Grid Management System
1. Witness:	Michael Schulte
2. Asset type:	7YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	471
5. Pin:	7817
6. CWBS Element:	CIT00SDPM781701
CWBS Description:	GM - Grid Management System
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	32,949	38,241	30,433	18,562	15,166	5,952	141,301

Due to rounding, totals may not tie to individual items.



Workpaper Title:

ADMS and DERMS Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Grid Management System
Project: ADMS & DERMS
CWBS Element: CIT-00-SD-PM-781701

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital	3,326	3,771	7,534	8,814	8,013	10,397	9,995	9,030	5,968	4,483	1,007	72,337
Vendor Contract	Capital	11,618	25,224	25,553	26,304	37,203	19,982	28,096	21,253	9,968	9,195	4,369	218,766
Software License COTS	Capital	-	-	4,900	7,183	2,197	1,670	-	-	1,526	1,412	525	19,414
Hardware and Data Center (App, DB, SAN,VM)	Capital	3,559	2,255	4,589	10,225	4,222	750	-	-	1,000	-	-	26,600
Cloud (SaaS)	Capital	-	-	-	-	-	-	-	-	-	-	-	-
Other	Capital	223	968	(949)	15,178	(1,498)	150	150	150	100	75	50	14,596
Total Capital:		**18,726**	**32,217**	**41,627**	**67,704**	**50,137**	**32,949**	**38,241**	**30,433**	**18,562**	**15,166**	**5,952**	**351,712**

Key Assumptions:
1. This estimate assumes Release 2 and new Release 3 capabilities (which extends ADMS and DERMS functionality by adding new mobile grid operations, outage management reporting, storm analytics and DER-based scenario analysis functions).
2. For years 2026-2028, software license costs is assumed to be 20% of product vendor contract cost.
3. GMS Release 3 deployment is assumed to occur in the 2027, 2028 timeline.
4. No HyperCare cost is assumped for GMS R3 as it will be deployed incrementally on the ADMS platform over a period of 2 years.
5. Recurring O&M for Release 3 is assumed to start in 2033, after 5 years from deployment.

Workpaper Title:

Capital Detail by WBS for Grid Platform

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Grid Management System
1. Witness:	Michael Schulte
2. Asset type:	7YR SWA
3. In-Service date:	12\1\9999
4. RO Model ID:	1055
5. Pin:	7817
6. CWBS Element:	CIT00DMDM000436
CWBS Description:	GM - Grid Platform
7. SRIIM Eligible:	No

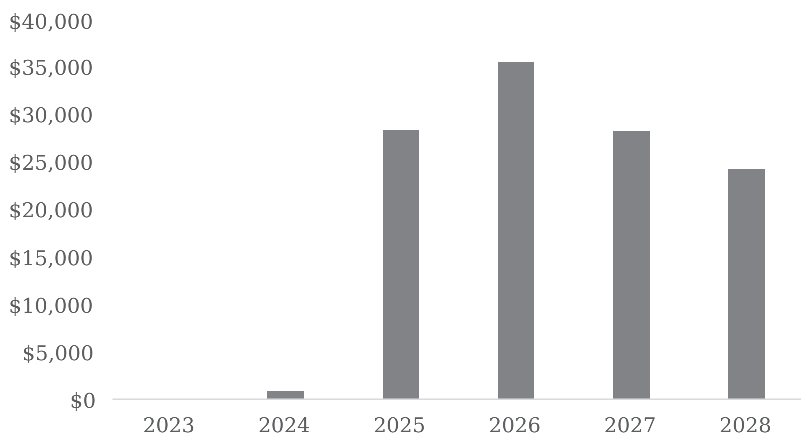
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	0	818	28,413	35,615	28,307	24,238

2023 - 2028 Total
117,391

Due to rounding, totals may not tie to individual items.



Workpaper Title:

Grid Platform Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Grid Management System
Project: Grid Platform
CWBS Element: CIT-00-DM-DM-000436

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital							500	6,501	6,178	4,439	3,144	20,762
Vendor Contract	Capital							318	19,262	20,632	16,952	13,551	70,715
Software License COTS	Capital							-	2,000	5,952	4,052	1,905	13,909
Hardware and Data Center (App, DB, SAN,VM)	Capital							-	600	2,793	2,794	5,588	11,775
Cloud (SaaS)	Capital							-	-	-	-	-	-
Other	Capital							-	50	60	70	50	230
Total Capital:		-	-	-	-	-	-	**818**	**28,413**	**35,615**	**28,307**	**24,238**	**117,391**

Key Assumptions:
1. For the 2025-2028 period, Grid Platform estimates assumes costs associated with Load Management ($88.1M) , Substation Device Management ($19.4M), and Power Quality ($8.5M) capabilities.
2. Load Management is assumed to continue in the 2029 ($17.6M) and 2030 ($12.5M) timeline, which is outside of the 2025 GRC cycle.

Load Management Assumptions
1. Load Management is assumed to consist of 1) V2G, 2) Integrated DRMS, and 3) enhancements to DER/STFE/OE capabilities. The execution phase for Load Management functions spans from 2025 through 2030.
2. Recurring O&M is assumed to start in 2033, after 5 years from deployment.

Substation Device Management Assumptions
1. Quote from Crossbow: The base scope of this is a test systems with 20 users and 100 IEDs, and it provides optional pricing for up to 9900 devices and unlimited users.
2. SCALE: 250 substations, 40 IEDs per station
3. Vendor cost estimate was based on a test system from 2017 - estimates scaled based on substations, IED devices, and inflation.
4. SCE Labor assumes supporting the integration of Grid Device Management with other SCE modules, and to support required training / onboarding. Arch, Design, PM, Testing, Implementation
5. Recurring O&M assumed to begin in 2028.

Power Quality Assumptions
1. Software would connect to approximately 1,000 sensors
2. SCE labor assumes costs associated with Arch, Design, Project Management, Testing, Deployment, and Implementation

Workpaper Title:

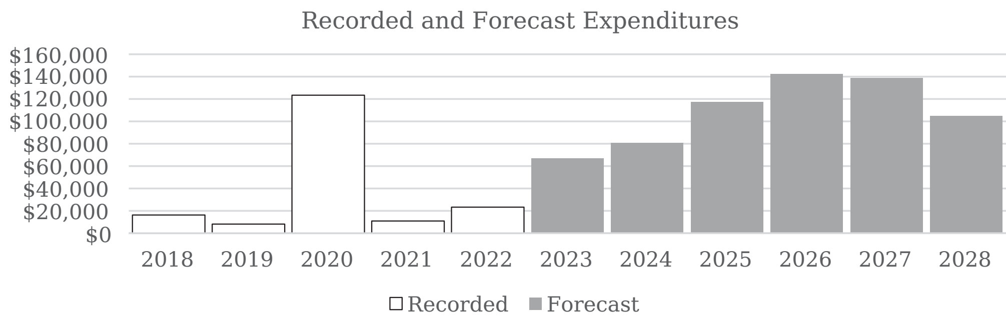
Communications Capital Expenditures

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-02 Grid Activities
Volume: 6 - Grid Modernization, Grid Technology, and Energy Storage

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures	16,272	8,148	123,395	10,915	23,298	66,975	80,551	117,264	142,479	138,873	104,846
Total Expenditures					182,028						650,988

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Communications	66,975	80,551	117,264	142,479	138,873	104,846	650,988
GRC Total	66,975	80,551	117,264	142,479	138,873	104,846	650,988

Workpaper Title:

Capital Detail by WBS for FAN

Southern California Edison
2025 GRC Capital Workpapers

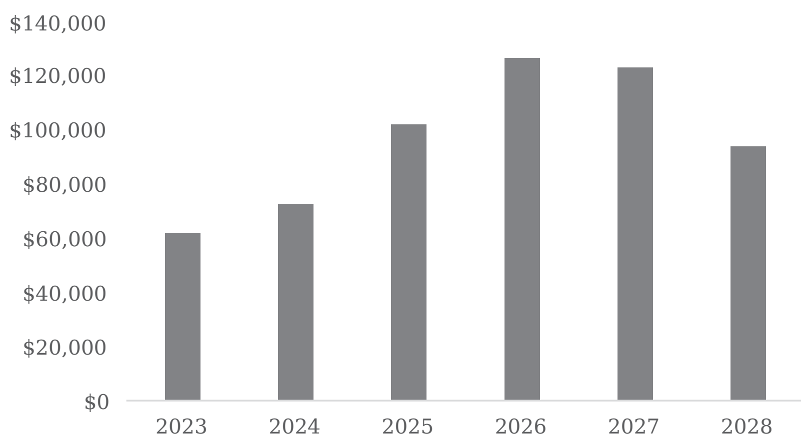
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Communications
1. Witness:	Michael Klein
2. Asset type:	TELECOMM
3. In-Service date:	12\1\9999
4. RO Model ID:	525
5. Pin:	7817
6. CWBS Element:	CIT00OPNS781701
CWBS Description:	GM - Field Area Network
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	61,889	72,656	102,054	126,650	123,069	94,003	580,322

Due to rounding, totals may not tie to individual items.



Southern California Edison
2025 GRC Capital Workpapers

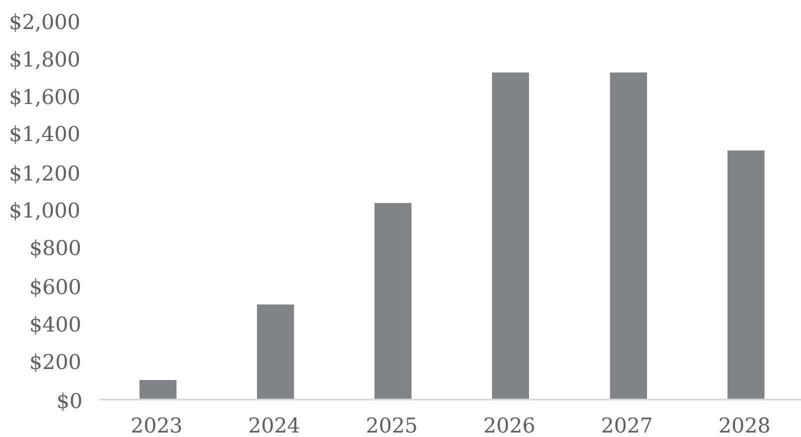
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Communications
1. Witness:	Michael Klein
2. Asset type:	TELECOMM
3. In-Service date:	12\1\9999
4. RO Model ID:	527
5. Pin:	7817
6. CWBS Element:	CIT00OPNS781703
CWBS Description:	GM - Fiber
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	102	502	1,036	1,724	1,725	1,313	6,401

Due to rounding, totals may not tie to individual items.



Workpaper Title:

FAN Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Communications
Project: Field Area Network
CWBS Element: CIT-00-OP-NS-781701, CIT-00-OP-NS-781703 & CIT-00-OP-NS-781704

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital	$1,427	$525	$127	$1,199	$1,906	$5,386	$6,428	$10,532	$15,590	$15,707	$12,834	$71,660
Vendor Contract	Capital	$10,508	$6,620	$3,314	$7,649	$11,254	$26,579	$44,033	$55,784	$61,930	$61,637	$42,097	$331,405
Software License	Capital	0	$0	$0	$0	$0	$15,007	$1,579	$2,372	$3,892	$2,834	$2,478	$28,162
Hardware & Material	Capital	$1,106	$135	$117	$279	$7,833	$12,980	$18,887	$31,137	$42,436	$40,273	$34,285	$189,469
Spectrum License	Capital	$0	$0	$118,951	$0	$0							$118,951
Other	Capital	$764	$205	$157	$734	$687	$2,038	$2,231	$3,265	$4,525	$4,343	$3,623	$22,572
Total Capital:		**$13,805**	**$7,485**	**$122,667**	**$9,862**	**$21,680**	**$61,990**	**$73,158**	**$103,090**	**$128,373**	**$124,795**	**$95,316**	**$762,221**

Key Assumptions:
1. Vendor Contract costs include Radio Access Network (RAN) physical site development costs and Network Equipment installations.
2. Software License costs include operating software licenses for Network Core, RAN, and Edge Device equipment.
3. Hardware & Material costs include Data Center equipment for the LTE/5G Cores, RAN components, Edge Device equipment, RAN structures, power systems and other construction materials.
4. Spectrum licenses acquired in FCC Auction 105.

Workpaper Title:

Capital Detail by WBS for CSP

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Communications

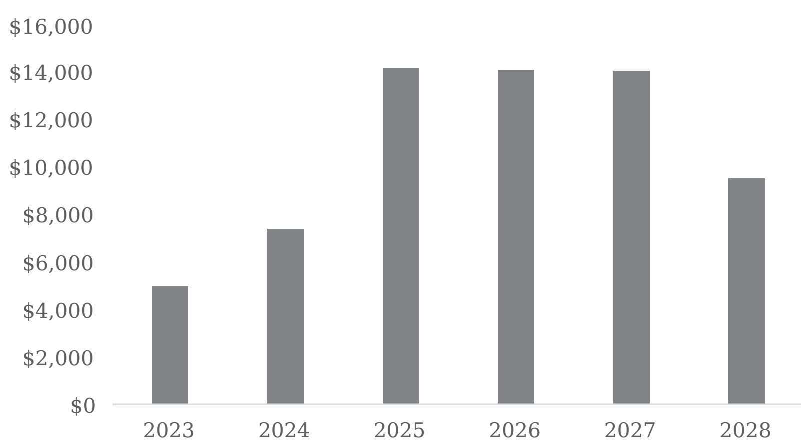
1. Witness:	Michael Klein
2. Asset type:	TELECOMM
3. In-Service date:	12\1\9999
4. RO Model ID:	526
5. Pin:	7817
6. CWBS Element:	CIT00OPNS781702
CWBS Description:	GM - Common Substation Platform
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	4,985	7,393	14,174	14,105	14,078	9,530	64,266

Due to rounding, totals may not tie to individual items.



Workpaper Title:

CSP Capital Workpaper

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity Communications
Project: Common Substation Platform
CWBS Element: CIT-00-OP-NS-781702 & CIT-00-OP-NS-781705

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital:													
SCE Labor	Capital	355	89	222	200	26	200	310	568	534	523	355	3,382
Vendor Contract	Capital	1,286	574	407	832	1,423	735	1,143	1,996	1,961	1,945	1,345	13,646
Software License COTS	Capital						675	990	1,935	1,935	1,935	1,305	8,775
Hardware and Data Center (App, DB, SAN,VM)	Capital	621	0	61	2	157	3,375	4,950	9,675	9,675	9,675	6,525	44,716
Cloud (SaaS)	Capital												-
Other	Capital	204	1	39	19	12							276
Total Capital:		**2,467**	**663**	**729**	**1,053**	**1,618**	**4,985**	**7,393**	**14,174**	**14,105**	**14,078**	**9,530**	**70,795**

Key Assumptions:
1. Annual Software License COTS are fixed at $45K per CSP.
2. Hardware and Data Center costs are fixed at $225K per CSP.
3. Majority of labor costs would be Vendor Contract labor.

Workpaper Title:

Power Quality Challenges

Power Quality Workpaper

Author: Matt Norwalk, Sr. Advisor

Introduction

The increasing complexity of the both the power system and customer loads in recent years has resulted in the need for advanced monitoring and modeling of the power system to ensure that threats are detected before widescale impacts are experienced. Electrification of transportation, DERs and automated manufacturing systems demand a level of power quality that far exceeds the abilities of traditional SCADA systems to capture and report. The examples provided in this workpaper were selected as representative examples of issues routinely faced across the SCE service territory.

DER Interference

A WDAT 20 MW PV plant interconnecting to a 33kV feeder was flagged for the potential to cause harmonics issues during the application phase. A harmonics compliance test was performed by SCE's Power Quality Department using a portable power quality analyzer where the plant was found to be exceeding IEEE 519 harmonic current distortion limits at the 49^{th} harmonic (2.94 kHz). The plant developer was requested to reduce the problematic harmonic current before being provided the permission to operate (PTO). The inverter manufacturer performed adjustments to the inverters, reducing the harmonics to acceptable levels and the PTO was granted after field verification.

Approximately 1 year later a phone line noise interference complaint was received from a residential customer in the area that was served from a 12kV feeder. In addition to phone line noise the customer experienced high frequency humming within hardwired smoke detectors and an induction cooktop. The customer reported that these issues were only occurring during daylight hours and that the rooftop PV system at the residence had experienced inverter faults and was not currently in operation. The initial investigators trained in detecting radiated powerline interference issues from sources such as tracking insulators and loose line hardware could not identify any nearby sources but confirmed the issue was conducted emissions from the primary distribution system. The issue was escalated to SCE's Power Quality Department for follow up.

The Power Quality investigator used a portable power quality analyzer to capture high frequency noise at the customer's electrical service in the range of 3 kHz and confirmed the issue was a result of PV generation based on the period of occurrence. Measurements along the feeder using the same instrument confirmed the source was on the 33kv side of the 33/12kV source substation. Recent switching had resulted in the 20 MW PV plant being placed onto the 33kV source line for the distribution customer. Measurements at the 20 MW PV plant identified the problematic 49^{th} harmonic current was again present at levels exceeding IEEE 519 limits.

The plant operator was contacted regarding SCE's findings and was unaware of the issues identified during commissioning of the plant. The operator worked with the inverter manufacturer to correct the issue by programming half of the inverters to output at a different power factor than the other half, thereby providing significant cancellation of the 3 kHz inverter switching frequency. Follow up measurements confirmed that the plant was once again within IEEE 519 limits. Measurements were performed at the residential customer and confirmed the issue had been resolved.

Analysis of SCE's SCADA system data indicated that no changes were observed before or after the noise issue that could be used as an indicator for similar issues in other areas of the system. Automated S&C Intellicap controllers are the only device at the feeder level capable of providing harmonics data but are limited to a total harmonic distortion calculation using values up to the 9th harmonic (540 Hz). At the substation, digital protective relays have similar performance values and are not intended to provide harmonic current data. In the absence of a Class A power quality analyzer to measure voltage and current at the feeder level, harmonic issues cannot be proactively identified and mitigated before impacting our customers or interfering with utility equipment.

EV Charging Disruption

A major EV manufacturer was in the process of commissioning a large charging site in Baker, California. Nearing the Thanksgiving holiday, the developer was under a tight deadline to complete the commissioning of the DC fast chargers to accommodate the significant number of EVs traveling between Los Angeles and Las Vegas. The charging equipment continued to generate high voltage faults, indicating an issue with the utility supply. Standard voltage measurement equipment did not indicate voltage above SCE's Rule 2 requirements for a maximum of 504 volts at the nominal 480v electrical service.

A portable power quality analyzer was connected at the main electrical service by SCE's Power Quality investigator which identified the source of the issues as harmonic voltage distortion. Analysis of the data (Figures 1 & 2) concluded that a harmonic frequency, 420 Hz, was responsible for a deviation in the voltage waveform causing the peak voltage to exceed the designed voltage operating range of the charging equipment. Typical causes for the level of distortion captured at the location includes converters such as the EV chargers, however, the chargers were not in operation at the time of the measurements and no other concentrations of similar loads were found in the area.

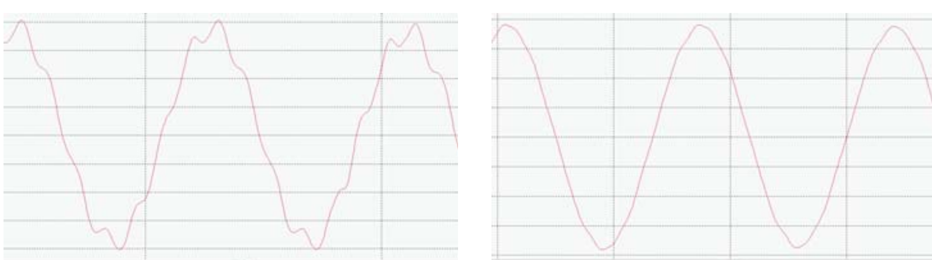


Figure 1 – Oscillography showing waveform distortion caused by excessive 7th harmonic (Left) compared to a normal waveform with typical distortion levels (Right).

At this point the major traffic through the area was just days away and solution was urgently needed. SCADA data was analyzed for all surrounding automated devices and found that a concentration of shunt capacitors connected at a neighboring substation had been recently energized. These capacitors were intended only for use during a sub-transmission line configuration change to support voltage in the Mountain Pass area. Engineers performed adjustments to the capacitor settings, turning the capacitors off. Modeling analysis was also performed and confirmed that a harmonic resonance condition existed with all capacitors switched in, where the 7th harmonic was identified as the resonant frequency.

The Power Quality investigator returned to the site and performed follow-up measurements that confirmed the voltage distortion levels had improved following the capacitor settings changes, restoring the voltage distortion to below IEEE 519 recommended limits. The site developer successfully completed commissioning testing in time for the busy holiday travel period, providing abundant chargers to the busy corridor.

Post event analysis concluded that these capacitors had been included into a distribution volt var control (DVVC) algorithm months prior, altering the intended use of the capacitors for only contingency scenarios. The reactive response jeopardized the availability of charging infrastructure in a busy corridor that suffered from extremely long waiting periods during the prior holiday driving periods. Feeder level power quality monitoring can provide fast identification of harmonic resonance issues in addition to other disturbances that can result in cessation of EV charging.

Light Flicker Affecting a New Development

Numerous residences in the Colton area began to experience flickering lights in the Fall of 2022. These occurrences were during the daytime hours and were reported to have started abruptly according to several residents in one area of a distribution circuit. The initial investigation focused on the underground distribution system feeding the housing development where these issues were reported. Voltage and current measurements performed by the Trouble Crews did not identify any abnormal values.

The investigation was escalated to SCE’s Power Quality Department to connect portable power quality analyzers at a few of the homes where issues were reported. The investigator noted that the development has rooftop solar at each home that was installed by the developer. Analysis of the collected data confirmed the presence of fluctuating voltages caused by the repeated disconnection and reconnection of solar inverters throughout the development. Flicker calculations performed by the analyzers concluded that the levels were reaching perceptible levels during the daytime hours.

The data also revealed the phase to neutral connected service transformers had total harmonic voltage distortion (V_{THD}) that was found to be exceeding the IEEE 519 upper limit of 8% and was predominately 3rd harmonic (180 Hz). SCADA data from the automated capacitor controllers on the circuit did not capture these harmonics due to the phase-to-phase connection of the potential transformers limiting the ability of the investigators to determine whether the harmonics were present before the residents started experiencing the light flicker.

The next step in the investigation was measuring harmonics at different points along the feeder while performing switching to move the circuit load to another feeder. This switching found the V_{THD} dropped approximately 3% when this change was made. These findings assisted in identifying a circuit configuration where the affected customers were split between two circuits, lowering the distortion levels to values that allowed the PV inverters to remain connected to the system.

Identifying the source of the harmonics and whether a sudden increase occurred at the time when residents began experiencing the light flicker was not possible due to the limitations of the existing SCADA system and capacitor controller PT connections. Feeder level power quality monitoring can provide the detailed harmonics data necessary to identify rising levels of harmonics and take action before PV inverter interference begins to occur. Sudden changes in harmonic levels can be the result of several causes including high impedance neutral connections and resonances, where historical data is essential in pinpointing circuit configuration changes and fault activity that may be the root cause.

Automated Manufacturing Impacted by Incipient Fault Events

A semiconductor manufacturer began to experience disruptive voltage sags several times per week. The customer-owned power quality analyzer permanently installed at the electrical service verified the source of the voltage sags was on SCE's distribution system. Unlike previous adjacent circuit fault events, SCE's interruption logs did not identify any potential causes. Data was provided to SCE's Power Quality Department for further analysis where it was determined from the waveform signature of these events that the cause was incipient fault activity.

Inspection of the circuit serving the customer was performed to ensure there were no visually identifiable issues including heat scanning components and ensuring line clearance from tree branches. The problems continued and increased in frequency. Approximately 2 weeks following the initial event a cable component on an adjacent circuit served from the same substation failed. This failure had not previously resulted in any operations of the circuit breaker. Following this event, the voltage sags were no longer occurring, confirming the source had been the incipient fault on the adjacent circuit.

Incipient fault activity can be very disruptive to advanced manufacturing facilities, resulting in lost product and delivery delays. Feeder level power quality monitoring can provide incipient fault magnitudes for events that would not otherwise trigger remote fault indicators due to their sub-cycle nature. In this example monitoring would have quickly identified the source circuit saving considerable downtime and disruption for this manufacturer. A distributed monitoring network provides a key advantage of providing additional location when compared to a traditional DFR system. Accurate incipient fault values can be input into circuit models to determine possible locations to send crews to perform repairs before a fault occurs.

Workpaper Title:

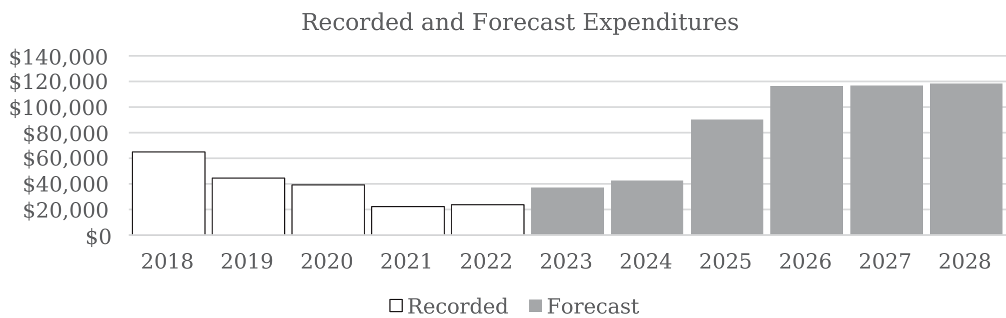
Automation Capital Workpaper

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-02 Grid Activities
Volume: 6 - Grid Modernization, Grid Technology, and Energy Storage

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures	64,946	44,507	39,189	22,233	23,712	36,905	42,451	90,239	116,315	116,527	118,068
Total Expenditures					194,588						520,505

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Automation	34,392	39,944	80,239	81,015	81,227	82,768	399,585
DER-Driven Grid Reinforcement	1,287						1,287
EMERGENT PROJECTS	1,226	2,507	10,000	35,300	35,300	35,300	119,633
GRC Total	36,905	42,451	90,239	116,315	116,527	118,068	520,505

Emergent Projects dollars are found in Load Growth Testimony. Please disregard this activity line item listed above totaling 119,633 2023-2028.

Workpaper Title:

Capital Details by WBS for

Reliability-driven Distribution Automation

Southern California Edison
2025 GRC Capital Workpapers

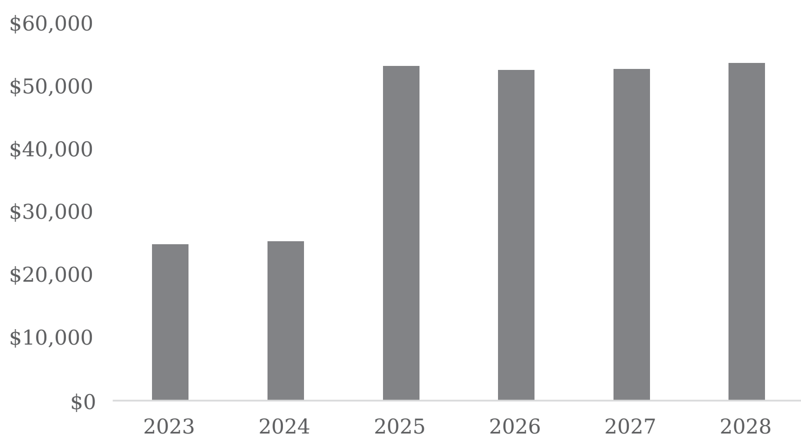
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Automation
1. Witness:	Mark Esguerra
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	101
5. Pin:	7817
6. CWBS Element:	CETPDGMRAMTW
CWBS Description:	Metro West
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	24,739	25,192	53,006	52,391	52,499	53,466	261,294

Due to rounding, totals may not tie to individual items.



Workpaper- Southern California Edison / 2025 GRC

Workpaper Title:
Reliability- and DER-driven Distribution Automation Capital

Workpaper- Southern California Edison / 2025 GRC

PURPOSE

This workpaper provides an overview of the benefit cost analysis (BCA) used to evaluate various automation architectures and device types to determine the Reliability-driven and DER-driven Distribution Automation approach and associated forecasts for the 2025 GRC.

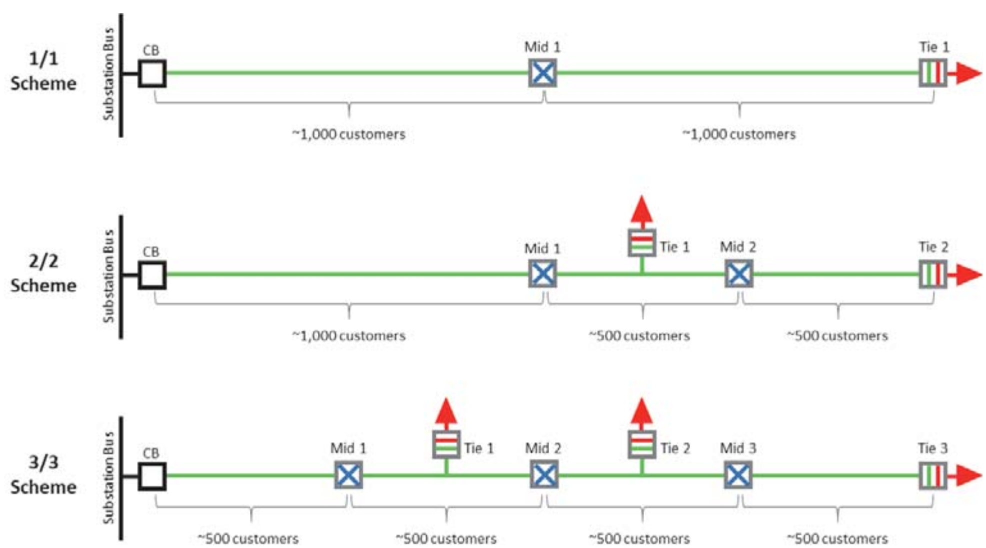
BACKGROUND

SCE performed a BCA to support the reasonableness of its 2021 GRC request for the 225 circuits included for Reliability-driven Distribution Automation. In the 2025 GRC, SCE continues to use a BCA to support the reasonableness of its Reliability-driven Distribution Automation request. In addition, SCE is also using this BCA approach to demonstrate the reasonableness of its DER-driven Distribution Automation request. Both programs will pursue the same automation scheme and automation device types. The difference is that whereas the Reliability-driven Distribution Automation circuits are selected based solely on the forecasted reliability improvement expected to result from additional automation, the DER-driven Distribution Automation circuits are first screened to determine whether they are forecasted to encounter high levels of DER penetration. The DER-driven circuits are then selected based on the highest value in terms of net reliability improvements (as identified by the BCA).

AUTOMATION ARCHITECTURES CONSIDERED

The Automation Program will equip each distribution circuit with up to three midpoint switches and up to three circuit tie switches, as illustrated below. This is referred to a 3/3 scheme in which a given circuit has three midpoint switches and three circuit tie switches.

Figure 1 – Distribution Automation Scheme Architectures



By increasing the number of midpoint and tie switches on each distribution circuit, the new system sectionalizes the load and DERs into smaller more manageable portions. Through the use of a modern control system like the ADMS, these smaller portions as configured in a 3/3 scheme (with three midpoint switches and three circuit tie switches) would allow SCE to prevent a sustained outage on three of the four sections, effectively reducing up to 75% of sustained outages in these circuits. Via its current deployment proposal though, distribution automation may also eliminate up to 75% of momentary outages (when deploying fault interrupting midpoint switches) and up to 75% of sustained outages. With additional circuit ties and knowledge of the real-time current/power on the circuits, operators can transfer the smaller load sections to various neighboring circuits with a higher success rate and less risk of unintended consequences.

In addition to the three distribution automation architectures, the BCA also evaluates the schemes using four switch type scenarios: (1) all load break switches (RCS) without telemetry, (2) all load break switches with telemetry (RCS+), (3) fault interrupting midpoint switches and load break circuit tie switches, and (4) all fault interrupting switches. In addition to these four switch type scenarios, SCE also evaluated an RFI-only scenario in which SCE would only add RFIs to a given circuit.

Finally, the BCA also evaluated three fault location, isolation and service restoration (FLISR) schemes: (1) Remote Switching, (2) Assisted Switching, and (3) Automated Switching.

Benefits

The BCA includes the value of reliability improvements forecasted to result from incremental distribution automation deployments. To prepare circuit-specific benefit cost ratios (BCRs), SCE forecasted the value of reliability improvements for each respective distribution circuit. These forecasts are based on three years of historical outage performance for each circuit, the expected reliability improvements that would result from installing incremental distribution automation on each of these circuits,[1] and circuit-specific VOS metrics. SCE prepared circuit-specific VOS metrics for both customer minutes of interruption (CMI) and momentary customer interruptions (MCI). These circuit-specific VOS metrics were calculated using the survey results of the 2019 Nexant Value of Service study prepared for SCE's 2021 GRC, which SCE adjusted to reflect the customer composition and historical weighted average outage durations of each respective distribution circuit. **Table 1** summarizes the VOS metrics from the VOS study for each customer category and outage duration.

Table 1 – Value of Service Metrics by Customer Category[2]

Customer Category	Momentary Outages *($ MCI)*	Sustained Outages *($/CMI; $ 2019)*			
		1 hour	4 hour	8 hour	24 Hour
Residential	$4.59	$0.11	$0.05	$0.04	$0.02
Small-Medium Business	$535.28	$51.65	$14.41	$9.69	$5.63
Large Commercial & Industrial	$17,696.69	$1,334.49	$630.46	$500.93	$309.75

[1] 2018 GRC Estimated Reliability Improvement due to Distribution Automation, included as Appendix 1 to this workpaper.
[2] Southern California Edison: 2019 Value of Service Study, included as Appendix 2 to this workpaper.

Costs

The costs reflected in the BCA include the incremental capital expenditures necessary to support each respective distribution automation scheme on a given distribution circuit. For example, for the 3/3 scheme, if a circuit already has two midpoint switches, the BCA model only adds an additional midpoint switch. For the scenarios that call for load break switches with telemetry, if a given circuit already has one or more load break switches without telemetry, then the BCA only includes the cost of retrofitting the existing switches with telemetry. The model also includes the capital expenditures necessary to refresh the automation devices after 15 years. Finally, the BCA includes the cost to maintain the equipment throughout the analysis period. **Table 2** reflects the potential number of switching devices necessary for each distribution automation scheme.

Table 2 – Switches Required by Distribution Automation Scheme

Automation Scheme	Automated Switches/Circuit	
	Mids	Ties
1/1	1	0.5
2/2	2	1
3/3	3	1.5
+1/+1	1	0.5

The unit cost assumptions summarized in **Table 3** are based on historical unit costs for each type of automation equipment. The unit costs from 2022 are escalated to 2025 to reflect the deployment year assumed in the BCA model. The refresh costs are escalated to 2040 to reflect the refresh year, assumed to be 15 years following deployment.

Workpaper- Southern California Edison / 2025 GRC

Table 3 – Unit Cost Assumptions

	2022	2025 *(Deployment)*	2040 *(Refresh Only)*
Overhead			
Remote Fault Indicators (per location)	$23,000	$26,058	
Remote Controlled Switch Retrofit	$20,000	$22,659	
Power Quality Monitor	$10,000	$11,329	
Load Break Switch - without Telemetry	50,000	$56,647	
Load Break Switch – with Telemetry	$55,000	$62,312	
Fault Interrupting Switch	$122,000	$138,219	
Underground			
Remote Fault Indicators (per location)	$30,000	$33,988	
Remote Controlled Switch Retrofit	$40,000	$45,318	
Power Quality Monitor	$10,000	$11,329	
Load Break Switch - without Telemetry	$110,000	$124,624	
Load Break Switch – with Telemetry	$150,000	$169,942	
Fault Interrupting Switch	$350,000	$396,531	
Vault Replacement	$645,000	$730,749	
Refresh *(replace after 15 years)*			
Overhead RFI	$23,000		$35,636
Underground RFI	$30,000		$46,126
Power Quality Monitor	$10,000		$15,375
Load Break Switch	$55,000		$84,564
Fault Interrupting Switch	$122,000		$187,579

BENEFIT COST ANALYSIS RESULTS

In the 2021 GRC, SCE paused the strategy described in the 2018 GRC where up to three midpoint and tie (3/3) intelligent automated switches with fault interruption capability were proposed. This was due to resource limitations associated with Wildfire Resiliency. In the 2025 GRC, SCE is returning to the 3/3 distribution automation scheme initially proposed in the 2018 GRC. This approach delivers the highest reliability value compared to other switch-type combinations, and improves the customer experience by allowing up to 75% of a circuit to avoid momentary and sustained outages. This approach also provides safety and asset health benefits by reducing the need to perform fault testing, and it enables greater operational flexibility by allowing a circuit to be partitioned into four smaller segments for reconfiguration either to avoid an overload or restore load following a fault. **Table 4** summarizes the *Reliability-driven Distribution Automation* benefits and costs for the 225 circuits with the highest BCR under the 3/3 distribution automation scheme using various switch-type and restoration approach combinations. The row shaded greed, SCE's proposed deployment approach, delivers the highest reliability value among these options, within the 2055 GRC timeframe. Although the Automated Switching (using fault interrupting midpoint switches) option delivers a higher benefit-cost ratio of 7.0, SCE maintains that this approach to service restoration is likely to be implemented after 2028.

Workpaper- Southern California Edison / 2025 GRC

Table 4 – Reliability-driven Automation Summary (255 Circuits)

255 Circuits ($ millions)	Annual CMI Avoided (millions)	Annual MCI Avoided (millions)	Benefit PV, 2023	Cost PVRR, 2023	Benefit-Cost Ratio	Implied Capex
All Load Break Switches with Telemetry (RCS+)						
Remote Switching	25.4	(0.15)	$798	$229	3.5	$182.2
Assisted Switching	39.2	(0.27)	$1,391	$222	6.3	$174.7
Automated Switching	41.6	(0.29)	$1,467	$221	6.6	$173.9
Fault Interrupting Midpoint Switches and Load Break Tie Switches						
Remote Switching	24.7	0.16	$1,435	$292	4.9	$203.6
Assisted Switching	**38.9**	**0.23**	**$2,078**	**$305**	**6.8**	**$211.5**
Automated Switching	41.2	0.23	$2,170	$308	7.0	$213.8
All Fault Interrupting Switches						
Remote Switching	25.1	0.15	$1,471	$369	4.0	$244.4
Assisted Switching	39.8	0.22	$2,182	$399	5.5	$264.0
Automated Switching	42.0	0.23	$2,265	$400	5.7	$264.1
RCS-only	17.9	(0.11)	$579	$313	1.9	$184.2
RFI-only	2.8	-	$173	$56	3.1	$37.1

Table 5 summarizes the *DER-driven Distribution Automation* benefits and costs for the 110 circuits with the highest BCR under the 3/3 distribution automation scheme using various switch-type and restoration approach combinations. Consistent with the Reliability-driven Distribution Automation circuits, the row shaded greed delivers the highest reliability value among these options, within the 2025 GRC timeframe.

Table 5 – DER-driven Automation Summary (110 Circuits)

110 Circuits ($ millions)	Annual CMI Avoided (millions)	Annual MCI Avoided (millions)	Benefit PV, 2023	Cost PVRR, 2023	Benefit-Cost Ratio	Implied Capex
All Load Break Switches with Telemetry (RCS+)						
Remote Switching	8.3	(0.04)	$193	$93	2.1	$73.3
Assisted Switching	12.2	(0.07)	$345	$89	3.9	$69.8
Automated Switching	12.9	(0.08)	$364	$88	4.1	$69.6
Fault Interrupting Midpoint Switches and Load Break Tie Switches						
Remote Switching	6.7	0.04	$391	$114	3.4	$79.7
Assisted Switching	**10.5**	**0.05**	**$553**	**$119**	**4.6**	**$83.4**
Automated Switching	11.1	0.06	$573	$119	4.8	$83.4
All Fault Interrupting Switches						
Remote Switching	6.9	0.04	$396	$144	2.8	$95.3
Assisted Switching	10.9	0.06	$558	$149	3.7	$99.0
Automated Switching	11.5	0.06	$578	$149	3.9	$99.0
RCS-only	6.1	(0.03)	$136	$144	0.9	$84.0
RFI-only	0.8	-	$35	$24	1.5	$15.8

Beginning in 2025, SCE will install additional distribution automation on approximately 91 circuits per year, augmenting them with up to three midpoint intelligent automated switches with fault interruption capability, up to three RCS circuit tie switches (with telemetry), and vault replacements, where necessary. Each circuit will also receive five remote fault indicators and the switch locations will also receive power quality monitors. These improvements are forecasted to deliver approximately 10 minutes of SAIDI improvement once deployment is complete at the end of 2028.[3]

[3] The SAIDI improvement equals the forecasted annual CMI improvement of 38.9 million for reliability-driven circuits and 10.5 million for the DER-driven circuits, divided by SCE's 5.16 million customers.

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Circuit-level Benefit Cost Analysis Results

Table 6 summarizes the benefits, costs and associated BCRs for the 225 reliability-driven distribution automation circuits with the highest BCR for each 3/3 scenario. The 225 circuits are numbered (rather than named) since the ranking of the top 225 circuits is different for each deployment scenario.

Table 6 – Reliability-driven Distribution Automation Results

DA Scheme	3 Mids : 3 Ties - Reliability-driven Distribution Automation Circuits																														RFI-only		
Switch Type	All RCS			All Load Break (RCS+)									Fault Interrupting Mids									All Fault Interrupting											
FLISR Scheme	Remote Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching					
	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs
Totals	1.9	579	313	3.5	798	229	6.3	1,391	222	6.6	1,467	221	4.9	1,435	292	6.8	2,078	305	7.0	2,170	308	4.0	1,471	369	5.5	2,182	399	5.7	2,265	400	3.1	173	56
Circuit Detail																																	
1	10.9	4.3	0.4	15.8	6.2	0.4	25.8	10.1	0.4	27.1	10.6	0.4	20.3	5.5	0.3	25.3	6.9	0.3	25.9	7.1	0.3	14.5	8.8	0.6	18.8	30.3	1.6	19.4	31.3	1.6	16.3	3.7	0.2
2	7.8	5.0	0.6	15.3	7.8	0.5	25.3	12.9	0.5	26.6	13.6	0.5	19.6	5.7	0.3	23.1	20.2	0.9	23.8	20.9	0.9	13.9	22.4	1.6	18.1	11.0	0.6	18.5	11.2	0.6	15.4	3.1	0.2
3	7.4	4.7	0.6	13.5	6.0	0.4	23.8	13.1	0.6	25.3	13.9	0.6	17.4	15.3	0.9	22.7	30.3	1.3	23.4	31.3	1.3	13.7	10.6	0.8	17.2	13.4	0.8	17.6	12.9	0.7	9.2	2.2	0.2
4	7.1	4.5	0.6	12.8	5.9	0.5	23.5	10.5	0.4	24.8	11.1	0.4	16.8	22.4	1.3	22.2	12.4	0.6	23.1	12.9	0.6	12.7	5.7	0.4	17.0	12.4	0.7	17.6	13.7	0.8	8.6	1.8	0.2
5	7.1	9.0	1.3	12.1	6.7	0.6	20.7	9.5	0.5	21.7	10.0	0.5	16.5	10.6	0.6	20.7	13.4	0.6	21.3	13.7	0.6	12.5	15.3	1.2	16.6	43.3	2.6	17.4	45.1	2.6	7.4	1.9	0.3
6	6.9	3.4	0.5	11.7	4.0	0.3	20.0	11.6	0.6	21.4	26.8	1.3	15.7	3.1	0.2	20.7	6.0	0.3	20.9	4.3	0.2	12.4	8.9	0.7	16.6	20.2	1.2	17.1	20.9	1.2	7.3	1.6	0.2
7	6.3	4.2	0.7	11.4	4.9	0.4	19.9	25.0	1.3	21.2	12.3	0.6	15.2	8.5	0.6	20.2	4.2	0.2	20.8	6.0	0.3	12.0	8.3	0.7	16.1	11.7	0.7	16.6	12.0	0.7	6.8	1.5	0.2
8	6.2	6.9	1.1	10.7	6.1	0.6	18.5	6.2	0.3	19.4	6.5	0.3	15.0	3.7	0.2	19.3	8.2	0.4	20.0	8.5	0.4	11.6	8.5	0.7	15.6	8.2	0.5	16.1	19.9	1.2	6.7	1.4	0.2
9	5.7	5.4	0.9	9.8	4.0	0.4	18.1	7.3	0.4	19.2	7.7	0.4	14.9	3.4	0.2	19.2	43.3	2.3	20.0	45.1	2.3	11.3	5.9	0.5	15.6	10.8	0.7	16.1	8.5	0.5	6.5	1.4	0.2
10	5.5	15.3	2.8	9.8	4.3	0.4	18.0	7.8	0.4	18.9	8.1	0.4	14.8	3.0	0.2	18.1	11.0	0.6	18.6	16.9	0.9	11.1	28.8	2.6	15.5	19.1	1.2	16.0	11.1	0.7	6.5	1.4	0.2
11	5.3	8.4	1.6	9.8	4.0	0.4	16.7	21.6	1.3	17.6	22.7	1.3	14.5	8.8	0.6	17.9	16.3	0.9	18.5	11.2	0.6	10.7	5.5	0.5	14.9	17.3	1.2	15.5	18.0	1.2	6.3	1.2	0.2
12	5.1	3.0	0.6	9.6	12.3	1.3	16.4	6.7	0.4	17.5	9.5	0.5	14.1	4.4	0.3	17.7	19.1	1.1	18.5	19.9	1.1	10.5	12.2	1.2	14.5	15.6	1.1	15.1	16.2	1.1	6.1	1.4	0.2
13	5.1	2.9	0.6	9.3	3.9	0.4	16.3	8.8	0.5	17.2	7.0	0.4	14.0	5.9	0.4	17.0	3.9	0.2	17.6	11.6	0.7	10.3	12.6	1.2	13.4	16.3	1.2	13.9	16.9	1.2	5.9	1.2	0.2
14	4.9	2.8	0.6	8.9	2.3	0.3	16.0	7.0	0.4	16.8	7.3	0.4	13.1	4.5	0.3	16.9	11.1	0.7	17.4	18.0	1.0	10.1	3.1	0.3	13.4	6.0	0.4	13.6	7.1	0.5	5.8	1.2	0.2
15	4.7	1.9	0.4	8.7	5.6	0.6	15.5	10.4	0.7	16.6	11.1	0.7	12.8	28.8	2.3	16.8	17.3	1.0	17.2	4.0	0.2	9.7	3.7	0.4	13.3	6.9	0.5	13.5	6.0	0.4	5.8	1.2	0.2
16	4.7	1.4	0.3	8.7	7.4	0.8	15.4	9.9	0.6	16.2	10.4	0.6	12.7	11.6	0.9	16.5	3.3	0.2	16.9	5.8	0.3	9.7	10.4	1.1	12.7	16.0	1.3	13.3	16.7	1.3	5.6	1.3	0.2
17	4.7	2.5	0.5	8.5	3.1	0.4	15.2	6.4	0.4	16.0	6.7	0.4	12.4	8.9	0.7	16.5	5.6	0.3	16.8	16.2	1.0	9.6	3.4	0.4	12.7	27.1	2.1	13.2	28.3	2.1	5.4	1.3	0.2
18	4.5	8.4	1.9	8.4	10.5	1.3	14.8	12.5	0.8	15.6	13.2	0.8	12.3	3.6	0.3	16.1	11.7	0.7	16.6	3.3	0.2	9.5	11.6	1.2	12.4	17.5	1.4	13.0	18.3	1.4	5.3	1.1	0.2
19	4.5	4.7	1.0	8.1	3.8	0.5	14.6	3.8	0.3	15.3	4.0	0.3	12.1	4.3	0.4	16.1	4.0	0.2	16.6	12.0	0.7	8.5	4.4	0.5	11.6	11.1	1.0	12.1	11.6	1.0	5.1	1.0	0.2
20	4.5	3.6	0.8	7.9	6.6	0.8	14.4	5.2	0.4	15.2	5.5	0.4	12.0	8.3	0.7	16.1	15.6	1.0	16.2	4.0	0.2	8.4	10.6	1.3	11.0	3.9	0.4	11.3	14.8	1.3	5.1	1.3	0.2
21	4.3	3.0	0.7	7.6	7.0	0.9	14.1	7.3	0.5	15.1	7.9	0.5	11.9	12.2	1.0	15.6	10.8	0.7	16.0	11.1	0.7	8.4	17.9	2.1	10.9	11.0	1.0	11.3	11.5	1.0	5.0	1.1	0.2
22	4.3	3.3	0.8	7.5	2.9	0.4	13.6	7.9	0.6	14.7	8.5	0.6	11.8	12.6	1.1	15.1	5.4	0.4	15.5	16.7	1.1	8.3	11.7	1.4	10.9	14.2	1.3	11.1	4.0	0.4	5.0	1.1	0.2
23	4.0	2.7	0.7	7.4	9.4	1.3	13.3	6.2	0.5	14.0	8.5	0.6	11.4	3.0	0.3	14.8	16.0	1.1	15.4	5.5	0.4	8.0	3.6	0.5	10.6	3.3	0.3	10.9	13.7	1.3	4.9	1.0	0.2
24	3.7	2.2	0.6	7.2	3.1	0.4	13.2	8.0	0.6	13.9	6.5	0.5	11.4	7.5	0.7	14.7	3.8	0.3	15.2	4.0	0.3	7.8	7.5	1.0	10.4	13.1	1.3	10.7	3.3	0.3	4.8	1.0	0.2
25	3.6	1.3	0.4	7.1	3.1	0.4	12.9	10.8	0.8	13.6	11.4	0.8	11.3	2.9	0.3	14.4	4.5	0.3	14.8	28.3	1.9	7.7	5.1	0.7	10.4	4.0	0.4	10.6	7.1	0.7	4.8	1.1	0.2
26	3.6	4.1	1.1	7.1	4.6	0.7	12.7	8.3	0.7	13.4	8.8	0.7	11.1	2.4	0.2	14.1	27.1	1.9	14.5	13.7	0.9	7.6	7.7	1.0	10.2	6.8	0.7	10.5	4.0	0.4	4.8	1.1	0.2
27	3.6	8.8	2.4	7.0	4.1	0.6	12.6	5.5	0.4	13.3	5.8	0.4	10.7	10.4	1.0	13.9	13.1	0.9	14.5	4.5	0.3	7.5	3.1	0.4	9.8	4.1	0.4	10.0	4.2	0.4	4.7	1.0	0.2
28	3.6	2.9	0.8	7.0	2.7	0.4	12.4	11.4	0.9	13.0	12.0	0.9	10.7	2.4	0.2	13.8	6.4	0.5	14.2	18.3	1.3	7.4	4.3	0.6	9.7	9.4	1.0	10.0	13.3	1.3	4.7	1.1	0.2
29	3.5	3.2	0.9	7.0	2.1	0.3	12.2	15.6	1.3	12.8	16.4	1.3	10.6	4.9	0.5	13.7	4.2	0.3	14.2	6.6	0.5	7.4	3.0	0.4	9.7	4.7	0.5	10.0	9.7	1.0	4.6	1.0	0.2
30	3.5	3.1	0.9	6.8	1.9	0.3	12.0	4.6	0.4	12.6	4.8	0.4	10.4	2.1	0.2	13.6	17.5	1.3	14.2	11.5	0.8	7.4	4.9	0.7	9.6	12.7	1.3	10.0	4.8	0.5	4.5	0.9	0.2
31	3.5	5.8	1.7	6.8	21.2	3.1	11.5	3.5	0.3	12.1	3.7	0.3	10.1	3.1	0.3	13.6	11.0	0.8	14.1	4.3	0.3	7.3	3.5	0.5	9.6	6.4	0.7	10.0	13.1	1.3	4.5	0.9	0.2
32	3.4	2.5	0.7	6.8	4.5	0.7	11.4	6.6	0.6	11.9	6.9	0.6	10.0	7.0	0.7	13.6	3.6	0.3	13.9	3.7	0.3	7.3	7.0	1.0	9.6	12.5	1.3	9.9	6.6	0.7	4.5	0.9	0.2
33	3.4	5.8	1.7	6.8	4.1	0.6	11.3	4.4	0.4	11.9	3.4	0.3	9.8	10.6	1.1	13.4	9.4	0.7	13.8	9.7	0.7	7.2	9.5	1.3	9.3	13.3	1.4	9.7	13.9	1.4	4.4	0.9	0.2
34	3.3	4.0	1.2	6.7	3.9	0.6	11.3	3.2	0.3	11.9	4.6	0.4	9.8	4.8	0.5	13.1	3.8	0.3	13.5	14.8	1.1	7.2	5.4	0.7	9.3	5.4	0.6	9.7	18.9	2.0	4.4	1.0	0.2
35	3.3	5.1	1.6	6.7	3.6	0.5	11.2	4.9	0.4	11.8	3.9	0.3	9.5	7.7	0.8	13.0	14.2	1.1	13.2	3.9	0.3	7.2	4.2	0.6	9.3	18.1	2.0	9.5	5.5	0.6	4.3	0.9	0.2
36	3.1	3.0	1.0	6.7	1.9	0.3	11.1	3.7	0.3	11.7	5.1	0.4	9.4	7.1	0.8	12.6	6.2	0.5	13.0	6.3	0.5	7.2	4.5	0.6	9.2	11.2	1.2	9.5	11.5	1.2	4.2	0.9	0.2
37	3.1	3.1	1.0	6.6	4.2	0.6	11.0	3.4	0.3	11.6	3.5	0.3	9.3	17.9	1.9	12.4	2.7	0.2	12.6	2.7	0.2	7.1	2.4	0.3	9.2	8.5	0.9	9.5	8.8	0.9	4.2	0.9	0.2
38	3.1	4.0	1.3	6.5	2.0	0.3	11.0	3.1	0.3	11.5	3.2	0.3	9.1	8.7	0.9	12.1	2.7	0.2	12.6	13.9	1.1	7.1	8.6	1.2	9.0	5.6	0.6	9.4	15.6	1.7	4.2	0.9	0.2
39	3.0	8.1	2.7	6.5	4.2	0.6	10.8	6.2	0.6	11.4	2.7	0.2	9.1	11.7	1.3	12.1	13.3	1.1	12.4	14.2	1.1	7.1	6.5	0.9	9.0	15.0	1.7	9.2	5.8	0.6	4.1	0.9	0.2
40	2.9	2.7	0.9	6.2	3.2	0.5	10.8	2.5	0.2	11.4	6.5	0.6	9.0	4.1	0.5	12.0	13.6	1.1	12.3	2.7	0.2	6.9	8.7	1.3	8.8	3.6	0.4	9.0	3.7	0.4	4.0	0.8	0.2
41	2.9	1.9	0.6	6.1	3.5	0.6	10.4	32.5	3.1	11.3	11.5	1.0	8.9	6.5	0.7	11.8	2.3	0.2	12.3	13.1	1.1	6.9	7.1	1.0	8.8	6.5	0.7	9.0	12.6	1.4	4.0	0.8	0.2
42	2.9	1.7	0.6	6.1	1.4	0.2	10.3	10.5	1.0	10.9	34.0	3.1	8.8	4.2	0.5	11.8	9.0	0.8	12.1	9.2	0.8	6.8	4.8	0.7	8.7	6.2	0.7	9.0	6.3	0.7	4.0	1.0	0.2
43	2.9	2.4	0.8	5.9	3.1	0.5	10.2	6.4	0.6	10.9	10.3	1.0	8.8	8.6	1.0	11.8	12.5	1.1	12.0	2.4	0.2	6.7	2.1	0.3	8.7	4.5	0.5	9.0	6.7	0.7	3.9	0.9	0.2
44	2.8	2.9	1.0	5.9	3.2	0.5	10.2	6.6	0.6	10.6	6.9	0.6	8.7	5.4	0.6	11.6	8.5	0.7	11.9	8.8	0.7	6.4	8.5	1.3	8.7	12.1	1.4	8.9	9.2	1.0	3.9	0.9	0.2
45	2.8	2.2	0.8	5.9	1.9	0.3	10.1	5.2	0.5	10.6	6.7	0.6	8.7	9.5	1.1	11.4	11.2	1.0	11.7	11.5	1.0	6.3	9.0	1.4	8.6	9.0	1.0	8.8	17.8	2.0	3.9	0.9	0.2
46	2.8	2.0	0.7	5.8	4.5	0.8	10.0	9.6	1.0	10.6	5.4	0.5	8.3	9.4	1.1	11.0	12.7	1.2	11.4	13.3	1.2	6.3	8.3	1.3	8.6	5.0	0.6	8.7	5.1	0.6	3.9	0.9	0.2
47	2.8	2.5	0.9	5.7	9.0	1.6	9.8	7.5	0.8	10.3	7.9	0.8	8.2	9.0	1.1	10.7	4.9	0.5	11.0	18.9	1.7	6.1	5.4	0.9	8.5	3.8	0.5	8.7	4.5	0.5	3.9	0.8	0.2
48	2.8	5.4	2.0	5.6	4.0	0.7	9.7	15.3	1.6	10.2	16.1	1.6	7.8	7.8	1.0	10.6	6.5	0.6	11.0	12.6	1.1	6.1	11.9	2.0	8.4	17.1	2.0	8.6	14.2	1.6	3.8	0.8	0.2
49	2.7	7.5	2.7	5.6	2.0	0.3	9.5	5.2	0.5	9.9	5.4	0.5	7.8	8.3	1.1	10.6	10.6	1.0	10.9	11.0	1.0	6.0	3.0	0.5	8.3	13.6	1.6	8.6	19.0	2.2	3.8	0.8	0.2
50	2.7	2.5	1.0	5.6	1.9	0.3	9.3	5.4	0.6	9.8	15.8	1.6	7.7	1.6	0.2	10.6	5.0	0.5	10.9	5.0	0.5	6.0	8.4	1.4	8.2	18.2	2.2	8.5	3.9	0.5	3.8	0.9	0.2
51	2.7	1.2	0.5	5.5	3.0	0.5	9.3	6.5	0.7	9.8	5.6	0.6	7.7	5.1	0.7	10.5	12.1	1.1	10.8	6.7	0.6	6.0	4.5	0.7	8.2	4.2	0.5	8.5	4.3	0.5	3.8	0.8	0.2
52	2.6	1.7	0.6	5.5	8.0	1.5	9.3	14.9	1.6	9.7	20.5	2.1	7.5	3.1	0.4	10.5	18.1	1.7	10.8	5.1	0.5	5.9	9.9	1.7	8.1	7.1	0.9	8.4	8.9	1.1	3.8	0.8	0.2
53	2.6	3.0	1.2	5.5	3.2	0.6	9.3	19.5	2.1	9.7	6.9	0.7	7.4	6.6	0.9	10.2	18.2	1.8	10.7	19.0	1.8	5.9	16.5	2.8	8.1	8.5	1.1	8.4	7.3	0.9	3.6	0.8	0.2
54	2.5	0.9	0.3	5.4	11.4	2.1	9.1	4.9	0.5	9.6	5.1	0.5	7.3	5.4	0.7	10.2	6.8	0.7	10.6	15.6	1.5	5.9	2.9	0.5	8.0	2.7	0.3	8.2	13.2	1.6	3.6	0.7	0.2
55	2.5	3.8	1.5	5.3	5.5	1.0	8.9	3.1	0.3	9.4	3.3	0.3	7.3	8.4	1.1	10.1	15.0	1.5	10.6	7.1	0.7	5.8	6.6	1.1	7.9	9.0	1.1	8.2	9.3	1.1	3.6	0.8	0.2
56	2.5	4.5	1.8	5.3	3.4	0.6	8.9	5.8	0.6	9.4	6.1	0.7	7.3	8.5	1.2	10.1	8.5	0.8	10.5	8.9	0.8	5.8	4.1	0.7	7.9	12.7	1.6	8.2	22.3	2.7	3.6	0.9	0.2
57	2.4	3.1	1.3	5.3	5.1	1.0	8.9	5.8	0.7	9.4	6.1	0.6	7.3	3.5	0.5	10.0	9.0	0.9	10.3	9.3	0.9	5.7	11.6	2.0	7.9	21.3	2.7	8.2	24.8	3.0	3.5	0.8	0.2
58	2.4	3.7	1.6	5.3	4.1	0.8	8.8	3.0	0.3	9.2	3.1	0.3	6.9	1.4	0.2	9.8	4.1	0.4	10.0	4.2	0.4	5.7	9.4	1.6	7.8	23.7	3.0	8.1	2.7	0.3	3.5	0.8	0.2
59	2.3	2.3	1.0	5.1	2.6	0.5	8.8	12.8	1.5	9.2	13.4	1.5	6.9	1.8	0.3	9.7	4.7	0.5	10.0	4.8	0.5	5.6	9.6	1.7	7.7	3.8	0.5	7.9	4.0	0.5	3.5	0.8	0.2
60	2.3	1.2	0.5	5.0	7.1	1.4	8.7	4.5	0.5	9.2	4.7	0.5	6.9	11.9	1.7	9.7	7.1	0.7	10.0	7.3	0.7	5.6	3.6	0.6	7.6	2.3	0.3	7.9	13.4	1.7	3.5	0.8	0.2
61	2.3	2.2	0.9	5.0	1.5	0.3	8.6	8.3	1.0	9.1	8.2	0.9	6.9	16.5	2.4	9.6	17.1	1.8	10.0	17.8	1.8	5.5	12.2	2.2	7.6	13.0	1.7	7.8	34.0	4.4	3.4	0.8	0.2
62	2.3	3.2	1.4	5.0	3.2	0.7	8.6	7.7	0.9	9.0	8.7	1.0	6.9	9.6	1.4	9.5	7.7	0.8	9.9	8.0	0.8	5.4	2.4	0.4	7.6	5.7	0.7	7.8	5.8	0.7	3.4	0.8	0.2
63	2.3	1.3	0.6	4.9	4.0	0.8	8.5	8.9	1.0	8.9	9.3	1.0	6.8	12.2	1.8	9.3	5.2	0.6	9.7	5.4	0.6	5.4	3.1	0.6	7.4	32.5	4.4	7.7	2.4	0.3	3.4	0.7	0.2
64	2.3	5.8	2.5	4.9	2.6	0.5	8.3	6.5	0.8	8.8	4.3	0.5	6.8	5.5	0.8	9.2	2.4	0.3	9.5	2.4	0.3	5.4	5.7	1.1	7.4	13.3	1.8	7.7	13.8	1.8	3.4	0.7	0.2
65	2.3	1.3	0.6	4.9	1.3	0.3	8.2	4.0	0.5	8.7	4.8	0.5	6.7	5.7	0.8	9.2	13.0	1.4	9.5	13.4	1.4	5.3	3.9	0.7	7.3	7.7	1.1	7.6	8.0	1.1	3.4	0.8	0.2
66	2.3	2.7	1.2	4.8	3.0	0.6	8.2	4.5	0.5	8.7	6.8	0.8	6.7	9.9	1.5	9.1	1.8	0.2	9.4	22.3	2.4	5.3	7.8	1.5	7.3	4.2	0.6	7.6	6.9	0.9	3.3	0.9	0.3
67	2.3	2.7	1.2	4.8	7.7	1.6	8.1	6.7	0.8	8.6	11.1	1.3	6.5	11.6	1.8	9.0	21.3	2.4	9.4	1.9	0.2	5.3	5.5	1.1	7.3	6.6	0.9	7.6	4.3	0.6	3.3	0.8	0.2
68	2.2	1.1	0.5	4.6	1.7	0.4	8.1	2.4	0.3	8.5	7.0	0.8	6.5	2.7	0.4	9.0	11.6	1.3	9.4	12.1	1.3	5.3	8.5	1.6	7.2	13.4	1.9	7.5	14.0	1.9	3.3	0.7	0.2
69	2.2	4.2	1.9	4.6	1.8	0.4	8.1	10.4	1.3	8.5	10.4	1.2	6.4	3.6	0.6	8.9	13.4	1.5	9.3	14.0	1.5	5.2	14.1	2.7	7.2	10.6	1.5	7.5	6.1	0.8	3.3	0.8	0.2
70	2.2	1.8	0.8	4.5	2.3	0.5	8.0	9.8	1.2	8.5	2.5	0.3	6.3	3.8	0.6	8.9	13.3	1.5	9.3	13.8	1.5	5.2	4.7	0.9	7.2	5.9	0.8	7.5	11.0	1.5	3.3	0.7	0.2
71	2.2	1.2	0.5	4.5	12.2	2.7	7.9	4.1	0.5	8.3	5.3	0.6	6.3	3.6	0.6	8.8	23.7	2.7	9.1	24.8	2.7	5.2	15.6	3.0	7.1	5.2	0.7	7.4	5.4	0.7	3.3	0.8	0.3
72	2.2	1.5	0.7	4.5	1.5	0.3	7.8	11.1	1.4	8.3	3.5	0.4	6.1	4.1	0.7	8.7	5.9	0.7	9.0	6.1	0.7	5.1	4.1	0.8	7.0	11.6	1.7	7.3	12.1	1.7	3.3	0.7	0.2
73	2.1	3.1	1.4	4.5	2.5	0.6	7.8	3.2	0.4	8.2	4.3	0.5	6.0	10.6	1.8	8.6	1.8	0.2	8.8	7.7	0.9	5.0	10.0	2.0	7.0	15.6	2.2	7.3	16.3	2.2	3.2	0.8	0.2
74	2.1	4.0	1.9	4.5	4.0	0.9	7.7	2.0	0.3	8.2	11.6	1.4	6.0	7.3	1.2	8.5	5.1	0.6	8.8	5.3	0.6	4.9	8.9	1.8	6.9	12.9	1.9	7.2	13.4	1.9	3.2	0.7	0.2
75	2.1	1.2	0.6	4.4	3.2	0.7	7.7	4.8	0.6	8.1	5.0	0.6	6.0	14.1	2.4	8.4	14.8	1.8	8.7	1.8	0.2	4.9	1.6	0.3	6.8	4.9	0.7	7.1	22.3	3.1	3.2	0.7	0.2
76	2.0	1.6	0.8	4.3	3.6	0.8	7.7	2.9	0.4	8.1	2.1	0.3	6.0	9.0	1.5	8.4	7.4	0.9	8.7	15.3	1.8	4.9	7.3	1.5	6.8	21.4	3.1	7.0	11.5	1.6	3.2	0.7	0.2
77	2.0	1.6	0.8	4.3	5.2	1.2	7.5	2.9	0.4	8.1	3.0	0.4	6.0	4.5	0.7	8.4	6.6	0.8	8.7	6.9	0.8	4.9	9.0	1.9	6.8	4.3	0.6	7.0	5.0	0.7	3.2	0.7	0.2
78	2.0	1.3	0.6	4.2	10.3	2.4	7.4	6.5	0.9	7.9	6.5	0.8	5.9	7.7	1.3	8.3	12.7	1.5	8.7	13.2	1.5	4.9	3.1	0.6	6.8	11.0	1.6	6.9	4.4	0.6	3.2	0.7	0.2
79	2.0	2.1	1.1	4.2	2.8	0.7	7.4	5.4	0.7	7.9	6.9	0.9	5.9	8.9	1.5	8.3	21.4	2.6	8.6	22.3	2.6	4.9	21.2	4.4	6.6	9.8	1.5	6.8	10.2	1.5	3.2	0.7	0.2
80	2.0	4.9	2.5	4.2	4.2	1.0	7.4	6.2	0.8	7.9	3.0	0.4	5.9	4.7	0.8	8.3	32.5	3.9	8.6	34.0	3.9	4.9	3.6	0.7	6.5	19.9	3.1	6.8	14.1	2.1	3.2	0.7	0.2
81	2.0	2.3	1.2	4.1	4.6	1.1	7.3	2.4	0.3	7.8	6.6	0.8	5.8	15.6	2.7	8.3	19.9	2.4	8.6	16.3	1.9	4.7	8.3	1.8	6.5	14.8	2.3	6.8	20.7	3.1	3.2	0.6	0.2
82	2.0	0.9	0.4	4.1	2.2	0.5	7.3	4.7	0.6	7.8	5.7	0.7	5.7	8.3	1.5	8.2	15.6	1.9	8.6	20.7	2.4	4.7	10.6	2.3	6.5	13.5	2.1	6.8	7.7	1.1	3.1	0.7	0.2
83	1.9	0.7	0.3	4.1	1.6	0.4	7.3	6.0	0.8	7.7	2.5	0.3	5.7	5.0	0.9	8.2	12.9	1.6	8.5	13.4	1.6	4.6	7.7	1.7	6.5	7.4	1.1	6.8	15.3	2.3	3.1	0.7	0.2
84	1.9	3.2	1.7	4.0	2.2	0.6	7.2	3.7	0.5	7.6	7.4	1.0	5.6	13.6	2.4	8.2	9.8	1.2	8.4	10.2	1.2	4.6	3.8	0.8	6.2	5.1	0.8	6.5	7.7	1.2	3.1	0.7	0.2
85	1.9	2.5	1.3	4.0	1.6	0.4	7.2	4.1	0.6	7.6	4.2	0.6	5.6	10.0	1.8	8.1	3.4	0.4	8.4	3.5	0.4	4.6	10.3	2.2	6.2	7.3	1.2	6.4	5.3	0.8	3.1	0.7	0.2

Table 6 – Reliability-driven Distribution Automation Results (continued)

DA Scheme	3 Mids : 3 Ties - Reliability-driven Distribution Automation Circuits																														RFI-only		
Switch Type	All RCS			All Load Break (RCS+)									Fault Interrupting Mids									All Fault Interrupting											
FLISR Scheme	Remote Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching					
	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs
Totals	1.9	579	313	3.5	798	229	6.3	1,391	222	6.6	1,467	221	4.9	1,435	292	6.8	2,078	305	7.0	2,170	308	4.0	1,471	369	5.5	2,182	399	5.7	2,265	400	3.1	173	56
Circuit Detail																																	
86	1.9	0.7	0.4	4.0	5.2	1.3	7.2	4.0	0.6	7.5	4.2	0.6	5.6	2.6	0.5	8.0	9.0	1.1	8.3	9.4	1.1	4.6	8.6	1.9	6.1	9.0	1.5	6.4	9.4	1.5	3.1	0.7	0.2
87	1.9	1.3	0.7	3.9	1.7	0.4	7.1	7.2	1.0	7.5	3.8	0.5	5.6	3.2	0.6	7.9	11.0	1.4	8.3	11.5	1.4	4.6	14.3	3.1	6.1	2.7	0.4	6.4	9.8	1.5	3.1	0.7	0.2
88	1.9	2.8	1.5	3.9	3.6	0.9	7.1	6.9	1.0	7.5	7.5	1.0	5.5	5.4	1.0	7.8	7.7	1.0	8.1	8.0	1.0	4.5	2.6	0.6	6.1	12.2	2.0	6.4	8.7	1.4	3.1	0.7	0.2
89	1.9	2.2	1.2	3.8	1.6	0.4	7.0	2.7	0.4	7.4	2.9	0.4	5.5	8.5	1.5	7.6	4.4	0.6	7.9	14.1	1.8	4.5	3.5	0.8	6.1	7.7	1.3	6.4	8.0	1.3	3.1	0.7	0.2
90	1.8	4.5	2.4	3.8	4.0	1.1	6.9	18.7	2.7	7.4	8.0	1.1	5.5	14.3	2.6	7.6	4.3	0.6	7.8	4.5	0.6	4.5	7.3	1.6	6.1	8.4	1.4	6.3	12.5	2.0	3.0	0.6	0.2
91	1.8	2.6	1.4	3.8	3.3	0.9	6.9	4.6	0.7	7.4	4.4	0.6	5.5	8.6	1.6	7.6	5.7	0.7	7.8	8.8	1.1	4.5	13.6	3.1	6.1	9.4	1.5	6.2	2.7	0.4	3.0	0.7	0.2
92	1.8	2.0	1.1	3.7	1.8	0.5	6.9	7.5	1.1	7.3	13.2	1.8	5.5	10.3	1.9	7.6	13.5	1.8	7.8	8.7	1.1	4.5	1.4	0.3	6.1	4.5	0.7	6.2	4.6	0.7	3.0	0.7	0.2
93	1.8	1.4	0.8	3.7	3.5	1.0	6.9	2.7	0.4	7.2	4.8	0.7	5.4	3.1	0.6	7.5	8.4	1.1	7.8	7.7	1.0	4.5	3.1	0.7	6.1	16.9	2.8	6.2	12.6	2.0	3.0	0.7	0.2
94	1.8	1.4	0.8	3.7	2.8	0.8	6.8	4.1	0.6	7.2	19.6	2.7	5.4	21.2	3.9	7.5	8.4	1.1	7.8	5.8	0.7	4.4	4.5	1.0	6.0	12.0	2.0	6.1	6.2	1.0	3.0	0.6	0.2
95	1.8	1.2	0.7	3.7	11.3	3.1	6.8	16.5	2.4	7.2	2.9	0.4	5.4	6.0	1.1	7.5	8.4	1.1	7.8	8.7	1.1	4.4	4.7	1.1	5.9	10.5	1.8	6.1	17.0	2.8	3.0	0.6	0.2
96	1.8	3.0	1.7	3.7	3.9	1.1	6.8	12.3	1.8	7.1	7.7	1.1	5.3	3.9	0.7	7.5	7.3	1.0	7.7	4.4	0.6	4.4	5.0	1.1	5.9	6.0	1.0	6.1	10.7	1.8	2.9	0.6	0.2
97	1.8	4.7	2.6	3.6	1.0	0.3	6.6	7.2	1.1	7.1	17.3	2.4	5.3	4.5	0.9	7.2	10.5	1.5	7.4	10.7	1.5	4.3	5.4	1.3	5.9	1.8	0.3	6.0	1.9	0.3	2.9	0.7	0.2
98	1.7	2.5	1.4	3.6	2.7	0.7	6.6	13.2	2.0	7.0	14.2	2.0	5.3	7.3	1.4	7.1	16.9	2.4	7.3	6.2	0.9	4.3	9.0	2.1	5.8	3.6	0.6	5.9	3.7	0.6	2.9	0.6	0.2
99	1.7	3.2	1.8	3.6	2.1	0.6	6.5	5.6	0.9	6.9	5.9	0.9	5.3	5.9	1.1	7.1	6.0	0.9	7.1	17.0	2.4	4.3	5.0	1.2	5.7	6.7	1.2	5.9	8.7	1.5	2.9	0.7	0.2
100	1.7	2.4	1.4	3.6	1.1	0.3	6.5	1.9	0.3	6.9	2.0	0.3	5.2	5.8	1.1	6.8	6.7	1.0	7.0	6.9	1.0	4.2	5.8	1.4	5.7	8.4	1.5	5.9	6.9	1.2	2.8	0.7	0.2
101	1.7	1.0	0.6	3.5	1.1	0.3	6.5	2.9	0.4	6.8	2.3	0.3	5.2	5.0	1.0	6.8	12.2	1.8	7.0	2.8	0.4	4.1	6.0	1.5	5.7	4.4	0.8	5.8	10.5	1.8	2.8	0.6	0.2
102	1.7	1.1	0.6	3.5	2.2	0.6	6.4	7.2	1.1	6.8	3.0	0.4	5.1	5.8	1.1	6.8	2.7	0.4	7.0	9.8	1.4	4.1	4.8	1.2	5.6	10.1	1.8	5.8	4.5	0.8	2.8	0.7	0.2
103	1.7	1.3	0.8	3.5	0.8	0.2	6.3	2.9	0.5	6.7	3.1	0.5	5.1	2.0	0.4	6.7	9.4	1.4	7.0	10.5	1.5	4.1	6.3	1.5	5.5	1.8	0.3	5.6	1.8	0.3	2.8	0.6	0.2
104	1.7	2.3	1.4	3.5	1.0	0.3	6.2	6.6	1.1	6.7	7.5	1.1	5.1	3.5	0.7	6.7	10.1	1.5	6.9	12.5	1.8	4.0	5.9	1.5	5.4	4.4	0.8	5.6	22.1	3.9	2.8	0.7	0.3
105	1.7	4.0	2.4	3.4	4.9	1.4	6.2	7.5	1.2	6.7	8.0	1.2	5.0	9.0	1.8	6.7	2.3	0.3	6.9	12.6	1.8	4.0	2.9	0.7	5.4	21.2	3.9	5.6	4.5	0.8	2.8	0.6	0.2
106	1.7	2.8	1.7	3.4	6.1	1.8	6.2	2.1	0.3	6.6	7.0	1.1	4.9	4.8	1.0	6.7	12.0	1.8	6.9	2.4	0.3	4.0	3.2	0.8	5.4	3.1	0.6	5.6	17.2	3.1	2.8	0.7	0.2
107	1.7	1.0	0.6	3.4	0.9	0.3	6.1	6.5	1.1	6.5	9.2	1.4	4.8	3.5	0.7	6.6	3.1	0.5	6.8	3.2	0.5	4.0	8.0	2.0	5.4	16.5	3.1	5.5	11.0	2.0	2.8	0.6	0.2
108	1.6	1.1	0.6	3.3	2.1	0.6	6.1	8.7	1.4	6.5	6.8	1.1	4.7	1.6	0.3	6.5	3.6	0.6	6.7	22.1	3.3	3.9	3.5	0.9	5.4	5.7	1.1	5.5	9.3	1.7	2.8	0.6	0.2
109	1.6	3.8	2.3	3.3	3.4	1.0	6.1	3.8	0.6	6.4	4.0	0.6	4.7	3.0	0.6	6.5	21.2	3.3	6.7	11.0	1.6	3.8	4.4	1.1	5.3	10.6	2.0	5.5	3.2	0.6	2.8	0.6	0.2
110	1.6	1.8	1.1	3.3	2.3	0.7	6.1	4.6	0.8	6.4	4.9	0.8	4.6	2.0	0.4	6.4	10.6	1.6	6.7	7.6	1.1	3.8	6.9	1.8	5.3	8.9	1.7	5.5	6.6	1.2	2.8	0.7	0.3
111	1.6	1.4	0.8	3.3	2.5	0.8	5.9	5.6	0.9	6.3	6.2	1.0	4.6	1.9	0.4	6.4	7.3	1.1	6.6	1.6	0.2	3.8	3.6	1.0	5.3	6.4	1.2	5.5	5.9	1.1	2.8	0.6	0.2
112	1.6	1.0	0.6	3.3	2.2	0.7	5.8	2.5	0.4	6.2	2.6	0.4	4.5	6.9	1.5	6.4	1.5	0.2	6.6	3.7	0.6	3.7	7.4	2.0	5.3	6.0	1.1	5.5	7.5	1.4	2.7	0.5	0.2
113	1.6	0.9	0.5	3.2	2.8	0.9	5.8	1.7	0.3	6.2	5.8	0.9	4.5	4.4	1.0	6.3	2.8	0.4	6.6	2.9	0.4	3.7	5.1	1.4	5.3	7.3	1.4	5.5	7.6	1.4	2.7	0.7	0.3
114	1.6	1.8	1.2	3.1	0.8	0.3	5.8	5.7	1.0	6.1	1.8	0.3	4.5	3.6	0.8	6.3	4.4	0.7	6.5	9.3	1.4	3.7	3.3	0.9	5.2	7.2	1.4	5.4	6.2	1.1	2.7	0.6	0.2
115	1.6	1.7	1.1	3.1	1.7	0.6	5.7	4.3	0.7	6.0	4.5	0.7	4.5	5.1	1.1	6.3	8.9	1.4	6.5	4.5	0.7	3.7	4.4	1.2	5.2	8.4	1.6	5.4	9.3	1.7	2.7	0.6	0.2
116	1.6	0.9	0.6	3.1	1.5	0.5	5.7	17.5	3.1	6.0	4.6	0.8	4.5	7.4	1.6	6.2	6.0	1.0	6.4	6.6	1.0	3.6	5.3	1.5	5.2	8.9	1.7	5.4	8.8	1.6	2.7	0.6	0.2
117	1.6	2.6	1.7	3.1	1.5	0.5	5.7	4.3	0.8	6.0	18.3	3.1	4.5	2.9	0.7	6.2	6.4	1.0	6.4	6.2	1.0	3.6	1.8	0.5	5.1	6.1	1.2	5.3	6.4	1.2	2.7	0.7	0.2
118	1.6	3.0	1.9	3.1	1.6	0.5	5.6	3.3	0.6	6.0	4.1	0.7	4.5	3.1	0.7	6.2	3.7	0.6	6.4	3.8	0.6	3.6	5.8	1.6	5.0	6.5	1.3	5.2	6.8	1.3	2.7	0.6	0.2
119	1.6	1.9	1.2	3.1	3.7	1.2	5.6	3.5	0.6	5.9	9.0	1.5	4.4	6.3	1.4	6.1	4.4	0.7	6.4	6.4	1.0	3.6	14.1	3.9	5.0	3.5	0.7	5.2	12.5	2.4	2.7	0.6	0.2
120	1.6	1.0	0.7	3.1	4.3	1.4	5.5	8.4	1.5	5.8	3.5	0.6	4.4	8.0	1.8	6.1	6.1	1.0	6.4	17.2	2.7	3.6	11.0	3.1	5.0	12.0	2.4	5.2	14.5	2.8	2.7	0.6	0.2
121	1.5	1.3	0.9	3.1	2.4	0.8	5.5	3.8	0.7	5.8	3.7	0.6	4.4	4.7	1.1	6.1	4.5	0.7	6.4	4.4	0.7	3.6	6.0	1.7	4.9	4.8	1.0	5.1	10.8	2.1	2.7	0.6	0.2
122	1.5	1.1	0.7	3.1	6.2	2.0	5.5	9.1	1.6	5.8	9.6	1.6	4.4	3.3	0.8	6.1	16.5	2.7	6.4	3.7	0.6	3.5	2.7	0.8	4.9	13.9	2.8	5.1	9.1	1.8	2.7	0.6	0.2
123	1.5	3.5	2.3	3.0	5.0	1.6	5.5	1.6	0.3	5.8	1.7	0.3	4.3	2.6	0.6	6.1	3.6	0.6	6.3	2.6	0.4	3.5	4.9	1.4	4.9	10.4	2.1	5.1	10.0	2.0	2.6	0.5	0.2
124	1.5	1.4	0.9	3.0	3.3	1.1	5.5	1.7	0.3	5.8	1.7	0.3	4.3	14.1	3.3	6.1	4.2	0.7	6.3	4.5	0.7	3.5	5.9	1.7	4.9	9.6	2.0	5.1	7.5	1.5	2.6	0.6	0.2
125	1.5	2.1	1.4	3.0	1.0	0.3	5.4	1.6	0.3	5.8	1.7	0.3	4.3	4.4	1.0	6.1	2.6	0.4	6.3	14.5	2.3	3.4	4.2	1.2	4.9	7.2	1.5	5.1	19.6	3.8	2.6	0.6	0.2
126	1.5	0.9	0.6	3.0	5.5	1.8	5.4	9.9	1.8	5.7	10.4	1.8	4.3	2.7	0.6	6.0	13.9	2.3	6.3	6.8	1.1	3.3	3.0	0.9	4.9	8.7	1.8	5.1	4.9	1.0	2.6	0.5	0.2
127	1.5	2.2	1.5	2.9	8.0	2.8	5.4	1.2	0.2	5.7	2.5	0.4	4.3	1.7	0.4	6.0	6.5	1.1	6.2	4.6	0.7	3.3	8.0	2.4	4.9	18.7	3.8	5.0	3.5	0.7	2.6	0.6	0.2
128	1.5	0.6	0.4	2.9	0.8	0.3	5.3	2.4	0.4	5.6	3.3	0.6	4.2	1.0	0.2	5.9	4.8	0.8	6.1	7.5	1.2	3.3	4.0	1.2	4.8	4.4	0.9	5.0	4.5	0.9	2.6	0.5	0.2
129	1.5	1.6	1.1	2.9	3.5	1.2	5.3	3.1	0.6	5.6	1.3	0.2	4.2	2.5	0.6	5.9	7.2	1.2	6.1	4.9	0.8	3.3	2.5	0.8	4.8	2.4	0.5	5.0	2.4	0.5	2.6	0.6	0.2
130	1.5	1.0	0.7	2.9	1.7	0.6	5.3	6.3	1.2	5.5	6.6	1.2	4.2	5.9	1.4	5.8	9.6	1.6	6.1	12.5	2.0	3.3	6.4	2.0	4.8	3.5	0.7	4.9	7.2	1.5	2.6	0.5	0.2
131	1.5	1.4	0.9	2.8	1.7	0.6	5.2	3.6	0.7	5.5	3.3	0.6	4.2	2.9	0.7	5.8	12.0	2.0	6.1	10.0	1.6	3.3	6.5	2.0	4.8	7.0	1.5	4.9	12.6	2.6	2.6	0.6	0.2
132	1.5	2.7	1.9	2.8	4.7	1.7	5.2	1.4	0.3	5.5	3.1	0.6	4.2	4.2	1.0	5.8	10.4	1.8	6.1	10.8	1.8	3.3	6.9	2.1	4.7	12.0	2.6	4.9	13.5	2.7	2.5	0.6	0.2
133	1.5	4.0	2.8	2.8	1.2	0.4	5.2	2.9	0.6	5.5	3.7	0.7	4.1	11.0	2.7	5.8	7.2	1.2	6.0	7.5	1.2	3.3	4.8	1.5	4.7	12.9	2.7	4.9	3.6	0.7	2.5	0.6	0.2
134	1.5	1.4	0.9	2.8	5.1	1.8	5.2	5.3	1.0	5.5	1.5	0.3	4.1	4.0	1.0	5.8	8.9	1.5	6.0	9.3	1.5	3.3	4.2	1.3	4.7	13.2	2.8	4.9	13.8	2.8	2.5	0.6	0.2
135	1.4	1.9	1.3	2.7	2.7	1.0	5.2	2.5	0.5	5.4	5.6	1.0	4.0	1.5	0.4	5.7	8.7	1.5	6.0	9.1	1.5	3.2	2.9	0.9	4.7	15.0	3.2	4.9	15.6	3.2	2.5	0.6	0.2
136	1.4	2.2	1.5	2.7	2.7	1.0	5.1	3.1	0.6	5.4	2.6	0.5	4.0	2.5	0.6	5.6	7.1	1.3	5.8	7.4	1.3	3.2	9.1	2.8	4.6	4.2	0.9	4.8	8.4	1.7	2.5	0.6	0.2
137	1.4	1.5	1.0	2.7	1.2	0.4	5.1	7.3	1.4	5.4	7.6	1.4	4.0	5.7	1.4	5.6	5.1	0.9	5.8	5.3	0.9	3.2	5.7	1.8	4.6	8.0	1.7	4.8	9.5	2.0	2.5	0.6	0.2
138	1.4	2.8	2.0	2.7	4.1	1.5	5.1	3.6	0.7	5.4	3.8	0.7	3.9	9.1	2.3	5.6	4.2	0.8	5.8	12.6	2.2	3.2	2.1	0.7	4.6	9.1	2.0	4.8	4.3	0.9	2.5	0.6	0.2
139	1.4	1.0	0.7	2.6	1.1	0.4	5.0	7.0	1.4	5.3	7.5	1.4	3.9	4.9	1.2	5.5	12.0	2.2	5.7	13.5	2.4	3.2	2.7	0.8	4.6	4.0	0.9	4.7	4.2	0.9	2.5	0.6	0.2
140	1.4	1.9	1.3	2.6	1.1	0.4	4.9	2.1	0.4	5.3	2.3	0.4	3.9	4.2	1.1	5.5	12.9	2.4	5.7	4.3	0.8	3.2	2.7	0.8	4.5	8.7	1.9	4.7	12.2	2.6	2.4	0.6	0.3
141	1.4	2.2	1.5	2.6	1.8	0.7	4.9	2.5	0.5	5.3	4.8	0.9	3.9	6.4	1.6	5.5	4.0	0.7	5.7	5.2	0.9	3.2	12.2	3.8	4.5	11.7	2.6	4.7	9.0	1.9	2.4	0.5	0.2
142	1.4	1.3	0.9	2.6	2.0	0.8	4.9	1.3	0.3	5.1	2.6	0.5	3.9	2.1	0.5	5.4	4.9	0.9	5.7	19.6	3.4	3.2	3.1	1.0	4.5	3.4	0.8	4.6	3.6	0.8	2.4	0.6	0.2
143	1.4	2.9	2.1	2.6	1.4	0.6	4.9	1.6	0.3	5.1	1.7	0.3	3.9	6.0	1.5	5.4	3.4	0.6	5.7	4.2	0.7	3.2	2.1	0.6	4.5	3.4	0.8	4.6	5.5	1.2	2.4	0.5	0.2
144	1.4	1.2	0.9	2.6	1.0	0.4	4.9	2.4	0.5	5.1	1.3	0.3	3.9	2.9	0.7	5.4	18.7	3.4	5.6	6.8	1.2	3.2	8.9	2.8	4.4	5.3	1.2	4.6	6.0	1.3	2.4	0.5	0.2
145	1.4	0.8	0.6	2.6	4.3	1.6	4.8	4.5	0.9	5.1	2.5	0.5	3.9	8.0	2.0	5.4	6.5	1.2	5.6	3.6	0.6	3.1	10.1	3.2	4.4	5.8	1.3	4.6	3.5	0.8	2.4	0.5	0.2
146	1.4	0.8	0.6	2.6	3.9	1.5	4.8	3.4	0.7	5.1	3.6	0.7	3.9	2.1	0.5	5.4	3.4	0.6	5.6	6.6	1.2	3.1	2.0	0.6	4.4	7.1	1.6	4.6	7.4	1.6	2.4	0.5	0.2
147	1.4	3.3	2.4	2.6	3.1	1.2	4.8	3.6	0.8	5.1	3.8	0.8	3.9	6.9	1.8	5.4	5.7	1.1	5.5	3.5	0.6	3.1	5.7	1.8	4.3	11.3	2.6	4.5	11.8	2.6	2.4	0.5	0.2
148	1.4	1.4	1.1	2.6	6.0	2.3	4.7	3.4	0.7	5.0	3.6	0.7	3.9	4.8	1.2	5.4	3.5	0.7	5.5	9.0	1.6	3.1	6.0	1.9	4.3	5.3	1.2	4.5	5.5	1.2	2.4	0.5	0.2
149	1.3	2.1	1.5	2.6	2.6	1.0	4.7	3.8	0.8	5.0	9.7	1.9	3.8	2.7	0.7	5.3	5.3	1.0	5.5	12.2	2.2	3.1	8.6	2.7	4.3	2.8	0.6	4.5	5.7	1.3	2.4	0.5	0.2
150	1.3	2.8	2.1	2.6	1.1	0.4	4.7	8.6	1.8	4.9	3.9	0.8	3.8	3.1	0.8	5.3	6.4	1.2	5.5	5.5	1.0	3.1	1.9	0.6	4.3	5.6	1.3	4.5	2.9	0.6	2.4	0.5	0.2
151	1.3	0.4	0.3	2.6	1.8	0.7	4.6	10.7	2.3	4.9	9.0	1.8	3.8	4.0	1.1	5.3	8.7	1.6	5.5	13.8	2.5	3.1	8.0	2.6	4.3	5.4	1.3	4.5	5.8	1.3	2.4	0.6	0.2
152	1.3	0.4	0.3	2.5	2.7	1.1	4.6	7.7	1.7	4.9	11.3	2.3	3.8	5.7	1.5	5.3	11.7	2.2	5.5	5.9	1.1	3.1	5.4	1.7	4.3	5.4	1.3	4.4	5.6	1.3	2.3	0.5	0.2
153	1.3	2.2	1.7	2.5	1.2	0.5	4.6	9.0	1.9	4.9	2.4	0.5	3.8	3.4	0.9	5.3	13.2	2.5	5.5	3.6	0.7	3.1	4.0	1.3	4.3	4.2	1.0	4.4	4.4	1.0	2.3	0.5	0.2
154	1.3	2.0	1.5	2.5	1.9	0.8	4.6	2.3	0.5	4.9	3.4	0.7	3.8	6.5	1.7	5.3	5.6	1.1	5.5	5.8	1.1	3.0	4.0	1.3	4.2	10.3	2.5	4.4	10.8	2.5	2.3	0.5	0.2
155	1.3	2.1	1.6	2.5	1.1	0.4	4.5	3.2	0.7	4.9	8.1	1.7	3.7	2.7	0.7	5.3	9.1	1.7	5.4	9.5	1.7	3.0	4.5	1.5	4.2	5.0	1.2	4.4	18.8	4.3	2.3	0.6	0.3
156	1.3	3.2	2.5	2.5	1.1	0.4	4.5	2.0	0.4	4.7	5.7	1.2	3.7	4.8	1.3	5.2	4.7	0.9	5.4	4.9	0.9	3.0	7.7	2.6	4.2	6.5	1.6	4.4	5.2	1.2	2.3	0.5	0.2
157	1.3	2.3	1.8	2.5	1.1	0.4	4.5	5.4	1.2	4.7	2.0	0.4	3.7	6.0	1.6	5.2	8.0	1.6	5.4	8.4	1.6	2.9	3.5	1.2	4.2	18.0	4.3	4.4	6.8	1.6	2.3	0.5	0.2
158	1.3	1.6	1.2	2.5	3.0	1.2	4.5	4.4	1.0	4.7	4.7	1.0	3.7	3.1	0.9	5.2	15.0	2.9	5.4	15.6	2.9	2.9	2.8	1.0	4.2	5.1	1.2	4.4	5.3	1.2	2.3	0.5	0.2
159	1.3	1.3	1.0	2.5	2.4	1.0	4.4	12.3	2.8	4.7	3.9	0.8	3.7	4.5	1.2	5.1	5.8	1.1	5.3	6.0	1.1	2.9	4.8	1.6	4.2	17.9	4.3	4.4	18.7	4.3	2.3	0.5	0.2
160	1.3	3.5	2.8	2.5	5.5	2.2	4.4	3.5	0.8	4.7	3.7	0.8	3.7	3.3	0.9	5.1	3.6	0.7	5.3	11.8	2.2	2.9	3.4	1.2	4.2	4.0	1.0	4.3	12.0	2.8	2.3	0.5	0.2
161	1.3	0.9	0.7	2.5	0.9	0.4	4.4	1.8	0.4	4.6	12.8	2.8	3.7	8.6	2.4	5.1	4.4	0.9	5.3	3.8	0.7	2.9	2.9	1.0	4.2	11.5	2.8	4.3	4.2	1.0	2.3	0.5	0.2
162	1.3	1.2	0.9	2.4	2.0	0.8	4.4	1.6	0.4	4.6	1.7	0.4	3.6	0.7	0.2	5.1	11.3	2.2	5.3	5.5	1.1	2.9	1.6	0.6	4.1	6.4	1.5	4.3	6.6	1.5	2.3	0.5	0.2
163	1.3	2.6	2.0	2.4	1.7	0.7	4.4	1.6	0.4	4.6	1.8	0.4	3.6	8.0	2.2	5.1	5.3	1.1	5.3	4.6	0.9	2.9	2.6	0.9	4.1	2.6	0.6	4.3	8.0	1.9	2.3	0.5	0.2
164	1.3	0.8	0.6	2.4	6.5	2.7	4.3	3.6	0.8	4.6	1.7	0.4	3.6	4.4	1.2	5.0	8.4	1.7	5.2	7.1	1.4	2.9	7.5	2.6	4.1	7.7	1.9	4.3	5.5	1.3	2.3	0.5	0.2
165	1.3	3.1	2.5	2.4	0.9	0.4	4.3	1.8	0.4	4.6	7.9	1.7	3.6	3.2	0.9	5.0	6.8	1.4	5.2	8.7	1.7	2.9	2.0	0.7	4.1	5.3	1.3	4.3	2.6	0.6	2.3	0.5	0.2
166	1.3	0.7	0.5	2.4	1.4	0.6	4.3	2.4	0.6	4.5	1.9	0.4	3.6	3.3	0.9	5.0	17.9	3.6	5.2	18.7	3.6	2.8	7.0	2.5	4.1	2.3	0.6	4.3	5.2	1.2	2.3	0.5	0.2
167	1.3	1.9	1.5	2.3	1.9	0.8	4.3	4.2	1.0	4.5	2.5	0.6	3.6	5.3	1.5	5.0	5.4	1.1	5.2	5.7	1.1	2.8	4.2	1.5	4.1	4.9	1.2	4.2	2.4	0.6	2.3	0.5	0.2
168	1.3	0.8	0.6	2.3	1.2	0.5	4.3	7.4	1.7	4.5	4.4	1.0	3.6	4.0	1.1	5.0	3.5	0.7	5.2	10.8	2.1	2.8	3.1	1.1	4.1	4.7	1.2	4.2	5.4	1.3	2.3	0.6	0.2
169	1.3	1.5	1.2	2.3	0.8	0.3	4.1	1.5	0.4	4.4	1.6	0.4	3.5	8.9	2.5	5.0	10.3	2.1	5.1	5.1	1.0	2.8	3.3	1.2	4.0	5.1	1.3	4.2	4.9	1.2	2.3	0.5	0.2
170	1.3	0.9	0.7	2.3	2.3	1.0	4.1	6.1	1.5	4.3	3.3	0.8	3.5	12.2	3.4	4.9	4.9	1.0	5.1	5.9	1.1	2.8	3.0	1.0	4.0	3.4	0.8	4.2	8.7	2.1	2.2	0.5	0.2

Workpaper- Southern California Edison / 2025 GRC

Table 6 – Reliability-driven Distribution Automation Results (continued)

DA Scheme	3 Mids : 3 Ties - Reliability-driven Distribution Automation Circuits																																				RFI-only		
Switch Type	All RCS			All Load Break (RCS+)									Fault Interrupting Mids									All Fault Interrupting											
FLISR Scheme	Remote Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching					
	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs
Totals	1.9	579	313	3.5	798	229	6.3	1,391	222	6.6	1,467	221	4.9	1,435	292	6.8	2,078	305	7.0	2,170	308	4.0	1,471	369	5.5	2,182	399	5.7	2,265	400	3.1	173	56
Circuit Detail																																	
171	1.3	0.9	0.7	2.3	0.6	0.3	4.1	3.1	0.8	4.3	2.8	0.7	3.5	4.2	1.2	4.9	5.6	1.1	5.1	5.4	1.1	2.8	4.4	1.6	4.0	5.6	1.4	4.2	5.9	1.4	2.2	0.4	0.2
172	1.2	1.1	0.9	2.3	3.4	1.5	4.1	1.8	0.4	4.3	4.7	1.1	3.5	10.1	2.9	4.9	1.9	0.4	5.1	5.4	1.1	2.8	3.2	1.1	4.0	8.4	2.1	4.1	3.5	0.8	2.2	0.5	0.2
173	1.2	0.8	0.6	2.3	3.5	1.5	4.1	1.2	0.3	4.3	6.4	1.5	3.5	5.4	1.6	4.9	5.2	1.1	5.0	3.5	0.7	2.8	3.6	1.3	4.0	4.1	1.0	4.1	7.1	1.7	2.2	0.6	0.3
174	1.2	0.4	0.3	2.3	2.0	0.9	4.0	3.1	0.8	4.3	1.3	0.3	3.5	7.7	2.2	4.9	5.1	1.1	5.0	5.6	1.1	2.8	3.4	1.2	4.0	4.4	1.1	4.1	5.4	1.3	2.2	0.5	0.2
175	1.2	1.7	1.4	2.3	1.6	0.7	4.0	1.7	0.4	4.3	1.7	0.4	3.4	2.6	0.7	4.8	5.3	1.1	5.0	5.5	1.1	2.8	3.5	1.3	4.0	5.2	1.3	4.1	8.2	2.0	2.2	0.5	0.2
176	1.2	1.7	1.4	2.3	1.1	0.5	4.0	2.8	0.7	4.3	1.9	0.4	3.4	1.0	0.3	4.8	5.4	1.1	5.0	1.9	0.4	2.8	5.2	1.9	3.9	6.8	1.7	4.1	4.3	1.0	2.2	0.5	0.2
177	1.2	1.5	1.2	2.3	2.8	1.2	4.0	1.7	0.4	4.2	3.2	0.8	3.4	2.6	0.8	4.8	7.0	1.5	5.0	5.7	1.1	2.8	7.7	2.8	3.9	7.9	2.0	4.1	4.6	1.1	2.2	0.5	0.2
178	1.2	1.3	1.1	2.2	4.1	1.8	4.0	6.5	1.6	4.2	1.8	0.4	3.4	3.0	0.9	4.8	5.4	1.1	5.0	8.2	1.7	2.7	11.8	4.3	3.9	9.6	2.4	4.1	10.0	2.4	2.2	0.5	0.2
179	1.2	1.9	1.6	2.2	1.7	0.8	4.0	1.4	0.3	4.2	2.9	0.7	3.4	0.6	0.2	4.8	7.9	1.7	5.0	12.0	2.4	2.7	3.5	1.3	3.9	5.4	1.4	4.1	5.7	1.4	2.2	0.5	0.2
180	1.2	2.6	2.2	2.2	0.7	0.3	4.0	2.8	0.7	4.2	1.5	0.3	3.4	3.5	1.1	4.8	11.5	2.4	4.9	5.2	1.0	2.7	11.8	4.3	3.9	9.5	2.4	4.1	5.9	1.5	2.2	0.5	0.2
181	1.2	1.7	1.4	2.2	0.8	0.4	3.9	6.7	1.7	4.2	7.2	1.7	3.4	5.6	1.7	4.7	4.1	0.9	4.9	7.2	1.5	2.7	2.1	0.8	3.9	5.7	1.5	4.1	9.9	2.4	2.2	0.5	0.2
182	1.2	1.4	1.2	2.2	0.6	0.3	3.9	6.0	1.5	4.2	1.8	0.4	3.4	7.5	2.2	4.7	5.0	1.0	4.9	4.2	0.9	2.7	3.8	1.4	3.9	3.7	0.9	4.0	3.8	0.9	2.2	0.5	0.2
183	1.2	1.2	1.0	2.2	3.2	1.5	3.9	4.3	1.1	4.2	6.8	1.6	3.3	7.0	2.1	4.7	4.1	0.9	4.9	4.3	0.9	2.7	4.2	1.5	3.9	2.5	0.7	4.0	5.4	1.4	2.2	0.4	0.2
184	1.2	1.8	1.5	2.2	2.5	1.2	3.9	5.4	1.4	4.2	2.9	0.7	3.3	3.3	1.0	4.7	2.5	0.5	4.9	18.8	3.9	2.7	2.6	0.9	3.8	3.6	0.9	4.0	3.7	0.9	2.2	0.5	0.2
185	1.2	1.1	1.0	2.2	4.4	2.0	3.9	3.3	0.8	4.2	5.7	1.4	3.3	3.8	1.1	4.7	3.0	0.6	4.8	5.4	1.1	2.7	3.3	1.2	3.8	5.9	1.5	4.0	6.1	1.5	2.2	0.5	0.2
186	1.2	1.5	1.3	2.2	1.3	0.6	3.9	1.5	0.4	4.1	2.2	0.5	3.3	4.5	1.4	4.7	18.0	3.9	4.8	2.6	0.5	2.7	5.6	2.1	3.8	5.2	1.4	4.0	8.0	2.0	2.2	0.4	0.2
187	1.2	1.1	1.0	2.2	3.0	1.4	3.9	1.1	0.3	4.1	6.3	1.5	3.3	0.7	0.2	4.6	2.5	0.5	4.7	2.5	0.5	2.7	6.5	2.4	3.8	5.6	1.5	3.9	2.6	0.7	2.2	0.5	0.2
188	1.2	1.7	1.4	2.1	3.0	1.4	3.9	1.5	0.4	4.1	1.2	0.3	3.3	3.6	1.1	4.6	5.2	1.1	4.7	8.0	1.7	2.7	3.4	1.3	3.8	7.7	2.0	3.9	5.8	1.5	2.1	0.5	0.2
189	1.2	3.2	2.7	2.1	2.9	1.4	3.9	8.7	2.2	4.1	2.6	0.6	3.3	3.4	1.0	4.6	1.3	0.3	4.7	10.0	2.1	2.7	5.3	2.0	3.8	2.5	0.6	3.9	6.5	1.7	2.1	0.5	0.2
190	1.1	1.5	1.3	2.1	0.6	0.3	3.9	2.1	0.5	4.1	3.5	0.8	3.3	11.8	3.6	4.5	9.9	2.2	4.7	10.2	2.2	2.6	6.4	2.4	3.8	2.7	0.7	3.9	7.2	1.9	2.1	0.5	0.2
191	1.1	0.6	0.5	2.1	1.7	0.8	3.9	4.6	1.2	4.1	1.6	0.4	3.2	3.4	1.1	4.5	7.7	1.7	4.7	1.3	0.3	2.6	2.5	0.9	3.8	6.3	1.7	3.9	8.7	2.2	2.1	0.5	0.2
192	1.1	3.2	2.8	2.1	1.4	0.6	3.8	4.5	1.2	4.1	5.2	1.3	3.2	7.0	2.2	4.5	9.6	2.1	4.7	3.0	0.6	2.6	3.4	1.3	3.8	7.0	1.9	3.9	2.8	0.7	2.1	0.5	0.2
193	1.1	3.0	2.6	2.1	1.8	0.8	3.8	4.9	1.3	4.1	4.7	1.2	3.2	3.8	1.2	4.5	9.5	2.1	4.7	9.9	2.1	2.6	0.7	0.3	3.7	8.4	2.2	3.9	2.5	0.6	2.1	0.5	0.2
194	1.1	0.7	0.6	2.1	5.5	2.6	3.8	2.2	0.6	4.0	9.1	2.2	3.2	2.4	0.8	4.5	0.9	0.2	4.7	1.0	0.2	2.6	3.8	1.5	3.7	5.5	1.5	3.9	5.9	1.5	2.1	0.4	0.2
195	1.1	2.4	2.1	2.1	1.0	0.5	3.8	5.7	1.5	4.0	4.8	1.2	3.2	5.3	1.7	4.4	3.4	0.8	4.6	8.0	1.7	2.6	2.7	1.0	3.7	5.6	1.5	3.9	5.8	1.5	2.1	0.5	0.2
196	1.1	0.4	0.4	2.1	0.5	0.2	3.7	2.4	0.6	4.0	2.6	0.6	3.2	3.4	1.1	4.4	5.5	1.3	4.6	5.8	1.3	2.6	2.6	1.0	3.7	4.1	1.1	3.8	4.8	1.2	2.1	0.5	0.2
197	1.1	2.1	1.8	2.1	1.7	0.8	3.7	1.0	0.3	4.0	2.3	0.6	3.2	3.5	1.1	4.4	7.7	1.7	4.6	3.5	0.8	2.6	2.5	1.0	3.7	4.6	1.2	3.8	9.1	2.4	2.1	0.5	0.2
198	1.1	0.8	0.7	2.1	2.8	1.3	3.7	3.9	1.1	4.0	4.8	1.2	3.2	2.1	0.7	4.4	7.0	1.6	4.6	7.2	1.6	2.6	3.6	1.4	3.7	8.8	2.4	3.8	11.3	3.0	2.1	0.4	0.2
199	1.1	1.6	1.4	2.1	1.5	0.7	3.7	1.3	0.4	4.0	5.9	1.5	3.2	3.6	1.1	4.3	14.0	3.2	4.5	14.6	3.2	2.6	4.5	1.7	3.7	10.9	3.0	3.8	5.1	1.4	2.1	0.5	0.2
200	1.1	0.6	0.6	2.1	1.3	0.6	3.7	5.5	1.5	4.0	4.2	1.1	3.2	7.7	2.4	4.3	6.2	1.4	4.5	5.9	1.3	2.6	3.9	1.5	3.7	4.9	1.4	3.8	10.4	2.7	2.1	0.4	0.2
201	1.1	1.6	1.4	2.1	0.8	0.4	3.7	5.7	1.5	3.9	6.1	1.5	3.1	2.1	0.7	4.3	5.7	1.3	4.5	7.9	1.8	2.6	3.8	1.5	3.6	10.0	2.7	3.8	4.2	1.1	2.1	0.5	0.3
202	1.1	0.7	0.6	2.1	0.9	0.4	3.7	1.5	0.4	3.9	5.8	1.5	3.1	0.7	0.2	4.3	1.7	0.4	4.5	4.1	0.9	2.5	4.2	1.7	3.6	14.0	3.8	3.8	14.6	3.8	2.1	0.5	0.2
203	1.1	1.1	1.0	2.1	1.0	0.5	3.7	4.5	1.2	3.9	1.7	0.4	3.1	1.7	0.5	4.3	7.6	1.8	4.5	4.8	1.1	2.5	5.7	2.2	3.6	7.6	2.1	3.8	7.9	2.1	2.1	0.5	0.2
204	1.1	1.5	1.4	2.1	2.4	1.2	3.7	10.0	2.7	3.9	1.6	0.4	3.1	3.5	1.1	4.3	4.6	1.1	4.4	11.3	2.6	2.5	7.0	2.8	3.6	8.5	2.3	3.8	8.8	2.3	2.1	0.5	0.2
205	1.1	2.5	2.3	2.1	3.0	1.4	3.7	1.7	0.5	3.9	1.4	0.4	3.1	2.5	0.8	4.3	3.9	0.9	4.4	6.5	1.5	2.5	2.1	0.8	3.6	3.6	1.0	3.7	6.0	1.6	2.1	0.5	0.2
206	1.1	0.7	0.7	2.1	0.5	0.2	3.7	3.2	0.9	3.9	1.1	0.3	3.1	0.6	0.2	4.3	10.9	2.6	4.4	5.2	1.2	2.5	3.4	1.4	3.6	9.9	2.8	3.7	10.2	2.8	2.0	0.4	0.2
207	1.1	1.9	1.8	2.1	2.6	1.2	3.6	1.5	0.4	3.9	3.4	0.9	3.1	6.5	2.1	4.3	5.1	1.2	4.4	6.3	1.4	2.5	4.7	1.9	3.6	5.8	1.6	3.7	8.4	2.3	2.0	0.4	0.2
208	1.1	1.2	1.1	2.0	0.6	0.3	3.6	2.3	0.6	3.9	3.0	0.8	3.0	5.2	1.7	4.2	6.3	1.5	4.4	6.0	1.4	2.5	3.7	1.5	3.6	8.0	2.3	3.7	3.8	1.0	2.0	0.4	0.2
209	1.1	1.3	1.2	2.0	3.5	1.7	3.6	4.2	1.2	3.8	1.8	0.5	3.0	11.8	3.9	4.2	3.2	0.7	4.4	3.2	0.7	2.5	5.0	2.0	3.5	3.2	0.9	3.7	3.9	1.1	2.0	0.4	0.2
210	1.1	0.8	0.8	2.0	4.7	2.3	3.6	2.8	0.8	3.8	2.4	0.6	3.0	6.4	2.1	4.2	3.0	0.7	4.4	8.4	1.9	2.5	2.7	1.1	3.5	3.8	1.1	3.6	4.1	1.1	2.0	0.5	0.2
211	1.1	2.8	2.6	2.0	1.8	0.9	3.6	2.3	0.6	3.8	10.4	2.7	3.0	3.4	1.1	4.2	8.0	1.9	4.4	6.1	1.4	2.5	3.1	1.2	3.5	8.4	2.4	3.6	7.6	2.1	2.0	0.4	0.2
212	1.1	0.6	0.6	2.0	1.0	0.5	3.6	4.5	1.2	3.8	4.4	1.2	3.0	2.2	0.7	4.2	6.8	1.6	4.4	7.1	1.6	2.5	0.7	0.3	3.5	3.9	1.1	3.6	8.8	2.4	2.0	0.4	0.2
213	1.1	1.5	1.4	2.0	5.1	2.6	3.6	2.9	0.8	3.8	1.4	0.4	3.0	3.7	1.3	4.2	5.8	1.4	4.4	10.4	2.4	2.5	3.1	1.2	3.5	7.3	2.1	3.6	3.2	0.9	2.0	0.4	0.2
214	1.1	1.1	1.0	2.0	0.8	0.4	3.6	1.3	0.4	3.8	3.0	0.8	2.9	4.8	1.6	4.2	5.9	1.4	4.3	8.8	2.0	2.5	5.9	2.4	3.4	6.8	2.0	3.6	7.1	2.0	2.0	0.4	0.2
215	1.1	0.5	0.4	2.0	0.5	0.2	3.6	3.1	0.9	3.8	4.7	1.2	2.9	2.8	1.0	4.2	0.8	0.2	4.3	3.2	0.7	2.5	3.3	1.4	3.4	6.2	1.8	3.6	5.9	1.7	2.0	0.4	0.2
216	1.1	0.7	0.6	2.0	2.5	1.3	3.6	2.3	0.6	3.8	5.6	1.5	2.9	4.7	1.6	4.2	4.0	1.0	4.3	1.7	0.4	2.5	1.3	0.5	3.4	5.7	1.7	3.6	5.1	1.4	2.0	0.5	0.2
217	1.1	2.2	2.1	2.0	0.7	0.4	3.5	5.2	1.5	3.8	7.8	2.1	2.9	3.1	1.1	4.2	10.0	2.4	4.3	4.2	1.0	2.5	5.6	2.3	3.4	4.9	1.4	3.5	8.9	2.5	2.0	0.4	0.2
218	1.1	1.1	1.1	2.0	3.9	2.0	3.5	7.3	2.1	3.7	2.4	0.6	2.9	5.0	1.7	4.2	8.5	2.0	4.3	8.8	2.0	2.5	4.7	1.9	3.4	3.3	1.0	3.5	3.4	1.0	2.0	0.4	0.2
219	1.1	1.4	1.4	2.0	3.4	1.7	3.5	4.4	1.2	3.7	3.2	0.9	2.9	5.6	1.9	4.1	5.1	1.2	4.3	8.7	2.1	2.4	1.8	0.7	3.4	3.4	1.0	3.5	3.5	1.0	2.0	0.4	0.2
220	1.0	2.7	2.6	2.0	3.9	2.0	3.5	2.3	0.7	3.7	4.6	1.2	2.9	3.8	1.3	4.1	2.2	0.5	4.2	0.8	0.2	2.4	3.7	1.5	3.4	5.1	1.5	3.5	5.2	1.5	1.9	0.4	0.2
221	1.0	1.6	1.5	2.0	2.9	1.5	3.5	4.8	1.4	3.6	1.4	0.4	2.9	4.2	1.5	4.1	8.4	2.0	4.2	2.3	0.5	2.4	6.6	2.7	3.4	8.5	2.5	3.5	6.4	1.8	1.9	0.5	0.2
222	1.0	2.0	1.9	2.0	1.7	0.9	3.5	1.0	0.3	3.6	5.0	1.4	2.9	9.2	3.2	4.1	8.4	2.1	4.2	11.5	2.8	2.4	3.9	1.6	3.3	5.1	1.5	3.5	11.5	3.3	1.9	0.4	0.2
223	1.0	1.2	1.1	1.9	1.4	0.7	3.5	5.1	1.5	3.6	3.2	0.9	2.8	2.7	0.9	4.1	3.3	0.8	4.2	3.4	0.8	2.4	7.1	3.0	3.3	6.2	1.8	3.5	6.3	1.8	1.9	0.4	0.2
224	1.0	1.0	0.9	1.9	0.7	0.4	3.5	9.0	2.6	3.6	9.5	2.6	2.8	4.2	1.5	4.0	4.0	1.0	4.2	5.2	1.2	2.4	9.2	3.8	3.3	2.5	0.8	3.4	7.1	2.1	1.9	0.4	0.2
225	1.0	2.0	1.9	1.9	1.4	0.7	3.4	3.1	0.9	3.6	1.0	0.3	2.8	1.3	0.5	4.0	3.8	0.9	4.2	4.2	1.0	2.4	4.8	2.0	3.3	11.0	3.3	3.4	7.0	2.0	1.9	0.4	0.2
226	1.0	0.5	0.5	1.9	1.0	0.5	3.4	1.3	0.4	3.6	5.4	1.5	2.8	3.9	1.4	4.0	11.0	2.8	4.2	3.9	0.9	2.4	2.0	0.8	3.3	3.0	0.9	3.4	6.7	2.0	1.9	0.5	0.2
227	1.0	2.0	2.0	1.9	2.5	1.3	3.4	6.4	1.8	3.6	5.9	1.6	2.8	5.0	1.8	4.0	3.0	0.8	4.1	9.6	2.3	2.4	5.0	2.1	3.3	3.2	1.0	3.4	5.1	1.5	1.9	0.4	0.2
228	1.0	0.4	0.4	1.9	2.0	1.0	3.4	4.5	1.3	3.6	6.6	1.8	2.8	2.8	1.0	4.0	9.2	2.3	4.1	7.6	1.8	2.4	5.6	2.3	3.3	6.8	2.1	3.4	2.6	0.8	1.9	0.5	0.2
229	1.0	0.5	0.5	1.9	3.1	1.6	3.4	1.0	0.3	3.6	4.7	1.3	2.8	4.7	1.7	4.0	6.5	1.6	4.1	9.1	2.2	2.3	2.4	1.0	3.3	6.7	2.0	3.4	9.0	2.6	1.9	0.4	0.2
230	1.0	0.6	0.6	1.9	2.1	1.1	3.4	1.6	0.5	3.6	1.0	0.3	2.8	1.8	0.6	4.0	8.8	2.2	4.1	6.8	1.6	2.3	5.6	2.4	3.3	6.4	2.0	3.4	5.2	1.5	1.9	0.4	0.2
231	1.0	1.1	1.1	1.9	1.3	0.7	3.4	5.5	1.6	3.5	1.7	0.5	2.8	3.9	1.4	4.0	7.3	1.8	4.1	3.1	0.8	2.3	3.3	1.4	3.3	4.9	1.5	3.4	8.5	2.5	1.9	0.4	0.2
232	1.0	1.0	1.0	1.9	1.2	0.7	3.4	1.3	0.4	3.5	4.5	1.3	2.8	4.5	1.6	4.0	3.2	0.8	4.1	5.1	1.2	2.3	2.2	0.9	3.3	8.6	2.6	3.4	11.2	3.3	1.9	0.4	0.2
233	1.0	1.6	1.6	1.9	0.7	0.4	3.3	6.8	2.0	3.5	4.6	1.3	2.8	2.2	0.8	3.9	4.9	1.2	4.1	1.1	0.3	2.3	4.8	2.1	3.2	8.2	2.5	3.4	9.2	2.8	1.9	0.4	0.2
234	1.0	2.4	2.4	1.9	2.8	1.5	3.3	2.9	0.9	3.5	3.7	1.0	2.8	2.6	0.9	3.9	1.0	0.3	4.1	6.4	1.6	2.3	3.8	1.7	3.2	10.7	3.3	3.3	3.2	1.0	1.9	0.4	0.2
235	1.0	1.8	1.8	1.9	1.3	0.7	3.3	0.8	0.2	3.5	1.4	0.4	2.8	7.1	2.6	3.9	0.9	0.2	4.1	5.1	1.3	2.3	2.6	1.1	3.2	8.9	2.8	3.3	3.0	0.9	1.9	0.4	0.2
236	1.0	1.8	1.9	1.9	4.3	2.3	3.3	4.3	1.3	3.5	3.1	0.9	2.8	3.1	1.1	3.9	3.0	0.8	4.0	3.1	0.8	2.3	5.8	2.5	3.2	2.7	0.8	3.3	9.6	2.9	1.9	0.4	0.2
237	1.0	0.6	0.6	1.9	2.6	1.4	3.3	3.4	1.0	3.5	6.1	1.7	2.8	6.6	2.4	3.9	6.2	1.6	4.0	0.9	0.2	2.2	7.5	3.3	3.1	9.2	2.9	3.3	7.3	2.2	1.8	0.4	0.2
238	1.0	2.0	2.1	1.9	0.9	0.5	3.3	4.4	1.3	3.5	2.4	0.7	2.8	5.7	2.1	3.9	4.9	1.3	4.0	1.9	0.5	2.2	1.5	0.7	3.1	9.0	2.9	3.3	9.3	2.9	1.8	0.4	0.2
239	1.0	1.0	1.0	1.8	2.8	1.5	3.3	4.2	1.3	3.5	5.8	1.7	2.8	2.2	0.8	3.9	1.8	0.5	4.0	7.1	1.8	2.2	4.1	1.8	3.1	7.0	2.2	3.3	11.2	3.4	1.8	0.4	0.2
240	0.9	1.5	1.6	1.8	0.7	0.4	3.3	1.6	0.5	3.5	4.5	1.3	2.8	4.5	1.6	3.9	2.5	0.7	4.0	7.0	1.8	2.2	4.6	2.1	3.1	10.8	3.4	3.2	11.4	3.5	1.8	0.4	0.2
241	0.9	0.8	0.8	1.8	2.1	1.1	3.3	2.3	0.7	3.5	7.0	2.0	2.8	5.6	2.0	3.8	2.7	0.7	4.0	3.2	0.8	2.2	3.5	1.6	3.1	0.9	0.3	3.2	12.8	4.0	1.8	0.4	0.2
242	0.9	0.9	1.0	1.8	1.6	0.9	3.3	5.5	1.7	3.5	1.4	0.4	2.7	2.0	0.7	3.8	2.0	0.5	4.0	2.1	0.5	2.2	2.2	1.0	3.1	11.0	3.5	3.2	11.7	3.7	1.8	0.4	0.2
243	0.9	0.9	1.0	1.8	2.1	1.2	3.3	4.7	1.4	3.5	0.8	0.2	2.7	5.6	2.0	3.8	6.8	1.8	4.0	9.3	2.4	2.2	2.8	1.3	3.1	12.3	4.0	3.2	13.9	4.3	1.8	0.4	0.2
244	0.9	1.5	1.6	1.8	2.2	1.2	3.3	1.3	0.4	3.5	1.3	0.4	2.7	0.7	0.3	3.8	6.7	1.8	4.0	4.5	1.1	2.2	4.3	2.0	3.1	11.3	3.7	3.2	7.0	2.2	1.8	0.4	0.2
245	0.9	2.1	2.2	1.8	1.1	0.6	3.3	1.7	0.5	3.5	3.9	1.1	2.7	7.5	2.8	3.8	9.0	2.4	3.9	3.7	0.9	2.2	1.3	0.6	3.1	6.7	2.2	3.2	7.6	2.4	1.8	0.4	0.2
246	0.9	2.6	2.8	1.8	3.5	1.9	3.3	8.4	2.6	3.5	1.7	0.5	2.7	1.4	0.5	3.8	5.6	1.5	3.9	2.6	0.7	2.2	3.2	1.5	3.1	13.3	4.3	3.2	8.1	2.5	1.8	0.4	0.2
247	0.9	1.6	1.7	1.8	4.4	2.5	3.3	2.6	0.8	3.5	4.9	1.4	2.7	2.8	1.0	3.8	4.4	1.1	3.9	5.8	1.5	2.2	5.7	2.6	3.1	7.8	2.5	3.2	2.7	0.8	1.8	0.4	0.2
248	0.9	2.6	2.8	1.8	3.7	2.1	3.3	0.8	0.2	3.4	1.6	0.5	2.7	3.3	1.2	3.8	0.8	0.2	3.9	6.3	1.6	2.2	4.4	2.0	3.1	4.9	1.6	3.2	0.9	0.3	1.8	0.4	0.2
249	0.9	0.5	0.5	1.8	2.7	1.5	3.3	1.3	0.4	3.4	1.8	0.5	2.7	6.2	2.3	3.8	6.1	1.6	3.9	9.0	2.3	2.2	5.5	2.5	3.1	3.0	1.0	3.2	7.9	2.5	1.8	0.4	0.2
250	0.9	0.9	1.0	1.8	1.9	1.1	3.2	7.6	2.3	3.4	1.8	0.5	2.7	5.9	2.2	3.8	3.6	0.9	3.9	8.9	2.3	2.2	0.6	0.3	3.1	7.3	2.4	3.2	10.4	3.3	1.8	0.4	0.2
251	0.9	1.0	1.0	1.8	3.8	2.1	3.2	3.3	1.0	3.4	8.8	2.6	2.7	1.1	0.4	3.7	8.5	2.3	3.9	6.7	1.7	2.2	4.5	2.1	3.1	6.5	2.1	3.2	6.8	2.1	1.8	0.4	0.2
252	0.9	1.4	1.6	1.8	2.7	1.5	3.2	7.4	2.3	3.4	1.3	0.4	2.6	0.6	0.2	3.7	8.6	2.3	3.9	2.2	0.6	2.1	2.2	1.0	3.1	7.6	2.5	3.2	5.1	1.6	1.8	0.4	0.2
253	0.9	2.5	2.8	1.8	3.0	1.7	3.2	1.7	0.5	3.4	0.8	0.2	2.6	3.3	1.2	3.7	2.1	0.6	3.9	11.2	2.9	2.1	2.8	1.3	3.1	10.0	3.3	3.2	3.2	1.0	1.8	0.4	0.2
254	0.9	1.4	1.5	1.8	2.1	1.2	3.2	3.6	1.1	3.4	3.5	1.0	2.6	1.8	0.7	3.7	6.4	1.7	3.9	11.4	2.9	2.1	2.8	1.3	3.1	4.0	1.3	3.2	4.2	1.3	1.8	0.4	0.2
255	0.9	2.5	2.8	1.7	0.5	0.3	3.2	1.3	0.4	3.4	8.0	2.3	2.6	1.7	0.7	3.7	11.0	2.9	3.9	5.9	1.5	2.1	7.1	3.3	3.0	3.9	1.3	3.1	4.8	1.5	1.7	0.4	0.2

Table 7 summarizes the benefits, costs and associated BCRs for the 110 DER-driven Distribution Automation circuits with the highest BCR for each 3/3 scenario. The 110 circuits are numbered (rather than named) since the ranking of the top 110 circuits is different for each deployment scenario.

Table 7 – DER-driven Distribution Automation Results

DA Scheme	3 Mids/3 Ties - DER-driven Distribution Automation Circuits																														RFI-only		
Switch Type	All RCS			All Load Break (RCS+)									Fault Interrupting Mids									All Fault Interrupting											
FLISR Scheme	Remote Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching					
	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs
Totals	0.9	136	144	2.1	193	93	3.9	345	89	4.1	364	88	3.4	391	114	4.6	553	119	4.8	573	119	2.8	396	144	3.7	558	149	3.9	578	149	1.5	35	24
Circuit Detail																																	
1	14.3	7.4	0.5	34.3	13.3	0.4	52.7	20.3	0.4	55.0	21.2	0.4	24.2	5.3	0.2	33.5	7.3	0.2	34.7	7.6	0.2	13.5	13.3	1.0	20.6	20.4	1.0	21.5	21.3	1.0	9.1	2.1	0.2
2	11.1	8.7	0.8	23.5	11.6	0.5	41.6	20.6	0.5	43.9	21.7	0.5	16.9	13.3	0.8	25.9	20.4	0.8	27.1	21.3	0.8	12.2	5.3	0.4	17.8	26.3	1.5	18.6	27.4	1.5	5.0	1.0	0.2
3	9.0	2.9	0.3	14.0	3.5	0.2	22.1	5.5	0.2	23.1	5.8	0.2	16.9	5.4	0.3	23.8	7.6	0.3	24.7	7.9	0.3	11.7	17.4	1.5	16.9	7.3	0.4	17.5	7.6	0.4	3.6	0.9	0.2
4	6.2	2.6	0.4	11.1	4.8	0.4	20.4	7.2	0.4	21.9	7.7	0.4	15.2	17.4	1.1	23.1	26.3	1.1	24.1	27.4	1.1	10.3	32.5	3.2	15.4	48.5	3.2	16.0	50.5	3.2	3.4	0.8	0.2
5	4.9	4.3	0.9	10.0	7.7	0.8	17.8	7.7	0.4	18.6	8.1	0.4	12.1	6.1	0.5	17.8	48.5	2.7	18.6	50.5	2.7	10.2	5.4	0.5	14.4	7.6	0.5	15.0	7.9	0.5	3.1	0.7	0.2
6	4.5	1.4	0.3	9.5	3.3	0.3	15.9	5.5	0.3	16.7	5.8	0.3	12.0	32.5	2.7	16.2	9.5	0.6	16.7	9.9	0.6	9.1	6.9	0.8	12.5	9.5	0.8	12.9	9.9	0.8	3.0	0.6	0.2
7	4.2	2.6	0.6	9.3	3.3	0.4	15.4	11.8	0.8	16.0	12.4	0.8	11.7	6.9	0.6	13.3	10.9	0.8	13.7	11.2	0.8	8.9	16.0	1.8	11.0	10.9	1.0	11.3	11.2	1.0	3.0	0.6	0.2
8	4.0	2.3	0.6	7.8	3.1	0.4	14.6	5.7	0.4	15.4	6.0	0.4	11.0	16.0	1.4	12.4	11.7	0.9	13.0	12.2	0.9	8.3	6.1	0.7	9.7	17.3	1.8	9.8	17.5	1.8	2.8	0.6	0.2
9	3.2	1.2	0.4	6.5	3.1	0.5	12.0	5.0	0.4	12.9	5.4	0.4	9.9	7.9	0.8	12.3	6.2	0.5	12.3	6.2	0.5	7.9	7.9	1.0	9.4	11.7	1.2	9.8	12.2	1.2	2.8	0.6	0.2
10	3.2	3.9	1.2	4.9	1.6	0.3	11.0	5.3	0.5	11.8	23.0	1.9	9.6	7.9	0.8	12.0	17.3	1.4	12.3	3.7	0.3	7.6	7.9	1.0	8.4	6.2	0.7	8.7	9.8	1.1	2.6	0.6	0.2
11	3.1	1.8	0.6	4.8	2.0	0.4	10.7	20.9	1.9	11.6	5.6	0.5	8.3	2.5	0.3	11.8	3.6	0.3	12.1	3.3	0.3	6.2	7.8	1.2	8.4	9.5	1.1	8.4	6.2	0.7	2.4	0.5	0.2
12	3.0	1.6	0.5	4.8	1.3	0.3	9.8	5.2	0.5	10.5	5.6	0.5	8.3	7.8	0.9	11.7	3.2	0.3	12.1	17.5	1.4	5.9	12.5	2.1	8.0	8.3	1.0	8.2	12.5	1.5	2.4	0.5	0.2
13	2.8	2.8	1.0	4.8	5.2	1.1	8.7	2.3	0.3	9.1	2.4	0.3	8.2	2.2	0.3	10.5	9.5	0.9	11.0	9.8	0.9	5.8	6.6	1.1	7.9	11.9	1.5	8.0	8.3	1.0	2.3	0.5	0.2
14	2.7	5.3	1.9	4.7	1.4	0.3	8.3	9.1	1.1	8.8	9.6	1.1	8.0	1.7	0.2	10.3	8.3	0.8	10.5	2.2	0.2	5.2	7.8	1.5	7.4	8.6	1.2	7.7	9.0	1.2	2.3	0.5	0.2
15	2.5	1.6	0.6	4.4	2.3	0.5	8.2	7.0	0.8	8.7	7.4	0.8	7.7	1.6	0.2	10.2	2.1	0.2	10.4	8.3	0.8	5.1	1.7	0.3	7.1	3.6	0.5	7.4	3.7	0.5	2.2	0.6	0.3
16	2.4	1.3	0.6	4.3	1.4	0.3	8.1	2.7	0.3	8.5	2.8	0.3	7.3	6.6	0.9	9.3	11.9	1.3	9.7	12.5	1.3	5.1	1.6	0.3	6.7	2.2	0.3	6.9	2.2	0.3	2.1	0.4	0.2
17	2.1	1.4	0.7	4.3	2.2	0.5	7.8	2.3	0.3	8.2	2.5	0.3	7.1	1.3	0.2	9.2	2.0	0.2	9.3	2.0	0.2	5.0	2.5	0.5	6.2	13.0	2.1	6.2	13.1	2.1	2.1	0.4	0.2
18	2.0	0.7	0.3	4.2	3.6	0.8	7.6	3.8	0.5	8.0	4.0	0.5	6.7	12.5	1.9	8.4	2.2	0.3	8.7	2.2	0.3	4.9	5.7	1.2	6.0	6.1	1.0	6.2	6.3	1.0	2.1	0.4	0.2
19	2.0	1.2	0.6	3.8	2.1	0.5	7.2	3.9	0.5	7.6	4.2	0.5	6.4	1.6	0.3	8.2	8.6	1.0	8.6	9.0	1.0	4.7	3.6	0.8	5.9	2.0	0.3	6.0	4.6	0.8	2.1	0.4	0.2
20	2.0	1.1	0.5	3.6	3.8	1.1	7.1	2.3	0.3	7.4	2.4	0.3	6.1	7.8	1.3	7.9	1.4	0.2	8.1	1.4	0.2	4.5	1.3	0.3	5.9	4.5	0.8	6.0	2.0	0.3	2.0	0.4	0.2
21	1.8	1.8	1.0	3.6	0.8	0.2	6.2	6.5	1.1	6.5	6.8	1.1	5.6	4.5	0.8	7.7	6.1	0.8	8.0	6.3	0.8	4.4	4.5	1.0	5.6	10.0	1.8	5.8	10.4	1.8	1.9	0.4	0.2
22	1.6	0.5	0.3	3.5	1.3	0.4	5.9	3.3	0.6	6.3	3.5	0.6	5.5	4.4	0.8	7.3	6.4	0.9	7.6	6.7	0.9	4.3	4.4	1.0	5.6	5.6	1.0	5.7	5.8	1.0	1.9	0.4	0.2
23	1.6	1.0	0.6	3.5	2.0	0.6	5.7	1.4	0.2	6.0	1.4	0.2	5.5	5.7	1.0	7.1	5.6	0.8	7.3	5.8	0.8	4.0	1.4	0.4	5.4	11.4	2.1	5.7	11.9	2.1	1.8	0.4	0.2
24	1.5	3.1	2.0	3.3	1.0	0.3	5.6	2.1	0.4	5.8	2.2	0.4	5.4	3.6	0.7	7.0	13.0	1.9	7.0	13.1	1.9	3.9	4.4	1.1	5.4	6.4	1.2	5.7	6.7	1.2	1.8	0.4	0.2
25	1.5	2.5	1.7	3.1	1.4	0.4	5.4	3.1	0.6	5.6	3.2	0.6	5.0	1.4	0.3	6.8	4.5	0.7	6.9	4.6	0.7	3.8	3.0	0.8	5.2	5.4	1.0	5.4	5.6	1.0	1.8	0.4	0.2
26	1.4	0.8	0.6	3.1	1.2	0.4	5.1	2.0	0.4	5.4	2.1	0.4	5.0	4.4	0.9	6.6	5.4	0.8	6.8	5.6	0.8	3.8	1.6	0.4	5.2	3.2	0.6	5.4	3.3	0.6	1.7	0.4	0.2
27	1.3	1.1	0.9	2.8	1.5	0.6	5.1	1.5	0.3	5.3	1.5	0.3	4.8	4.2	0.9	6.4	11.4	1.8	6.7	11.9	1.8	3.7	6.6	1.8	5.2	4.0	0.8	5.3	4.1	0.8	1.7	0.3	0.2
28	1.2	0.8	0.7	2.7	1.1	0.4	4.9	2.0	0.4	5.2	2.1	0.4	4.5	3.8	0.8	6.4	10.0	1.6	6.6	10.4	1.6	3.7	2.2	0.6	5.1	1.4	0.3	5.2	2.2	0.4	1.7	0.4	0.2
29	1.2	0.9	0.8	2.7	0.8	0.3	4.8	2.1	0.4	5.0	2.2	0.4	4.4	3.0	0.7	6.0	4.0	0.7	6.2	4.1	0.7	3.6	3.8	1.0	5.1	2.1	0.4	5.2	1.4	0.3	1.7	0.4	0.2
30	1.1	1.0	0.9	2.6	5.0	1.9	4.3	1.9	0.5	4.7	2.1	0.5	4.3	1.4	0.3	5.8	1.8	0.3	6.0	1.9	0.3	3.6	7.5	2.1	4.7	9.5	2.0	4.9	9.8	2.0	1.7	0.3	0.2
31	1.1	1.6	1.5	2.5	0.9	0.4	4.3	2.5	0.6	4.5	2.7	0.6	4.3	1.3	0.3	5.6	5.4	1.0	5.9	5.6	1.0	3.6	4.2	1.2	4.5	9.3	2.1	4.7	9.7	2.1	1.6	0.4	0.3
32	1.1	1.4	1.3	2.4	0.8	0.3	4.3	1.4	0.3	4.5	1.4	0.3	4.2	7.5	1.8	5.6	1.6	0.3	5.7	1.8	0.3	3.4	2.4	0.7	4.5	1.6	0.4	4.5	1.6	0.4	1.6	0.3	0.2
33	1.1	0.8	0.8	2.4	0.9	0.4	4.2	1.5	0.4	4.4	1.5	0.4	4.2	6.6	1.6	5.6	1.7	0.3	5.7	1.6	0.3	3.4	6.8	2.0	4.3	3.0	0.7	4.4	5.6	1.3	1.5	0.4	0.2
34	1.1	1.9	1.8	2.4	1.5	0.6	4.1	2.7	0.7	4.3	2.9	0.7	4.2	2.4	0.6	5.2	3.0	0.6	5.4	3.0	0.6	3.0	6.3	2.1	4.2	5.4	1.3	4.4	3.0	0.7	1.5	0.4	0.2
35	1.0	0.5	0.5	2.4	1.4	0.6	4.0	2.5	0.6	4.3	1.8	0.4	4.1	0.8	0.2	5.2	9.5	1.8	5.4	9.8	1.8	2.9	3.8	1.3	4.1	5.5	1.3	4.3	5.7	1.3	1.5	0.3	0.2
36	1.0	0.5	0.5	2.3	1.8	0.8	3.9	2.9	0.8	4.2	2.6	0.6	3.8	0.7	0.2	5.2	1.1	0.2	5.3	1.0	0.2	2.8	3.6	1.3	4.0	5.3	1.3	4.1	5.5	1.3	1.5	0.4	0.3
37	0.9	2.5	2.7	2.3	1.6	0.7	3.9	1.6	0.4	4.1	3.1	0.8	3.7	6.8	1.8	5.2	0.9	0.2	5.3	1.1	0.2	2.8	3.8	1.3	3.9	4.4	1.1	3.9	1.9	0.5	1.5	0.3	0.2
38	0.9	0.9	1.0	2.3	1.1	0.5	3.8	1.3	0.3	4.0	1.4	0.3	3.7	3.6	1.0	5.0	9.3	1.9	5.2	9.7	1.9	2.8	1.4	0.5	3.8	1.8	0.5	3.9	4.4	1.1	1.4	0.3	0.2
39	0.9	0.5	0.6	2.3	0.8	0.4	3.7	1.3	0.4	3.8	1.4	0.4	3.7	2.3	0.6	5.0	4.4	0.9	5.0	4.4	0.9	2.6	0.8	0.3	3.4	1.7	0.5	3.5	1.8	0.5	1.4	0.4	0.3
40	0.9	0.5	0.6	2.2	0.5	0.2	3.7	1.4	0.4	3.8	1.5	0.4	3.5	3.8	1.1	4.8	5.3	1.1	5.0	5.5	1.1	2.6	2.3	0.9	3.3	1.1	0.3	3.4	1.0	0.3	1.4	0.3	0.2
41	0.9	0.9	1.0	2.2	2.5	1.1	3.6	1.7	0.5	3.8	2.5	0.7	3.4	6.3	1.9	4.8	5.5	1.2	5.0	5.7	1.2	2.6	1.3	0.5	3.3	0.9	0.3	3.4	1.1	0.3	1.4	0.3	0.2
42	0.8	1.2	1.5	2.1	1.5	0.7	3.6	1.0	0.3	3.8	1.1	0.3	3.3	1.1	0.4	4.5	2.8	0.6	4.6	2.9	0.6	2.5	1.8	0.7	3.3	3.7	1.1	3.4	3.8	1.1	1.4	0.3	0.2
43	0.8	0.9	1.0	2.0	0.6	0.3	3.6	2.4	0.7	3.8	1.8	0.5	3.2	3.8	1.2	4.0	3.0	0.7	4.2	3.1	0.7	2.4	0.7	0.3	3.2	2.8	0.9	3.3	2.9	0.9	1.3	0.3	0.2
44	0.8	0.5	0.6	2.0	2.4	1.2	3.5	2.5	0.7	3.7	4.5	1.2	3.0	1.8	0.6	4.0	2.0	0.5	4.2	3.8	0.9	2.3	1.5	0.6	3.2	3.0	0.9	3.3	3.1	0.9	1.3	0.3	0.2
45	0.8	1.4	1.8	2.0	1.2	0.6	3.5	4.3	1.2	3.7	2.6	0.7	3.0	1.5	0.5	4.0	3.7	0.9	4.1	1.5	0.4	2.2	2.1	0.9	3.1	2.0	0.6	3.2	2.0	0.6	1.3	0.3	0.2
46	0.8	2.2	2.7	2.0	0.9	0.4	3.5	3.9	1.1	3.6	4.1	1.1	2.8	2.1	0.7	4.0	1.4	0.4	4.1	2.0	0.5	2.2	2.5	1.1	3.0	2.2	0.7	3.1	2.2	0.7	1.3	0.3	0.2
47	0.8	1.3	1.7	1.9	3.5	1.8	3.4	0.7	0.2	3.6	1.6	0.4	2.8	2.4	0.8	3.8	1.3	0.4	3.9	1.4	0.4	2.1	3.0	1.4	2.9	4.1	1.4	3.0	3.6	1.2	1.3	0.3	0.2
48	0.8	1.1	1.4	1.9	1.5	0.8	3.4	1.5	0.4	3.5	0.8	0.2	2.8	0.8	0.3	3.7	3.1	0.8	3.8	3.2	0.8	2.1	1.5	0.7	2.9	3.4	1.2	3.0	4.3	1.4	1.2	0.3	0.2
49	0.8	0.3	0.4	1.8	0.5	0.2	3.3	2.7	0.8	3.5	2.8	0.8	2.7	1.5	0.5	3.6	1.9	0.5	3.7	2.0	0.5	2.0	2.4	1.2	2.9	9.4	3.3	3.0	9.8	3.3	1.2	0.2	0.2
50	0.8	1.9	2.5	1.8	4.1	2.3	3.2	5.7	1.8	3.5	1.5	0.4	2.7	2.5	0.9	3.6	2.2	0.6	3.7	2.2	0.6	2.0	4.3	2.2	2.8	1.9	0.7	2.9	2.0	0.7	1.2	0.2	0.2
51	0.8	2.1	2.8	1.7	0.7	0.4	3.2	1.4	0.4	3.4	2.8	0.8	2.6	0.9	0.4	3.5	4.1	1.2	3.7	4.3	1.2	2.0	3.7	1.9	2.7	3.3	1.2	2.8	3.5	1.2	1.2	0.3	0.2
52	0.7	0.4	0.6	1.7	2.1	1.2	3.2	7.3	2.3	3.4	6.0	1.8	2.6	3.0	1.2	3.5	3.4	1.0	3.6	3.6	1.0	1.9	2.3	1.2	2.7	3.1	1.2	2.8	6.7	2.4	1.2	0.2	0.2
53	0.7	0.3	0.5	1.7	0.4	0.2	3.2	2.6	0.8	3.3	7.7	2.3	2.6	1.6	0.6	3.4	2.2	0.6	3.5	2.2	0.6	1.9	6.2	3.3	2.7	6.4	2.4	2.8	1.5	0.5	1.2	0.3	0.3
54	0.7	0.7	1.0	1.7	0.8	0.5	3.1	1.9	0.6	3.3	2.0	0.6	2.3	2.0	0.8	3.3	2.8	0.8	3.4	2.9	0.8	1.9	2.6	1.4	2.6	1.4	0.5	2.7	3.2	1.2	1.2	0.2	0.2
55	0.7	0.6	0.8	1.7	1.1	0.7	3.1	3.8	1.2	3.2	4.0	1.2	2.3	2.3	1.0	3.3	3.3	1.0	3.4	3.5	1.0	1.8	2.0	1.1	2.6	2.8	1.1	2.7	2.9	1.1	1.1	0.3	0.2
56	0.7	1.8	2.6	1.6	0.5	0.3	3.0	1.2	0.4	3.2	1.3	0.4	2.3	2.6	1.1	3.2	9.4	2.9	3.3	9.8	2.9	1.8	0.8	0.5	2.6	4.9	1.9	2.7	3.8	1.4	1.1	0.3	0.2
57	0.7	1.2	1.8	1.6	0.4	0.3	2.9	0.7	0.2	3.0	0.7	0.2	2.3	4.3	1.9	3.2	3.6	1.1	3.3	3.8	1.1	1.8	2.2	1.2	2.6	3.6	1.4	2.7	5.1	1.9	1.1	0.3	0.3
58	0.6	1.8	2.8	1.6	0.6	0.4	2.8	0.8	0.3	2.9	0.9	0.3	2.2	3.7	1.7	3.1	3.7	1.2	3.3	3.8	1.2	1.8	4.2	2.4	2.5	6.0	2.5	2.6	6.3	2.5	1.1	0.3	0.2
59	0.6	0.4	0.6	1.5	2.5	1.6	2.8	4.5	1.6	2.9	2.0	0.7	2.1	2.2	1.0	3.1	3.0	1.0	3.2	3.1	1.0	1.7	0.9	0.5	2.4	5.3	2.2	2.5	5.4	2.2	1.1	0.2	0.2
60	0.6	1.5	2.6	1.5	2.5	1.7	2.7	1.0	0.4	2.9	4.7	1.6	2.1	2.5	1.2	3.1	0.9	0.3	3.1	6.3	2.0	1.7	1.7	1.0	2.4	4.2	1.8	2.5	4.3	1.8	1.1	0.3	0.2
61	0.6	1.6	2.8	1.5	0.5	0.4	2.7	1.1	0.4	2.9	1.1	0.4	2.1	1.0	0.5	3.0	6.0	2.0	3.1	0.9	0.3	1.7	4.1	2.5	2.3	3.7	1.6	2.4	3.8	1.6	1.1	0.3	0.2
62	0.6	0.9	1.5	1.4	0.7	0.5	2.7	1.8	0.7	2.9	1.1	0.4	2.1	6.2	2.9	2.9	6.4	2.2	3.1	6.7	2.2	1.6	1.6	1.0	2.3	3.1	1.3	2.4	3.3	1.3	1.1	0.3	0.2
63	0.6	1.6	2.8	1.4	1.2	0.8	2.7	0.7	0.3	2.8	0.7	0.3	2.1	1.9	0.9	2.9	2.3	0.8	3.1	2.4	0.8	1.6	1.0	0.6	2.3	6.6	2.8	2.4	6.8	2.8	1.1	0.3	0.2
64	0.6	0.4	0.7	1.3	1.1	0.8	2.7	0.6	0.2	2.8	0.7	0.2	2.1	2.0	1.0	2.9	1.3	0.5	3.0	1.4	0.5	1.6	1.4	0.9	2.3	2.1	0.9	2.4	2.2	0.9	1.1	0.2	0.2
65	0.5	0.9	1.6	1.3	0.6	0.5	2.4	1.3	0.5	2.6	3.2	1.2	2.1	1.0	0.5	2.9	2.6	0.9	3.0	2.7	0.9	1.6	2.5	1.6	2.3	2.3	1.0	2.4	2.4	1.0	1.1	0.2	0.2
66	0.5	0.4	0.7	1.3	0.3	0.2	2.4	2.0	0.8	2.6	1.4	0.5	2.0	4.1	2.0	2.9	4.9	1.7	3.0	3.3	1.1	1.6	1.0	0.6	2.3	3.0	1.3	2.4	3.1	1.3	1.1	0.3	0.3
67	0.5	0.7	1.3	1.3	1.5	1.1	2.3	1.2	0.5	2.5	2.1	0.8	2.0	1.5	0.8	2.8	3.1	1.1	3.0	5.1	1.7	1.6	1.9	1.2	2.2	2.3	1.0	2.3	2.3	1.0	1.0	0.3	0.3
68	0.5	0.5	0.9	1.3	0.8	0.6	2.3	2.8	1.2	2.4	1.3	0.5	2.0	4.2	2.2	2.8	5.3	1.9	2.9	2.2	0.8	1.6	1.3	0.8	2.2	2.2	1.0	2.3	3.6	1.6	1.0	0.2	0.2
69	0.5	0.2	0.4	1.3	0.7	0.5	2.3	4.0	1.7	2.4	4.1	1.7	1.9	1.5	0.8	2.7	2.1	0.8	2.9	5.4	1.9	1.6	1.1	0.7	2.2	3.4	1.6	2.3	2.2	1.0	1.0	0.2	0.2
70	0.5	0.7	1.4	1.2	3.3	2.8	2.2	0.9	0.4	2.4	1.0	0.4	1.9	1.1	0.6	2.7	3.7	1.4	2.8	3.9	1.4	1.5	2.7	1.8	2.1	2.6	1.2	2.2	3.9	1.7	1.0	0.2	0.2
71	0.5	1.4	2.8	1.2	2.6	2.2	2.2	1.0	0.5	2.3	0.8	0.3	1.9	1.4	0.7	2.7	1.5	0.6	2.8	4.3	1.5	1.5	1.5	1.0	2.1	3.7	1.7	2.2	2.7	1.2	1.0	0.2	0.2
72	0.5	0.4	0.8	1.2	0.4	0.4	2.2	0.8	0.3	2.3	1.1	0.5	1.9	1.0	0.5	2.7	4.2	1.5	2.8	1.6	0.6	1.5	2.0	1.3	2.1	7.0	3.3	2.2	7.3	3.3	1.0	0.2	0.2
73	0.5	0.9	1.9	1.1	0.5	0.5	2.1	1.4	0.6	2.3	1.4	0.6	1.9	1.7	0.9	2.6	6.6	2.5	2.8	6.8	2.5	1.5	4.3	2.8	2.1	2.5	1.2	2.2	2.6	1.2	1.0	0.2	0.2
74	0.5	0.3	0.6	1.1	0.5	0.4	2.1	0.8	0.4	2.2	0.9	0.4	1.9	2.0	1.1	2.6	2.7	1.0	2.7	2.8	1.0	1.5	2.0	1.3	2.1	5.8	2.7	2.2	6.0	2.7	1.0	0.2	0.3
75	0.5	1.1	2.4	1.1	1.2	1.0	2.1	5.8	2.8	2.2	6.1	2.8	1.8	2.5	1.4	2.6	1.2	0.5	2.7	3.6	1.3	1.5	1.4	0.9	2.1	1.9	0.9	2.2	1.8	0.8	0.9	0.2	0.2
76	0.5	0.9	2.0	1.1	0.9	0.8	2.1	0.7	0.3	2.2	0.7	0.3	1.8	1.4	0.8	2.6	5.8	2.2	2.7	6.0	2.2	1.5	3.3	2.3	2.1	1.7	0.8	2.2	3.9	1.8	0.9	0.2	0.2
77	0.4	0.2	0.5	1.1	1.8	1.7	2.1	2.3	1.1	2.2	2.4	1.1	1.8	1.3	0.7	2.6	3.4	1.3	2.7	2.6	1.0	1.5	2.1	1.5	2.1	3.7	1.8	2.2	2.0	0.9	0.9	0.2	0.2
78	0.4	0.4	0.9	1.1	3.0	2.8	2.1	0.4	0.2	2.2	2.5	1.2	1.8	2.7	1.5	2.6	1.3	0.5	2.7	1.3	0.5	1.5	4.8	3.3	2.1	4.9	2.4	2.2	5.1	2.4	0.9	0.2	0.2
79	0.4	1.1	2.5	1.0	2.9	2.8	2.0	2.3	1.2	2.1	0.5	0.2	1.8	2.1	1.2	2.6	2.5	1.0	2.7	1.3	0.5	1.4	3.9	2.7	2.0	5.8	2.9	2.1	6.0	2.9	0.9	0.2	0.2
80	0.4	1.2	2.7	1.0	0.4	0.3	1.9	2.0	1.0	2.0	2.1	1.0	1.7	3.9	2.2	2.5	1.9	0.7	2.6	2.0	0.7	1.4	2.2	1.6	2.0	4.1	2.1	2.1	2.8	1.3	0.9	0.2	0.3
81	0.4	0.2	0.5	1.0	0.4	0.4	1.9	4.3	2.2	2.0	4.5	2.2	1.7	1.7	1.0	2.5	1.9	0.8	2.6	2.0	0.8	1.4	1.7	1.2	2.0	1.2	0.6	2.1	4.3	2.1	0.9	0.2	0.2
82	0.4	0.3	0.7	1.0	0.5	0.5	1.8	2.5	1.3	1.9	2.6	1.3	1.7	1.8	1.0	2.5	2.3	0.9	2.6	2.3	0.9	1.4	2.5	1.7	2.0	2.7	1.3	2.1	3.0	1.5	0.9	0.2	0.2
83	0.4	1.1	2.6	1.0	0.7	0.7	1.8	4.6	2.5	1.9	4.8	2.5	1.7	4.3	2.5	2.5	7.0	2.9	2.6	7.3	2.9	1.4	1.5	1.0	2.0	2.9	1.5	2.0	1.3	0.6	0.9	0.2	0.2
84	0.4	0.9	2.1	1.0	0.3	0.3	1.8	1.8	1.0	1.9	2.0	1.0	1.7	2.2	1.3	2.4	4.9	2.0	2.5	5.1	2.0	1.4	3.3	2.4	2.0	0.9	0.5	2.0	0.9	0.5	0.9	0.2	0.2
85	0.4	0.5	1.2	1.0	1.7	1.7	1.8	0.9	0.5	1.9	0.9	0.5	1.7	4.8	2.9	2.4	1.7	0.7	2.5	1.8	0.7	1.4	2.5	1.8	1.9	1.5	0.8	2.0	1.6	0.8	0.9	0.2	0.2

Workpaper- Southern California Edison / 2025 GRC

Table 7 – DER-driven Distribution Automation Results (continued)

DA Scheme	3 Mids/3 Ties - DER-driven Distribution Automation Circuits														
Switch Type	All RCS			All Load Break (RCS+)									Fault Interrupting Mids		
FLISR Scheme	Remote Switching			Remote Switching			Assisted Switching			Automated Switching			Remote Switching		
	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs
Totals	0.9	136	144	2.1	193	93	3.9	345	89	4.1	364	88	3.4	391	114
Circuit Detail															
86	0.4	0.6	1.5	1.0	0.6	0.6	1.8	1.1	0.6	1.9	1.1	0.6	1.6	3.3	2.0
87	0.4	1.1	2.8	1.0	0.4	0.4	1.8	1.4	0.8	1.8	0.9	0.5	1.6	1.5	0.9
88	0.4	0.7	1.9	1.0	0.4	0.4	1.7	2.9	1.7	1.8	1.5	0.8	1.6	1.3	0.8
89	0.4	0.2	0.6	1.0	1.3	1.3	1.7	2.3	1.3	1.8	2.5	1.3	1.6	1.0	0.6
90	0.4	0.9	2.3	0.9	0.6	0.7	1.7	0.8	0.5	1.8	3.0	1.7	1.6	1.7	1.1
91	0.4	0.9	2.4	0.9	1.1	1.2	1.7	2.9	1.7	1.8	3.0	1.7	1.6	3.3	2.0
92	0.4	1.1	2.8	0.9	1.6	1.7	1.7	2.8	1.7	1.8	0.8	0.5	1.6	1.4	0.9
93	0.4	0.8	2.3	0.9	2.1	2.3	1.6	4.6	2.8	1.7	2.9	1.7	1.6	2.5	1.6
94	0.4	0.4	1.0	0.9	2.3	2.5	1.6	0.6	0.4	1.7	0.7	0.4	1.6	1.3	0.8
95	0.4	0.9	2.5	0.9	0.3	0.3	1.6	0.8	0.5	1.7	4.8	2.8	1.6	2.7	1.7
96	0.4	0.4	1.2	0.9	2.5	2.8	1.6	4.5	2.8	1.7	1.1	0.7	1.6	0.8	0.5
97	0.4	0.7	1.9	0.9	0.4	0.4	1.6	1.1	0.7	1.7	4.7	2.8	1.6	1.0	0.6
98	0.4	1.0	2.8	0.9	0.5	0.5	1.5	3.5	2.3	1.6	0.9	0.5	1.5	3.8	2.5
99	0.3	0.2	0.6	0.9	0.7	0.8	1.5	1.2	0.8	1.6	1.3	0.8	1.5	2.0	1.3
100	0.3	0.5	1.5	0.8	2.3	2.7	1.5	1.2	0.8	1.6	3.7	2.3	1.5	2.6	1.7
101	0.3	0.5	1.6	0.8	0.9	1.0	1.5	0.8	0.5	1.6	1.1	0.7	1.5	1.6	1.1
102	0.3	0.2	0.7	0.8	1.1	1.3	1.5	1.0	0.7	1.6	1.3	0.8	1.5	0.7	0.4
103	0.3	0.6	1.9	0.8	1.2	1.5	1.5	1.9	1.3	1.5	2.0	1.3	1.4	0.8	0.6
104	0.3	0.2	0.7	0.8	0.5	0.6	1.4	0.5	0.3	1.5	1.9	1.3	1.4	2.3	1.6
105	0.3	0.3	0.9	0.8	1.0	1.3	1.4	1.0	0.7	1.5	1.7	1.1	1.4	1.4	1.1
106	0.3	0.8	2.8	0.8	2.1	2.7	1.4	0.6	0.4	1.5	0.8	0.5	1.3	1.2	0.9
107	0.3	0.8	2.8	0.8	0.2	0.3	1.4	1.7	1.3	1.5	0.5	0.3	1.3	1.0	0.7
108	0.3	0.2	0.7	0.7	1.2	1.5	1.4	0.7	0.5	1.5	1.1	0.7	1.3	0.9	0.7
109	0.3	0.2	0.7	0.7	0.8	1.1	1.4	3.6	2.6	1.5	3.8	2.6	1.3	1.6	1.2
110	0.3	0.2	0.8	0.7	0.4	0.5	1.3	2.1	1.5	1.5	0.6	0.4	1.3	4.9	3.8

DA Scheme	3 Mids/3 Ties - DER-driven Distribution Automation Circuits														RFI-only		
Switch Type	Fault Interrupting Mids						All Fault Interrupting										
FLISR Scheme	Assisted Switching			Automated Switching			Remote Switching			Assisted Switching			Automated Switching				
	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs	BCR	Benefits	Costs
Totals	4.6	553	119	4.8	573	119	2.8	396	144	3.7	558	149	3.9	578	149	1.5	35	24
Circuit Detail																		
86	2.4	2.9	1.2	2.5	3.0	1.2	1.3	1.0	0.7	1.9	1.3	0.7	1.9	2.1	1.1	0.9	0.2	0.2
87	2.4	3.7	1.6	2.5	3.9	1.6	1.3	1.0	0.7	1.9	2.0	1.1	1.9	1.4	0.7	0.9	0.2	0.2
88	2.4	4.1	1.7	2.5	4.3	1.7	1.3	1.3	1.0	1.9	1.9	1.0	1.9	2.0	1.0	0.9	0.2	0.2
89	2.3	2.1	0.9	2.4	6.0	2.5	1.3	1.1	0.8	1.8	1.3	0.7	1.8	2.5	1.4	0.9	0.2	0.2
90	2.3	5.8	2.5	2.4	2.2	0.9	1.3	3.8	2.9	1.8	2.4	1.4	1.8	1.4	0.7	0.9	0.2	0.2
91	2.3	2.0	0.9	2.4	2.1	0.9	1.3	2.7	2.1	1.8	1.1	0.6	1.8	7.8	4.2	0.8	0.2	0.3
92	2.2	2.4	1.1	2.3	2.5	1.1	1.3	1.8	1.3	1.8	7.5	4.2	1.8	2.2	1.2	0.8	0.2	0.2
93	2.2	2.8	1.3	2.3	2.9	1.3	1.3	2.6	2.0	1.7	2.1	1.2	1.8	5.5	3.1	0.8	0.2	0.2
94	2.2	2.3	1.1	2.2	2.4	1.1	1.3	1.7	1.4	1.7	5.3	3.1	1.8	1.1	0.6	0.8	0.2	0.2
95	2.1	0.9	0.4	2.2	1.0	0.4	1.3	1.4	1.1	1.7	3.8	2.3	1.7	2.9	1.7	0.8	0.2	0.2
96	2.1	3.4	1.6	2.2	3.5	1.6	1.2	1.5	1.2	1.7	1.2	0.7	1.7	3.5	2.0	0.8	0.2	0.2
97	2.1	1.7	0.8	2.1	1.7	0.8	1.2	0.8	0.7	1.7	2.8	1.7	1.7	1.3	0.7	0.8	0.2	0.2
98	2.0	2.1	1.1	2.1	2.2	1.1	1.2	4.9	4.2	1.7	3.4	2.0	1.7	2.4	1.4	0.8	0.2	0.2
99	2.0	7.5	3.8	2.1	7.8	3.8	1.2	3.6	3.1	1.7	2.3	1.4	1.7	2.5	1.4	0.8	0.2	0.2
100	2.0	1.7	0.9	2.1	1.8	0.9	1.2	1.0	0.8	1.6	2.4	1.4	1.7	3.9	2.3	0.8	0.2	0.2
101	2.0	2.4	1.2	2.0	2.5	1.2	1.2	1.3	1.1	1.6	2.1	1.3	1.7	2.2	1.3	0.8	0.1	0.2
102	1.9	1.2	0.6	2.0	6.9	3.4	1.2	2.0	1.7	1.6	2.8	1.7	1.7	2.9	1.7	0.7	0.2	0.3
103	1.9	6.7	3.4	2.0	4.3	2.1	1.1	1.6	1.4	1.6	1.8	1.1	1.7	1.9	1.1	0.7	0.2	0.2
104	1.9	4.1	2.1	2.0	5.5	2.8	1.1	2.3	2.0	1.6	6.7	4.1	1.7	6.9	4.1	0.7	0.2	0.2
105	1.9	5.3	2.8	2.0	1.3	0.6	1.1	1.0	0.9	1.6	1.7	1.1	1.7	1.8	1.1	0.7	0.1	0.2
106	1.9	1.0	0.5	2.0	1.9	1.0	1.1	1.6	1.4	1.6	4.1	2.6	1.6	4.3	2.6	0.7	0.1	0.2
107	1.9	1.4	0.7	1.9	1.5	0.7	1.1	1.4	1.3	1.6	4.1	2.6	1.6	4.3	2.6	0.7	0.2	0.2
108	1.9	1.8	1.0	1.9	1.0	0.5	1.1	1.2	1.1	1.6	1.3	0.8	1.6	1.3	0.8	0.7	0.2	0.2
109	1.9	3.8	2.0	1.9	1.3	0.7	1.1	1.9	1.7	1.6	1.4	0.9	1.6	1.5	0.9	0.7	0.1	0.2
110	1.8	1.3	0.7	1.9	3.9	2.0	1.1	1.4	1.3	1.5	1.8	1.2	1.6	1.9	1.2	0.7	0.1	0.2

Workpaper- Southern California Edison / 2025 GRC

Appendix 1

Workpaper Title:

2018 GRC Estimated Reliability Improvement due to Distribution Automation

I. OBJECTIVE

This paper describes the methodology and calculations through which Southern California Edison (SCE) establishes the expected annual incremental reliability improvement to be realized through the installation of various levels of Distribution Automation (D.A.) on its distribution circuits.

II. OVERVIEW

Reliability is expressed in terms of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) where SAIDI is measured in minutes and SAIFI is quantified in occurrences per year. SCE seeks to understand how may SAIDI and SAIFI be affected by the installation of D.A. equipment on its circuits. In this paper, the incremental reliability improvement in progressing from one lesser level of automation to the ultimate 3-mids 3-ties configuration is calculated for five representative circuits and, subsequently, the averaged results is applied to all distribution circuits to estimate the total system reliability improvement.

III. METHODOLOGY

1. Calculate the sum of year 2013 through year 2015 main-line Customer Minutes of Interruption (CMI) and Customer Interruption (CI) for each of SCE's 4600 distribution circuits where only main-line interruptions are considered since D.A. exclusively affects main-line events. Data from SCE's Outage Database Reliability Metrics (ODRM) system was used for all calculations. Refer to Tab "**Metric Calcs**" of file "**Reliability ImprovementAsFunctionOfDA.xlsx**" for further details.
2. Determine the existing level of automation for each circuit. There are 16 combinations of automation; ranging from zero mid and zero tie to three mids and three ties. The number of mid Remote Controlled Switch (RCS) and tie RCS for each circuit is established by querying data extracted from SCE's Outage Management System (OMS). Refer to Tab "**Metric Calcs**" of file "**ReliabilityImprovementAsFunction OfDA.xlsx**" for further details.
3. For each level of automation, calculate the optimal SAIDI and SAIFI for each of the five representative circuits by exhaustively searching for the ideal location of each successive mid RCS. See **TABLE T-1** and **TABLE T-2a** through **TABLE T-2e** for a summary of the results. Refer to files "**CYME Simulation Results.docx**" and Tab "**CYME WCR'd Simulation Results.xlsx**" of file "**ReliabilityImprovementAs FunctionOfDA.xlsx**" for further details.
4. Calculate the percent incremental reliability improvement while progressing from each level of automation to the ultimate 3-mids 3-ties scheme. Refer to Tab "**CYME WCR'd Simulation Results.xlsx**" of file "**Reliability ImprovementAsFunction OfDA.xlsx**" for further details.
5. Calculate the total theoretical improvement for the top 200 worst performing circuits. The improvement for each circuit is directly dependent on its existing level of automation and on its historical performance. See **TABLE T-1** and **TABLE T-3** for summary.

IV. RESULTS

Based on reliability simulation results and historical interruption data, SCE estimates approximately 7% reduction in SAIDI and 5% reduction in SAIFI might be achieved annually if the top 200 worst performing circuits are upgraded to the 3-mids 3-ties automation scheme.

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Average Expected Reliability Improvement				
#MIDs	**#TIEs**	**% SAIDI Improvement**	**% SAIFI Improvement**	**% MAIFI Improvement**
0	0	63%	65%	-67%
0	1	62%	65%	-67%
0	2	62%	65%	-67%
0	3	62%	65%	-67%
1	0	52%	54%	-32%
1	1	37%	39%	-16%
1	2	37%	39%	-16%
1	3	37%	39%	-16%
2	0	44%	46%	-23%
2	1	20%	22%	-7%
2	2	18%	21%	-6%
2	3	19%	22%	-6%
3	0	38%	40%	-17%
3	1	14%	18%	-6%
3	2	3%	3%	-1%
3	3	0%	0%	0%

TABLE T-1

Estimated Reliability Improvement due to D.A.								
YEAR	**CMI**	**CI**		**SAIDI**	**SAIFI**		**% SAIDI**	**% SAIFI**
1	33,116,694	234,629		6.62	0.047		6.62%	4.69%
2	18,979,055	154,929		3.80	0.031		3.80%	3.10%
3	14,682,672	129,326		2.94	0.026		2.94%	2.59%
4	12,633,715	115,869		2.53	0.023		2.53%	2.32%
5	9,185,675	90,307		1.84	0.018		1.84%	1.81%

TABLE T-3

BONANZA 12kV CYME Simulation Results

#MIDs	#TIEs	cSAIDI	cSAIFI	cMAIFI	% SAIDI Improvement	% SAIFI Improvement	% MAIFI Improvement
0	0	5.572	2.419	3.229	55%	56%	-42%
0	1	5.434	2.419	3.229	54%	56%	-42%
0	2	5.433	2.419	3.229	54%	56%	-42%
0	3	5.396	2.419	3.229	53%	56%	-42%
1	0	4.720	2.020	3.627	47%	48%	-27%
1	1	3.282	1.273	4.374	23%	17%	-5%
1	2	3.240	1.273	4.374	22%	17%	-5%
1	3	3.240	1.273	4.374	22%	17%	-5%
2	0	3.921	1.609	4.039	36%	34%	-14%
2	1	2.936	1.277	4.370	14%	17%	-5%
2	2	2.894	1.277	4.370	13%	17%	-5%
2	3	2.894	1.277	4.370	13%	17%	-5%
3	0	3.587	1.461	4.187	30%	28%	-10%
3	1	3.422	1.678	3.969	26%	37%	-16%
3	2	2.798	1.199	4.449	10%	12%	-3%
3	3	2.522	1.054	4.594	0%	0%	0%

TABLE T-2a

SPRAGUE 12kV CYME Simulation Results

#MIDs	#TIEs	cSAIDI	cSAIFI	cMAIFI	% SAIDI Improvement	% SAIFI Improvement	% MAIFI Improvement
0	0	6.975	3.009	3.637	69%	66%	-55%
0	1	6.885	3.009	3.637	69%	66%	-55%
0	2	6.839	3.009	3.637	69%	66%	-55%
0	3	6.815	3.020	3.637	68%	66%	-55%
1	0	4.851	2.311	4.335	56%	56%	-30%
1	1	4.271	2.245	4.401	50%	54%	-28%
1	2	4.250	2.245	4.401	49%	54%	-28%
1	3	4.210	2.245	4.401	49%	54%	-28%
2	0	3.850	1.713	4.933	44%	40%	-14%
2	1	2.696	1.307	5.339	20%	22%	-5%
2	2	2.675	1.307	5.339	20%	22%	-5%
2	3	2.662	1.307	5.339	19%	22%	-5%
3	0	3.205	1.424	5.222	33%	28%	-8%
3	1	2.456	1.306	5.340	13%	22%	-5%
3	2	2.162	1.022	5.624	1%	0%	0%
3	3	2.149	1.022	5.624	0%	0%	0%

TABLE T-2b

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OPPORTUNITY 16kV CYME Simulation Results

#MIDs	#TIEs	cSAIDI	cSAIFI	cMAIFI	% SAIDI Improvement	% SAIFI Improvement	% MAIFI Improvement
0	0	1.429	0.789	0.822	62%	68%	-65%
0	1	1.429	0.789	0.822	62%	68%	-65%
0	2	1.429	0.789	0.822	62%	68%	-65%
0	3	1.429	0.789	0.822	62%	68%	-65%
1	0	1.056	0.548	1.063	48%	53%	-28%
1	1	0.881	0.424	1.187	38%	40%	-14%
1	2	0.877	0.424	1.187	37%	40%	-14%
1	3	0.877	0.424	1.187	37%	40%	-14%
2	0	0.947	0.481	1.130	42%	47%	-20%
2	1	0.733	0.339	1.273	25%	24%	-7%
2	2	0.698	0.341	1.270	21%	25%	-7%
2	3	0.698	0.341	1.270	21%	25%	-7%
3	0	0.860	0.464	1.147	36%	45%	-18%
3	1	0.640	0.306	1.306	14%	16%	-4%
3	2	0.550	0.256	1.356	0%	0%	0%
3	3	0.550	0.256	1.356	0%	0%	0%

TABLE T-2c

SIZZLER 12kV CYME Simulation Results

#MIDs	#TIEs	cSAIDI	cSAIFI	cMAIFI	% SAIDI Improvement	% SAIFI Improvement	% MAIFI Improvement
0	0	1.826	0.943	0.566	59%	66%	-110%
0	1	1.781	0.943	0.566	58%	66%	-110%
0	2	1.781	0.943	0.566	58%	66%	-110%
0	3	1.778	0.943	0.566	58%	66%	-110%
1	0	1.412	0.684	0.825	47%	53%	-44%
1	1	1.123	0.530	0.979	34%	39%	-21%
1	2	1.123	0.530	0.979	34%	39%	-21%
1	3	1.118	0.530	0.979	34%	39%	-21%
2	0	1.274	0.649	0.860	42%	50%	-38%
2	1	0.972	0.446	1.064	24%	28%	-12%
2	2	0.894	0.407	1.102	17%	21%	-8%
2	3	0.888	0.407	1.102	16%	21%	-8%
3	0	1.178	0.595	0.914	37%	46%	-30%
3	1	0.830	0.364	1.145	10%	12%	-4%
3	2	0.744	0.322	1.187	0%	0%	0%
3	3	0.743	0.322	1.187	0%	0%	0%

TABLE T-2d

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CONCOURSE 16kV CYME Simulation Results

#MIDs	#TIEs	cSAIDI	cSAIFI	cMAIFI	% SAIDI Improvement	% SAIFI Improvement	% MAIFI Improvement
0	0	0.708	0.439	0.507	70%	71%	-62%
0	1	0.663	0.439	0.507	68%	71%	-62%
0	2	0.663	0.439	0.507	68%	71%	-62%
0	3	0.663	0.439	0.507	68%	71%	-62%
1	0	0.532	0.328	0.619	61%	61%	-32%
1	1	0.364	0.221	0.725	42%	42%	-13%
1	2	0.364	0.228	0.718	42%	44%	-14%
1	3	0.354	0.221	0.725	41%	42%	-13%
2	0	0.484	0.303	0.644	57%	58%	-27%
2	1	0.261	0.159	0.787	20%	19%	-4%
2	2	0.261	0.159	0.787	20%	19%	-4%
2	3	0.274	0.173	0.773	23%	26%	-6%
3	0	0.443	0.273	0.674	53%	53%	-22%
3	1	0.225	0.133	0.813	7%	4%	-1%
3	2	0.225	0.133	0.813	7%	4%	-1%
3	3	0.210	0.128	0.819	0%	0%	0%

TABLE T-2e

Appendix 2

Workpaper Title:

Southern California Edison: 2019 Value of Service Study

REPORT

Southern California Edison: 2019 Value of Service Study

July 29, 2019

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1 Executive Summary

This report summarizes the results of Southern California Edison's (SCE) 2019 Value of Service (VOS) study. This research project was designed to collect detailed outage cost information from SCE's residential, small and medium business (SMB), and large commercial and industrial (C&I) customer classes. The report also contains a detailed description of the methodology used to survey each customer segment and the econometric procedures for analyzing the data.

The primary objective of the VOS study was to estimate system-wide outage costs by customer class. The VOS analyses are based on data from three separate surveys (one for each customer class) conducted between December, 2018 and June, 2019. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 30 years by various parties.[1]

This report includes results for four different interruption cost metrics: cost per customer minute interrupted (CMI), cost per outage event, cost per average kW, and cost per unserved kWh. The primary metric of interest for SCE is cost per CMI and these results are summarized by customer class and for the SCE system as a whole in Table 1-1.

Table 1-1: Cost per Average CMI Estimates by Customer Class

Outage Duration	Residential ($/CMI)	SMB ($/CMI)	Large C&I ($/CMI)	Systemwide ($/CMI)
Momentary	$0.92	$107.06	$3,539.34	$13.28
1 hour	$0.11	$51.65	$1,334.49	$6.14
4 hours	$0.05	$14.41	$630.46	$1.97
8 hours	$0.04	$9.69	$500.93	$1.38
24 hours	$0.02	$5.63	$309.75	$0.81

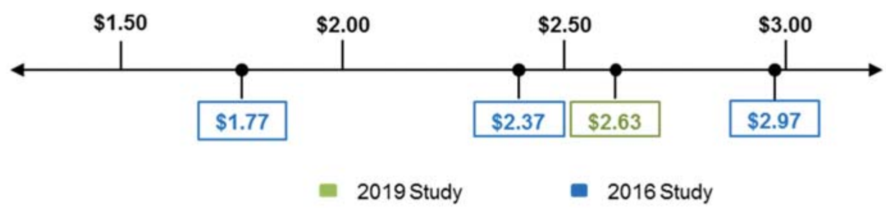
The results obtained from this study are similar to those of a previous study carried out in 2016 by Nexant. In that study, Nexant used information from the Interruption Cost Estimate (ICE) Calculator to estimate an average cost per interruption minute of $2.37 (adjusted for inflation). The estimated average cost per CMI for the 2019 study is $2.63. Figure 1-1 compares the systemwide cost per average CMI to the results from the 2016 study.[2] The blue numbers represent the lower bound, midpoint, and upper bound respectively from 2016 (in $2019 – adjusted for inflation) and the green number represents the results from the current study. The

[1] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook.* Report no. TR-106082. Palo Alto, CA: EPRI.

[2] Schellenberg, J., and J. Gai (2016). *Southern California Edison Customer Interruption Cost Analysis.* Prepared for Southern California Edison Company. June 15, 2017 (Version 2).

blended cost per average CMI of $2.63 lies between the midpoint and the upper bound from the previous study.

Figure 1-1: Systemwide Cost per Average CMI Estimates



2 Introduction

Nexant, Inc. was retained by Southern California Edison to conduct its 2019 Value of Service study to estimate the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from SCE's residential, SMB, and large C&I customer classes. This report summarizes the methodology and results of the study. The primary objective of the VOS study was to estimate systemwide outage costs overall and by customer class.

Outage cost estimates are used to assess the cost-effectiveness of investments in generation, transmission and distribution systems and to strategically compare alternative investments in order to determine which provides the most combined benefits to the utility and its customers. This comprehensive approach to valuing reliability, commonly known as "value-based reliability planning," has been a well-established theoretical concept in the utility industry for the past 30 years.

2.1 Study Methodology

The VOS estimates provided in this report are based on data from three separate surveys (one for each customer class) conducted between December 2018 and June 2019. This survey methodology has been implemented by many electric utilities throughout the United States over the past 30 years, including several studies by Pacific Gas & Electric Company (PG&E) (most recently in 2012).[3] This study and the prior studies employed a common survey methodology, including sample designs, measurement protocols, survey instruments, and operating procedures. This methodology is described in detail in LBNL's Interruption Cost Estimation Guidebook.[4] The results of 34 prior studies conducted using this methodology are part of a meta-analysis of nationwide outage costs that is summarized in a 2015 report by LBNL.[5]

2.2 Economic Value of Service Reliability

The purpose of VOS research is to measure the economic value of service reliability, using information regarding outage costs as a proxy. Under the general theory of welfare economics, the economic value of service reliability is equal to the economic losses that customers experience as a result of service interruptions. The history of efforts to measure customer outage costs goes back several decades. In that time, several approaches have been used. These include:

- Scaled macro-economic indicators (i.e., gross domestic product, wages, etc.);

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[3] Freeman, Sullivan & Co. (2012). *Pacific Gas & Electric Company's 2012 Value of Service Study*. Prepared for Pacific Gas & Electric Company.

[4] Sullivan, M.J., Collins, M.T., Schellenberg, J., & Larsen, P.H. (2018). *Estimating Power System Interruption Costs*. Berkeley, CA.

[5] Sullivan, M. J., Schellenberg, J. & Blundell, M., 2015. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Berkeley, CA: Lawrence Berkeley National Laboratory.

- Market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates); and
- Survey-based indicators (i.e., cost estimates obtained from surveys of representative samples of utility customers).

The most widely used approach to estimating customer outage costs is through analysis of data collected via customer surveys. In a customer outage cost survey, a representative sample of customers is asked to estimate the costs they would experience given a number of hypothetical outage scenarios. In these hypothetical outage scenarios, key characteristics of the outages described in these scenarios are varied systematically in order to measure differential effects of service outage events with different characteristics. A variety of statistical techniques are then used to identify and describe the relationships between customer economic losses and outage attributes.

Survey-based methods are generally preferred over the other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability conditions not observable using the other techniques. These methods were selected for use for this SCE VOS study.

2.3 Valuation Methods

Two basic valuation methods are used to measure outage costs in the surveys – direct cost measurement and willingness to pay (WTP). Direct cost measurement techniques involve asking customers to estimate the direct costs they will experience during a service outage. WTP measurement techniques involve measuring the amount customers say they would be willing to pay to avoid experiencing the outage. In both approaches, the surveys ask respondents to provide these estimates for a number of outage scenarios, which vary in terms of the characteristics of the event.

2.3.1 Direct Cost Measurement

Nexant used direct cost measurement for non-residential customers (SMB, and large C&I), because outage costs for these customers are tangible and relatively simple to estimate directly. At its most general level, the direct cost of an outage is defined as follows:

$$\begin{aligned} Direct\ Cost = Value\ of\ Lost\ Production + Outage\ Related\ Costs \\ - Outage\ Related\ Savings \end{aligned}$$

The *Value of Lost Production* is the amount of revenue the surveyed business would have generated in the absence of the outage minus the amount of revenue it was able to generate given that the outage occurred. It is the business's net loss in the economic value of production after its ability to make up for lost production has been taken into account. It includes the entire cost of making or selling the product as well as any profit that could have been made on the production.

Outage Related Costs are additional production costs directly incurred because of the outage. These costs include:

- Labor costs to make up any lost production (which can be made up);

- Labor costs to restart the production process;
- Material costs to restart the production process;
- Costs resulting from damage to input feed stocks;
- Costs of re-processing materials (if any); and
- Cost to operate backup generation equipment.

Outage Related Savings are production cost savings resulting from the outage. When production or sales cannot take place, there are economic savings resulting from the fact that inputs to the production or sales process cannot be used. For example, during the time electric power is interrupted, the enterprise cannot consume electricity and thus will experience a savings on its electric bill. In many cases, savings resulting from outages are small and do not significantly affect outage cost calculations. However, for manufacturing enterprises where energy and feedstock costs account for a significant fraction of production cost, these savings may be quite significant and must be measured and subtracted from the other cost components to ensure outage costs are not double counted. These savings include:

- Savings from unpaid wages during the outage (if any);
- Savings from the cost of raw materials not used because of the outage;
- Savings from the cost of fuel not used; and
- Scrap value of any damaged materials.

In measuring outage costs, only the incremental losses resulting from unreliability are included in the calculations. Incremental losses include only those costs described which are above and beyond the normal costs of production. If the customer is able to make up some percentage of its production loss at a later date (e.g., by running the production facility during times when it would normally be idle), the outage cost does not include the full value of the production loss. Rather, it is calculated as the value of production not made up plus the incremental cost of additional labor and materials required to make up the share of production eventually recovered.

2.3.2 Willingness to Pay Approach

Outage cost estimates for the residential segment are based customers' stated willingness to pay to avoid hypothetical electrical outages. This approach was employed because a substantial fraction of residential interruption costs is intangible (e.g., discomfort and inconvenience) and not directly measurable; and WTP measurements are capable of measuring these costs in addition to the direct worth of economic losses they might experience. The WTP approach to outage cost estimation is quite different than the direct cost measurement approach. Rather than asking what an outage would cost the customer, the WTP approach asks how much the customer would pay to avoid its occurrence. This technique employs the concept of compensating valuation, where customers are asked to estimate the economic value that would leave their welfare unchanged compared to a situation in which no outage occurred. This approach is especially useful when intangible costs are present, which by their nature are difficult to estimate using the direct cost measurement approach.

2.4 Report Organization

The remainder of this report proceeds as follows:

- **Section 3 – Survey Methodology:** This section covers the survey methodology, including details on the survey implementation approach by customer class, survey instrument design, sample design, and data collection procedures for each customer class.
- **Section 4 – Outage Cost Estimation Methodology**: The results of this study focus on the following four metrics: cost per outage event, cost per customer minute interrupted, cost per average kW, and cost per unserved kWh. This section explains what each of these four key metrics represents, how they are calculated from the survey data and how they are related to each other.
- **Sections 5 through 8 – Results**: These four sections provide the results for residential customers (Section 5), small/medium business (Section 6), large C&I (Section 7), and systemwide results (section 8). Results are presented for the metrics defined in Section 4.

3 Survey Methodology

Table 3-1 provides an overview of the survey implementation approach by customer class. Residential customers were recruited with a letter that encouraged them to go online to complete the survey (the letter included a link to the online survey along with a unique access code specific to each customer). If a residential customer did not complete the survey online, Nexant arranged to have a paper copy sent to the customer's mailing address. Customers for whom SCE had email addresses were sent an email with a direct link to that customer's unique online survey. SMB customers were sent a letter and email (when applicable) to introduce them to the study, then recruited by telephone. They were encouraged to fill out the survey online, but were also offered the option of receiving a paper survey to complete and submit through the mail. If the customer preferred to go online to complete the survey, a link to the online survey and a unique access code specific to each customer were provided in an email. Large C&I customers were recruited by telephone and received an in-person interview. SCE account representatives assisted with recruitment by contacting large C&I customers to inform them of the study and request their participation.

Although all survey instruments included variations of WTP and direct cost questions, the results in Sections 5 through 8 are based on the valuation methods listed in Table 3-1.

Table 3-1: Survey Implementation Approach by Customer Class

Customer Class	Initial Sample Design Target	Recruitment Method	Data Collection Approach	Valuation Method	Incentive Provided
Residential	1,000	Letter/Email	Mail/Internet Survey	WTP	$5
SMB	800	Telephone	Mail/Internet Survey	Direct Cost	$50
Large C&I	150	Telephone	In-person Interview	Direct Cost	$150

3.1 Survey Instrument Design

This discussion of the survey instrument design focuses on the outage scenarios, which were designed the same for all segments. The survey instruments are included as appendices in case more detail is required on other aspects of the survey.

Considering that most customers rarely experience sustained power interruptions, an outage cost survey presents the respondent with hypothetical outage scenarios that are specific to a certain time period. A key objective of this study was to estimate the average outage cost across all time periods. Outages are distributed throughout the day for all customer classes. As shown in Figure 3-1, there is no single hour in a given season that accounts for more than 2% of outages or less than 0.5% of outages. The objective of estimating the average outage cost across all time periods was accomplished by randomizing the outage scenarios in proportion to the distribution of onset times and onset season in Figure 3-1. As a result, the outage cost estimates provided in Sections 4 through 8 are representative of the average outage cost across all time periods as opposed to just one time period.

Figure 3-1: Distribution of Sustained Outages by Onset Time and Season

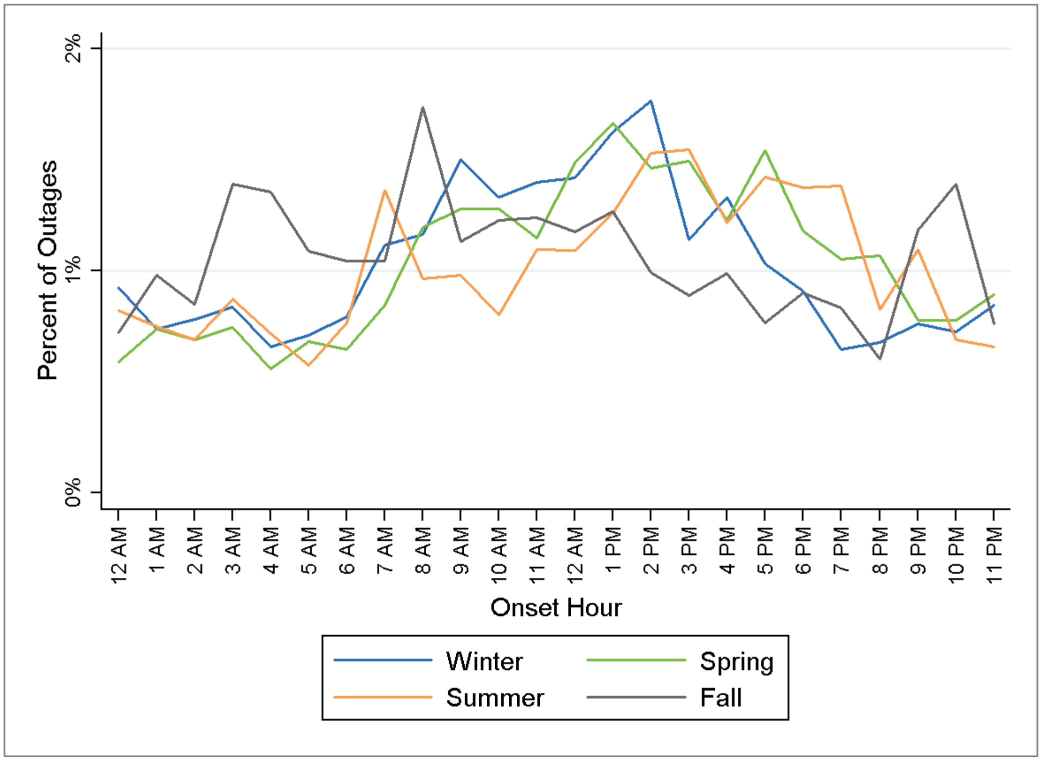


Table 3-2 provides an example set of outage scenarios. In accordance with Figure 3-1, this onset time of 11 AM in the summer was assigned to approximately 1.1% of respondents. Each respondent was assigned the same onset time for all scenarios in order to minimize respondent burden. An alternative was to randomize the onset time for every scenario and respondent, but that would likely lead to confusion and the survey would be more difficult to complete. In order to determine the degree to which planned outages affected outage costs, Scenario A had an additional question that asked the customer how their outage costs would differ if the scenario included an advance warning.

Scenario F was always the single weekend scenario, which provided very useful information on how outage costs are affected by timing during the week. Finally, each set of scenarios always included durations of 5 minutes (Momentary), 1 hour, 4 hours, 8 hours and 24 hours. Scenario A was 4 hours for half of customers and 8 hours for the remaining customers, with Scenario D containing the other duration. In this example set of outage scenarios, the 4-hour duration was randomly assigned to the weekend outage scenario F, which was not always the case. In fact, there were 960 different, randomly assigned versions of the survey (4 possible seasons x 5 possible durations for the weekend scenario x 24 possible hours for the onset times x 2 different possible durations for Scenario A/C).

Table 3-2: Example Set of Outage Scenarios

Scenario	Season	Time of Week	Start Time	End Time	Duration
A A (w/ notice)	Summer	Weekday	11:00 AM	3:00 PM	4 hours
B	Summer	Weekday	11:00 AM	Noon	1 hour
C	Summer	Weekday	11:00 AM	11:05 AM	5 minutes (Momentary)
D	Summer	Weekday	11:00 AM	7:00 PM	8 hours
E	Summer	Weekday	11:00 AM	11:00 AM (Next Day)	24 hours
F	Winter	Weekend	11:00 AM	3:00 PM	4 hours

3.1.1 Resilience Questions

As a part of the survey, residential and SMB customers were asked about how SCE could improve various elements of their service. The elements of service included improving power quality, providing environmentally clean electricity, preparing for emergencies such as earthquakes or terrorist attacks, preventing wildfires, and avoiding power outages. Respondents were asked to rank each element on a scale of one to ten in terms of how important they found each element. Residential and SMB customers were also asked how satisfied they were with SCE's current service reliability. Finally, residential customers were asked to assume there was a California ballot initiative that established a fund for making improvements to the electrical grid. The improvements would prevent damage from threats like wind storms, wildfires, and cyberattacks. The respondents were asked whether they would vote for the ballot initiative if each household would be required to pay either $12, $30, or $60 per year to make the improvements listed above. Each customer was randomly assigned one of these three amounts.

3.2 Sample Design

The study aimed for the following number of completed surveys for each customer class:

- 1,000 residential customers;
- 800 SMB customers;
- 150 large C&I customers.

In addition to segmentation by usage within each customer class, as described below, the initial sample design targets for residential customers were further divided between 400 Net Energy Metered (NEM) Customers and 600 non-NEM customers. This design allowed for a comparison of outage costs between residential customers with and without distributed generation, most commonly rooftop photovoltaic (solar) systems.

Before detailing the sample design methodology and how these sample points were distributed among usage categories, it is important to note that a "customer" refers to a unique combination of "customer number" and "service address" in SCE's customer database. For residential customers, there was generally only one account ID associated with each unique combination. For non-residential customers, there could be multiple account IDs for each customer number-service address combination. When customers completed an outage cost survey, they provided cost estimates for the specific service address. Usage and customer contact information were aggregated across all of the accounts associated with each entity at each service address and then the customers were sampled.

Nexant stratified each customer class by the estimated outage cost calculated using the underlying data in the ICE Calculator by employing a two-step process to achieve an optimal sample stratification scheme. In the first step, Nexant identified the optimal strata boundaries using the Dalenius-Hodges method. Next, it determined the optimal allocation among the Dalenius-Hodges strata using the Neyman allocation. This two-step approach is particularly useful for measuring skewed populations and maximizes survey precision for a given sample size and number of strata. This sampling approach is necessary as the distribution of usage per customer is highly skewed. Since there is no way to precisely account for distributed generation behind the meter when analyzing the net usage data for NEM customers, Nexant looked at average nighttime kW (when there would be no solar generation) when calculating outage costs for NEM customers. This prevented any distortion in relative customer size caused by different levels of generation behind the meter.

Table 3-3, Table 3-4, Table 3-5, and Table 3-6 summarize the sample designs for residential (NEM and non-NEM), SMB, and large C&I customers respectively. The residential and SMB customer classes each had four sample strata. The large C&I customer class was divided into three strata. For each of the customer classes, the sample stratification method led to the stratum with the largest average kW having a larger percentage of customers in the sample than in the population. As intended, this design allowed the sample to capture the higher and more variable outage costs for customers in those categories.

Table 3-3: Sample Design Summary – non NEM Residential

Stratum	Usage Range (Average kW)	Population	% of Population	Initial Sample Design Target	% of Sample
1	0 to 0.3	610,649	15%	134	22%
2	0.3 to 0.6	1,422,110	35%	158	26%
3	0.6 to 1.1	1,443,273	36%	159	27%
4	1.1 and above	580,226	14%	149	25%
Overall		**4,056,258**	**100%**	**600**	**100%**

Table 3-4: Sample Design Summary – NEM Residential

Stratum	Usage Range (Average Nighttime kW)	Population	% of Population	Initial Sample Design Target	% of Sample
1	0 to 0.7	43,691	15%	88	22%
2	0.7 to 1.1	93,612	35%	95	26%
3	1.1 to 1.9	91,299	36%	110	27%
4	1.9 and above	33,019	15%	107	24%
Overall		**261,621**	**100%**	**400**	**100%**

Table 3-5: Sample Design Summary – SMB

Stratum	Usage (Average kW)	Population	% of Population	Initial Sample Design Target	% of Sample
1	0.86	235,248	54%	72	9%
2	4.95	152,901	35%	460	57%
3	25.4	37,692	9%	132	17%
4	105	11,978	3%	136	17%
Overall		**437,819**	**100%**	**800**	**100%**

Table 3-6: Sample Design Summary – Large Commercial and Industrial

Stratum	Usage (Average kW)	Population	% of Population	Initial Sample Design Target	% of Sample
1	210	1,608	46%	46	23%
2	665	1,493	43%	72	36%
3	3,728	366	11%	82	42%
Overall		**3,467**	**100%**	**150**	**100%**

3.3 Data Collection Procedures

This section summarizes the data collection procedures for each customer class.

3.3.1 Residential Customers

The residential survey was conducted online and via mail. It was distributed to the target respondents in two waves. In the first wave, respondents received a $5 bill and a cover letter on SCE stationery explaining the purpose of the study and requesting their participation. This letter also contained a URL and unique respondent ID number so that respondents could complete the survey online. Customers for which SCE had email addresses were also sent emails explaining the study and containing a unique URL, which customers could use to access their survey directly. Approximately three to four weeks after the first wave was mailed, respondents who did not complete the online survey received a reminder letter with a paper copy of the survey. The letters and survey packet included an 800 number that respondents could call to verify the legitimacy of the survey and ask questions. After the paper survey was sent, customers who had not filled out the survey received one communication via email and another via mail to remind them to complete the survey.

3.3.2 Small & Medium Business Customers

SMB customers were sent a paper letter introducing them to the study, informing them that a survey recruiter would be contacting them via phone, and providing a toll-free number they could use to contact the survey recruiter directly. Customers for which SCE had email addresses that were not on the 'Do Not Contact' list were also sent emails with the same information. SMB customers were recruited by telephone to ensure that Nexant identified the appropriate individuals for answering questions related to energy and outage issues for that company; and to secure a verbal agreement from them to complete the survey. Telephone interviewers explained the purpose of the survey and indicated that a $50 incentive would be provided as a token of appreciation. The appropriate individuals were then sent an email containing an individualized survey link or had the survey package mailed or faxed to them containing:

- Additional explanation of the purpose of the research;
- Clear and easy-to-understand instructions for completing the survey questions;
- A telephone number they could call if they had questions about the research or wished to verify its authenticity;
- The survey booklet (or a link in the email to compete the survey online); and
- Return envelope with pre-paid postage (for the paper survey option).

After the survey link was emailed or the paper survey mailed, respondents were occasionally reminded via telephone and email to complete the survey. Reminder communications were capped at five to mitigate any negative impacts to customers. An incentive of $50 was mailed to respondents who completed the survey form.

The recruitment effort for the initial sample of 8,000 customers did not yield the expected response rate of 10 percent, which was based on previous VOS studies and tested with a small-scale pre-test prior to the main pain of the study. To boost the number of responses partway through the study, Nexant drew an additional sample of 5,330 SMB customers to raise the total sample to 13,330. All sampled customers were called via telephone to attempt to recruit them to participate. Customers that were not contacted were left messages to return the call. Five attempts were made to make contact with the customers before it was assumed that they would not return the call.

Due to time constraints, SCE and Nexant decided to forgo recruiting additional respondents after 413 SMB customers completed surveys and the entire sample had either been contacted or attempted five times. The response rate increased modestly from initial levels, but remained low compared to the PG&E study. In the past seven years since the PG&E study, the recruitment of SMB customers for this type of long and detailed survey has become particularly difficult, which may be due to the increasing rate of scam phone calls, particularly those that involve fraudulent use of the utility name. This environment drastically increases the challenge of reaching the right person within a business and subsequently convincing him/her to provide a large amount of private information about their business through the survey. As a result, Nexant is considering modifications to the SMB phone recruitment strategy for future surveys.

3.3.3 Large C&I Customers

For large C&I customers, SCE account reps first contacted the customer and identified the best person at each sampled business to call and recruit for the study. Then an experienced telephone recruiter contacted the appropriate representative at each of the sampled premises to ask them if they would participate in the study. The target respondent was usually a plant/building manager or engineering manager – someone who was familiar with the cost structure of the enterprise. Once the target respondent was identified and agreed to participate, the scheduler set up an appointment with the field interviewer. Once the appointment was scheduled, Nexant emailed the customer a confirmation along with a written description of the study and an explanation of the information they would be asked to provide. The interview was scheduled at the convenience of the customer. A financial incentive of $150 was offered for completion of the interview. On the agreed upon date, Nexant's field interviewer visited the sampled site and conducted the in-person interview. If the customer was unable to do an in-person interview, the interview was conducted over the phone instead.

As with SMB customers, the recruitment effort for the initial sample of 300 large C&I customers did not yield the expected response rate, which was primarily based on the 2012 PG&E VOS Study. To boost the number of responses, Nexant drew an additional sample of 100 large C&I customers to raise the total sample to 400. The additional sample size was determined to balance the goal of a higher sample size with impacts to both customers and SCE business operations. The response rate increased modestly from initial levels, but remained low compared to previous studies. A number of customers were interviewed who were unable to provide the necessary interruption cost data during the interview, due to either confidentiality considerations or lack of knowledge of the interviewee. Interviewers followed up via phone or email after the interview to try to obtain any critical information necessary to obtaining interruption cost estimates. Ultimately, interviewers collected complete data from 72 large C&I customers out of an initial sample design target of 150.

4 Outage Cost Estimation Methodology

4.1 Outage Cost Metrics

The results sections for each customer class (Sections 5 through 8) primarily focus on the following four outage cost metrics:

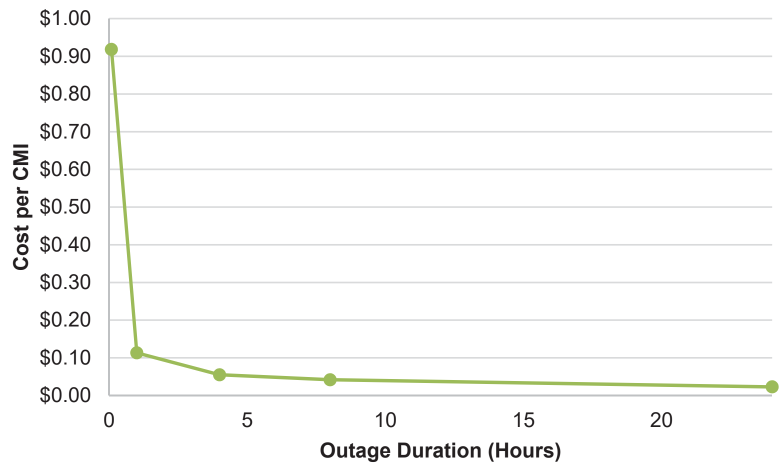
- Cost per Outage Event
- Cost per Customer Minute Interrupted (CMI)
- Cost per Average kW
- Cost per Unserved kWh

Before presenting the results, it is important to understand how each of these metrics was derived. This section begins with a description of the cost per outage event estimate, as it came directly from the survey responses and the other cost metrics were derived from this one.

Cost per outage event is the average cost of each outage duration for each customer class. The calculations account for the oversampling of large customers in each customer class by applying population weights. Each scenario on the survey focused on a specific outage event and then asked the respondent to provide the cost estimate. Before calculating the average outage cost, customers who estimated that longer outages would have lower costs than shorter outages were dropped from residential and SMB. These responses were dropped because respondents sometimes provide erroneous estimates when taking an outage cost survey, because they misunderstand or misinterpret the WTP question. This step was skipped for large C&I customers as trained interviewers were walking customers through the questions. After cleaning the survey responses, cost per outage event was derived as an average of the customer responses, weighted by usage category for each segment (and by the NEM status for the residential segments).

Cost per CMI is the average cost per outage event divided by the number of customer minutes interrupted for each outage duration and customer class. To create an overall cost per CMI across all durations, Nexant plotted the average cost per CMI for each calculated duration—5 minutes (momentary), 1 hour, 4 hours, 8 hours, and 24 hours—for each customer class. An example of this plot is shown below in Figure 4-1. Each line connecting each pair of outage costs can be expressed by an equation relating the y-value (cost per CMI) to the x-value (duration). Outage durations greater than 24 hours were assumed to have the same relationship as outages between 8 and 24 hours. For each SCE outage from 2013-2018, Nexant used the equations of these lines to determine the *cost per CMI* value of the outage. Each outage value was weighted by the number of customers affected by the outage. We then calculated the average cost per CMI across all outages from 2013-2018. The outage data provided by SCE did not indicate which historical outages impacted which customer classes—only the total number of customers impacted. This analysis assumed that the distribution of outage durations was the same for each customer class. This assumption allowed Nexant to apply SCE's historical outage data to each customer class for the blended estimates.

Figure 4-1: Residential Cost per CMI



Cost per average kW is the average cost per outage event normalized by average customer demand. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. Cost per average kW was derived by dividing average cost per outage event by the weighted average customer demand among respondents for each outage duration by customer class. It is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each outage duration and customer class, average cost per event was first calculated using the steps above and then divided by the average demand among respondents. The average demand for each respondent was calculated as the annual kWh usage divided by 8,760 hours in the year, as shown in the following equation:

$$Average\ Demand = \left(\frac{Annual\ kWh\ usage}{8{,}760}\right)$$

As in the cost per outage event average calculation, the average customer demand (the denominator of the ratio) was weighted by usage category for each segment.

Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. As in the cost per average kW calculation, cost per unserved kWh is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each duration and customer class, average cost per event was first calculated using the steps above and then divided by the expected unserved kWh. The expected unserved kWh is the estimated quantity of electricity that would have been consumed if an outage had not occurred.

4.2 Systemwide Outage Costs

The systemwide outage costs were calculated using a method similar to the one described above. The average systemwide cost per outage event was derived as an average of the customer responses, weighted by usage category for each segment and by the segment's size relative to the total SCE population. Once the average cost per outage event had been calculated for all of SCE, the same methodology described above was used to calculate each of the different outage metrics for the SCE system.

4.3 Special Considerations

Master metered customers: Approximately 5% of SMB respondents were master metered, or bulk metered, meaning that one meter would serve the property owner, but that the building was occupied by multiple tenants. Approximately 30% of these tenants were residential and 70% were non-residential. These tenants may or may not be sub-metered by a third party so that the property owner could bill them for electricity. SCE did not have contact information or consumption data for the tenants, as it did not directly meter the tenants. However, outage costs were incurred by the tenants. Interruption costs for master metered buildings were calculated by adding the outage costs for the property owner/manager with an estimate of the costs borne by the tenants. Tenant costs were estimated using either SMB or residential (depending on the type of master metered building) cost per square foot estimates and scaling them to the square footage occupied by the tenants in the building.

Unsampled SMB customers: Approximately 24% of SMB customers had an average demand of less than 0.25 kW. For non-residential customers, these types of accounts with low usage are often associated with customers that are not actively managing energy consumption. These accounts tend to have much lower response rates to surveys and were thus excluded from the sample. To account for the outage costs of these customers, Nexant estimated their outage costs based on the cost per average kW for sampled customers and adjusted the results to reflect that 24% of the population incurs outage costs significantly lower than the sampled population.

5 Residential Results

5.1 Response to Survey

Table 5-1 summarizes the survey response for residential customers. With 1,025 total completed surveys, customer response was above the overall sample design target of 1,000. Overall, the survey had a 31% response rate that varied across usage categories and by NEM status. NEM customers had a higher response rate overall, with a response rate of 35% compared to a response rate of 29% for non-NEM customers. The response rate also tended to be lower for customer segments with larger usage. However, non-response bias among high and low usage residential customers is not a significant concern for the outage cost estimates because usage category is factored into the stratification weights in the analysis.

Table 5-1: Residential Customer Survey Response Summary

NEM Status	Usage Category (Average kW Range)	Population	Initial Sample Design Target	Records Sampled	Completed Responses	Response Rate
Non-NEM	0 to 0.3	610,649	134	442	141	32%
	0.3 to 0.6	1,422,110	158	520	150	29%
	0.6 to 1.1	1,443,273	159	525	152	29%
	1.1 and above	580,226	149	493	123	25%
	non-NEM Overall	*4,056,258*	*600*	*1,980*	*566*	*29%*
NEM	0 to 0.7	43,691	88	289	113	39%
	0.7 to 1.1	93,612	95	315	120	38%
	1.1 to 1.9	91,299	110	363	125	34%
	1.9 and above	33,019	107	354	101	29%
	NEM Overall	*261,621*	*400*	*1,321*	*459*	*35%*
Overall		**4,317,879**	**1,000**	**3,301**	**1,025**	**31%**

Before presenting the outage cost estimates, it is important to summarize the prevalence of invalid responses. This summary is only provided for the residential segment because its cost estimates are derived from a WTP question. Some respondents are confused by WTP questions and sometimes seem to be answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such “protest responses” do not accurately reflect the cost of an outage for a customer, so they were removed from the analysis.

To identify these protest responses, the survey included a follow-up question for respondents that indicated a WTP value of $0. If the respondent verified that WTP was $0 because the outage scenario would not in fact result in any noticeable costs, the $0 response was confirmed as valid and included in the cost estimate calculations. However, if the respondent indicated that WTP was $0 because they thought it was unfair to pay more for electric service, the response was deemed invalid and not included in the cost estimate calculations. Table 5-2 summarizes the prevalence of invalid responses by outage duration in the residential survey. The percentage of responses deemed invalid was approximately 30% of all responses. The residential interruption cost estimates are based on the number of responses indicated in the "Valid Responses" category, which is fewer than the 1,025 overall responses.

Table 5-2: Summary of Invalid Responses – Residential

Outage Duration	Total Responses	Invalid Responses		Valid Responses
		N	%	
Momentary	985	299	30%	686
1 hour	985	295	30%	690
4 hours	985	309	31%	676
8 hours	985	312	32%	673
24 hours	985	323	33%	662

5.2 Outage Cost Estimates

Figure 5-1 and Table 5-3 provide the residential cost per outage event estimates by NEM status. For a 1-hour outage, residential customers experience a cost of $6.79 on average across all customers. Cost per outage event increases to $19.98 at 8 hours and $32.91 for a 24-hour outage. NEM customers experience higher outage costs than non-NEM customers across all durations. For momentary outages, NEM outage costs are 22% higher than those of non-NEM customers. This difference increases sharply at 1 hour, where NEM outage costs are nearly 90% higher, which may be due to NEM respondents factoring in the potential distributed generation losses that accumulate beyond momentary outages. Between 4 and 24 hours, NEM outage costs are consistently 45% to 50% higher. These differences result in a 4-hour outage for the average NEM customer costing the same (around $19) as the cost of an 8-hour outage for the average non-NEM customer.

RESIDENTIAL RESULTS

Figure 5-1: Residential Cost per Outage Event Estimates

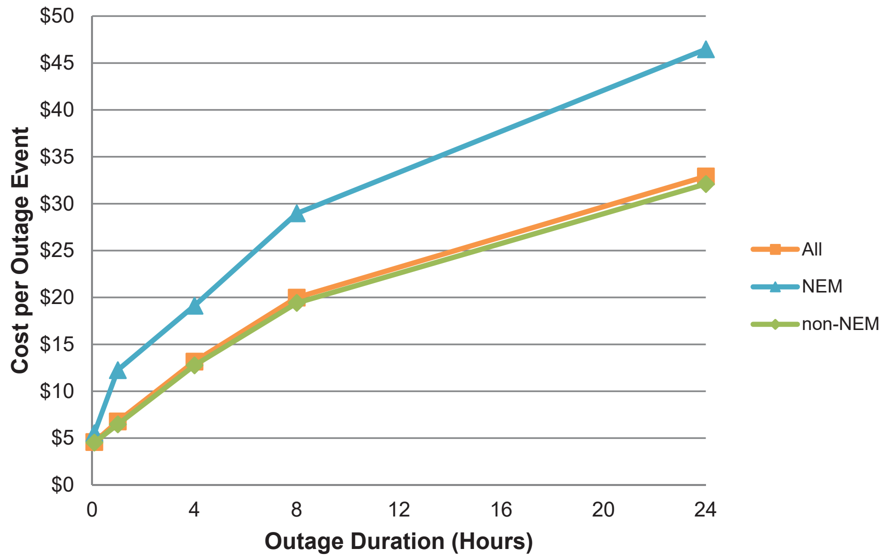


Table 5-3: Residential Cost per Outage Event Estimates by NEM Status

NEM Status	Outage Duration	N	Cost per Outage Event	90% Confidence Interval Lower Bound	90% Confidence Interval Upper Bound
non-NEM	Momentary	372	$4.53	$2.80	$6.27
	1 hour	382	$6.47	$4.73	$8.20
	4 hours	348	$12.76	$10.75	$14.77
	8 hours	369	$19.42	$16.79	$22.05
	24 hours	352	$32.09	$27.78	$36.40
NEM	Momentary	295	$5.53	$3.63	$7.43
	1 hour	295	$12.26	$9.11	$15.40
	4 hours	296	$19.12	$15.59	$22.65
	8 hours	282	$28.97	$24.01	$33.92
	24 hours	278	$46.46	$39.72	$53.21
All	Momentary	667	$4.59	$2.96	$6.22
	1 hour	677	$6.79	$5.16	$8.42
	4 hours	644	$13.17	$11.26	$15.07
	8 hours	651	$19.98	$17.49	$22.48
	24 hours	630	$32.91	$28.87	$36.94

Table 5-4 summarizes the residential cost per CMI by NEM status. For a 1-hour outage, residential customers experience a cost of $0.11 per CMI. As duration increases, cost per CMI decreases steeply because the CMI increases linearly with the number of minutes while cost per outage event increases at a decreasing rate. NEM customers experience higher outage costs than non-NEM customers across all durations. Overall, the NEM cost per CMI is $0.11, almost 60% higher than the cost of $0.07 for the average residential customer. Due to the methodology used to calculate the overall cost per CMI, confidence intervals are not provided for this metric.

Table 5-4: Residential Cost per CMI Estimates by NEM Status

NEM Status	Outage Duration	N	Cost per CMI	90% Confidence Interval	
				Lower Bound	Upper Bound
non-NEM	Momentary	372	$0.91	$0.56	$1.25
	1 hour	382	$0.11	$0.08	$0.14
	4 hours	348	$0.05	$0.04	$0.06
	8 hours	369	$0.04	$0.03	$0.05
	24 hours	369	$0.02	$0.03	$0.05
	Overall	368	$0.07	-	-
NEM	Momentary	295	$1.11	$0.73	$1.49
	1 hour	295	$0.20	$0.15	$0.26
	4 hours	296	$0.08	$0.06	$0.09
	8 hours	282	$0.06	$0.05	$0.07
	24 hours	278	$0.03	$0.03	$0.04
	Overall	289	$0.11	-	-
All	Momentary	667	$0.92	$0.59	$1.24
	1 hour	677	$0.11	$0.09	$0.14
	4 hours	644	$0.05	$0.05	$0.06
	8 hours	651	$0.04	$0.04	$0.05
	24 hours	630	$0.02	$0.02	$0.03
	Overall	654	$0.07	-	-

Table 5-5 summarizes residential cost per average kW. For a 1-hour outage, residential customers experience a cost of $9.47 per average kW. The cost per average kW estimates are roughly 30% higher than the cost per outage event estimates because average demand for residential respondents was around 0.7 kW. We also see that once normalized to account for net energy usage, the difference between NEM customers and non-NEM customers is lowered due to the fact that NEM respondents had an average *net* demand of about 0.9 kW while non-NEM respondents had an average demand of about 0.7 kW. It is worth noting that the average electricity demand of NEM customers is most likely substantially higher than 0.9 kW, but there is no way to precisely account for distributed generation behind the meter when analyzing the net usage data for NEM customers.

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Table 5-5: Residential Cost per Average kW Estimates by NEM Status

NEM Status	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
non-NEM	**Momentary**	372	$6.34	$3.88	$8.80
	1 hour	382	$9.19	$6.76	$11.63
	4 hours	348	$17.47	$14.70	$20.23
	8 hours	369	$26.97	$23.25	$30.70
	24 hours	352	$45.07	$38.60	$51.54
NEM	**Momentary**	295	$5.86	$3.87	$7.85
	1 hour	295	$13.10	$9.79	$16.40
	4 hours	296	$20.09	$16.42	$23.76
	8 hours	282	$29.68	$24.62	$34.75
	24 hours	278	$49.20	$42.05	$56.35
All	**Momentary**	667	$6.30	$4.04	$8.57
	1 hour	677	$9.47	$7.22	$11.71
	4 hours	644	$17.71	$15.13	$20.28
	8 hours	651	$27.18	$23.72	$30.63
	24 hours	630	$45.30	$39.36	$51.23

Table 5-6 provides the residential cost per unserved kWh estimates. For a 1-hour outage, residential customers experience a cost of $9.47 per unserved kWh, which is equivalent to the cost per average kW estimate because the expected amount of unserved kWh is also around 0.7 at 1 hour. For a momentary outage, the system-wide cost estimate is $75 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. Similar to cost per CMI, as duration increases, cost per unserved kWh decreases steeply because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 5-6: Residential Cost per Unserved kWh Estimates by NEM Status

Customer Type	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
non-NEM	**Momentary**	372	$76.13	$46.61	$105.64
	1 hour	382	$9.19	$6.76	$11.63
	4 hours	348	$4.37	$3.68	$5.06
	8 hours	369	$3.37	$2.91	$3.84
	24 hours	352	$1.88	$1.61	$2.15
NEM	**Momentary**	295	$70.36	$46.48	$94.24
	1 hour	295	$13.10	$9.79	$16.40
	4 hours	296	$5.02	$4.11	$5.94
	8 hours	282	$3.71	$3.08	$4.34
	24 hours	278	$2.05	$1.75	$2.35
All	**Momentary**	667	$75.61	$48.43	$102.79
	1 hour	677	$9.47	$7.22	$11.71
	4 hours	644	$4.43	$3.78	$5.07
	8 hours	651	$3.40	$2.97	$3.83
	24 hours	630	$1.89	$1.64	$2.13

5.2.1 Planned Outages

Table 5-7 compares the residential average cost per CMI for a planned outage with that of an unplanned outages for 4-hour and 8-hour durations. For both durations, there is very little difference between a planned and an unplanned outage.

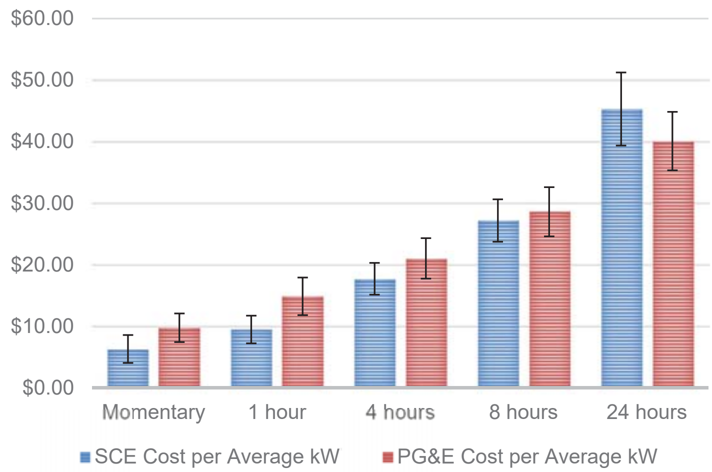
Table 5-7: Residential Cost per CMI for Planned vs. Unplanned Outages

Outage Duration	Unplanned Cost per Average CMI	Planned Cost per Average CMI	% Difference
4 hours	$0.05	$0.06	1%
8 hours	$0.04	$0.04	-2%

5.3 Comparison to 2012 PG&E Study

Figure 5-2 compares the cost per average kW of this study with the 2012 PG&E VOS study. The confidence bands for each outage estimate are indicated by the black error bars. We see that the cost per average kW was generally higher for the PG&E study, with the 1 hour outage 57% higher than the SCE estimated outage cost. The WTP question design and outage scenario descriptions were not exactly the same in the two studies, so some of the differences between the SCE and PG&E estimates may be due to these factors. Nonetheless, the confidence bands overlap at each duration, so the results of the two studies generally align, even though the SCE estimates are lower.

Figure 5-2: Comparison of PG&E and SCE Estimated Cost per Average kW – Residential

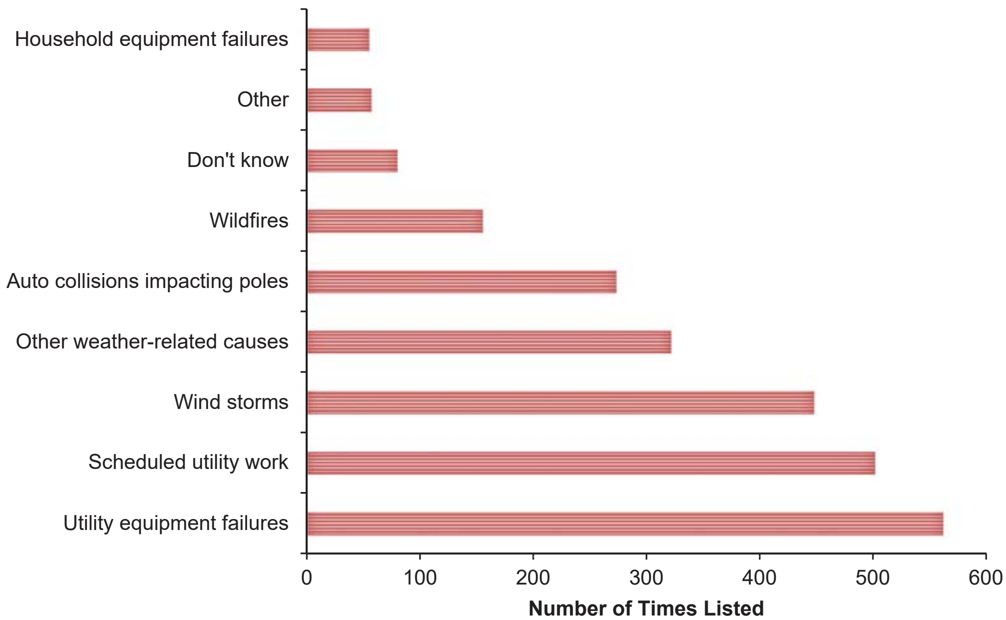


5.4 Perceptions of Resilience and Reliability

After the outage scenarios, customers were asked questions about resilience and reliability. First, they were asked to list what they thought were the three leading causes of power outages. Figure 5-3 lists potential causes of power outages as well as how many times each option was listed as a perceived top-3 cause by a customer. Utility equipment failures were listed most often, followed by scheduled utility work.

RESIDENTIAL RESULTS

Figure 5-3: Perceived Causes of Power Outages for Residential Customers

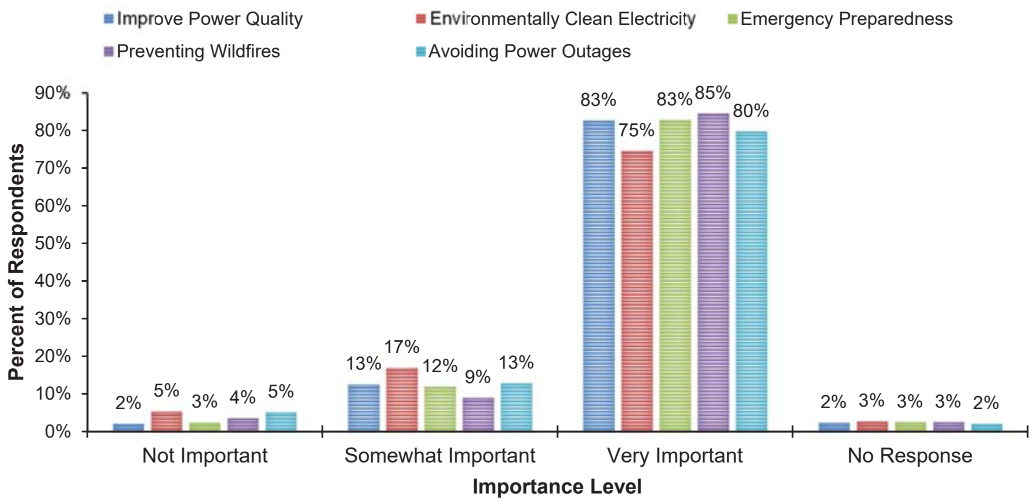


The survey instrument additionally included five questions which had the following instructions:

> *Please tell us how important it is for SCE to improve each of the following elements by rating each from 1 to 10 (1 = not important to improve; 10 = very important to improve).*

The responses to rating elements of SCE's service were aggregated into four categories based on the scores: important (score of 8-10), somewhat important (4-7), not important (1-3), and no response. Figure 5-4 summarizes the responses to each element in terms of its importance. A total of 85% of residential respondents felt that it was very important to prevent wildfires, while only 75% of customers felt it was very important to invest in more environmentally clean electricity.

Figure 5-4: Residential Ranking of Improvement Priorities



The survey also asked the customers about the following hypothetical ballot initiative:

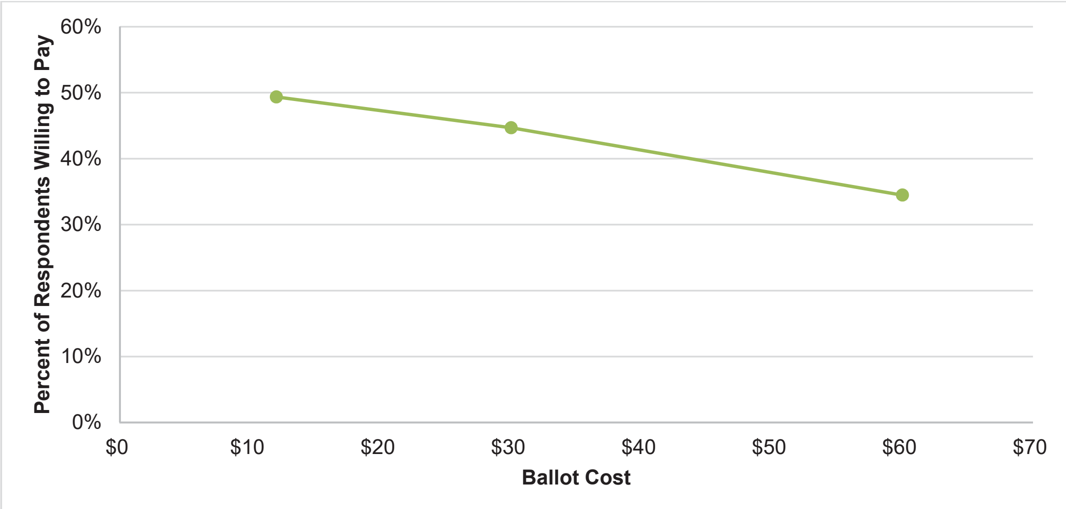
> *Assume there were a California ballot initiative that established a fund for making improvements to the electrical grid. The improvements would prevent damage from threats like wind storms, wildfires, and cyberattacks.*

Figure 5-5 summarizes the percent of respondents who were willing to pay for the ballot initiative as a function of the cost that they were assigned (either $12, $30, or $60). Almost 50% of respondents were willing to pay at least $12 per year for improvements, while 34% of respondents were willing to pay at least $60 per year for improvements.

The trend over the three values on the survey is approximately linear. If the trend extended to the left and right until it reached each axis, the area under the line (i.e. the area of the triangle formed by the two axes and the line) is 42 (dollars). Thus, $42 represents the weighted average annual willingness to pay—assuming all households are subject to the cost—for a fund that would pay for improvements to the electrical grid.

RESIDENTIAL RESULTS

Figure 5-5: Residential Respondents Willing to Pay Annual Cost for Resilience Improvements



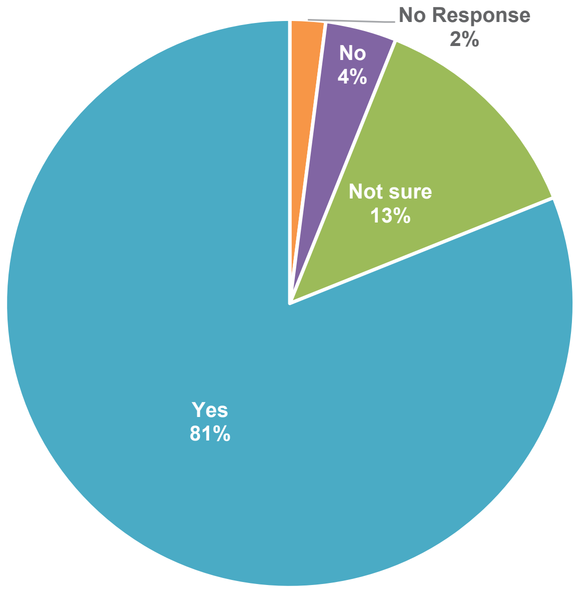
Finally, the survey instrument included the following question:

> *Does SCE do a good job of providing safe and reliable electric service?*

Figure 5-6 summarizes the customer responses. A total of 81% of respondents are currently satisfied with SCE's electric service reliability.

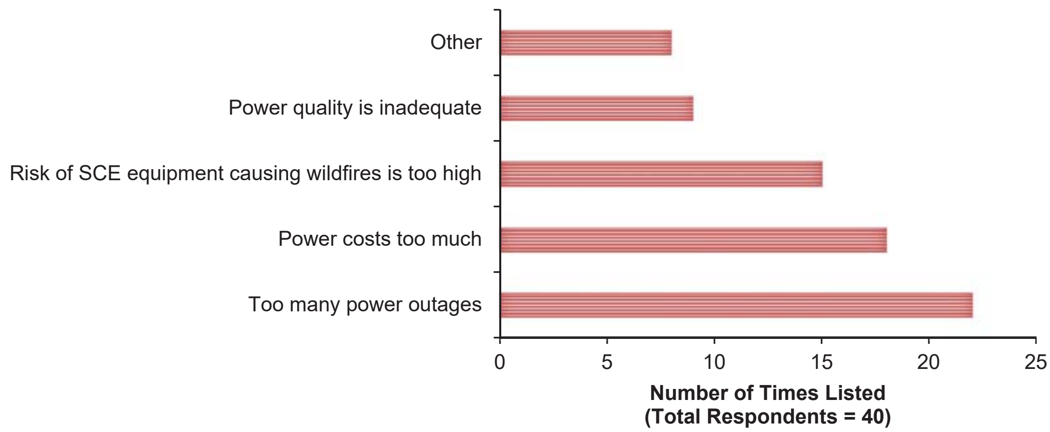
RESIDENTIAL RESULTS

Figure 5-6: Residential Customer Opinion of Whether SCE Doing a Good Job of Providing Safe and Reliable Electric Service



If the customer responded that they did not think that SCE did a good job of providing safe and reliable service, they were asked to select the reasons they did not feel SCE did a good job. Figure 5-7 shows the number of times each reason was listed by survey respondents. The reason listed most frequently was too many power outages, followed by power costing too much.

Figure 5-7: Reasons Why Residential Customers Feel SCE Not Doing a Good Job of Providing Safe and Reliable Service



6 Small & Medium Business Results

6.1 Response to Survey

Table 6-1 summarizes the survey response for SMB customers. With 413 total completed surveys, customer response was below the overall sample design target of 800. The original sample design had a sample draw of 8,000 customers for an expected response rate of 10 percent. Once the customers in the first sample draw had been contacted and it was clear that the response rate was below target, Nexant worked with SCE to boost responses by adding 5,330 customers to the sample, as discussed in Section 3.3.2. The response rate was 3 percent across all four strata.

Table 6-1: SMB Customer Survey Response Summary

Usage Category (Average kW of Stratum)	Population	Initial Sample Design Target	Records Sampled	Completed Responses	Response Rate
0.86	235,248	72	1,314	40	3%
4.95	152,901	460	8,205	265	3%
25.4	37,692	132	2,045	58	3%
105	11,978	136	1,767	50	3%
All	**437,819**	**800**	**13,331**	**413**	**3%**

6.2 Outage Cost Estimates

Figure 6-1 and Table 6-2 provide the SMB cost per outage event estimates. For a 1-hour outage, SMB customers experience a cost of $3,099. SMB cost per outage event increases to $4,651 at 8 hours and $8,110 for a 24-hour outage.

SMALL & MEDIUM BUSINESS RESULTS

Figure 6-1: Cost per Outage Event Estimates – SMB

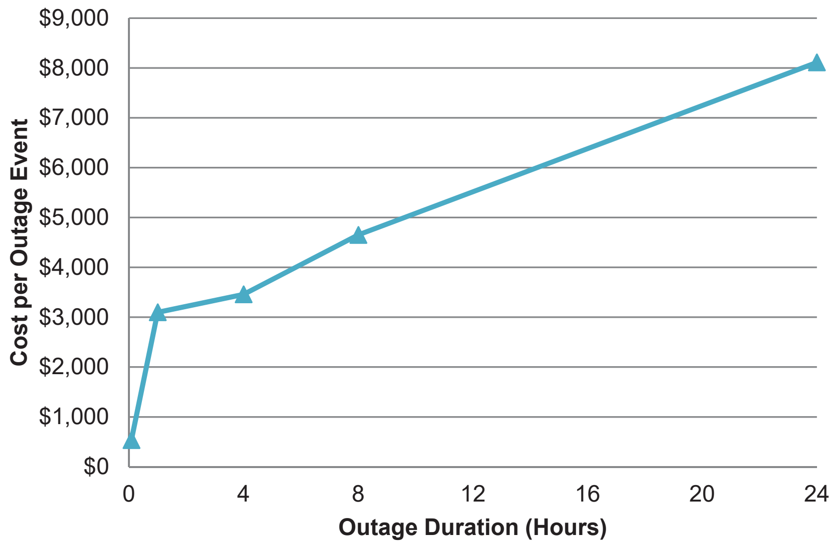


Table 6-2: SMB Cost per Outage Event Estimates

Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	390	$535.28	$282.71	$787.86
1 hour	401	$3,098.95	$358.77	$5,839.12
4 hours	395	$3,459.23	$2,173.03	$4,745.44
8 hours	397	$4,650.89	$3,400.91	$5,900.87
24 hours	398	$8,110.52	$6,069.29	$10,151.76

Table 6-3 summarizes SMB cost per CMI. For a 1-hour outage, SMB customers experience a cost of $51.65 per average CMI. As the duration increases, the cost per CMI decreases, and for a 24-hour outage the cost per average CMI is $5.63. Table 6-4 summarizes SMB cost per average kW. For a 1-hour outage, SMB customers experience a cost of $432 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event because average demand for SMB respondents was around 7 kW. Table 6-5 summarizes SMB cost per unserved kWh. For a 1-hour outage, SMB customers experience a cost of $432 per unserved kWh – same as the cost per average kW estimate. For momentary outages (5 minutes), the system-wide estimate is over $827, as the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. For a 24-hour outage, cost per unserved kWh is $45.

SMALL & MEDIUM BUSINESS RESULTS

Table 6-3: SMB Cost per Average CMI Estimates

Outage Duration	N	Cost per Average CMI	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	390	$107.06	$56.54	$157.57
1 hour	401	$51.65	$5.98	$97.32
4 hours	395	$14.41	$9.05	$19.77
8 hours	397	$9.69	$7.09	$12.29
24 hours	398	$5.63	$4.21	$7.05

Table 6-4: SMB Cost per Average kW Estimates

Outage Duration	N	Cost per Average kW	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	390	$68.93	$35.54	$102.32
1 hour	401	$431.60	$54.85	$808.35
4 hours	395	$473.79	$301.08	$646.50
8 hours	397	$684.34	$506.22	$862.46
24 hours	398	$1,085.12	$797.11	$1,373.14

Table 6-5: SMB Cost per Unserved kWh Estimates

Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	390	$827.14	$426.47	$1,227.81
1 hour	401	$431.60	$54.85	$808.35
4 hours	395	$118.45	$75.27	$161.62
8 hours	397	$85.54	$63.28	$107.81
24 hours	398	$45.21	$33.21	$57.21

6.2.1 Planned Outages

Table 6-6 compares the SMB average cost per CMI for a planned outage with that of an unplanned outages for 4-hour and 8-hour durations. We see that for a 4-hour outage, the outage costs are 54% lower for a planned outage compared to an unplanned outage, while for an 8-hour outage the difference is 12%.

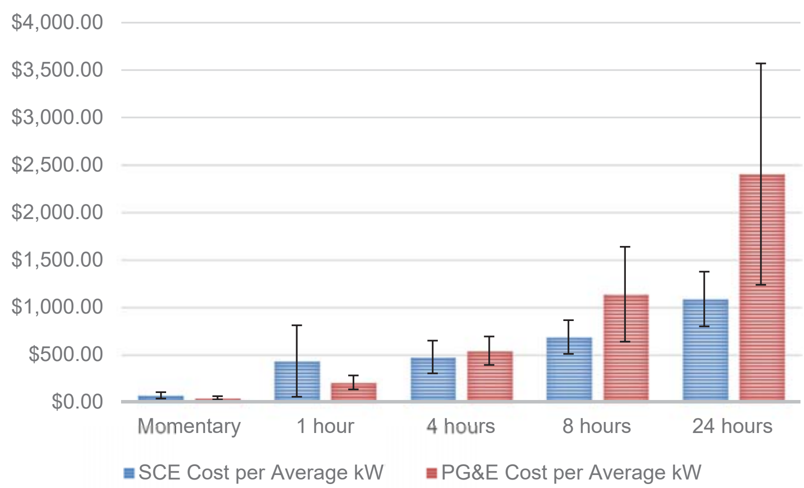
Table 6-6: SMB Cost per CMI for Planned vs. Unplanned Outages

Outage Duration	Unplanned Cost	Planned Cost	% Difference
4 hours	$14.41	$6.64	-54%
8 hours	$9.69	$8.50	-12%

6.3 Comparison to 2012 PG&E Study

Figure 6-2 compares the SCE outage cost per average kW for SMB customers with the PG&E 2012 outage cost study. The confidence bands for the estimates are indicated by black error bars. The costs for shorter durations are relatively similar, while PG&E outage cost estimates for a 24 hour outage are significantly higher than the SCE estimates. The outage scenario descriptions included seasonal variation for the SCE study, whereas the PG&E study only included summer scenarios to align with its prior studies, so some of the differences between the SCE and PG&E estimates may be due to seasonal factors. Nonetheless, the confidence bands overlap at each duration, so the results of the two studies generally align, even though the SCE estimates are lower at most durations.

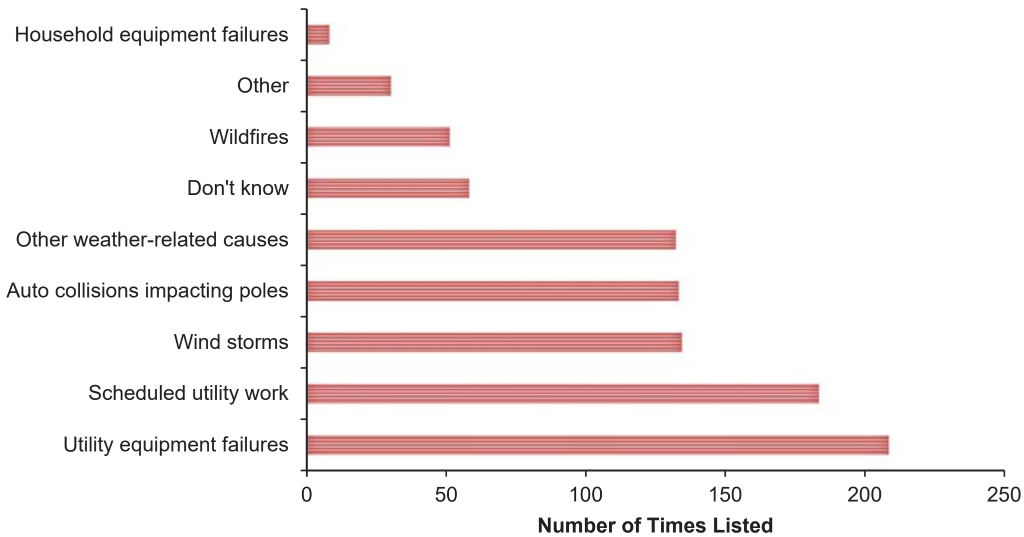
Figure 6-2: Comparison of PG&E and SCE Estimated Cost per Average kW - SMB



6.4 Perceptions of Resilience and Reliability

At the end of the survey, customers were asked questions about SCE's resilience and reliability. First, they were asked to list what they thought were the three leading causes of power outages. Figure 6-3 lists potential causes of power outages as well as how many times each option was listed as a top-3 cause by a customer. Similar to the residential responses, utility equipment failures were listed most often, followed by scheduled utility work.

Figure 6-3: SMB Perceived Causes of Power Outages

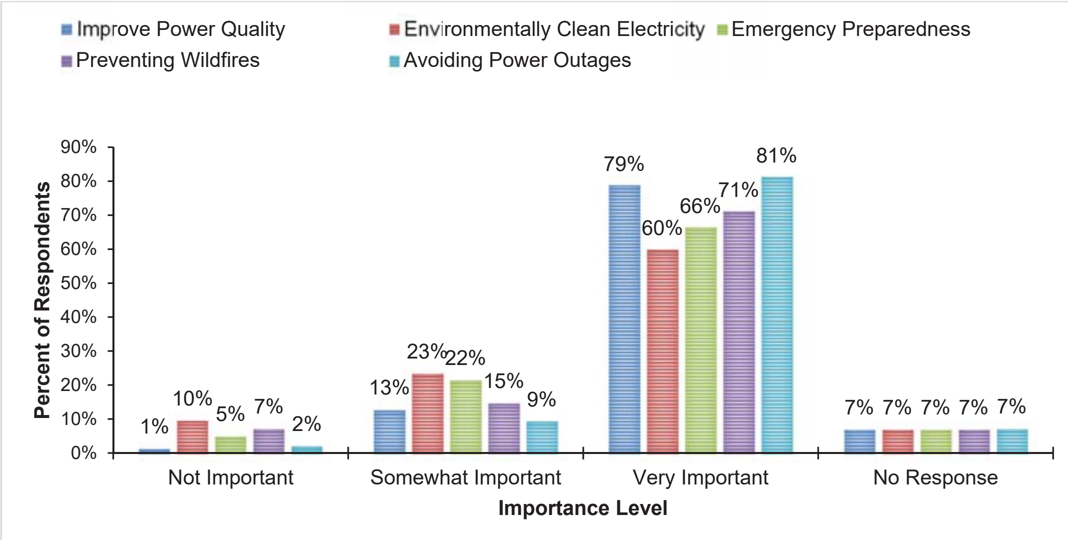


The survey instrument additionally included five questions which had the following instructions:

> *Please tell us how important it is for SCE to improve each of the following elements by rating each from 1 to 10 (1 = not important to improve; 10 = very important to improve).*

The responses to rating elements of SCE's service were aggregated into four categories based on the scores: important (score of 8-10), somewhat important (4-7), not important (1-3), and no response. Figure 6-4 summarizes the responses to each element in terms of its importance. A total of 81% of SMB respondents felt that it was very important to improve reliability, while only 60% of respondents felt it was very important to invest in more environmentally clean electricity.

Figure 6-4: SMB Ranking of Improvement Priorities

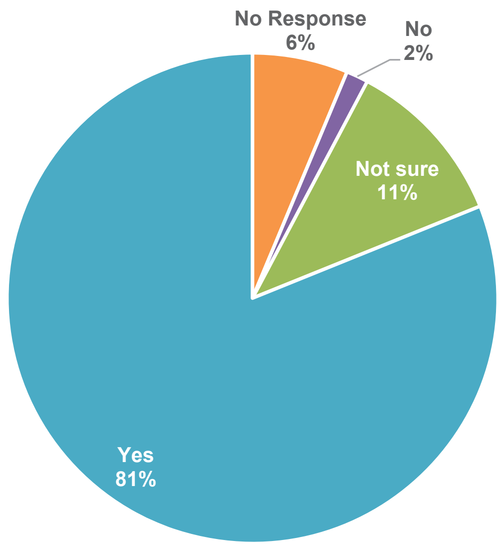


Finally, the survey instrument included the following question:

Does SCE do a good job of providing safe and reliable electric service?

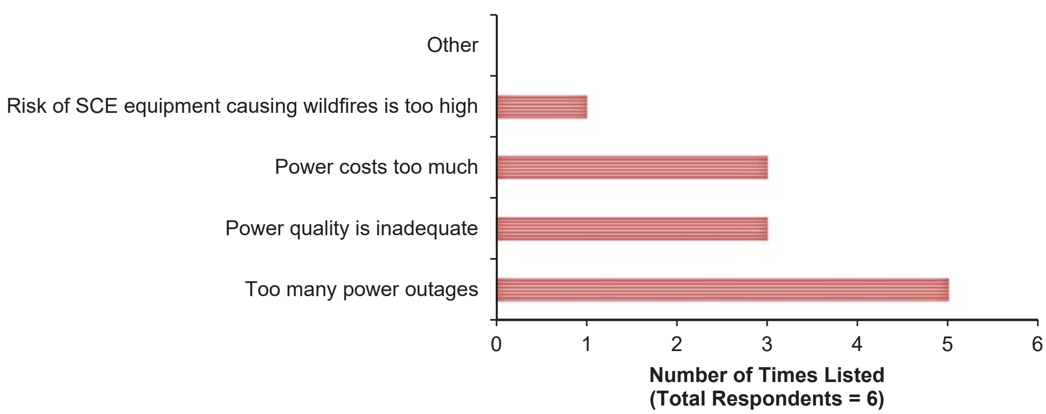
Figure 6-5 summarizes the customer responses. A total of 81% of respondents are currently satisfied with SCE's electric service reliability.

Figure 6-5: SMB Customer Opinion of Whether SCE Doing a Good Job of Providing Safe and Reliable Electric Service



If the customer responded that they did not think that SCE did a good job of providing safe and reliable service, they were asked to select the reasons why. Figure 6-6 summarizes the number of times each reason was listed. The reason listed most frequently was too many power outages, followed by inadequate power quality and power costing too much. It is worth noting that only 6 SMB customers responded that they did not feel that SCE did a good job of providing reliable and electric service, and these customers listed 12 total reasons why they were not satisfied with SCE's service.

Figure 6-6: Reasons Why SMB Customers Feel SCE Not Doing Good Job of Providing Safe and Reliable Service



7 Large C&I Results

7.1 Response to Survey

Table 7-1 summarizes the survey response for large C&I customers. With 72 total completed surveys, customer response was below the overall sample design target of 150. The original sample design had a sample draw of 300 customers for an expected response rate of 50 percent. Once the customers in the first sample draw had been contacted and it was clear that the response rate was below target, Nexant worked with SCE to boost responses by adding 100 customers to the sample, as discussed in Section 3.3.3. The response rate was 18% overall, with the highest response rate of 25% for the stratum with the largest customers.

Table 7-1: Customer Survey Response Summary – Large C&I

Usage Category (Average kW of Stratum)	Population	Sample Design Target	Records Sampled	Completed Interviews	Response Rate
210	1,608	46	91	11	12%
665	1,493	72	143	19	13%
3,728	366	82	166	42	25%
All	**3,467**	**150**	**400**	**72**	**18%**

7.2 Outage Cost Estimates

Figure 7-1 and Table 7-2 provide the large C&I cost per outage event estimates. For a 1-hour outage, large C&I customers experience a cost of $80,069. The large C&I cost per outage event increases to $240,444 at 8 hours and $446,044 for a 24-hour outage.

LARGE C&I RESULTS

Figure 7-1: Large C&I Outage Event Estimates

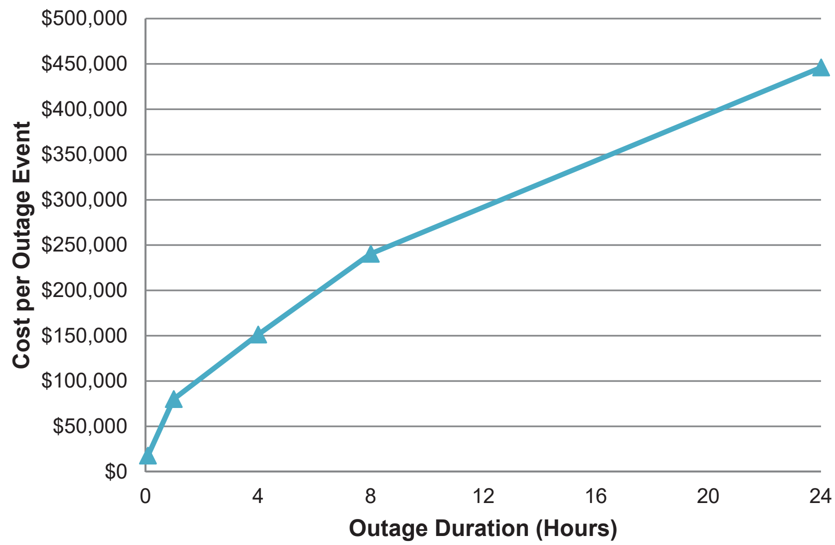


Table 7-2: Large C&I Cost per Outage Event Estimates

Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	62	$17,696.69	$5,114.95	$30,278.42
1 hour	61	$80,069.38	$29,953.87	$130,184.88
4 hours	67	$151,310.84	$61,028.65	$241,593.03
8 hours	66	$240,444.30	$117,630.00	$363,258.59
24 hours	58	$446,044.94	$183,809.50	$708,280.38

Table 7-3 summarizes the large C&I cost per CMI. For a 1-hour outage, large C&I customers experience a cost of $1,334 per average CMI. As the duration increases, the cost per CMI decreases, and for a 24-hour outage the cost per average CMI is $310. Table 7-4 summarizes the large C&I cost per average kW. For a 1-hour outage, large C&I customers experience a cost of $78 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event because average demand for large C&I respondents was around 820 kW. Table 7-5 summarizes large C&I cost per unserved kWh. For a 1-hour outage, large C&I customers experience a cost of $78 per unserved kWh – same as the cost per average kW estimate. For momentary outages (5 minutes), the system-wide estimate is over $258, as the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. For a 24-hour outage, cost per unserved kWh is $26.

LARGE C&I RESULTS

Table 7-3: Large C&I Cost per Average CMI Estimates

Outage Duration	N	Cost per Average CMI	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	62	$3,539.34	$1,022.99	$6,055.68
1 hour	61	$1,334.49	$499.23	$2,169.75
4 hours	67	$630.46	$254.29	$1,006.64
8 hours	66	$500.93	$245.06	$756.79
24 hours	58	$309.75	$127.65	$491.86

Table 7-4: Large C&I Cost per Average kW Estimates

Outage Duration	N	Cost per Average kW	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	62	$21.50	$6.70	$36.29
1 hour	61	$78.28	$30.96	$125.59
4 hours	67	$187.80	$82.72	$292.88
8 hours	66	$295.58	$151.26	$439.90
24 hours	58	$622.61	$290.39	$954.83

Table 7-5: Large C&I Cost per Unserved kWh Estimates

Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
			Lower Bound	Upper Bound
Momentary	62	$257.94	$80.39	$435.50
1 hour	61	$78.28	$30.96	$125.59
4 hours	67	$46.95	$20.68	$73.22
8 hours	66	$36.95	$18.91	$54.99
24 hours	58	$25.94	$12.10	$39.78

7.2.1 Planned Outages

Table 7-6 compares the large C&I average cost per CMI for a planned outage with that of an unplanned outage for 4-hour and 8-hour durations. We see that for a 4-hour outage there is almost no difference in outage costs, while for an 8-hour outage the outage costs are 57% lower for a planned outage compared to an unplanned outage.

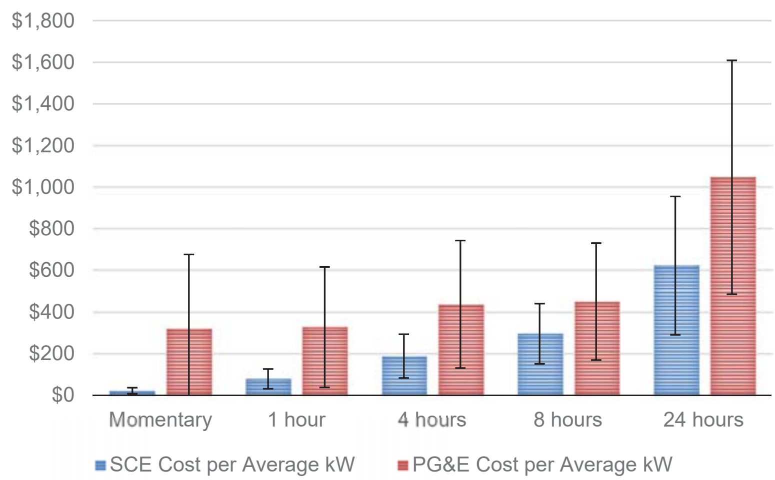
Table 7-6: Large C&I Cost per CMI for Planned vs. Unplanned Outages

Outage Duration	Unplanned Cost per Average CMI	Planned Cost per Average CMI	% Difference
4 hours	$630.46	$628.06	0%
8 hours	$500.93	$215.17	-57%

7.3 Comparison to 2012 PG&E Study

Figure 7-2 compares the SCE outage cost per average kW for large C&I customers with the PG&E 2012 outage cost study. The confidence bands for the estimates are indicated by black error bars. PG&E outage cost estimates are significantly higher than the SCE estimates for all outage durations. In the 2012 PG&E study, a small subset of Bay Area customers had extremely high outage costs, which increased the average cost substantially and created relatively wide confidence bands for the estimates, even though the large C&I study had over 200 respondents. The SCE study did not have this issue, and as a result, the outage cost estimates are more consistent with prior studies and the confidence bands are not as wide, even though the sample size was smaller.

Figure 7-2: Comparison of PG&E and SCE Estimated Cost per Average kW – Large C&I



8 Systemwide Results

8.1 Systemwide Across Customer Classes

This section summarizes the systemwide results for all customers. Sampling was conducted on a per-customer basis and the outage costs were collected and aggregated on a per-customer basis. The systemwide estimate calculations utilize the weighted average of per-customer costs as well as the weighted average of per-customer usage in order to scale the costs by kWh. Given that costs and usage are significantly higher for non-residential customers (particularly large C&I), their responses increase both average cost and usage. Thus the systemwide 'cost per average kW' and 'cost per unserved kWh' estimates account for non-residential customers having higher consumption.

Table 8-1 shows the systemwide cost per outage event estimate for each outage duration. The third column from the left—labeled 'N'—shows the number of responses (after data cleaning) from residential, SMB, and large C&I combined. Tables Table 8-2 through Table 8-4 show the systemwide outage cost for the other metrics presented in sections 5 through 7. The systemwide cost of a 1-hour outage is $368, and the cost of a systemwide 24-hour outage is $1,174.

Table 8-1: Cost per Outage Event Estimates – Systemwide Results

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	Momentary	1,119	$66.38	$40.65	$92.12
	1 hour	1,139	$368.39	$87.26	$649.52
	4 hours	1,106	$472.62	$319.42	$625.82
	8 hours	1,114	$660.52	$497.05	$823.99
	24 hours	1,086	$1,173.54	$872.12	$1,474.96

Table 8-2: Cost per Average CMI Estimates – Systemwide Results

Region	Outage Duration	N	Cost per Average CMI	90% Confidence Interval	
				Lower Bound	Upper Bound
All	Momentary	1,119	$13.28	$8.13	$18.42
	1 hour	1,139	$6.14	$1.45	$10.83
	4 hours	1,106	$1.97	$1.33	$2.61
	8 hours	1,114	$1.38	$1.04	$1.72
	24 hours	1,086	$0.81	$0.61	$1.02

SYSTEMWIDE RESULTS

Table 8-3: Cost per Average kW Estimates – Systemwide Results

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	Momentary	1,119	$33.05	$20.33	$45.76
	1 hour	1,139	$179.81	$43.80	$315.82
	4 hours	1,106	$234.41	$161.52	$307.29
	8 hours	1,114	$341.24	$263.65	$418.84
	24 hours	1,086	$607.05	$462.01	$752.09

Table 8-4: Cost per Unserved kWh Estimates – Systemwide Results

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	Momentary	1,119	$396.59	$244.01	$549.18
	1 hour	1,139	$179.81	$43.80	$315.82
	4 hours	1,106	$58.60	$40.38	$76.82
	8 hours	1,114	$42.66	$32.96	$52.36
	24 hours	1,086	$25.29	$19.25	$31.34

8.1.1 Planned Outages

Table 8-5 compares the systemwide average cost per CMI for a planned outage with that of an unplanned outages for 4-hour and 8-hour durations. We see that overall, planned outages have a lower cost than an unplanned outage. Planned outage costs are 13% lower for a 4-hour duration and 3% lower for an 8-hour duration.

Table 8-5: Cost per CMI for Planned vs. Unplanned Outages – Systemwide

Outage Duration	Unplanned Cost per Average CMI	Planned Cost per Average CMI	% Difference
4 hours	$1.33	$1.15	-13%
8 hours	$1.04	$1.01	-3%

8.2 Systemwide Across Duration

Table 8-6 summarizes the cost per Average CMI across all durations for each customer class. Overall, the systemwide cost per average CMI across all durations is $2.63.

SYSTEMWIDE RESULTS

Table 8-6: Cost per Average CMI Estimates – Systemwide Results

Region	Customer Class	Systemwide Cost per Average CMI
All	Residential	$0.07
	SMB	$20.77
	Large C&I	$713.57
	All	**$2.63**

8.3 Comparison to 2016 SCE Study

In 2016, SCE retained Nexant to estimate the costs that customers incur as a result of sustained and momentary interruptions on its system. Using three years of historical power interruption data from SCE, Nexant provided lower and upper bound estimates of the average cost per customer minute interrupted (CMI) and the average cost per momentary interruption for each customer. In order to accurately compare the results, Nexant adjusted the 2016 costs for inflation when comparing them with the cost for this study. Figure 8-1 compares the systemwide cost per Average CMI to the results from the 2016 analysis in $2019. The blue numbers represent the lower bound, midpoint, and upper bound respectively from 2016 and the green number represents the results from the current study. This study estimates that the blended cost per CMI is $2.63, which lies between the midpoint and the upper bound from the previous study.

Figure 8-1: Systemwide Cost per Average CMI Estimates

For the cost of a momentary outage, this study produced a systemwide estimate of $66.38 per event ($2019) (see Table 8-1). The 2016 SCE study estimated a lower bound of $67.2 and an upper bound of $112.7 (in $2016). The current estimate is lower than this previous range. However, there is a fundamental difference between how the two estimates were generated. The 2016 study was based on a nationwide meta-analysis that fit a regression model to outage costs across a wide range of durations from 1 minute to 24 hours. Thus, the estimates may not have been as accurate when estimating costs at either end of that range. On the other hand, the 2019 study was based on the survey results specifically for the momentary outage, so it did not require fitting a regression model to the data and then estimating the costs of a momentary outage.

9 Appendices

Appendix A Customer Damage Functions

This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics. For example, these models were used to develop the results in Sections 5 through 8 related to how outage costs vary by time of day and week for each customer class.

To model outage costs, Nexant used a two-part model. The two-part model first estimates the latent probability that customers experience an outage cost with a Probit model. Then, it estimates the outage costs for customers who reported values greater than zero with a Generalized Linear Model (GLM). The models were estimated with corrections to account for the structure of the survey data (i.e., clustering by customer, population weights and stratification). This approach was first used to model health care expenditures, which, like outage costs, follow a highly skewed distribution. Nexant applied this model to a meta-analysis of outage costs in a 2009 study prepared for Lawrence Berkeley National Laboratory[6] and then in 2012 for the PG&E VOS Study.

Nexant employed out-of-sample testing to select and validate the best econometric model for each customer segment. Because the model coefficients were derived from a systemwide survey, out-of-sample testing was used to ensure that the estimates were robust to a variety of conditions. For each customer segment, different model specifications were tested and estimates generated from each model while withholding 25% of the data from the regression. To select the final model, we compared the out-of-sample predicted outage costs from each model with the reported outage costs.

A.1 Residential Customers

To predict outage costs for residential customers, Nexant estimated an econometric model for residential customers from the 2019 SCE survey data. The analysis included variables that capture customer size, NEM status, whether the outage was planned, whether or not an outage was experienced in the last 12 months, and outage timing as well as variables meant to capture the duration of the outage.

Table A-1 shows the variables included in the residential customer damage function and the estimated coefficients for each part of the model. The average kW usage captures the influence of customer size on reported outage costs while duration and duration squared capture the impact of outage duration on reported outage costs. The square of the duration variable captures the non-linear relationship between outage costs and duration. The coefficient on the usage variable is significant at the 1% level when predicting the magnitude of the outage cost,

[6] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

and the duration variables are significant at the 1% level for both models. The variable indicating whether or not the outage was planned, when interacted with the duration of the planned outage, is a significant predictor of whether or not an outage cost is experienced. NEM is not a significant predictor of whether an outage cost is experienced but it is significant when predicting the magnitude of the outage cost. Nearly all of the outage timing variables are statistically *insignificant individually*, however, they are included in the regression models because they are jointly significant and increase predictive power.

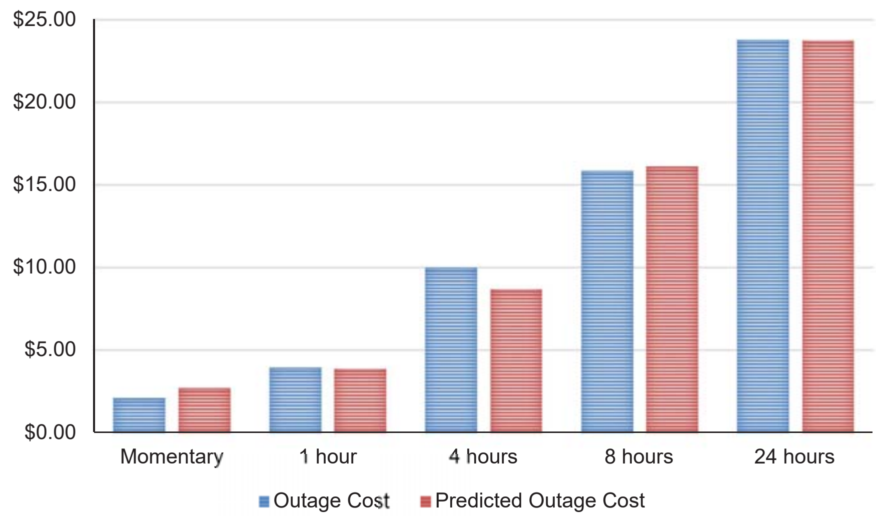
Table 9-1: Coefficients of Residential Customer Damage Function

(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Nature Log of Average kW	0.089	0.219***
Duration	0.255***	0.094***
Duration Squared	-0.008***	-0.002***
Net Metering Status (NEM)	-0.082	0.149*
Outage in Past 12 Months	-0.252	0.161
Interaction between Planned Outage and Duration	-0.027**	-0.004
Outage Timing		
Weekday Night	-0.223	0.157
Weekend Night	-0.22	0.23
Weekday Morning	-0.083	0.027
Weekend Morning	0.139	0.373
Weekday Afternoon	-0.123	0.227
Weekend Afternoon	0.045	0.251
Weekday Evening	0.072	0.043
Weekend Evening (Base)		
Winter	-0.028	0.339**
Summer	0.001	0.138
Spring	-0.167	0.111
Fall (Base)		
Constant	-0.358	2.089***

Figure 9-1 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts well across all outage durations. The percent error for a 24-hour outage is 0%; an 8-hour outage is 2%; a 4-hour outage, -13%; an hour, -1%; and momentary, 29%.

Figure 9-1: Comparison of Predicted and Reported Residential Outage Cost by Outage Duration



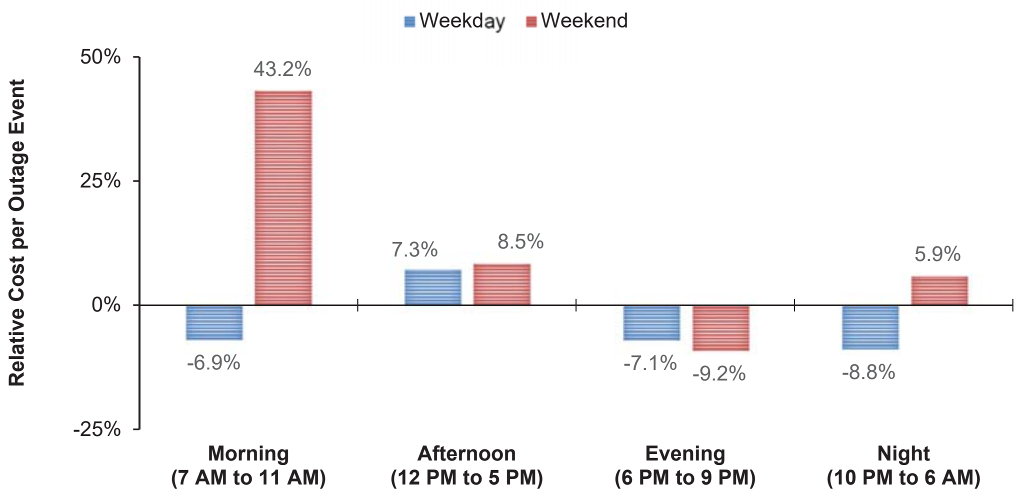
Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods on weekdays and weekends with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 9-2 provides the relative cost per outage event estimates which were derived from the residential customer damage functions described above. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each residential outage cost estimate in Section 5.2 (referred to as the “base value”). As shown in the figure, outage costs for residential customers are somewhat sensitive to onset time, varying from 9.2% lower than the base value on a weekend evening to 43.2% higher on a weekend morning.

Figure 9-2: Relative Cost per Outage Event Estimates by Season and Day of Week – Residential



A.2 Small & Medium Business Customers

For SMB customers, variables that capture the size, whether or not an outage was experienced in the last 12 months, basic outage timing (night versus day and season), and industry group and whether or not a premise is a multitenant facility were included for each premise as well as variables meant to capture the duration of the outage. Multiple two-part models were tested. The criteria for selection of the final model included performance on out-of-sample tests, performance on in-sample tests and significance of coefficients on important variables.

Table 9-2 shows the variables included in the SMB customer regression model and the estimated coefficients for each part of the model. All of the most important variables, including usage, planned, and duration variables are significant in both the Probit model and the GLM model. The outage timing variables are statistically significant in the GLM model, indicating that outage timing determines the magnitude of experienced outage costs. A few industry variables are mostly significant in the GLM model, but not in the Probit model, indicating that the industry of a particular premise determines the magnitude of outage costs, but not whether or not outage costs are experienced.

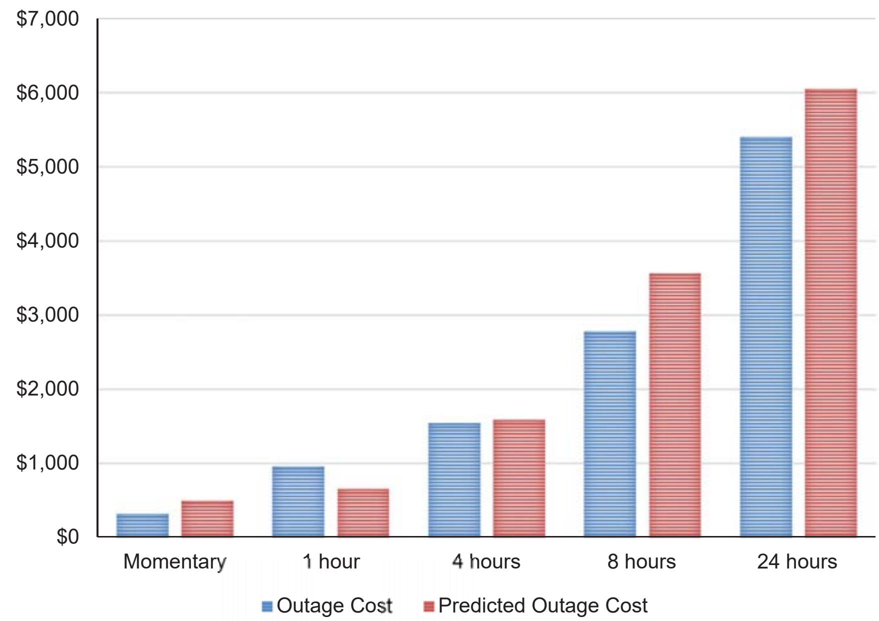
Table 9-2: Coefficients of SMB Customer Damage Function

(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.093	0.292***
Duration	0.165***	0.228***
Duration Squared	-0.005***	-0.006***
Outage in Past 12 Months	-0.144	0.005
Interaction between Planned Outage and Duration	-0.041***	0.031**
Multitenant	0.165	-0.275
Outage Timing		
Night	-0.096	-0.509**
Day (Base)		
Winter	-0.375	-0.153
Summer	-0.226	-0.573**
Spring	-0.25	0.590*
Fall (Base)		
Industry		
Mining/Construction (Base)		
Manufacturing	0.145	0.786**
Wholesale, Transport, Utilities	0.08	0.684
Retail Stores	0.135	-0.394
Offices, Hotels, Finance, Services	0.217	0.863**
Schools	-0.721*	-0.035
Institutional/Government	-0.018	0.22
Other or unknown	0.274	0.013
Constant	-0.15	6.212***

Figure 9-3 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts relatively well across all outage types. The percent error for a 24-hour outage is 12%; an 8-hour outage is 28%; a 4-hour outage, 3%; an hour, -32%; and momentary, 57%. Although the percentage difference for a momentary outage is quite high, the magnitude of the difference is not substantial considering that momentary outage costs are relatively low.

Figure 9-3: Comparison of Predicted and Reported SMB Outage Cost by Outage Duration



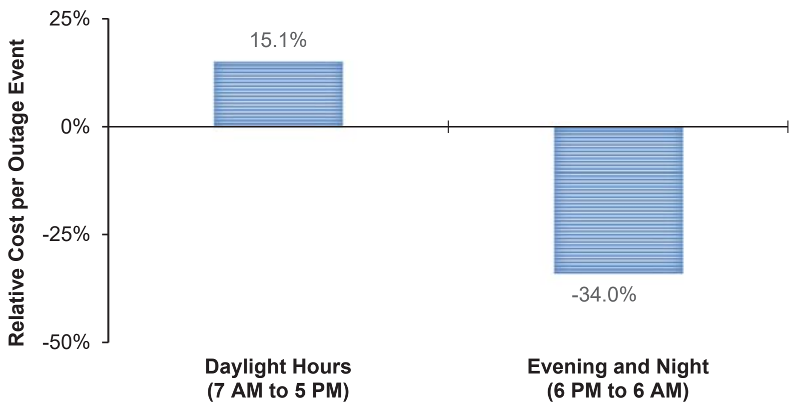
Impact of Outage Timing

For the SMB analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 9-4 provides the relative cost per outage event estimates, which were derived from the SMB customer damage functions described above. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each large C&I outage cost estimate in Section 6.2 (referred to as the "base value"). As shown in the figure, outage costs for large C&I customers are somewhat sensitive to onset time, varying from 15.1% higher than the base value during daylight hours to 34.0% lower during the evening and night.

Figure 9-4: Relative Cost per Outage Event Estimates by Onset Time – SMB



A.3 Large C&I Customers

To predict outage costs for large C&I customers, Nexant estimated an econometric model from the 2019 SCE survey data. Nexant included variables that capture the size, whether or not an outage was experienced in the last 12 months, basic outage timing (night versus day), and basic industry group (commercial versus industrial) as well as variables meant to capture the duration of the outage. Because there were only 72 large C&I customers in the survey data, this model could not include as many variables as the SMB model.

The final Probit and GLM models for large C&I customers include 9 variables. Table Table 9-3 shows the variables included in the large C&I customer regression model and the estimated coefficients for each part of the model. The natural log of average kW is a significant predictor both of whether or not customers experience outage costs and of the magnitude of outage costs for customers who do report them. The duration variable is significant for the Probit model, while the duration squared variable is only significant for the GLM model. Similarly whether or not an outage was planned was not a significant predictor for whether or not a cost was experienced, but it was a significant predictor for the magnitude of the cost. A simple binary variable indicating whether the outage occurred at night or during the day was also included.

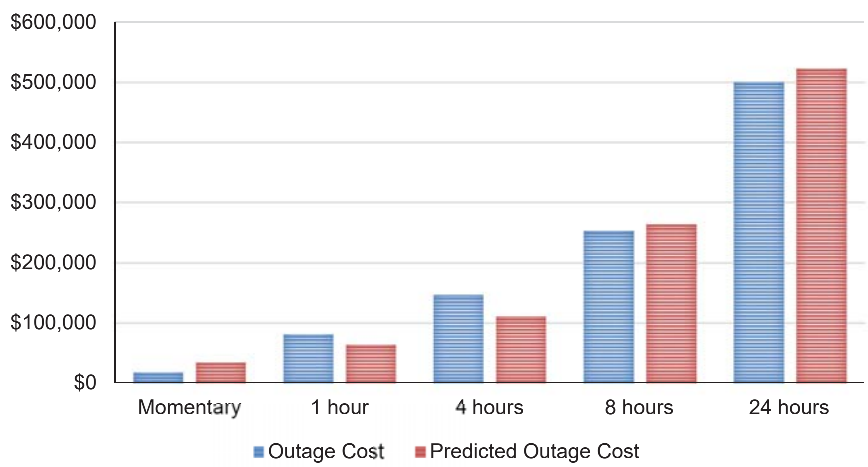
Table 9-3: Coefficients of Large C&I Customer Damage Function

(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.27	0.771***
Duration	0.131**	0.310***
Duration Squared	-0.004	-0.008***
Outage in Past 12 Months	-0.141	-1.111*
Interaction between Planned Outage and Duration	0.016	-0.044**
Outage Timing		
Night	0.423	0.142
Day (Base)		
Industry		
Industrial (Base)		
Commercial	-0.918**	-0.969
Constant	-0.664	6.328***

Figure 9-5 provides a comparison of the model predicted and reported outage cost values by outage duration. The percent error for a 24-hour outage is 4%; an 8-hour outage is 4%; a 4-hour outage, -25%; an hour, -21%; and momentary, 86%.

Figure 9-5: Comparison of Predicted and Reported Large C&I Outage Cost by Outage Duration



Impact of Outage Timing

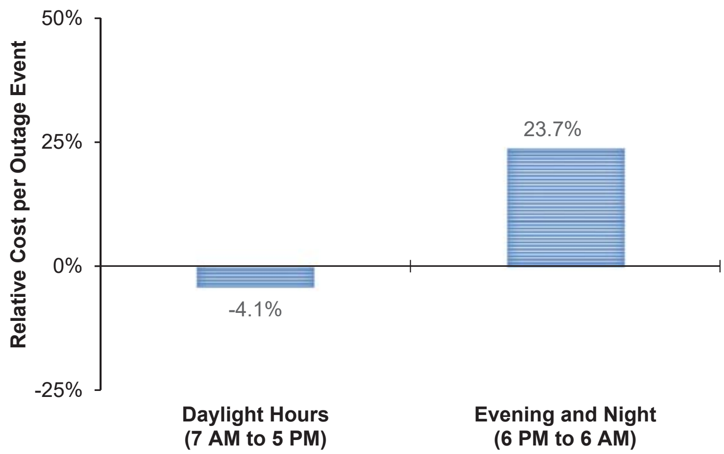
For the large C&I analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and

- Evening and Night (6 PM to 6 AM).

Figure 9-6 provides the relative cost per outage event estimates, which were derived from the large C&I customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each large C&I outage cost estimate in Section 7.2 (referred to as the "base value"). As shown in the figure, outage costs for large C&I customers are somewhat sensitive to onset time, varying from 4.1% lower than the base value during daylight hours to 23.7% higher during the evening and night.

Figure 9-6: Relative Cost per Outage Event Estimates by Onset Time – Large C&I



Appendix B Residential Survey Instrument

SOUTHERN CALIFORNIA EDISON
CUSTOMER INTERRUPTION COST SURVEY

Residential Customers

Thank you in advance for participating in this valuable study. Completing the survey will only take a few minutes of your time.

All of your answers will be kept confidential. Your name and address will be kept anonymous and will not be associated with the information you provide.

Please return your completed survey in the enclosed return envelope. If you have any concerns, please contact Southern California Edison at 1-800-684-8123. For specific questions about the survey, please contact VuPoint Research at 1-800-738-4020 Monday through Friday between the hours of 9:00 AM and 5:00 PM.

This survey is also available online at: vupointresearch.com/SCEHomeSurvey
Your survey ID is: «NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your residence. Power outages can be caused by many factors such as bad weather, traffic accidents, or equipment failures. If you share a building with other owners or tenants, please answer the questions only about your residence.

1. **Over the past 12 months, about how many outages of the durations listed below have you experienced at your home? Please enter the number of outages in the blanks below. (If none, use "0".)**

   ________ Short duration (5 minutes or less)
   ________ Longer than 5 minutes and up to 1/2 hour
   ________ Longer than 1/2 hour and up to 1 hour
   ________ Longer than 1 hour and up to 4 hours
   ________ Longer than 4 hours and up to 24 hours
   ________ Over 24 hours

2. **Do you feel that the number of power outages your residence experiences is (Choose one.):**

   ○ Very low
   ○ Low
   ○ Moderate
   ○ High
   ○ Very high

3. **How satisfied are you with the reliability of the electrical service you receive from Southern California Edison (SCE)? (Choose one.)**

   ○ Very dissatisfied
   ○ Somewhat dissatisfied
   ○ Neither satisfied nor dissatisfied
   ○ Somewhat satisfied
   ○ Very satisfied
   ○ Don't know

4. **In general, how long can an outage last at your home before the costs become significant? Please estimate that time length.**

   ______ hours and ______ minutes

5. **Do you or any of your household members work at home most of the time? (Choose one.)**

   ○ No
   ○ Yes—What kind of business is it? ____

   a. **If you answered "Yes" in question 5, how are you compensated for the work you perform at home? (Choose one.)**

      ○ Self-employed
      ○ Salary from employer
      ○ Hourly wage from employer
      ○ Other – Please explain: ____

6. **Do you or does anyone in your household have any health conditions for whom a power outage could be a problem? (Choose one.)**

   ○ No
   ○ Yes – Please explain: ____

7. **Do you currently own a plug-in electric vehicle? (Choose one.)**

   ○ No
   ○ Yes

8. **Do you plan to purchase or lease an electric vehicle within the next three years? (Choose one.)**

   ○ No
   ○ Yes

In the following sections, we will ask you about 6 different hypothetical scenarios involving electrical power outages. For each scenario, we would first like to know how you and your household would adjust to the outage. Second, we will ask you to estimate the extra expenses that your household would experience as a result of the outage as well as an estimated cost associated with any inconvenience or hassle.

Because every person may have different expenses and may feel differently about the amount of inconvenience or hassle, there are no right or wrong answers to these questions. We simply want your honest opinion.

IMPORTANT

As you answer questions about the hypothetical scenarios, please remember these two definitions:

Extra expenses
This category covers additional expenses you experience as a direct result of the power outage. This section may include, but is not necessarily limited to:
- Food spoilage
- Dining out (if you are unable to cook at home)
- The cost of fuel used to power a generator
- Lost wages for lost work time due to outages

Please do **not** include expenses that your household would have incurred whether or not the power outage happened. For example, if you decided to dine out during the outage **instead of** going out another night, the cost of the dinner should **not** be considered as an extra expense because it is simply shifted from another night. However, if you had to dine out during the outage **in addition to** another night, the cost of the dinner should be considered an extra expense.

Inconvenience or hassle costs
Although inconveniences or hassles do not have a monetary price associated with them, this category includes the value that you place on, for example:
- Having to use flashlights, batteries, and/or candles
- Having to leave your residence
- Being unable to charge your computer or mobile phone
- Not being able to watch television
- Having limited or no internet access
- Being unable to use solar photovoltaic (PV) equipment or charge your electric vehicle

Note: If you have solar PV panels installed, your household will still experience the power outage and your solar PV system will not feed electricity into the grid.

Case A

Suppose that on a «SEASON» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **«HOUR1» hours** your household's electricity is fully restored. (Note that **all** of the remaining cases occur at **«ONSET»**.)

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	«HOUR1» hours	**End time:**	«END1»

A1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

☐ There's generally no one home at this time
☐ Stay home and do activities that don't require electricity
☐ Find an alternative location to work (if someone from your household works from home)
☐ Go out to eat, shop or visit friends
☐ Run a backup power generator
☐ Find a different location to charge electric vehicle
☐ Use a propane/gas stove or grill for cooking
☐ Reset clocks and appliances after outage
☐ Other (please describe) ____

A2. How much do you think it would cost your household in extra expenses <u>and</u> in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ___________ extra expenses **<u>and</u>** inconvenience costs

A3. Of the above amount, how much of it would be just for the extra expenses?

$ ___________ extra expenses **<u>only</u>**

A4. Suppose a company (<u>other than SCE</u>) could immediately provide you with a temporary backup power service to handle all of your household's electricity needs during <u>this particular outage</u>. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the <u>one-time</u> amount you would be willing to pay for this temporary backup service to avoid <u>this particular</u> outage. (Please choose or specify one amount.)

○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
$0	$1	$3	$5	$10	$15	$20	$30	$40	$50	$75	$100	$150	$200	$250

○ Other (please specify) $_________

a. **Which of the following reasons best describes why you selected $0 in question A4? (Choose one.)**

○ The outage is not an inconvenience
○ I should not be expected to pay more for reliable service
○ I can use my own backup generator to power my home during the outage
○ Other – Please explain: ____

A5. Suppose you receive advance notice from SCE by mail, telephone, and/or text at least 3 days before this outage occurs. The notice informs you that the outage will occur at «ONSET» and last for «HOUR1» hours, giving you some time to prepare.

Please indicate the one-time amount you would be willing to pay for the same temporary backup power service to avoid this particular outage. (Please choose or specify one amount.)

○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
$0	$1	$3	$5	$10	$15	$20	$30	$40	$50	$75	$100	$150	$200	$250

○ Other (please specify) $__________

b. Which of the following reasons best describes why you selected $0 in question A5? (Choose one.)

○ The outage is not an inconvenience
○ I should not be expected to pay more for reliable service
○ I can use my own backup generator to power my home during the outage
○ Other – Please explain: ____

Case B

Without any warning, on a «SEASON» weekday, a complete power outage occurs at «ONSET». You don't know how long it will last, but in this case your household's electricity is fully restored after **1 hour**.

Summary Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	1 hour	**End time:**	«END2»

B1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

☐ There's generally no one home at this time
☐ Stay home and do activities that don't require electricity
☐ Find an alternative location to work (if someone from your household works from home)
☐ Go out to eat, shop or visit friends
☐ Run a backup power generator
☐ Find a different location to charge electric vehicle
☐ Use a propane/gas stove or grill for cooking
☐ Reset clocks and appliances after outage
☐ Other (please describe) ____

B2. How much do you think it would cost your household in extra expenses <u>and</u> in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ___________ extra expenses **<u>and</u>** inconvenience costs

B3. Of the above amount, how much of it would be just for the extra expenses?

$ ___________ extra expenses **<u>only</u>**

B4. Suppose a company (<u>other than SCE</u>) could immediately provide you with a temporary backup power service to handle all of your household's electricity needs during <u>this particular outage</u>. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the <u>one-time</u> amount you would be willing to pay for this temporary backup service to avoid <u>this particular</u> outage. (Please choose or specify one amount.)

○ $0 ○ $1 ○ $3 ○ $5 ○ $10 ○ $15 ○ $20 ○ $30 ○ $40 ○ $50 ○ $75 ○ $100 ○ $150 ○ $200 ○ $250

○ Other (please specify) $_________

a. **Which of the following reasons best describes why you selected $0 in question B4? (Choose one.)**

○ The outage is not an inconvenience
○ I should not be expected to pay more for reliable service
○ I can use my own backup generator to power my home during the outage
○ Other – Please explain: ____

Case C

Similar to the earlier cases, suppose that on a «SEASON» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but in this case your household's electricity is fully restored after **5 minutes**.

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	5 minutes	**End time:**	«END3»

C1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

☐ There's generally no one home at this time
☐ Stay home and do activities that don't require electricity
☐ Find an alternative location to work (if someone from your household works from home)
☐ Go out to eat, shop or visit friends
☐ Run a backup power generator
☐ Find a different location to charge electric vehicle
☐ Use a propane/gas stove or grill for cooking
☐ Reset clocks and appliances after outage
☐ Other (please describe) ____

C2. How much do you think it would cost your household in extra expenses <u>and</u> in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ___________ extra expenses **<u>and</u>** inconvenience costs

C3. Of the above amount, how much of it would be just for the extra expenses?

$ ___________ extra expenses **<u>only</u>**

C4. Suppose a company (<u>other than SCE</u>) could immediately provide you with a temporary backup power service to handle all of your household's electricity needs during <u>this particular outage</u>. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the <u>one-time</u> amount you would be willing to pay for this temporary backup service to avoid <u>this particular</u> outage. (Please choose or specify one amount.)

○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
$0	$1	$3	$5	$10	$15	$20	$30	$40	$50	$75	$100	$150	$200	$250

○ Other (please specify) $_________

a. **Which of the following reasons best describes why you selected $0 in question C4? (Choose one.)**

○ The outage is not an inconvenience
○ I should not be expected to pay more for reliable service
○ I can use my own backup generator to power my home during the outage
○ Other – Please explain: ____

Case D

Similar to the earlier cases, suppose that on a «SEASON» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but in this case your household's electricity is fully restored after **«HOUR2» hours**.

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	«HOUR2» hours	**End time:**	«END4»

D1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

☐ There's generally no one home at this time
☐ Stay home and do activities that don't require electricity
☐ Find an alternative location to work (if someone from your household works from home)
☐ Go out to eat, shop or visit friends
☐ Run a backup power generator
☐ Find a different location to charge electric vehicle
☐ Use a propane/gas stove or grill for cooking
☐ Reset clocks and appliances after outage
☐ Other (please describe) ____

D2. How much do you think it would cost your household in extra expenses <u>and</u> in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ___________ extra expenses **<u>and</u>** inconvenience costs

D3. Of the above amount, how much of it would be just for the extra expenses?

$ ___________ extra expenses **<u>only</u>**

D4. Suppose a company (<u>other than SCE</u>) could immediately provide you with a temporary backup power service to handle all of your household's electricity needs during <u>this particular outage</u>. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the <u>one-time</u> amount you would be willing to pay for this temporary backup service to avoid <u>this particular</u> outage. (Please choose or specify one amount.)

○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
$0	$1	$3	$5	$10	$15	$20	$30	$40	$50	$75	$100	$150	$200	$250

○ Other (please specify) $_________

a. **Which of the following reasons best describes why you selected $0 in question D4? (Choose one.)**

○ The outage is not an inconvenience
○ I should not be expected to pay more for reliable service
○ I can use my own backup generator to power my home during the outage
○ Other – Please explain: ____

Case E

Similar to the earlier cases, suppose that on a «SEASON» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but in this case your household's electricity is fully restored after **24 hours**.

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	24 hours	**End time:**	«END5» (Next Day)

E1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

☐ There's generally no one home at this time
☐ Stay home and do activities that don't require electricity
☐ Find an alternative location to work (if someone from your household works from home)
☐ Go out to eat, shop or visit friends
☐ Run a backup power generator
☐ Find a different location to charge electric vehicle
☐ Use a propane/gas stove or grill for cooking
☐ Reset clocks and appliances after outage
☐ Other (please describe) ____

E2. How much do you think it would cost your household in extra expenses <u>and</u> in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ___________ extra expenses <u>**and**</u> inconvenience costs

E3. Of the above amount, how much of it would be just for the extra expenses?

$ ___________ extra expenses <u>**only**</u>

E4. Suppose a company (<u>other than SCE</u>) could immediately provide you with a temporary backup power service to handle all of your household's electricity needs during <u>this particular outage</u>. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the <u>one-time</u> amount you would be willing to pay for this temporary backup service to avoid <u>this particular</u> outage. (Please choose or specify one amount.)

○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
$0	$1	$3	$5	$10	$15	$20	$30	$40	$50	$75	$100	$150	$200	$250

○ Other (please specify) $_________

a. **Which of the following reasons best describes why you selected $0 in question E4? (Choose one.)**

○ The outage is not an inconvenience
○ I should not be expected to pay more for reliable service
○ I can use my own backup generator to power my home during the outage
○ Other – Please explain: ____

Case F

Now, suppose that a complete power outage occurs at «ONSET» on a «SEASON» **WEEKEND**, without any warning. You don't know how long it will last, but in this case your household's electricity is fully restored after **«DURATION».**

SUMMARY:

Conditions:	«SEASON» **WEEKEND**	**Start time:**	«ONSET»
Duration:	«DURATION»	**End time:**	«END6»

F1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

☐ There's generally no one home at this time
☐ Stay home and do activities that don't require electricity
☐ Find an alternative location to work (if someone from your household works from home)
☐ Go out to eat, shop or visit friends
☐ Run a backup power generator
☐ Find a different location to charge electric vehicle
☐ Use a propane/gas stove or grill for cooking
☐ Reset clocks and appliances after outage
☐ Other (please describe) ____

F2. How much do you think it would cost your household in extra expenses <u>and</u> in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ___________ extra expenses **<u>and</u>** inconvenience costs

F3. Of the above amount, how much of it would be just for the extra expenses?

$ ___________ extra expenses **<u>only</u>**

F4. Suppose a company (<u>other than SCE</u>) could immediately provide you with a temporary backup power service to handle all of your household's electricity needs during <u>this particular outage</u>. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the <u>one-time</u> amount you would be willing to pay for this temporary backup service to avoid <u>this particular</u> outage. (Please choose or specify one amount.)

○ $0 ○ $1 ○ $3 ○ $5 ○ $10 ○ $15 ○ $20 ○ $30 ○ $40 ○ $50 ○ $75 ○ $100 ○ $150 ○ $200 ○ $250

○ Other (please specify) $_________

a. **Which of the following reasons best describes why you selected $0 in question F4? (Choose one.)**

○ The outage is not an inconvenience
○ I should not be expected to pay more for reliable service
○ I can use my own backup generator to power my home during the outage
○ Other – Please explain: ____

To better understand how electrical power outages affect your household, we would like to gather some information on your household characteristics. Please answer the following questions to the best of your ability. If you live in an apartment building or duplex, answer only for the part of the building you actually live in.

In addition, information about your opinions of SCE's service will help us understand how we can improve. Again, all of your answers are confidential. Your name and address will be kept anonymous and will not be associated with the information you provide.

9. What is the size of your residence?

________square feet

10. Which of the following categories best describes your total annual household income before taxes and other deductions? Please include all income to the household including social security, interest, welfare payments, child support, etc. (Choose one.)

○ Under $25,000
○ $25,000 - $49,999
○ $50,000 - $74,999
○ $75,000 - $99,999
○ $100,000 - $124,999
○ $125,000 - $149,999
○ $150,000 - $174,999
○ $175,000 - $199,999
○ $200,000 - $250,000
○ Above $250,000

11. What do you believe are the 3 leading causes of power outages that affect your home? (Check 3 that apply.)

☐ Wind storms
☐ Wildfires
☐ Other weather-related causes
☐ Household equipment failures
☐ Utility equipment failures
☐ Scheduled utility work
☐ Auto collisions impacting poles
☐ Other
☐ Don't know

12. Please tell us how important it is for SCE to improve each of the following elements by rating each from 1 to 10 (1 = not important to improve; 10 = very important to improve). (Choose one.)

a. Avoiding power outages

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

b. Preventing utility-related wildfires

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

c. Preparing for emergencies such as earthquakes or terrorist attacks

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

d. Providing environmentally clean electricity

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

e. Ensuring power quality (reducing spikes, drops, surges)

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

13. Assume there were a California ballot initiative that established a fund for making improvements to the electrical grid. The improvements would prevent damage from threats like wind storms, wildfires, and cyberattacks. It would cost each household «BALLOT_COST» per year. Would you vote for the ballot initiative? (Choose one.)

○ No
○ Yes
○ Not sure

14. Does SCE do a good job of providing safe and reliable electric service? (Choose one.)

○ No
○ Yes
○ Not sure

a. **If you answered “No” in question 14, why do you feel SCE is not doing a good job of providing safe and reliable service? (Check all that apply.)**

☐ Too many power outages
☐ Power costs too much
☐ Power quality is inadequate (too many spikes, drops, surges)
☐ Risk of SCE equipment causing wildfires is too high
☐ Other – Please explain: ____

Please share any additional comments:

____

____

____

____

Appendix C Small/Medium Business Survey Instrument

SOUTHERN CALIFORNIA EDISON
2018 CUSTOMER INTERRUPTION COST SURVEY

Non-Residential Customers

Thank you for agreeing to participate in this important study. We ask that you complete this survey thinking **only** about the facilities that your organization occupies **at this location**:

«SERV_STREET_ADDR», «SERV_CITY_NAME»

If your organization shares a building with other businesses or you're the property manager at the above address(es), please answer the questions only for the space **your organization** occupies at this location and the activities **your organization** undertakes.

All your answers will be kept confidential. Your name and your organization's name and address will be kept anonymous and will not be associated with the information you provide.

Please return your completed survey in the enclosed return envelope to receive your $50 check. If you have any concerns, please contact Southern California Edison at 1-800-990-7788. For specific questions about the survey, please contact VuPoint Research at 1-800-738-4020 Monday through Friday between the hours of 9:00 AM and 5:00 PM.

Sincerely,

Lauren Burnett
Manager, Customer Insights

This survey is also available online at: www.vupointresearch.com/SCESurvey
Your survey ID is «NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your facility. Power outages can be caused by many factors, such as bad weather, traffic accidents and equipment failures.

1. **In the past 3 months, how many brief interruptions of five minutes or less have you experienced at your business location?**

   ________ Brief interruptions (5 minutes or less)

2. **In the past 3 months, how many lengthy outages of more than five minutes have you experienced at your business location?**

   ________ Lengthy outages (more than 5 minutes)

3. **In general, how disruptive have outages been for your organization? (Choose one.)**

○	○	○	○	○	○	○
1 Not at all disruptive	2	3	4	5	6	7 Very disruptive

4. **What type(s) or duration(s) of outages at this location have financial effects on other sites owned by your company?**

   ____

   ____

   ____

5. **Has your organization ever sent employees home during a power outage? (Choose one.)**

   ○ No
   ○ Yes

6. **In general, how long can an outage last at your facility before it has a substantial impact on your operations? Please estimate that time length.**

   ______ hours and ______ minutes

7. **How much advance warning of a power outage does your organization need to significantly reduce the problems caused by a power outage? (Choose one.)**

   ○ Advance notice would not reduce problem(s)
   ○ At least 1 hour
   ○ At least 4 hours
   ○ At least 8 hours
   ○ At least 24 hours

8. How satisfied are you with the reliability of the electrical service you receive from Southern California Edison (SCE)? (Choose one.)

- ○ Very dissatisfied
- ○ Somewhat dissatisfied
- ○ Neither satisfied nor dissatisfied
- ○ Somewhat satisfied
- ○ Very satisfied
- ○ Don't know

9. Are there electric vehicle chargers on the premises, or do you plan to add any in the next 3 years? (Choose one.)

- ○ No
- ○ Yes

The next section describes six different power outage scenarios. We'd like to know the costs to your business of adjusting to each of these power outages.

The costs of a power outage depend upon the particular situation, and may vary from day to day depending upon business conditions. So for each outage scenario, you'll be given the opportunity to report the range of outage costs that your business might face (from low to high), as well as to estimate the cost that you would most likely have under typical circumstances.

It's important to try to answer all of the questions. If a question is difficult for you to answer, please give us an estimate and feel free to write down any comments about your answer.

Case A

On a «SEASON» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **«HOUR1» hours** your organization's electricity is fully restored. Note that **all** of the remaining cases occur at **«ONSET».**

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	«HOUR1» hours	**End time:**	«END1»

A1. How disruptive would this power outage be to your organization? (Choose one.)

○	○	○	○	○	○	○
1	2	3	4	5	6	7
Not disruptive at all						Very disruptive

A2. Would your operations or services typically stop or slow down as a result of this power outage? (If yes, please state the number of hours.) (Choose one.)

○ No
○ Yes

a. **If you answered "Yes" in question A2, please enter the number of hours that operations or services would stop or slow down (include time <u>during and after</u> the power outage?**

___________ hours

A3. What's the approximate dollar value of the operations or services that typically would be lost, at least temporarily, during the power outage and any slow period after the power outage? (If you're not sure please make your best guess.)

$ ___________ value of lost work or services

[Add to this table and sum at the end]

Category	Costs Due to Outage
A3. Operations and Services Lost	$

A4. What percent of the operations or services typically would be made up after the power outage? (Choose one.)

○	○	○	○	○	○	○	○	○	○	○
0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%

A5. Would there be labor costs associated with this power outage such as salaries and wages for staff who would be unable to work or overtime pay to make up for operations or services? (Choose one.)

○ No
○ Yes

a. **If you answered "Yes" in question A5, please state the cost for lost labor as well as the cost for overtime labor to make up for lost work.**

$ ____________ labor costs of staff unable to work during the power outage
$ ____________ labor costs in overtime/extra shifts to make up for lost work

[Add to this table and sum at the end]

Category	Costs Due to Outage
A5-1. Labor Costs During the Outage	$
A5-2. Overtime/Extra Shifts to Make Up for Lost Time	$

A6. Would there be any damage costs associated with this power outage such as damage to equipment, materials, etc.? (Choose one.)

○ No
○ Yes

a. **If you answered "Yes" in question A6, please state how much the damage cost for equipment would be and how much the damage cost to materials would be.**

$ ____________ damage to equipment
$ ____________ damage to materials

[Add to this table and sum at the end]

Category	Costs Due to Outage
A6-1. Damage to Equipment	$
A6-2. Damage to Materials	

A7. Would there be additional tangible costs associated with this power outage (such as extra restart costs, and costs to run and/or rent backup equipment)? (Choose one.)

○ No
○ Yes

a. **If you answered "Yes" in question A7, please state the additional costs.**

$ ___________ additional tangible costs

[Add to this table and sum at the end]

Category	Costs Due to Outage
A7. Other Tangible Costs	$

A8. Would there be <u>intangible costs</u> due to this power outage (such as inconvenience, potential liability, or loss of customers)? (Choose one.)

○ No
○ Yes

a. **If you answered "Yes" in question A8, please estimate the intangible costs.**

$ ___________ intangible costs

[Add to this table and sum at the end]

Category	Costs Due to Outage
A8. Intangible Costs	$

A9. In addition to the costs discussed above, some organizations may avoid expenses because of electrical outages. Some examples include a lower electrical bill, lower material outlays, and lower personnel costs. Would you experience any savings associated with this power outage? (Choose one.)

○ No
○ Yes

a. **If you answered "Yes" in question A7, please state the savings.**

$ ___________ savings

[Add to this table and sum at the end]

Category	Savings Due to Outage
A9. Savings Due to the Outage	$

Fill in the following table using your answers above, summing the costs to find a subtotal, and then subtracting the savings to find your total costs due to the outage.

Category	**Costs Due to Outage**
A3. Operations and Services Lost	$
A5-1. Labor Costs During the Outage	$
A5-2. Overtime/Extra Shifts to Make Up for Lost Time	$
A6-1. Damage to Equipment	$
A6-2. Damage to Materials	$
A7. Other Tangible Costs	$
A8. Intangible Costs	$
Subtotal:	**$**
A9. Savings Due to the Outage (Subtract from Subtotal)	$
TOTAL:	**$**

A10. Considering all of the costs you might experience as a result of this <u>«HOUR1»-hour «SEASON» weekday outage beginning at «ONSET»</u>, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________________	$__________________	$__________________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

A11. Assume you had at least 3 days advance notice from SCE that this «HOUR1»-hour outage would occur at «ONSET». Given the time you now have to prepare for this outage, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario, and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________________	$__________________	$__________________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case B

Without any warning, on a «SEASON» weekday, a complete power outage occurs at «ONSET». You don't know how long it will last, but **after 1 hour** your organization's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	1 hour	**End time:**	«END2»

B1. Considering all of the costs you might experience as a result of this <u>1-hour «SEASON» weekday outage beginning at «ONSET»</u>, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$______________________	$______________________	$______________________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case C

Without any warning, on a «SEASON» weekday, a complete power outage occurs at «ONSET». You don't know how long it will last, but after **5 minutes** your organization's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	5 minutes	**End time:**	«END3»

C1. Considering all of the costs you might experience as a result of this <u>5-minute «SEASON» weekday outage beginning at «ONSET»</u>, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$______________________	$______________________	$______________________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case D

Without any warning, on a «SEASON» weekday, a complete power outage occurs at «ONSET». You don't know how long it will last, but after **«HOUR2» hours** your organization's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	«HOUR2» hours	**End time:**	«END4»

D1. Considering all of the costs you might experience as a result of this <u>«HOUR2»-hour «SEASON» weekday outage beginning at «ONSET»</u>, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario, and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$______________________	$______________________	$______________________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case E

Without any warning, on a «SEASON» weekday, a complete power outage occurs at «ONSET». You don't know how long it will last, but after **24 hours** your organization's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON» weekday	**Start time:**	«ONSET»
Duration:	24 hours	**End time:**	«END5» (Next Day)

E1. Considering all of the costs you might experience as a result of this 24-hour «SEASON» weekday outage beginning at «ONSET», please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$______________________	$______________________	$______________________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case F

Without any warning, on a «SEASON» **WEEKEND**, a complete power outage occurs at «ONSET». You don't know how long it will last, but after **«DURATION»** your organization's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON» **WEEKEND**	**Start time:**	«ONSET»
Duration:	«DURATION»	**End time:**	«END6»

F1. Considering all of the costs you might experience as a result of this «DURATION» «SEASON» WEEKEND outage beginning at «ONSET», please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$______________________	$______________________	$______________________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

ABOUT YOUR ORGANIZATION

Some background information about your organization will help us understand how power outages affect your type of organization.

Please remember that all of your answers are confidential. Your name and address will be kept anonymous and will not be associated with the information you provide.

10. What's the approximate square footage of this facility?

__________ Square feet

11. Which of the following categories best describes your organization? (Choose one.)

- ○ Agriculture/Agricultural Processing
- ○ Assembly/Light Industry
- ○ Chemicals/Paper/Refining
- ○ Food Processing
- ○ Government
- ○ Grocery Store/Restaurant
- ○ Hospital
- ○ Lodging (hotel, dormitory, prison, etc.)
- ○ Lumber/Mining/Plastics
- ○ Office
- ○ Oil/Gas Extraction
- ○ Retail
- ○ School/University
- ○ Stone/Glass/Clay/Cement
- ○ Technology
- ○ Transportation
- ○ Utility
- ○ Other (please specify):________________

12. How many full-time (30+ hours per week) employees are employed by your organization at that location?

__________ Full-time employees

13. List the number of people employed by your organization at this location in each of the following categories:

__________ # of part-time year-round employees

__________ # of full-time seasonal employees

__________ # of part-time seasonal employees

14. What's the approximate value of your business's <u>total</u> annual revenue for this facility?

$ __________ per year

15. What's the approximate value of your business's <u>total</u> annual expenses (including labor, rent, materials, and other overhead expenses)?

$ __________ per year

16. Approximately what percentage of your business's annual operating budget is spent on electricity?

__________ %

17. Does your organization have any electrical equipment that's sensitive to fluctuations in voltage, frequency, short interruptions (less than two seconds), or other such irregularities in electricity supply? (Choose one.)

- ○ No
- ○ Yes

a. If you answered "Yes" in question 17, please state the type of equipment.

____

18. Does your organization own or rent/lease any of the following devices (Check all that apply.)

- ☐ Back-up generator(s)
- ☐ Uninterruptible power supply
- ☐ Line conditioning device(s)
- ☐ Surge suppressor(s)
- ☐ Isolation transformer(s)

19. Does your business have any electrical equipment that would continue to operate during a power outage? (Choose one.)

○ No
○ Yes

a. If you answered "Yes" in question 19, please state the type of equipment.

____

20. What do you believe are the 3 leading causes of power outages that affect your business? (Check 3 that apply.)

☐ Wind storms
☐ Wildfires
☐ Other weather-related causes
☐ Household equipment failures
☐ Utility equipment failures
☐ Scheduled utility work
☐ Auto collisions impacting poles
☐ Other
☐ Don't know

21. Please tell us how important it is for SCE to improve each of the following elements by rating each from 1 to 10 (1 = not important to improve; 10 = very important to improve). (Choose one.)

a. Avoiding power outages

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

b. Preventing utility-related wildfires

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

c. Preparing for emergencies such as earthquakes or terrorist attacks

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

d. Providing environmentally clean electricity

○	○	○	○	○	○	○	○	○	○
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

e. Ensuring power quality (reducing spikes, drops, surges)

O	O	O	O	O	O	O	O	O	O
1 Not Important	2	3	4	5	6	7	8	9	10 Very Important

22. Does SCE do a good job of providing safe and reliable electric service? (Choose one.)

O No
O Yes
O Not sure

a. If you answered "No" in question 14, why do you feel SCE is not doing a good job of providing safe and reliable service? (Check all that apply.)

☐ Too many power outages
☐ Power costs too much
☐ Power quality is inadequate (too many spikes, drops, surges)
☐ Risk of SCE equipment causing wildfires is too high
☐ Other – Please explain: ____

Please share any additional comments:

____

____

____

THANK YOU FOR YOUR HELP

Please provide your contact information so that we may mail you the incentive check. The incentive check can be made out to your company, or any individual or charitable organization as designated by you. The check should arrive within 4-6 weeks. If you choose not to accept any incentive, please write "decline."

Name on check: ____

Address (Line 1): ____

Address (Line 2): ____

City: ______________________________ State: ______ Zip Code: _______________

To receive your $50 check, please return this survey in the enclosed business reply envelope to:

VuPoint Research
8959 SW Barbur Blvd., Suite 204
Portland, OR 97219

«NEXID»

Appendix D Large Commercial & Industrial Survey Instrument

Associated Delivery Numbers (Acct #)

NEXID #: «cust_name»

Date of Interview: ___________________

Interviewer Name: ___________________

Interview Start Time: _________________

Interview End Time: _________________

Name: **Title:**

Name: **Title:**

Name: **Title:**

I'd like to talk to you about the costs of power outages for:
(Describe the part of the site served by the selected deliveries.)

Company Name:

Service Address:

If delivery serves only part of the site, describe location served:

OUTAGE SCENARIOS

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON»	Weekday	«ONSET»	«END1»	«HOUR1»
2	«SEASON»	Weekday	«ONSET»	«END2»	1 hour
3	«SEASON»	Weekday	«ONSET»	«END3»	5 minutes
4	«SEASON»	Weekday	«ONSET»	«END4»	«HOUR2»
5	«SEASON»	Weekday	«ONSET»	«END5»	24 hours
6	«SEASON»	WEEKEND	«ONSET»	«END6»	«DURATION»

What are the operating hours of this facility?

Use military time. If open 24 hours, use 00:00 to 00:00.

	Weekday		Saturday		Sunday	
	Open	Close	Open	Close	Open	Close
Shift 1						
Shift 2						
Shift 3						

PRODUCT AND PROCESS DESCRIPTION

1) What products do you make and/or what services do you provide at this facility?

____

____

____

____

____

2) What processes do you use to make these products and/or generate these services?

____

____

____

____

____

OUTAGE EXPERIENCE

In the past 12 months, about how many outages of the durations listed below have you had at this business location? Write a number in each blank. *(Use 0 if none.)* NOTE: the term “outage” refers to a complete loss of power.

3.1) Short duration (5 minutes or less) _______

3.2) Longer than 5 minutes and up to ½ hour _______

3.3) Longer than ½ hour and up to 1 hour _______

3.4) Longer than 1 hour and up to 4 hours _______

3.5) Longer than 4 hours and up to 24 hours _______

3.6) Over 24 hours _______

MOST RECENT OUTAGE EVENTS
Please describe your three most recent power outages:

	Outage Date *Mo/Yr*	Duration *Hrs/Mins/Secs*	Time *Military*	Weather Conditions *Clear/Stormy*	Description of Impacts
3.7)	_______	_________	______	________	____
3.8)	_______	_________	______	________	____
3.9)	_______	_________	______	________	____

4) What normally happens to your facility’s operations when a prolonged power outage (lasting more than 5 minutes) occurs?
(Prompt for major equipment affected, worst effects on operations, etc.)

____

____

____

5.1) Does an outage at this location have financial effects on other sites owned by your company?
1) Yes 2) No *(if No, skip to Q5.4)*

5.2) What type(s) or duration(s) of outages at this location have financial effects on other sites owned by your company?
(Probe for interdependencies of the production network.)

____

____

____

5.3) What are the specific financial effects?

____

____

____

____

5.4) Does an outage at this location have financial effects at your customers' sites?

1) Yes 2) No

5.5) In general, how disruptive have outages been for your organization?
(Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not at all disruptive						Very disruptive

6.1) Does your firm generate any of its own electricity (separate from backup power)?

1) Yes 2) No *(if No, skip to Q6.4)*

6.2) What percentage of your electrical demand is supplied by your generation equipment?

________________ %

6.3) What is the rated capacity of your generation equipment?

____ Circle one: kW MW hp

6.4) Does your firm have some form of backup electrical power?
1) Yes 2) No *(if No, skip to Q1C1)*

6.5) What percentage of your electrical demand could be supplied by your backup generation equipment?

_______________ %

6.6) What's the rated capacity of your backup generation equipment?

____________ Circle one: kW MW hp

7) Are there electric vehicle chargers on premise, or do you plan to add any in the next 3 years?

☐ No
☐ Yes

8) How satisfied are you with the reliability of the electrical service you receive from Southern California Edison?

☐ Very dissatisfied
☐ Somewhat dissatisfied
☐ Neither satisfied nor dissatisfied
☐ Somewhat satisfied
☐ Very satisfied
☐ Don't know

The next section describes six different types of power outages. We'd like to know the costs to your business of adjusting to each of these power outages. **Assume that all of the described outages arise from issues associated with Southern California Edison's infrastructure.**

The costs of a power outage depend upon the particular situation, and may vary from day to day depending upon business conditions. For each outage type, please estimate the costs that you'd be most likely to have under average circumstances.

Since some businesses have more than one building at one location, and others have multiple buildings in several locations, please remember to fill out these questions thinking <u>only</u> about the building(s) that your business occupies at the location specified for this survey.

It's important to try to answer all of the questions. If a question is difficult for you to answer, please give us an estimate and feel free to provide any comments about your answer.

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON»	Weekday	«ONSET»	«END1»	«HOUR1»

1C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.1C6)

1C2) By what percentage would activities stop or slow down? _________ %

1C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

1C4) What percent of this lost output is likely to be made up? _________ %

1C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST

1C6) Damage/spoilage to raw or intermediate materials _________ $

1C7) Cost of disposing of hazardous materials _________ $

1C8) Damage to your organization's plant or equipment _________ $

1C9) Costs to run backup generation or equipment _________ $

1C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)

1C11) Savings from unused raw and intermediate materials (except fuel) _________ $

1C12) Savings on your firm's fuel (electricity) bill _________ $

1C13) Scrap value of damaged products or inputs _________ $

LABOR COST

1C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

1C15) Labor costs to make-up lost output _________ $

1C16) Extra labor costs to restart activities _________ $

1C17) Savings from wages that were not paid _________ $

1C18) Other costs _________ $

1C19) Other savings _________ $

1C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

Case	Season	Day	Start Time	End Time	Duration
1	Same as Case 1, but customer receives 3-day advance notice (AN) of outage.				

1C1-AN) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.1C6)

1C2-AN) By what percentage would activities stop or slow down? _________ %

1C3-AN) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

1C4-AN) What percent of this lost output is likely to be made up? _________ %

1C5-AN) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST

1C6-AN) Damage/spoilage to raw or intermediate materials _________ $

1C7-AN) Cost of disposing of hazardous materials _________ $

1C8-AN) Damage to your organization's plant or equipment _________ $

1C9-AN) Costs to run backup generation or equipment _________ $

1C10-AN) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)

1C11-AN) Savings from unused raw and intermediate materials (except fuel) _________ $

1C12-AN) Savings on your firm's fuel (electricity) bill _________ $

1C13-AN) Scrap value of damaged products or inputs _________ $

LABOR COST

1C14-AN) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

1C15-AN) Labor costs to make-up lost output _________ $

1C16-AN) Extra labor costs to restart activities _________ $

1C17-AN) Savings from wages that were not paid _________ $

1C18-AN) Other costs _________ $

1C19-AN) Other savings _________ $

1C20-AN) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

Case	Season	Day	Start Time	End Time	Duration
2	«SEASON»	Weekday	«ONSET»	«END2»	1 hour

2C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.2C6)

2C2) By what percentage would activities stop or slow down? _________ %

2C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

2C4) What percent of this lost output is likely to be made up? _________ %

2C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST

2C6) Damage/spoilage to raw or intermediate materials _________ $

2C7) Cost of disposing of hazardous materials _________ $

2C8) Damage to your firm's plant or equipment _________ $

2C9) Costs to run backup generation or equipment _________ $

2C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)

2C11) Savings from unused raw and intermediate materials (except fuel) _________ $

2C12) Savings on your firm's fuel (electricity) bill _________ $

2C13) Scrap value of damaged products or inputs _________ $

LABOR COST

2C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

2C15) Labor costs to make-up lost output _________ $

2C16) Extra labor costs to restart activities _________ $

2C17) Savings from wages that were not paid _________ $

2C18) Other costs _________ $

2C19) Other savings _________ $

2C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

Case	Season	Day	Start Time	End Time	Duration
3	«SEASON»	Weekday	«ONSET»	«END3»	5 minutes

3C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.3C6)

3C2) By what percentage would activities stop or slow down? _________ %
3C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

3C4) What percent of this lost output is likely to be made up? _________ %
3C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST
3C6) Damage/spoilage to raw or intermediate materials _________ $

3C7) Cost of disposing of hazardous materials _________ $

3C8) Damage to your firm's plant or equipment _________ $

3C9) Costs to run backup generation or equipment _________ $

3C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)
3C11) Savings from unused raw and intermediate materials (except fuel) _________ $

3C12) Savings on your firm's fuel (electricity) bill _________ $

3C13) Scrap value of damaged products or inputs _________ $

LABOR COST
3C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

3C15) Labor costs to make-up lost output _________ $

3C16) Extra labor costs to restart activities _________ $

3C17) Savings from wages that were not paid _________ $

3C18) Other costs _________ $

3C19) Other savings _________ $

3C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

Case	Season	Day	Start Time	End Time	Duration
4	«SEASON»	Weekday	«ONSET»	«END4»	«SERVICE_CITY»

4C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.4C6)

4C2) By what percentage would activities stop or slow down? _________ %

4C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

4C4) What percent of this lost output is likely to be made up? _________ %

4C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST

4C6) Damage/spoilage to raw or intermediate materials _________ $

4C7) Cost of disposing of hazardous materials _________ $

4C8) Damage to your firm's plant or equipment _________ $

4C9) Costs to run backup generation or equipment _________ $

4C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)

4C11) Savings from unused raw and intermediate materials (except fuel) _________ $

4C12) Savings on your firm's fuel (electricity) bill _________ $

4C13) Scrap value of damaged products or inputs _________ $

LABOR COST

4C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

4C15) Labor costs to make-up lost output _________ $

4C16) Extra labor costs to restart activities _________ $

4C17) Savings from wages that were not paid _________ $

4C18) Other costs _________ $

4C19) Other savings _________ $

4C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

Case	Season	Day	Start Time	End Time	Duration
5	«SEASON»	Weekday	«ONSET»	«END5»	24 hours

5C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.5C6)

5C2) By what percentage would activities stop or slow down? _________ %

5C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

5C4) What percent of this lost output is likely to be made up? _________ %

5C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST

5C6) Damage/spoilage to raw or intermediate materials _________ $

5C7) Cost of disposing of hazardous materials _________ $

5C8) Damage to your firm's plant or equipment _________ $

5C9) Costs to run backup generation or equipment _________ $

5C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)

5C11) Savings from unused raw and intermediate materials (except fuel) _________ $

5C12) Savings on your firm's fuel (electricity) bill _________ $

5C13) Scrap value of damaged products or inputs _________ $

LABOR COST

5C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

5C15) Labor costs to make-up lost output _________ $

5C16) Extra labor costs to restart activities _________ $

5C17) Savings from wages that were not paid _________ $

5C18) Other costs _________ $

5C19) Other savings _________ $

5C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

Case	Season	Day	Start Time	End Time	Duration
6	«SEASON»	WEEKEND	«ONSET»	«END6»	«DURATION»

6C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.6C6)

6C2) By what percentage would activities stop or slow down? _________ %
6C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

6C4) What percent of this lost output is likely to be made up? _________ %
6C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST
6C6) Damage/spoilage to raw or intermediate materials _________ $

6C7) Cost of disposing of hazardous materials _________ $

6C8) Damage to your firm's plant or equipment _________ $

6C9) Costs to run backup generation or equipment _________ $

6C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)
6C11) Savings from unused raw and intermediate materials (except fuel) _________ $

6C12) Savings on your firm's fuel (electricity) bill _________ $

6C13) Scrap value of damaged products or inputs _________ $

LABOR COST
6C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

6C15) Labor costs to make-up lost output _________ $

6C16) Extra labor costs to restart activities _________ $

6C17) Savings from wages that were not paid _________ $

6C18) Other costs _________ $

6C19) Other savings _________ $

6C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

9) Now that we have discussed the *direct* costs associated with these outages, would you experience any *intangible* costs such as loss of good will, potential liability, or loss of customers?

1) Yes *(if Yes, please explain)*
2) No

____

____

____

ABOUT YOUR BUSINESS

Some background information about your business will help us understand how power outages affect your type of business. Please remember all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

10.1) Which one of the following categories best describes your business?

- ❑ Agriculture/Agricultural Processing
- ❑ Assembly/Light Industry
- ❑ Chemicals/Paper/Refining
- ❑ Food Processing
- ❑ Grocery Store/Restaurant
- ❑ Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑ High Tech
- ❑ Lumber/Mining/Plastics
- ❑ Office
- ❑ Oil/Gas Extraction
- ❑ Retail
- ❑ Stone/Glass/Clay/Cement
- ❑ Transportation
- ❑ Utility
- ❑ Other *(please specify)*: ______________________________

10.2) What's the approximate square footage of the facility?

__________ Square feet

10.3) How many **full-time** (30+ hours per week) employees are employed by your business at this location?

__________ Full-time employees

10.4) List the number of people employed by your business at this location in each of the following categories:

__________ # of part-time year-round employees

__________ # of full-time seasonal employees

__________ # of part-time seasonal employees

10.5) What's the approximate value of your business' annual operations or services (income)?

$_____________ per year

10.6) What's the approximate value of your business' total annual expenses (including labor, rent, materials, and other overhead expenses)?

$_____________ per year

10.7) Approximately what percentage of your business' annual operating budget is spent on electricity?

__________ %

That concludes our interview today. Thank you very much for your time.

FOR INTERNAL USE ONLY:

Based on your observations of this facility, give a brief summary of the facility, any unusual occurrences with their power supply, and the critical factors that minimize and/or exacerbate outage costs.

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Workpaper Title:

Capital Details by WBS for

DER-Driven Distribution Automation

Southern California Edison
2025 GRC Capital Workpapers

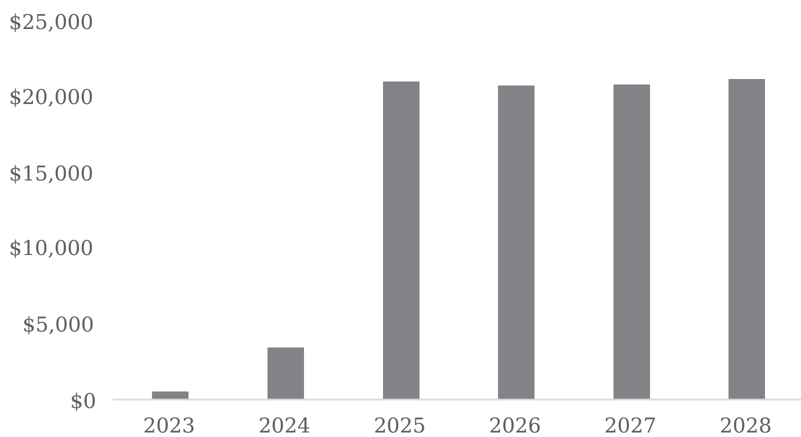
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Automation
1. Witness:	Mark Esguerra
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	99
5. Pin:	7817
6. CWBS Element:	CETPDGMDMMTW
CWBS Description:	Metro West
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	518	3,436	20,956	20,713	20,755	21,137	87,514

Due to rounding, totals may not tie to individual items.



Workpaper Title:

Capital Details by WBS for

Small-scale Deployments

Southern California Edison
2025 GRC Capital Workpapers

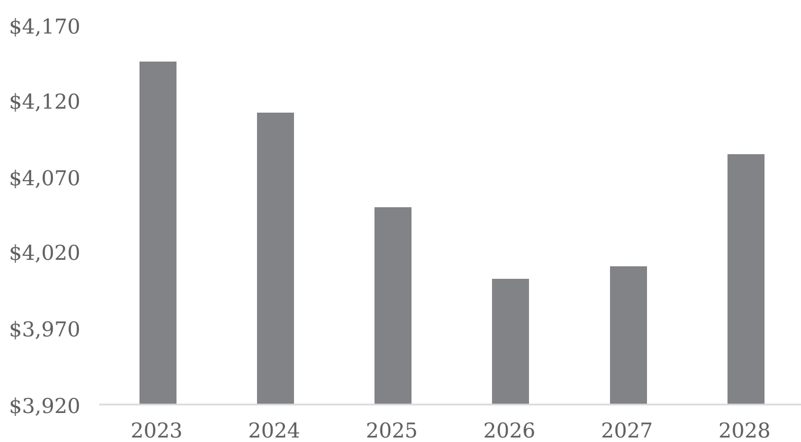
Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Automation
1. Witness:	Mark Esguerra
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	100
5. Pin:	7817
6. CWBS Element:	CETPDGMISMTW
CWBS Description:	Metro West
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	4,146	4,112	4,050	4,003	4,011	4,085	24,406

Due to rounding, totals may not tie to individual items.



Workpaper:

Distribution Automation Small Scale Deployment (SSD)

Purpose

This workpaper supports the 2025–2029 forecast for Distribution Automation Small Scale Deployment (SSD) program. As described in testimony, while pre–commercial distribution automation technologies are demonstrated under SCE's Electric Program Investment Charge (EPIC) program, additional validation efforts are necessary to validate full equipment integration into SCE's Distribution Electric Grid. These activities help SCE realize the benefits of Distribution Automation Full Scale Deployment (FSD).

The efforts entail:

- Validating technical aspects of equipment: Technical Design, Construction, Installation, and Operation at a scale larger than a Pilot but still limiting potential impacts companywide.
- Validating documentation aspects of equipment: All processes and procedure are in place to support companywide integration of the new equipment.
- Providing: Awareness, Communication, and Training on the new equipment with all impacted stakeholders.

In developing annual forecasts, the forecast captures cost required, per year, for the integration of distribution protection and interrupting equipment, distribution sectionalizing equipment, and grid sensors. Below is a breakdown by technology type of the different attributes/capabilities. The project forecast reflects project cost to support the integration of the new equipment as well as new capabilities, new features, enhancements, and the evolution of existing devices.

2025–2029 Forecasted Expenditures ($000s)

Year	2025	2026	2027	2028
	$4,050	$4,003	$4,011	$4,085

Integration of distribution protection and interrupting equipment to support the end goals for future bi–directional power flow and Fault Location, Isolation, and Service Restoration (FLISR) schemes.

Remote Automatic Recloser (RAR) / Remote Sectionalizing Recloser (RSR)

- Remote Automatic Recloser (RAR) / Remote Sectionalizing Recloser (RSR) for Underground Applications
  - Integration of protection/interrupting equipment to provide Programmable Logic, 3-Ph Voltage, 3-Ph Current, Real Power, Reactive Power, Apparent Power, Power Direction, and Fault Indication

- Remote Automatic Recloser (RAR) / Remote Sectionalizing Recloser (RSR) for Padmount Applications

Workpaper – Southern California Edison (SCE) | 2025 General Rate Case (GRC)

- Integration of protection/interrupting equipment to provide Programmable Logic, 3-Ph Voltage, 3-Ph Current, Real Power, Reactive Power, Apparent Power, Power Direction, and Fault Indication

- Remote Automatic Recloser (RAR) / Remote Sectionalizing Recloser (RSR) w/ Power Quality Capabilities
  - Integration of protection/interrupting equipment to provide Programmable Logic, 3-Ph Voltage, 3-Ph Current, Real Power, Reactive Power, Apparent Power, Power Direction, Fault Indication, and Power Quality Measurements

Integration of distribution sectionalizing equipment to support the end goals for future bi–directional power flow and Fault Location, Isolation, and Service Restoration (FLISR) schemes.

Remote Controlled Switch (RCS)

- Remote Controlled Switches w/ Telemetry for Underground Applications
  - By expanding the application to underground sectionalizing equipment for wider system application and benefit
  - Integration of sectionalizing equipment to provide 3–Ph Voltage, 3–Ph Current, Real Power, Reactive Power, Apparent Power, Power Direction, and Fault Indication

- Remote Controlled Switches w/ Telemetry for Padmount Applications
  - By expanding the application to Padmount sectionalizing equipment for wider system application and benefit
  - Integration of sectionalizing equipment to provide 3–Ph Voltage, 3–Ph Current, Real Power, Reactive Power, Apparent Power, Power Direction, and Fault Indication

- Remote Controlled Switches w/ Telemetry for Overhead Applications, where existing equipment can be Retrofitted w/ Telemetry
  - By expanding the application to existing, and eligible, overhead sectionalizing equipment for wider system application and benefit
  - Expansion of existing sectionalizing equipment to provide 3–Ph Voltage, 3–Ph Current, Real Power, Reactive Power, Apparent Power, Power Direction, and Fault Indication

Integration of sensor equipment to support the end goals for future bi–directional power flow and Fault Location, Isolation, and Service Restoration (FLISR) schemes.

Grid Sensors

- Remote Fault Indicator (RFI)
  - Implementation for overhead, underground, and Padmount applications

- Distribution Line Sensors
  - Implementation of sensor technology on fire resistant distribution poles to help identify fires, vibrations, misalignments, or damage
  - Power quality monitors that measure harmonic disturbances on the distribution system that can potentially impact substation relays and customer equipment

Distribution Automation Small Scale Deployment (SSD) Support Analysis

From 2025–2029, SCE will execute small scale deployments for overhead, underground, and Padmount fault interrupting equipment w/ telemetry, sectionalizing equipment w/ telemetry, and grid sensors to support and validate a systemwide equipment integration in preparation for Full Scale Deployment (FSD). Total project cost forecast is calculated based on actual and estimated unit cost, unit installation cost, and multiplied by the total of units required as part of the Small Scall Deployment (SSD).

Estimated unit costs for distribution automation technologies include labor, materials, and other associated miscellaneous costs (e.g., allocations/overheads). All unit cost estimates include funding for the below:

- Technical Design
- Standards Development
- Vendor Contract Negotiations
- Material Procurement
- Equipment Scoping
- Equipment Installation Design
- Work Order Creation
- Securing Easements
- Securing Jurisdictional Permits
- Submitting request for Base Maps, Look Ups, & Rights Checks
- Construction Scheduling
- Construction and/or Installation

- Commissioning/In–Servicing
- Work Order Closeout

Workpaper Title:

Capital Details by WBS for DER-driven Substation Automation

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	Automation

1. Witness:	Mark Esguerra
2. Asset type:	DS-SUB
3. In-Service date:	12\1\9999
4. RO Model ID:	314
5. Pin:	7817
6. CWBS Element:	CETETGMSA781706
CWBS Description:	DER-driven Substation Automation
7. SRIIM Eligible:	No

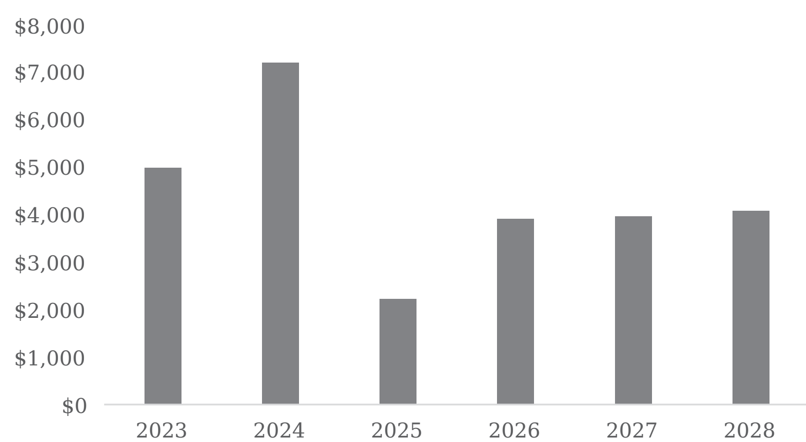
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	4,989	7,204	2,227	3,909	3,962	4,080

2023 - 2028 Total
26,371

Due to rounding, totals may not tie to individual items.



Workpaper:

Distributed Energy Resource (DER) Driven Substation Automation

Workpaper – Southern California Edison (SCE) | 2025 General Rate Case (GRC)

Purpose

This workpaper supports the 2025 GRC (2025–2028) methodology for the DER Driven Substation Automation program.

Analysis

The criteria for substation selection are determined by: (1) an individual circuit at a substation exceeding 16MW or (2) a percentage of circuits at a substation experience reverse power flow of a specific DER value.

$$\text{No. of Substations} = \sum_{1}^{\text{All Substations}} \begin{matrix} \text{Total Nameplate DER MW > 16MW (No. \% of Circuits Threshold)} \\ \text{DERs > 15 MW, 50\% of Circuits w/ Reverse Power Flow} \\ \text{DERs > 10 MW, 75\% of Circuits w/ Reverse Power Flow} \\ \text{DERs > 8 MW, 100\% of Circuits w/ Reverse Power Flow} \end{matrix}$$

Applicability of Unit Cost to Projects

DER integration capability and Cybersecurity of Substation Automation 3 (SA-3) requires:

- Human Machine Interface (HMI)
  - To allow configuration of Intelligent Electronic Devices (IEDs)
- Modern Microprocessor Relays
  - To perform advanced protection functions over International Electrotechnical Commission (IEC) 61850 protocols, and to perform over–the–air settings and updates

The upgrades required at each substation vary and depend on the existing automation and equipment in place to build a full cybersecure SA-3 platform. For example:

- An existing RTU/Non–SAS station will require: HMI installation, relay upgrades, and CSP installation[1]
- An existing SA-1 station will require: HMI upgrade, relay upgrades, and CSP installation
- An existing SA-2 station may require: Relay upgrades, and will require CSP installation
  - If modern microprocessor relay already exists, then only CSP installation is required
- An existing SA-3 (Hybrid) station will require relay upgrades, and will require CSP Installation
  - Modern microprocessor relays are required to support secure IEC 61850 communications

[1] The capital expenditures necessary to support CSP installations are included in the Common Substation Platform workstream, not DER-driven Substation Automation.

Below are five substations with high DER penetration that meet the criteria provided above.

Need Date	B-Bank Substation	Current Automation	HMI	Relays	CSP
2022	Victor 115/12 kV	SA-2	X	X	X
2022	Las Lomas 66/12 kV	SA-2	X	X	X
2022	Kimball 66/12 kV	SA-2	X	X	X
2022	Little Rock 66/12 kV	SA-2	X	X	X
2022	Moorpark 66/16 kV	SA-2	X	X	X

Human Machine Interface (HMI) Unit Cost

The average HMI unit cost is derived as follows and is the same HMI unit cost used in all of SCE's substation projects at B–Bank Substations.

$$HMI\ Unit\ Cost_{B-Bank} = \frac{Total\ Sum\ of\ HMI\ Constant\ Cost_{B-Bank}}{Number\ of\ New\ HMIs_{B-Bank}}$$

Relay Unit Cost

The average Relay unit cost is derived as follows and is the same relay unit cost used in all of SCE's substation projects at B–Bank Substations.

$$Relay\ Unit\ Cost_{B-Bank} = \frac{Total\ Sum\ of\ Relay\ Constant\ Cost_{B-Bank}}{Number\ of\ New\ Relays_{B-Bank}}$$

Forecast

For years 2025–2028, SCE determined the number of distribution substations (B–Bank substations) that require an SA-3 upgrade due to high DER penetration. The total cost of required for each substation was calculated and is the total of the needed components multiplied by the unit cost per component to provide the total cost of the SA-3 upgrade.

Operating Date	B-Bank Substation	Current Automation	Capital Expenditures			
			2025	2026	2027	2028
2025	Victor 115/12 kV	SA-2	$1,800,000			
2026	Las Lomas 66/12 kV	SA-2	$300,000	$900,000	$1,800,000	
2028	Kimball 66/12 kV	SA-2		$990,000	$750,000	$1,260,000
2028	Little Rock 66/12 kV	SA-2		$990,000	$750,000	$1,260,000
2028	Moorpark 66/16 kV	SA-2		$990,000	$600,000	$1,410,000
		Total	$2,100,000	$3,870,000	$3,900,000	$3,930,000
		Total (Escalated)	$2,227,401	$3,908,523	$3,962,247	$4,079,701

Conclusion

The DER-driven Substation Automation projects were determined for areas where the high DER penetration was identified. The substation automation for each substation is required to monitor and manage new distributed energy resources and provide cybersecurity. The cybersecurity provided to the substations are important due to the circuits within each substation themselves, are now the source of electric power for a period of time for the Substation and Subtransmission system.

Workpaper Title:

Capital Details by WBS for

Subtransmission Relay Upgrade Program

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Modernization
GRC Activity:	DER-Driven Grid Reinforcement
1. Witness:	Mark Esguerra
2. Asset type:	DS-SUB
3. In-Service date:	12\1\9999
4. RO Model ID:	313
5. Pin:	7817
6. CWBS Element:	CETETGMSA781700
CWBS Description:	Trans Subs Modern Microprocessor Relays
7. SRIIM Eligible:	No

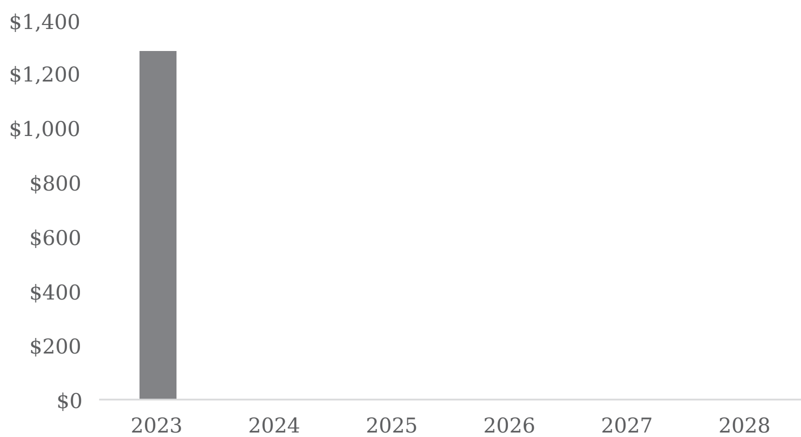
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	1,287	0	0	0	0	0

2023 - 2028 Total
1,287

Due to rounding, totals may not tie to individual items.



Workpaper Title:

Subtransmission Relay Upgrade Program

Business Planning Group: System Augmentation
Business Planning Element: Grid Modernization
GRC Activity DER Hosting Capacity Reinforcement
Project: Subtransmission Relay Upgrades
CWBS Element: CET-ET-GM-SA-781700

Nominal $000 in Thousands

Cost Estimation Sheet

Cost Type	Funding	Recorded 2018	Recorded 2019	Recorded 2020	Recorded 2021	Recorded 2022	2023	2024	2025	2026	2027	2028	11-Year Total
Capital (by Substation):													
Viejo Substation	Capital	335	16	17	275	570	908						2,121
Santiago Substation	Capital	56	32	-	3	48							140
O'Neill Substation	Capital	75	14	5	47	39	50						229
Moulton Substation	Capital	34	7	1	12	7	67						129
Limestone Substation	Capital	160	5	2	28	90	116						
Chiquita Substation	Capital	173	39	24	21	131	146						
Borrego Substation	Capital	31	25	3	11	92							162
Total Capital (by Substation):		**863**	**139**	**54**	**398**	**976**	**1,287**	**-**	**-**	**-**	**-**	**-**	**2,781**

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2025 General Rate Case

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Workpapers

SCE-02 Grid Activities
Volume 6 - Grid Modernization, Grid Technology, and Energy Storage
Technology Assessment

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Technology Assessments, Pilots & Adoption
Activity:	Technology Assessment
Witness:	Juan Castaneda

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	7,201	11,403
Non-Labor	2,317	3,699
Other	0	0
Total	9,518	15,102

Due to rounding, totals may not tie to individual items.

Description of Activity:

Technology Assessments - Operation Supervision and Engineering - Includes the cost of labor, materials used, and expenses incurred to perform engineering studies related to the implementation or development of new technologies for the grid and expenses related to software projects and enhancements. Also includes the costs charged to Transmission and Distribution by SCE's Information Technology department for providing and maintaining computer equipment and programs related to transmission assets and personnel. Includes related costs such as: transportation expenses; meals, traveling, lodging, and incidental expenses; division overhead; and supply and tool expense.

Forecast Methods - Summary of Results of Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Technology Assessments, Pilots & Adoption
Activity:	Technology Assessment
Witness:	Juan Castaneda

Cost Type	Recorded/Adj.				
	2018	2019	2020	2021	2022
Labor	8,848	7,306	8,303	7,750	7,201
Non-Labor	2,228	2,486	1,975	1,520	2,317
Other	0	0	0	0	0
Total	**11,075**	**9,792**	**10,278**	**9,270**	**9,518**

Cost Type	Results of Linear Trending					
	3 Years: 2020 - 2022		4 Years: 2019 - 2022		5 Years: 2018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	5,547	1.00	7,249	0.05	6,457	0.42
Non-Labor	2,622	0.18	1,641	0.08	1,711	0.11
Other	0	0.00	0	0.00	0	0.00
Total	**8,169**	**N/A**	**8,890**	**N/A**	**8,168**	**N/A**

Cost Type	Results of Averaging							
	2 Years:		3 Years:		4 Years:		5 Years:	
	2021 - 2022	sd**	2020 - 2022	sd**	2019 - 2022	sd**	2018 - 2022	sd**
Labor	7,475	275	7,751	450	7,640	435	7,882	620
Non-Labor	1,919	398	1,937	326	2,074	369	2,105	336
Other	0	0	0	0	0	0	0	0
Total	**9,394**	**N/A**	**9,689**	**N/A**	**9,715**	**N/A**	**9,987**	**N/A**

Cost Type	Last Recorded Year		
	2023	2024	2025
Labor	7,201	7,201	7,201
Non-Labor	2,317	2,317	2,317
Other	0	0	0
Total	**9,518**	**9,518**	**9,518**

Cost Type	Itemized Forecast		
	2023	2024	2025
Labor	8,615	9,337	11,403
Non-Labor	4,092	3,735	3,699
Other	0	0	0
Total	**12,707**	**13,072**	**15,102**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Technology Assessments, Pilots & Adoption
Activity:	Technology Assessment
Witness:	Juan Castaneda

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		TY Forecast Incr/(Decr) from 2022
	2018	2019	2020	2021	2022	2023	2024	2025	Method	($000)	
Labor	8,848	7,306	8,303	7,750	7,201	8,615	9,337	11,403	Itemized	11,403	4,202
Non-Labor	2,228	2,486	1,975	1,520	2,317	4,092	3,735	3,699	Itemized	3,699	1,383
Other											
Total	11,075	9,792	10,278	9,270	9,518	12,707	13,072	15,102		15,102	5,585

Due to rounding, totals may not tie to individual items.

Analysis of Forecasting Methods

Itemized Forecast:
Itemized Forecast Method

Other Forecast Methods not Selected

Last Recorded Year:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Last Recorded Year method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Last Recorded Year method is not appropriate.

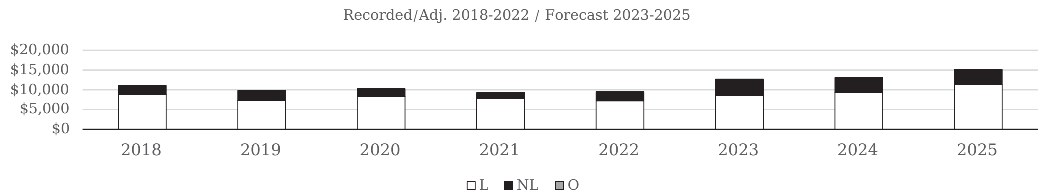
Linear Trending:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate. For this activity the Linear Trending method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Linear Trending method is not appropriate.

Averaging:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility’s control, an average of recorded-expenses is appropriate. For this activity the Averaging method does not account for the variables discussed in testimony to determine the 2025 Test Year forecast. Therefore, the Averaging method is not appropriate.

2025 GRC Year Over Year Variance

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Technology Assessments, Pilots & Adoption
Activity:	Technology Assessment
Witness:	Juan Castaneda



Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	8,848	7,306	8,303	7,750	7,201	8,615	9,337	11,403
	Non-Labor	2,228	2,486	1,975	1,520	2,317	4,092	3,735	3,699
	Other	0	0	0	0	0	0	0	0
	Total	**11,075**	**9,792**	**10,278**	**9,270**	**9,518**	**12,707**	**13,072**	**15,102**

Labor	Prior Year Total		8,848	7,306	8,303	7,750	7,201	8,615	9,337
	Change		(1,541)	997	(553)	(549)	1,414	722	2,066
	Total		**7,306**	**8,303**	**7,750**	**7,201**	**8,615**	**9,337**	**11,403**
Non-Labor	Prior Year Total		2,228	2,486	1,975	1,520	2,317	4,092	3,735
	Change		259	(512)	(454)	797	1,775	(357)	(36)
	Total		**2,486**	**1,975**	**1,520**	**2,317**	**4,092**	**3,735**	**3,699**
Other	Prior Year Total		0	0	0	0	0	0	0
	Change		0	0	0	0	0	0	0
	Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Change	Prior Year Total		11,075	9,792	10,278	9,270	9,518	12,707	13,072
	Change		(1,283)	485	(1,007)	247	3,189	365	2,030
	Total		**9,792**	**10,278**	**9,270**	**9,518**	**12,707**	**13,072**	**15,102**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Grid Technology Assessments, Pilots & Adoption
Activity:	Technology Assessment
Witness:	Juan Castaneda

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	2019	2020	2021	2022	2023	2024	2025
Recorded / Forecast	Labor	8,848	7,306	8,303	7,750	7,201	8,615	9,337	11,403
	Non-Labor	2,228	2,486	1,975	1,520	2,317	4,092	3,735	3,699
	Other	0	0	0	0	0	0	0	0
	Total	11,075	9,792	10,278	9,270	9,518	12,707	13,072	15,102

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)
See Testimony

Forecast (2023-2025)
See Testimony

Workpaper Title:

Technology Assessment O&M Forecast

Exhibit	SCE-02 Grid Activities
Volume	Vol 6 Pt II Grid Technology Assessments Pilot and Adoption
Business Planning Element	Grid Technology Assessment Pilot and Adoption
Activity	Technology Assessment
Workpaper Title	Technology Assessment Forecast
Witness	Juan Castaneda

Purpose	This workpaper shows the build up of Technology Assessment's O&M budget including 2022 Actuals and Test Year 2025. Compares 2022 actuals to test year 2025.

Source	1. Uses data published monthly in the "Current Org Management Report" by Business Line Planning. 2. SLR or Standard Labor Rates pulled from the SLR tab in the Opearting Plan templates published by Operation Finance team. 3. Sr Managers from Grid Tech PMO, Grid Technology, and Manager from Lab Operations provided input on new and replacement positions and start dates along with non-labor expected spend each year.

Technology Assessment Forecast (Constant 2022 $)

	2022	2023	2024	2025	Variance
Labor	**$7,200,952**	**$8,615,435**	**$9,337,168**	**$11,403,137**	**$4,202,185**
Vacancies[1]				$1,318,721	**$1,318,721**
New Positions[2]				$1,130,038	**$1,130,038**
Other Adjustments[3]				$1,753,426	**$1,753,426**
Non-Labor	**$2,316,802**	**$4,091,721**	**$3,735,063**	**$3,699,320**	**$1,382,518**
Return to Historical Baseline[1]				$647,621.00	**$647,621**
Infrastructure Investment & Jobs Act[2]				$648,223.00	**$648,223**
Other Adjustments[3]				$86,674.00	**$86,674**
Totals	**$9,517,754**	**$12,707,156**	**$13,072,231**	**$15,102,457**	**$5,584,703**

Notes and Assumptions

Labor

1. Labor adjustment of $1,318,721 for 11 vacancies. The need for 11 resources was identified based on the level of SCE's Grid Technology work returning back to the historical baseline level, these vacancies now need to be filled so that SCE has the resources necessary to support SCE-internal evaluation projects in the areas of energy storage, distribution automation, substation automation and vehicle-grid-integration, and external/industry collaborations.

2. Labor adjustment of $1,130,038 for anticipated growth of 10 positions. The need for Grid Technology work is expanding at a rapid pace as the number of activities and complexity of these activities continues to grow in areas such as vehicle-to-grid integration (especially "V2G," vehicle-to-grid), climate adaption, microgrids, and digital transformation, which includes cybersecurity, information system architecture required to facilitate information technology / operational technology (IT/OT) convergence (also referred to as "IoT," Internet of Things) and predictive analytics.

3. Adjustments attributable to SCE's employee compensation program and resources supporting both Capital and O&M related activities.

Vacancies and Start Dates	Count	Standard Labor Rate
Analyst-Program/Project 2	**1**	**113,892**
4/1/2023	1	113,892
Bus Ops Anlys, Sr Spec	**1**	**106,900**
4/1/2023	1	106,900
Emerg Tech Acq & Implm Prj Mgr	**2**	**275,732**
1/1/2023	2	275,732
Engineer 1	**2**	**158,961**
4/1/2023	2	158,961
Engineer 3	**3**	**389,707**
1/1/2023	3	389,707
Lab Svs, Sr Spec	**1**	**120,100**
4/1/2023	1	120,100
Sr Engineer 1	**1**	**153,430**
4/1/2023	1	153,430
Grand Total	**11**	**1,318,721**

New Positions and Start Dates	Count	Standard Labor Rate
Bus Ops Anlys, Specialist	**1**	**84,700**
4/1/2023	1	84,700
Emerg Tech Acq & Implm Prj Mgr	**1**	**137,866**
4/1/2025	1	137,866
Eng, Mgr	**1**	**159,620**
4/1/2023	1	159,620
Engineer 1	**1**	**79,481**
4/1/2023	1	79,481
Project Mgmt Support, Specialist	**2**	**169,400**
4/1/2023	2	169,400
Project Mgmt Support, Sr Specialis	**1**	**94,700**
4/1/2023	1	94,700
Senior Engineer 2	**1**	**99,219**
7/1/2023	1	99,219
Sr Engineer 1	**1**	**153,430**
4/1/2025	1	153,430
Strgc Allicances, Sr Advisor	**1**	**151,623**
1/1/2023	1	151,623
Grand Total	**10**	**1,130,038**

Non-Labor

1. Non-Labor adjustment of $.65 million SCE deferred certain non-wildfire-related activities and programs in order to prioritize emergent public safety risks pertaining to wildfire-related events. However, with the level of SCE's lab operations work returning back to the historical baseline level, additional non-labor expenses will be incurred to support this work.

2. Labor adjustment of $.65 million to account for pre-award work that will be necessary to support the application process for federal Infrastructure Investment and Jobs Act (IIJA) initiatives. Pre-award costs are those incurred prior to the effective date of the federally awarded grant and thus are not recoverable through the grant program. SCE intends to pursue a variety of grants for several important projects during this GRC cycle, which collectively will provide value to SCE's customers and the grid, as well as further the State's environmental and related policy goals.

3. Company-wide escalation and compensation adjustments.

Workpaper Title:

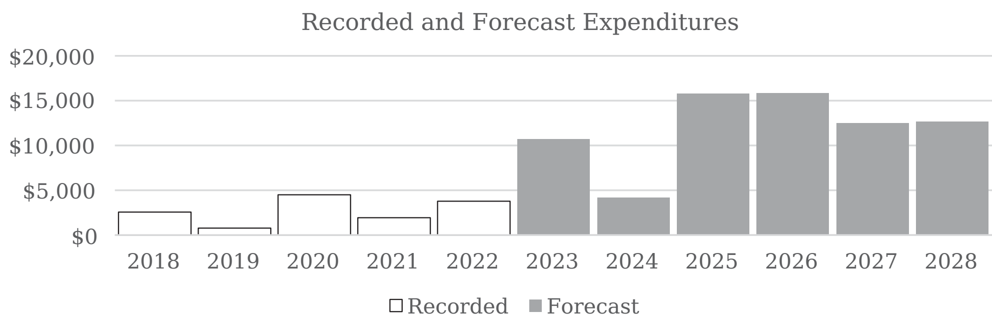
Grid Technology Laboratory Operations
Capital Summary

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-02 Grid Activities
Volume: 6 - Grid Modernization, Grid Technology, and Energy Storage

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures	2,566	776	4,496	1,937	3,778	10,699	4,185	15,760	15,847	12,503	12,675
Total Expenditures					13,554						71,668

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Laboratory Operations	10,699	4,185	15,760	15,847	12,503	12,675	71,668
GRC Total	10,699	4,185	15,760	15,847	12,503	12,675	71,668

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Grid Technology Assessments, Pilots & Adoption
GRC Activity:	Laboratory Operations

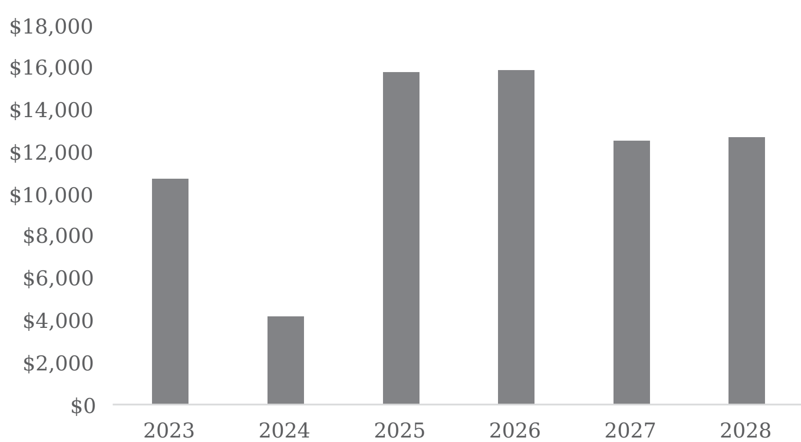
1. Witness:	Juan Castaneda
2. Asset type:	DS-SUB
3. In-Service date:	12\1\9999
4. RO Model ID:	900
5. Pin:	6424
6. CWBS Element:	CETOTOTAT642400
CWBS Description:	Advanced Technology Capital
7. SRIIM Eligible:	No

Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028	2023 - 2028 Total
SCE$	10,699	4,185	15,760	15,847	12,503	12,675	71,668

Due to rounding, totals may not tie to individual items.



Workpaper Title:

Grid Technology Laboratories

Purpose: This workpaper contains information and tables related to the Fenwick, Energy Storage and Transportation, and EDEF Test facilities capital forecast.

Table 1 Description: This table identifies the name of each test space and provides a brief description of its use and capabilities with the Fenwick Test Facilities.

Table 1: Fenwick Test Facilities Descriptions.	
Test Space Name	**Description and Capabilities of Test Space**
Power Systems (PS)	The Power Systems Lab houses 17 Real Time Digital Simulator (RTDS) racks making it one of the largest power system modeling and simulation facilities. The RTDS is a valuable tool for testing complex relay protection systems, transient and performing power system studies. The lab is being used to test and simulate the SCE power system using parallel processing computer technology. Being able to simulate the system in real-time allows for the incorporation of actual hardware (HIL: hardware-on-the-loop). Another important functionality of the Power Systems lab is the simulation and testing of relay protection devices prior to field testing during commission and maintenance. **Potential project support capability:** Providing simulation support and resources to other labs Providing support for distribution network testing and simulation
Distributed Energy Resources (DER)	The purpose of Distributed Energy Resources lab is to simulate real-world conditions for inverter-based resources that have a low-voltage connection (0 to 600V_{RMS}) to the grid. The lab is currently configured to validate solar inverters, energy storage inverters, DC-coupled inverters, electric vehicle supply equipment
Substation Automation (SA)	The Substation Automation Lab is designed for interconnecting and testing next generation substation communications, improving network efficiency to increase reliability and resiliency for automation/protection equipment, and soon we will begin testing of virtualization technology for protection equipment. Projects utilizing the Substation Automation Lab continue to improve on the Substation Automation (SA-3) Standard, which implements the latest devices using the International Substation Automation Standard called IEC 61850. The IEC 61850 standard provides the utility industry with interoperability amongst vendor equipment, common device configuration formats and data naming conventions; which has allowed for substation modeling to be automated. Currently the team is moving forward with projects that will introduce Process Bus designs to the SCE's SA-3 standard. Grid simulation tools like RTDS are being leveraged for testing real-time scenarios, exercising protection logic and overall device interoperability. Lab work includes, piloting, testing and developing standards for the: Integration of IEC 61850 into the substation automation system Deployment of SCE's new SA3 HMI enhanced with new features for A-stations Supervisory control and data acquisition, commonly referred to as SCADA, and device-to-device communications over TCPIP (previously Serial communication) Creating requirements for a virtual environment that will host automation and protection functions. The virtual environment will be reliable, scalable and resilient to failures.
Distribution Automation	The distribution automation lab provides the necessary tools and equipment to demonstrate next generation distribution automation equipment including relays, sensors, and radios. Furthermore, we can test software suites that manage, communicate with, and control distribution automation devices that can be deployed in the distribution system. We are also demonstrating equipment that has sensing, control and automation capability in the transmission system. The lab contains equipment to test the analog and digital I/O of distribution and transmission devices.
Controls	The purpose of the Controls lab is to create an environment where Control system Hardware can be integrated with the real-time simulator (RTDS), commonly known as Hardware-in-the-Loop testing (HIL). Capabilities and current activities of this lab include: EPIC III Microgrid testbeds: Protection and Control of MGs, Smart City, Remote Microgrid testbed (QAS) Microgrid modeling (i.e., USC-Catalina island, Remote Grids, College campus, Smart City) Microgrid Protection design and testing, along with process documentation. Automated control system testing, with the capability to run/control multiple test scenarios continuously, and perform data analysis, data storage and visualization.

Distribution Grid Analytics (DGAL)	The purpose of the distribution grid analytics lab is to focus on addressing challenges and opportunities associated with distributed energy resource (DER) integration, modeling and evaluation, and improvements in distribution planning, monitoring and operations leveraging advanced analytics, through advanced system studies, tool and technology development, proof of concepts, pilots and demonstration projects. The lab supports SCE's new decarbonization and transportation electrification goals initiatives also through modeling and analyzing circuit and customer characteristics to inform distribution design standards and determine mitigation strategies for high penetration of Distributed Energy Resources (DER) that is critical as we move towards a one hundred percent clean power grid. Capabilities available or being deployed: Isolated 3rd party partner grid tool and technology development and test hardware (Linux, Windows) sandbox environments to increase value from DOE, CEC and EPRI projects providing access to grid data, tools and support High performance parallel computing 6-node cluster (12x24 cores, 1536GB memory, 1296TB Storage) with integrated Cloudera enterprise and manager, to scale, analyze and process large grid analytical workloads. Services include: Impala Pig, Squoop, Hive, Hbase, Spark, Kafka, Oozie, Zookeeper, and CDSW data science workbench (Scala, python, R, natural language search, AI/machine learning). Grid integrated data and innovation software environment (GrIDIS) to accelerate development of proof-of-concepts for grid planning and operations software tools, grid tools and technologies, supporting 3rd party EPIC demonstrations, internal SCE studies and analytical software development projects: compute engines – vCPU, GPU, pre-built software services, containers, AI/machine learning, API gateways Real Time Digital Simulator (RTDS) racks (NovaCor RTDS- 2 chassis) – planned for 2023

Storage and Transportation Test Facility.

Table 2: Energy Storage and Transportation Test Facility Description.	
Energy Storage and Transportation	SCE's Energy Storage and Transportation test facility has 6 interconnected lab spaces that provides a broad range of energy storage and electric transportation testing capabilities, focusing on solutions for automakers, battery manufacturers, government agencies, business and industrial fleet customers, residential customers and more. The Energy Storage and Transportation test pad consists of a 1200 A Switchgear and a 150kW, 600kWh Tesla battery that was designed to minimize the amount of civil and electrical work needed when installing electrical equipment and Distributed Energy Resources (DERs).

Table 3 Description: This table provides a brief description the use and capabilities with the EDEF Test Facility.

Table 3: EDEF Test Facility Description.	
EDEF	Consists of the main control building which houses the Control Room, Grid Simulator Lab, and Equipment Demonstration Evaluation Facility (EDEF). EDEF is a test facility located on the southside of the EDEF Labs building, adjacent to the EDEF substation. EDEF is fed from the BRAVES 12kV circuit off the EDEF substation. The facility is used for high and low voltage (up to 12kV) tests and demonstration purposes. The EDEF circuit consists of several pad mount gas switches, overhead lines, and load banks (resistive and reactive) to make testing new equipment and concepts on a live circuit possible. Although EDEF is made for demonstrating "proof of concept," this does not mean that it has the capabilities for simulating any sort of electrical fault. It is intended for tests and demonstrations that are known to be safe and for equipment that has been previously lab tested.

Table 4 Description: This table summarizes the total Lab Operations Test Facilities capital forecast for 2023 - 2028.

Table 4: Total Lab Operations Test Facilities Capital Request (Nominal $000)

	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Total Request	**$10,699**	**$4,185**	**$15,760**	**$15,847**	**$12,503**	**$12,675**

Table 5 Description: This table identifies which capability will be upgraded, at what year, and how much it is forecasted to cost. The "Activity" column describes each capability enhancement and scheduled upgrade to accommodate Lab Operations

Fenwick/Energy Storage and Transportation/EDEF Labs Capital Request Breakdown (Nominal $000)							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Activity at Energy Storage and Transportation							
Energy Storage and Transportation Test Facility Expansion	$ 2,500.0	$ -	$ -	$ -	$ -	$ -	$ 2,500.0
Energy Storage and Transportation Test Asset Hardware Expansion and Equipment Refresh	$ 662.0	$ -	$ -	$ -	$ -	$ -	$ 662.0
Total	**$ 3,162.0**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,162.0**
Activity at Fenwick	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Power Systems RTDS NovaCor expansion	$ 1,900	$ 2,000	$ 2,100	$ 2,200	$ -	$ -	$ 8,200
Power Systems Test Asset expansion	$ 595	$ -	$ -	$ -	$ -	$ -	$ 595
Lab infrastructure upgrades/test assets/hardware replacements	$ -	$ 1,000	$ 1,150	$ 500	$ 500	$ 500	$ 3,650
DER RTDS NovaCor Test Asset expansion	$ 1,200	$ -	$ -	$ -	$ -	$ -	$ 1,200
DER test assets/hardware replacements	$ 210	$ 55	$ -	$ 300	$ -	$ -	$ 565
Substation Automation Test Asset replacements	$ 420	$ 225	$ 500	$ 500	$ 500	$ 500	$ 2,645
Distribution Automation Test Asset replacements	$ 265	$ -	$ -	$ 500	$ -	$ -	$ 765
Controls Test Asset Equipment and Hardware Refresh	$ 210	$ -	$ 100	$ 100	$ -	$ -	$ 410
DGAL IT Architecture	$ 600	$ -	$ -	$ -	$ -	$ -	$ 600
Total	**$ 5,400**	**$ 3,280**	**$ 3,850**	**$ 4,100**	**$ 1,000**	**$ 1,000**	**$ 18,630**
Activity at EDEF	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
EDEF Test Assets and Equipment	**$ 115**	**$ 120**	**$ 120**	**$ 125**	**$ 125**	**$ 125**	**$ 730**
Other Activities	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
EPIC Smart City and Service Center of the Future	**$ 1,642**	**$ 505**	**$ 11,035**	**$ 11,141**	**$ 11,238**	**$ 11,393**	**$ 46,954**

Table 6 Description: This table identifies what is being expanded and/or upgraded in each test space within the Fenwick, Energy Storage and Transportation, and EDEF Test Facilities

Activity	Activity Detail
RTDS NovaCor	The RTDS NovaCore's upgrades for Power Systems and Distributed Energy Resource test spaces will be used to run SCE Bulk Power System Modeling and help implement the distribution system and simulation in a more detailed and accurate way. The system enhancements are for 2023 to 2026 and will expand its testing environment by added these NovaCore units. It will also integrate with the Typhoon to ensure detailed and high-fidelity modeling and simulation.
RHETTA/E-Truc	SCE's labs currently do not have the capability to evaluate high power EV chargers greater than 250 kW and do not have the ability to support large vehicles, such as would be used in the SCE fleet or would be supported by the Charge Ready Transit program. In addition, SCE has signed letters of commitment under the CEC RHETTA proposal to work with partners on a state hub for research and demonstration on heavy duty and high power charging stations to support truck and bus electrification.
Energy Storage and Transportation Microgrid	Energy Storage and Transportation TSD AES Test Pad physical upgrade (procurement and installation of new and existing equipments) and HMI development for microgrid and EV projects testing. PV inverter and site controller will allow to test real world communication, control and cybersecurity issues and solutions between microgrid controller and PV systems. This will support EPIC III microgrid projects and can be used for future projects. Support laboratory testing of microgrid and transportation electrification projects funded by EPIC, DOE and Capital.
EPIC Smart City and Service Center of the Future	Both of these projects are looking to convert the EPIC field demonstration to a Capital Pilot. The customers desire to maintain the equipment in service longer than an EPIC demonstration typically allows. This approach also is better for establishing the pilot standards for a microgrid application.
DGAL - Sprints	The 2023 Distribution Grid Analytics Lab (DGAL) sprints are the execution and build phase activities, that follow the architectural solution analysis completed in 2022 by SCE IT architecture and cybersecurity, to enable and build an integrated innovation and pilot lab environment at Fenwick Grid Technology labs, to uncover more rapid and deeper insights into safety, reliability, affordability and environmental impacts, and to unlock new grid value, as the grid decarbonizes to support California's decarbonization goals, and as climate impacts increase. This DGAL environment will support filling technology gaps identified in SCE's Pathway 2045 analysis, for analytics, DER integration and end-use electrification and energy management. This integrated sandbox environment would support scaling needed innovations, de-risking emerging technologies, and accelerating adoption of needed innovative and technology solutions to support customers, and SCE needs and goals. Additional O&M benefits include: technology adoption, external engagement improvements – leveraging industry Dept of Energy, and CEC funding and resources, productivity cost savings – labor, improvement. Roadmap capabilities will also support improving on aforementioned capabilities, advancing wider grid situational awareness to better understand grid needs, and building, testing and deploying new advanced grid simulation tools being developed with the Dept of Energy national labs, to better estimate future grid needs as the operations and future of the grid becomes more complex and uncertain, and as the need to address resource adequacy and grid flexibility challenges increases. These new DGAL capabilities would also aid in providing direction to the industry regarding needed technology capabilities, and providing support for defensible general rate case justification for future grid investments to support a safe, clean, reliable, flexible, affordable and equitable grid for SCE's customers.
Controls Test Asset Hardware Expansion	The Controls Test Facility is requesting a minor expansion of its existing test capabilities for 2023, 2025, and 2026. This expansion will add test hardware to be able to integrate preproduction control systems that are being proposed by the utility control industry. This will better position the Controls Test Facility to quickly evaluate new control systems for potential operational grid deployment.

Table 6: Fenwick/Energy Storage and Transportation/EDEF Labs Capital Request Breakdown

EDEF Fire Midigation Testing	The EDEF test facility provides a controlled location where SCE can simulate and mimic actual circuit conditions for evaluation and testing. The results help to understand new equipment performance capabilities or constraints without having to impact customers on actual circuits. The EFD equipment applications that is being proposed will add to existing EFD hardware which has been incorporated to the test facility. The existing EFD sensors are configured to monitor each of the 3 primary voltage phases individually. These applications at primary voltage have shown to preform well for detecting asset defects and system anomalies with around 3 circuit mile distance, or 9 conductor miles, for distribution circuit voltages. However, due to the radial configuration of distribution circuits there are times where the three phase primary voltage sensors are not able to be situated to monitor the 3 circuit miles of circuitry. This leaves two options, (1) not to monitor a circuit section or (2) to install the primary voltage sensors to monitor less circuitry increasing the cost of deployment on a per mile basis. There are many 1-mile single phase tapline section, around 2 conductor miles, where alternate sensor applications known as the single phase secondary EFD sensor may provide benefits. These single phase secondary sensors are applied to the low voltage side of a transformer greatly reducing the cost of installation, although the sensitivity is reduced. To combat the sensitivity reduction, less conductor is them monitors for a sensor pair as compared to the three phase primary voltage variant. Applying these single phase secondary EFD sensors at EDEF allows performance testing under controlled lab environment for the new sensor. SCE anticipates testing various defect tests at EDEF incorporating these new Radio Frequency monitoring sensors. One key testing component is to further explore the potential for tooling to create partial discharge signals on distribution networks. This tooling could be used to improve data quality of circuit conductor lengths, particularly as EFD is applied to underground systems where accurate lengths may not be a easily obtained due to the underground system construction.
Root Cause and Anylysis Equipment at Fenwick	Tensile testing equipment line hardware to benchmark mechanical performance of aged and new components. Microscope has digital features to perform physical measurements of samples.
Substation Automation upgrades and Hardware Expansion	What is being requested is the laboratory equipment and devices needed to evaluate and test the next generation protection and control systems. The request is primarily the networking, test equipment, and devices required to expand the lab capability to evaluate and test up-coming projects as well as support field demonstrations and deployments.

Table 7 - 16 Description: The following tables identify what is required for the capabilities to be enhanced or upgraded from Table 5 and are broken up into the capital cost estimates and yearly spend per each capability enhancement or upgrade.

Table 7: Power Systems Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Ttoal
(2) NovaCor RTDS Racks	$ 1,900	$ 2,000	$ 2,100	$ 2,200	$ -	$ -	$ 8,200
(2) Doble Amplifiers	$ 250	$ -	$ -	$ -	$ -	$ -	$ 250
Harmonic/Waveform Analyzer	$ 200	$ -	$ -	$ -	$ -	$ -	$ 200
DANEO 400 for IEC 61850	$ 65	$ -	$ -	$ -	$ -	$ -	$ 65
(3) Advantech/SEL workstations	$ 30	$ -	$ -	$ -	$ -	$ -	$ 30
(2) Cisco/Ruggedcom managed network switchs	$ 30	$ -	$ -	$ -	$ -	$ -	$ 30
GPS clock source and antenna	$ 20	$ -	$ -	$ -	$ -	$ -	$ 20
Section Total	**$ 2,495**	**$ 2,000**	**$ 2,100**	**$ 2,200**	**$ -**	**$ -**	**$ 8,795**

Table 8: Distributed Energy Resource Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
(2) NovaCor RTDS Racks	$ 1,200	$ -	$ -	$ -	$ -	$ -	$ 1,200
(2) Doble Amplifiers	$ 160	$ -	$ -	$ -	$ -	$ -	$ 160
Data Acquisition Devices	$ 50	$ 55	$ -	$ -	$ -	$ -	$ 105
NovaCor Chassis				$ 300			$ 300
Section Total	**$ 1,410**	**$ 55**	**$ -**	**$ 300**	**$ -**	**$ -**	**$ 1,765**

Table 9: Substation Automation Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
(3) Redbox applications	$ 80	$ -	$ -	$ -	$ -	$ -	$ 80.00
CATS Cyber Security updates	$ 25	$ -	$ -	$ -	$ -	$ -	$ 25.00
Dedicated RTDS workstation	$ 20	$ -	$ -	$ -	$ -	$ -	$ 20.00
GE Relays	$ 155	$ -	$ -	$ -	$ -	$ -	$ 155.00
NovaCor RTDS Racks/Software Upgrades	$ 140	$ 225	$ 500	$ 500	$ 500	$ 500	$ 2,365.00
Section Total	**$ 420**	**$ 225**	**$ 500**	**$ 500**	**$ 500**	**$ 500**	**$ 2,645.00**

Table 10: Controls Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
(2) Doble Amplifiers	$ 160	$ -	$ -	$ 100	$ -	$ -	$ 260
SEL RTAC, SEL-651RA, SEL-751, and PQ meters	$ 50	$ -	$ -	$ -	$ -	$ -	$ 50
Data Acquisition Devices	$ -	$ -	$ 100	$ -	$ -	$ -	$ 100
Section Total	**$ 210**	**$ -**	**$ 100**	**$ 100**	**$ -**	**$ -**	**$ 410**

Table 11: Distribution Grid Analytics Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
DGAL Sprints	$ 600	$ -	$ -	$ -	$ -	$ -	$ 600
Infrastructure Upgrades	$ -	$ 500	$ -	$ -	$ -	$ -	$ 500
Section Total	**$ 600**	**$ 500**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,100**

Table 12: Root Cause and Analysis Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
High Power Microscope	$ -	$ -	$ 150	$ -	$ -	$ -	$ 150
Section Total	**$ -**	**$ -**	**$ 150**	**$ -**	**$ -**	**$ -**	**$ 150**

Table 13: Distribution Automation Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
(3) Doble power amplifiers	$ 230	$ -	$ -	$ 200	$ -	$ -	$ 430
(3) DC Power Supply	$ 6	$ -	$ -	$ -	$ -	$ -	$ 6
(4) Circuit Breaker CBS-1	$ 24	$ -	$ -	$ -	$ -	$ -	$ 24
(2) Test Moter for RCS RAG/RAM	$ 5	$ -	$ -	$ -	$ -	$ -	$ 5
Infrastructure Upgrades	$ -	$ -	$ -	$ 300	$ -	$ -	$ 300

Section Total	**$ 265**	**$ -**	**$ -**	**$ 500**	**$ -**	**$ -**	**$ 765**

Table 14: Energy Storage and Transportation Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
RHETTA/Etruc Lab Build	$ 2,500	$ 1,000	$ -	$ -	$ -	$ -	$ 3,500
Microgrid Lab infrastrucre upgrade	$ 250	$ -	$ -	$ -	$ -	$ -	$ 250
Dewetron Measurement device	$ 100	$ -	$ -	$ -	$ -	$ -	$ 100
Doble power amplifier	$ 200	$ -	$ -	$ -	$ -	$ -	$ 200
(2) Grid Simulators	$ 100	$ -	$ -	$ -	$ -	$ -	$ 100
Solectria Inverter/PV Site Controller	$ 60	$ -	$ -	$ -	$ -	$ -	$ 60
(4) SEL 651RA	$ 24	$ -	$ -	$ -	$ -	$ -	$ 24
RTAC Axion	$ 11	$ -	$ -	$ -	$ -	$ -	$ 11
(2) SEL 735 P/Q Meter	$ 10	$ -	$ -	$ -	$ -	$ -	$ 10
(2) SEL 751 Recloser Relay	$ 7	$ -	$ -	$ -	$ -	$ -	$ 7
Infrastructure Upgrades	$ -	$ -	$ 1,000	$ 500	$ 500	$ 500	$ 2,500
Section Total	**$ 3,262**	**$ 1,000**	**$ 1,000**	**$ 500**	**$ 500**	**$ 500**	**$ 6,762**

Table 15: EDEF Test Asset Hardware Expansion (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
EFD Test Asset Devices	$ 115	$ -	$ -	$ -	$ -	$ -	$ 115
Infrastructure Upgrades	$ -	$ 120	$ 120	$ -	$ 125	$ 125	$ 490
Load Bank Refresh	$ -	$ -	$ -	$ 125	$ -	$ -	$ 125
Section Total	**$ 115**	**$ 120**	**$ 120**	**$ 125**	**$ 125**	**$ 125**	**$ 730**

Table 16: EPIC Projects (Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
EPIC Smart Cityand Service Center of the Future	$ 1,642	$ 505	$ 4,690	$ 2,451	$ 3,034	$ 1,139	$ 13,461
							$ -
Field Capital Pilots	$ -	$ -	$ 6,345	$ 8,690	$ 8,204	$ 10,254	$ 33,493
							$ -
Section Total	**$ 1,642**	**$ 505**	**$ 11,035**	**$ 11,141**	**$ 11,238**	**$ 11,393**	**$ 46,954**

Workpaper Title:

Capital Pilot – Concept of Operations Smart City Demonstration, EPIC 3 Project GT-18-005

Concept of Operation

EPIC 3 Project: GT-18-005

Smart City Demonstration

Version: 1.0

Template Version Date: 9/25/19

Document Number: GT-18-005 ConOp v1.0

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1 Document Control

1.1 Revision History

Version	Date Modified	Author	Brief Description of Change
0.9	*2019-09-20*	*Joshua McDonald*	*Initial Draft*
1.0	*2019-09-24*	*Prajwal K Gautam*	*Review and Updates*

1.2 Approvals

Name	Title	Date	Signature
Prajwal K Gautam	Technical Lead		
David M Taylor	Project Manager		
Josh Mauzey	Technical Lead Manager		
Jessica Lim	Project Sponsor		
Brandon Tolentino	Project Sponsor		
Anthony Johnson	EPIC Chief Engineer		

1.3 Acronyms

ADMS	Advanced Distribution Management System
BESS	Battery Energy Storage System
BTM	Behind the Meter
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
EPIC	Electric Program Investment Charge
ESIP	Energy Storage Integration Program
EV	Electric Vehicle
FTM	Front of the Meter
GMS	Grid Management System
M&V	Measurement and Verification
MCS	Microgrid Control System
MGPOI	Microgrid Point of Interconnection
P&Q	Real and Reactive Power
PSPS	Public Safety Power Shutoff
SCE	Southern California Edison
V1G	One-way power flow from Grid to EV Battery
V2G	Two-way power flow to and from EV Battery and Grid. The inverter may be on the EV or the charging system

2 Scope

2.1 Document Overview

The purpose of this concept of operation is to communicate the users' need and expectations of the proposed system to the users, project stakeholders, sponsors, project managers, procurement representatives, vendors, and system developers. It is intended to document the current understanding of the users' need and how the proposed system will operate to meet those needs. This concept of operation will document project use cases and business requirements, inform system development activities, and familiarize new team members with the project.

2.2 SCE's Technology Roadmap and Strategic Goals

Southern California Edison (SCE) has implemented a Strategic Plan[1] in order to build a next generation energy company that delivers superior value to customers and enables a clean energy future. The strategy includes five key pillars:

1. Addressing Wildfire Risk
2. Cleaning the Power System
3. Grid Strengthening and Modernization
4. Customer Energy Choices
5. Operational and Service Excellence

To support the practical implementation of the strategy, SCE developed a companion Technology Roadmap[2] whereby the strategies were reviewed for their technology needs and then translated into Technology Objectives, each with a supporting set of Technology Capabilities. For Electric Program Investment Charge (EPIC) funded projects, the Technology Roadmap helps to prioritize investments, identify capability needs, and develop projects that advance SCE's technical capabilities which ultimately support SCE's five strategies.

This Project is in alignment with the following SCE strategic goals:

a. Strategic Pillar: Grid Strengthening & Modernization
Objective #3: Optimize use of DERs across multiple applications (customer, grid and markets)
Capability #8: Ability to support future-state DSO technical requirements via platform systems, communications, analytical tools, market transaction and grid management tools

b. Strategic Pillar: Customer Energy Choices
Objective #2: Improve value of DERs to customers and grid by enabling improved load management capabilities and other services (e.g. volt/var support)
Capability #8: Ability to coordinate BTM resources to optimally meet customer and grid needs

2.3 Project Introduction

The California Public Utilities Commission (CPUC) established the Electric Program Investment Charge (EPIC) to provide funding for technology evaluation from 2012-2020. Southern California Edison (SCE), Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and the California Energy Commission (CEC) administer the EPIC Program. EPIC is divided into three areas:

- Applied research and development,
- Technology demonstration and deployment, and
- Market facilitation of clean energy resources.

The Smart City Demonstration is an EPIC III Project that has been approved by the CPUC for technology demonstration and deployment. SCE is interested in partnering with a city that is planning to install a community

[1] https://edisonintl.sharepoint.com/ourcompany/pages/strategy.aspx. Note that Strategy 1 is still being developed
[2] https://edisonintl.sharepoint.com/Teams/at/PST/ET/External%20Files/GT%20Work%20Initiation/References/20180330%20SPOP%20Technology%20Roadmap.pdf

microgrid for grid resiliency. The US Department of Energy (DOE) defines the microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode." [3] Per California Public Utility Code 8370(d), "Microgrid" means an interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure. [4] Recent legislative and regulatory efforts have prioritized activities related to the demonstration and evaluation of microgrids in order to support grid resiliency, renewable generation support, customer reliability and bill savings. The Commission has initiated an Order Instituting Rulemaking (OIR) 19-09-009 to begin crafting a policy framework surrounding the commercialization of microgrids. This rulemaking will focus on implementation of Senate Bill (SB) 1339. One of the benefits of the project is it will serve as a platform for working through technical and regulatory challenges that will need to be addressed in a multi-meter community microgrid

In this project, the participating city's essential facilities (e.g. fire station, police station, community center, senior center, water agency, emergency shelter, etc.) will benefit from grid resiliency in the event of planned and unplanned power outages. The purpose of this project is to demonstrate how a utility could use both customer and utility-owned distributed energy resources (DERs) to operate a multi-meter (a.k.a. front of the meter) microgrid to enhance resiliency while maintaining the safety and reliability of the electric grid. The project will leverage distributed control architectures and improve planning processes to support city planning, communications, and integration of DERs. The project objectives are categorized into primary and secondary objectives. The primary objectives define the success of the project, however, secondary objectives are "nice to have" and will be decided whether to include within the scope of the project upon identification of host city.

The primary objectives of the project are to:

- Deploy a front of the meter microgrid to power a significant portion of customer loads leveraging on-site renewable DERs (e.g. solar, energy storage) during outages, thus enhancing grid and customer resiliency.
- Evaluate installation of SCE owned energy storage to support microgrid operation using black-start and islanding capability.

The secondary objectives of the project are to:

- Evaluate electric vehicles (e.g. electric school bus) to serve as energy storage.
- Demonstrate broadcasting events to customer DERs (solar+storage) to maximize value of DERs in an outage using communication protocol such as IEEE 2030.5.
- Assess opportunities to leverage Customer Service energy programs and resources e.g. Energy Efficiency, Demand Response, Charge Ready, Community Sheltering / Resources Centers etc. depending on customer needs, in support of the stated resiliency use case.

2.4 Alternatives Considered

The only significant alternative considered for the Smart City project was whether to demonstrate a Behind the Meter (BTM) or Front of the Meter (FTM) microgrid. A BTM microgrid is classified here as a single facility (e.g., a hospital) or customer (e.g., a military base or campus), while an FTM microgrid includes multiple customers on one or more circuits and can intentionally island with multiple meters. Ultimately, while a BTM microgrid may provide

[3] https://building-microgrid.lbl.gov/about-microgrids
[4] https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=4.1.&title=&part=&chapter=4.5.&article=

more customer satisfaction due to being able to fully control the microgrid and seamless transition during outages, a FTM-based microgrid was chosen as it better supported achieving all of the project objectives and goal of demonstrating a utility-managed community microgrid. The FTM microgrid will also benefit from optimizing DER portfolios owned by multiple customers and SCE.

2.5 Proposed System Overview

Figure 1 shows a high level architecture for the Smart City demonstration. The project will be procuring a Microgrid Control System (MCS) and possibly Microgrid Point of Interconnection (MGPOI) infrastructure such as synchronizing circuit breakers, relays, meters, etc. The hardware and/or software solution for MCS will be deployed in the field and utilized to optimize and control SCE's battery energy storage system (BESS) and customer DERs during planned and unplanned outage conditions (e.g. scheduled maintenance, PSPS, etc.). Figure 1 demonstrates the microgrid sectionalized circuit represented by dashed line and ideally the MCS will be located in the SCE's BESS container. The MCS will interface with SCE's back office Grid Management System (GMS) in order to receive notifications of upcoming scheduled Public Safety Power Shutoffs (PSPS) shutoffs and provide necessary measurements. To simulate outages for the demonstration, SCE's Advanced Distribution Management System (ADMS) and/or Distributed Energy Resource Management System (DERMS) will be used to open the circuit breaker or command the MCS to in order to sectionalize a circuit containing the BESS, customer generation and priority loads. Note that the SCE BESS will be deployed by the Energy Storage Integration Program (ESIP) and may provide other grid or market services not depicted in the above.

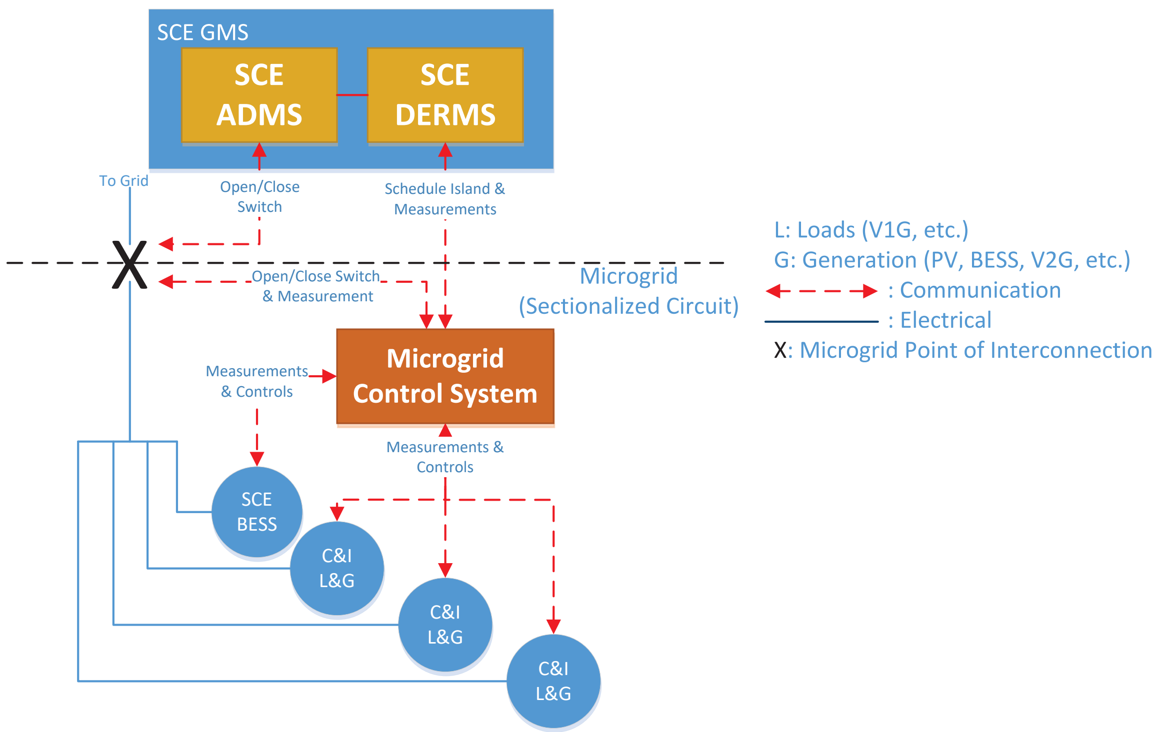

FIGURE 1- SYSTEM CONTEXT DIAGRAM FOR THE SMART CITY EPIC III DEMONSTRATION

2.6 References

The following hyperlinks refer to project and external documents utilized for planning by the Smart City project

Template Owner **Emerging Technologies & Valuation**	Title/Subject **Concept of Operation: GT-18-005**		Number **ConOp**
Document Author *Prajwal K Gautam*	Approved by *Josh Mauzey*	Version **1.0**	Page **6 of 20**
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- Project Charter
- Project GT PMO Site
- EPIC III CPUC Filing
- GMS Presentation
- GMS & DERMS Use Cases
- Senate Bill (SB) 1339
- Senate Bill (SB) 774
- IEEE 2030.7
- IEEE 2030.8
- IEEE 2030.9
- IEEE C.30

3 Description of the Current System

The deployment and use of multi-customer microgrids are currently in a nascent state in California and SCE has yet to conduct any front of the meter microgrid demonstrations outside of lab-based modeling and simulation. Additionally, microgrid-related standards are still emerging (e.g., for microgrid protection) and need to be validated for wide scale implementation.

4 Changes to Current System and Rationale

As mentioned previously, the California legislature has directed the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) to support regulatory and technical evaluations related to the deployment of microgrids (SB 1339 and SB 774). Additionally, SCE's upcoming Grid Management System (GMS) systems implementation includes use cases and requirements that support FTM and BTM microgrids. The Smart City project, as well as the EPIC III GT-18-0018[5] project, will support the GMS implementation of the these use cases and requirements.

5 Concept for the Proposed System

5.1 Description of the Proposed System

The Smart City microgrid project will be lab tested before being demonstrated in the field. The system will include a small segmented section of a circuit consisting of two or more essential facilities of the participating city. Selected siting criteria priorities include that it:

1. Is in a disadvantaged community
2. Is located in a high risk fire area subject to planned PSPS
3. Includes essential facilities that benefit and are accessible to the community
4. Contains customer owned storage + solar DERs and space for other DERs, including SCE's BESS

The project will deploy circuit breaker, relay or other equipment on a feeder in order to isolate microgrid from the larger electrical grid. The MCS that will be sourced via a competitive bid will be able to open and close the breaker in order to demonstrate microgrid use cases such as planned outage (e.g., PSPS, maintenance) and unplanned outage (e.g. grid faults outside the microgrid boundary). The project demonstration will include the use of customer and SCE DERs to prepare for a planned islanding, black start for unplanned outages, managing power

[5] https://edisonintl.sharepoint.com/Teams/at/TD/PMO/GT180018/SitePages/Home.aspx

quality during island conditions, protection and re-synching to the grid. The MCS will coordinate and schedule real and reactive power production for SCE-owned and customer-owned DERs as necessary during transition to island mode and maintain voltage and frequency of the microgrid system within limits during islanded operation. The MCS will support SCE or customer's business rules and constraints e.g. thermal limits, voltage limits, charge/discharge constraints.

The project team will work with various stakeholders to develop a process for operation of the microgrid (e.g., roles and responsibilities, steps to disconnect and connect to the grid, etc.) to be used by the requisite stakeholders and owners of the system after the demonstration concludes.

5.2 Major System Components and Interconnections

The Smart City system will include the following applications/components and interconnections:

Application/Component	Description
Microgrid Point of Interconnection (MGPOI)	The electrical connection point which at which the microgrid systems connects to the larger electrical grid. SCE meters, synchronizing circuit breakers, relays and other equipment required to sectionalize a feeder segment which contains the SCE BESS and customer DERs (generation and load). The MGPOI will interface with SCE's ADMS and the local Microgrid Control System (MCS)
Microgrid Control System (MCS)	Software and hardware microgrid solution that integrates with and manages SCE and customer resources (e.g., MGPOI, DERs, Loads, SCE BESS, non-inverter generation, etc.) in order to: • Support pre-islanding, islanding and grid-connected operations (e.g., power quality, power flows, modes of operation, etc.) • Aggregate and provide microgrid status, measurement and other information to DERMS • Provide configuration management and real time and historical information and analysis to operator
DERMS	SCE GMS system that will interface with ADMS and MCS
ADMS	SCE GMS system that interfaces with DERMS and MGPOI
SCE BESS	ESIP will deploy the SCE energy storage, inverter and associated systems. During microgrid preparation and island conditions it will be managed by the MCS in order to balance power flows, support power quality and support black start services. At other times it will be managed per ESIP requirements via ESIP defined interfaces
Customer DERs and Loads	Probably consists of photovoltaic (PV), ESS, Electric Vehicles (EVs) and other controllable loads and generation. Will interface with MCS in order to balance power flows and support power quality. May be supported by customer owned energy/building management system
Communications Equipment (RTUs, radios, routers, firewalls, etc.)	Supports communications and security for SCE and customer communications, per Cybersecurity requirements. This includes back office (Vendor DMZ and CSN) cyber tools.

FIGURE 2- SMART CITY APPLICATIONS AND COMPONENTS

5.3 Data Flow and Interfaces

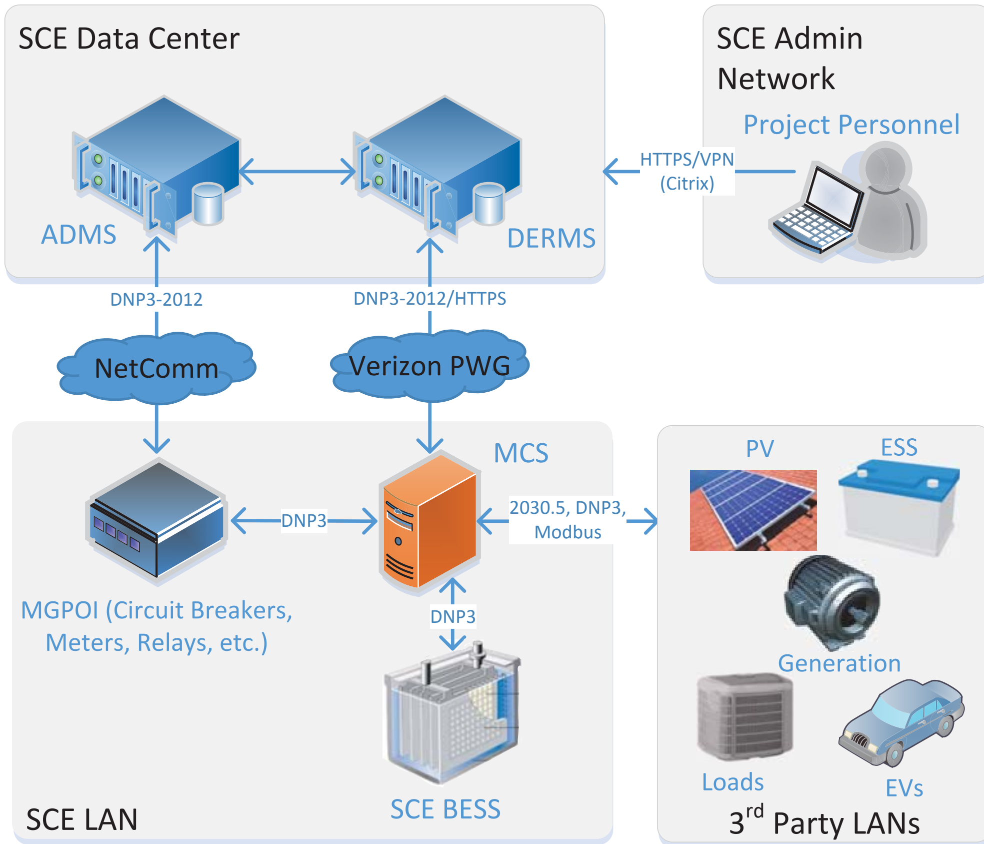

FIGURE 3- LOGICAL COMMUNICATIONS DIAGRAM

Figure 3 details major interfaces expected to be used for the project. Not shown in this this diagram are communications or security devices (e.g., firewalls, gateways, integration busses, routers, radios, RTUs, etc.). Lower level architectures will be made in concert with IT, cybersecurity, and vendors depending on technical requirements and what is available in the field. Project personnel will access the site from the Admin network by accessing the Citrix in the Data Center and then using the Verizon PWG transport to the site. Project team may configure the MCS directly from the admin network or SCE back office production system. This depends on IT/Cyber validated architecture.

5.4 Assumption and Constraints

Assumptions:

- The project will be able to conform to SCE cyber security requirements
- An appropriate location is available and agreements with all necessary customers will be completed
- Microgrid control system that meet the project requirements are available
- ESIP BESS will be deployed to support the Smart City project

Constraints:

- A test instance of the GMS systems will be available to conduct unit and integration testing in the Grid Technology lab prior to Measurement & Verification (M&V or field testing)
- Production instances of the GMS system will be available to conduct project M&V according to the project timeline
- Existing DERs may not be controllable locally or do not support standard protocols
- Regulatory processes that allow for the management of customer DERs do not exist and are in development via the Microgrids OIR (R. 19-09-009).

5.5 System Boundaries

From a grid perspective, the boundaries between the distribution grid and the segmented feeder section during a microgrid event will be the MGPOI.

From a communications perspective, several networks will be utilized. These include:

- SCE's internal networks including the LAB, QAS, PROD and Admin networks
- SCE's external Verizon PWG and NetComm networks to support MCS, BESS and MGPOI
- Customer networks where DERs are located

5.6 System Modes of Operation

The Microgrid Control System (MCS) will have the following high level modes of operation:

1) Grid Support Mode: This is the normal operation mode of the MCS. For the Smart City Project the MCS will not control customer DER's for any grid services due to regulatory and tariff constraints and such control is not required to meet the objectives of the project. However, the MCS may support grid services use cases identified for the ESIP project to minimize the number of interfaces between SCE BESS to back office system. The MCS will also send measurements and status information to DERMS.

2a) Planned Islanding Mode: In this island transition mode, the MCS has received information about an upcoming planned outage (e.g., start time, expected duration, etc.) from DERMS. The MCS will zero out power flows at the MGPOI and inform SCE System Operator when completed. Upon approval from SCE System Operator via ADMS/DERMS systems, the MCS will open the MGPOI circuit breaker.

2b) Black Start Mode: This island transition mode is initiated after an unplanned outage has occurred. The steps for this mode include opening the MGPOI circuit breaker, changing necessary settings e.g. protection functions, energizing SCE's BESS, and then starting the customer distributed generation and critical loads in coordination with DERMS. An unplanned island scenario where the MCS autonomously and seamlessly transitions from grid connected to island mode when there is an outage is beyond the scope of the project. This is due to technical and safety issues energizing distribution lines between two or more customers in high fire risk areas.

2) Island Mode: Island mode is the operating mode for the microgrid after the MGPOI has been de-energized and the generation and load started. During this mode the MCS will manage the Active and Reactive Power of the microgrid energy resources and is optimized to manage voltage and frequency during the operation of the microgrid.

3) Grid Synch Mode: After the MCS senses the grid has been restored and been notified that the planned outage is completed, the MCS will enter Grid Synch Mode in order to prepare the sectionalized circuit to be reconnected to the distribution grid. The MCS will only reconnect to the grid after being given permission by the SCE System Operator via ADMS/DERMS systems. Following Grid Synch Mode, the MCS will revert to Grid Support Mode.

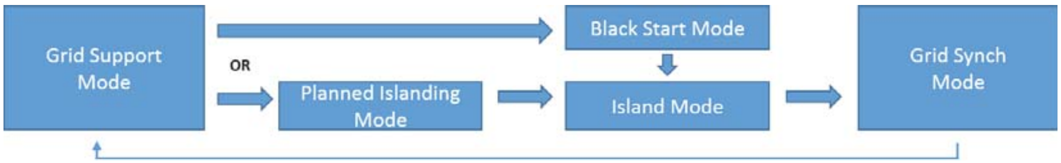

FIGURE 4- SEQUENCE OF MICROGRID MODES

6 High level Business Use Cases

The following use cases are specific to the Smart City Microgrid demonstration. The planned island and black start use cases are discussed in detail below.[6]

6.1 Use Case #1 Planned Islanding

Use case name	Microgrid for Planned Islanding
Description	When a planned outage is scheduled on the circuit where the microgrid system is located, the Microgrid Control System is notified and prepares the microgrid system (SCE BESS to VSI mode, balancing P&Q, etc.) to be disconnected from the larger electrical grid. Prior to the outage beginning, with SCE System Operator approval using ADMS/DERMS systems, the circuit breaker is opened by the MCS. The island is maintained with SCE's BESS, preferably through the duration of the outage, with priority given to energizing critical loads first, and other loads second. After the outage concludes, the MCS prepares the microgrid system (P&Q, Phase Angle, etc.) to reconnect to the grid, notifies SCE System Operator for the permission to reconnect via DERMS/ADMS, and then reconnects to the grid once approved.
Use case ID	UC1
Actors	• ADMS • DERMS • SCE System Operator • MGPOI • Microgrid Control System (MCS) • SCE BESS • Customer generation • Customer Loads
Pre-conditions	• The Smart City Microgrid has been validated and tested (e.g., cybersecurity, lab testing, production integration, etc.) • The MCS is registered with the DERMS and has SCE's TLS Cert • SCE orgs, customers, vendors, California Independent System Operator (CAISO) and other necessary stakeholders have agreed to and documented notification processes, roles and responsibilities in relation to islanding and re-connecting to the grid • MCS is continuously monitoring the local grid status, logging, and sending aggregate measurements to DERMs
Flow of events	Steps:

[6] The grid support use cases will be identified and added to the document after the site selection with support from Distribution Engineering. The MCS may support grid service use cases depending upon the communication interface between SCE BESS and back office, and ownership of the microgrid infrastructure post-project.

	1- Due to maintenance, Public Safety Power Shutoff or some other known condition, determine that the circuit where the Smart City Microgrid resides must be de-energized. 2- SCE's System Operator using ADMS or other SCE systems, through DERMS, sends a planned outage notification to MCS 3- MCS configures SCE BESS inverter to go to Voltage Source Inverter (VSI) mode and optimizes P&Q of SCE BESS, customer generation and loads to achieve a balance of load and generation at the MGPOI 4- MCS signals to DERMS that the Microgrid is ready to be disconnected from the grid. The MCS maintains this state. 5- DERMS notifies ADMS of MCS's readiness to be disconnected. 6- After required external processes are completed by the SCE System Operator the ADMS, through the DERMS, notifies the MCS to open the synchronizing circuit breaker thus islanding the microgrid area prior to the outage 6a. If the breaker is not opened after X minutes, the SCE System Operator via ADMS System may open the breaker to prevent backfeed. 7- The MCS manages the load and generation resources (SCE's BESS is the primary resource) in order to maintain a locally balanced system. 8- Once the MCS senses that the grid is restored it will prepare the system to reconnect to the grid (e.g., optimize Voltage, Frequency, Phase Angle, etc.) 9- The MCS notifies DERMS it is ready to reconnect to the grid 10- DERMS notifies ADMS the MCS is ready to reconnect to the grid 11- ADMS, through DERMS, signals the MCS to close the switch once other decisions/processes are completed by the SCE System Operator. 12- MCS configures SCE BESS to return to Current Source Inverter (CSI) mode and default operation 13- MCS returns customer DERs to default mode
Scenario 1	For project demonstration purposes, a simulated planned outage may be demonstrated. Modified steps are detailed below: 1. Project personnel notify SCE orgs, customers, vendors, CAISO and other necessary stakeholder of the date, time and duration of planned outage 2. Project personnel initiates outage notification to MCS (#2 above) from DERMS 3. MCS configures SCE BESS inverter to go to Voltage Source Inverter (VSI) mode and optimizes P&Q of SCE BESS, customer generation and loads to achieve a balance of load and generation (same) 4. MCS signals to DERMS that the Microgrid is ready to be disconnected from the grid. The MCS maintains this state. (Same) 5. DERMS notifies ADMS of MCS's readiness to be disconnected. (Same) 6. Once all operational steps are complete, the project operator, through the DERMS, notifies the MCS to open the synchronizing switch prior to the outage thus islanding the microgrid area. Steps 7-12 are the same as above.
Post condition	• The microgrid area is reconnected to the grid • The ESIP BESS is operating in default mode • Customer generation and loads are operating in default mode • The MCS is sending status and measurements to DERMS

6.2 Use case #2 Black Start

Use case name	Microgrid for Black Start
Description	When an unplanned outage occurs on the circuit where the microgrid system is located, the Microgrid Control System will support the creation of an electrical island at the microgrid location. This includes disconnecting from the larger electrical grid at the MGPOI and performing black start functions using the SCE BESS. After the island is established, it is maintained with SCE's BESS, preferably through the duration of the outage, with priority given to energizing critical loads first, and other loads second. After the outage concludes, the MCS prepares the microgrid system (P&Q, Phase Angle, etc.), notifies DERMS/Operator, and then reconnects to the grid once approved.
Use case ID	UC2
Actors	• ADMS • DERMS • SCE System Operator • MGPOI • Microgrid Control System • SCE BESS • Customer generation • Customer Loads
Pre-conditions	• The Smart City Microgrid has been validated and tested (e.g., cybersecurity, lab testing, production integration, etc.) • The MCS is registered with the DERMS and has SCE's TLS Cert • SCE orgs, customers, vendors, CAISO and other necessary stakeholders have agreed to and documented notification processes, roles and responsibilities in relation to islanding and re-connecting to the grid • MCS is continuously monitoring the local grid status, logging, and sending aggregate measurements to DERMs
Flow of events	Steps: 1- Due to an unplanned outage (eg. grid faults), the sectionalized circuit where the Smart City Microgrid resides is de-energized. 2- The MCS senses this and notifies ADMS through DERMS 3- The SCE System Operator using ADMS or other SCE Systems, through DERMS, tells the MCS to disconnect from the grid at the MGPOI 4- The MCS opens the breaker and go begin the microgrid 4a. If the breaker is not opened after X minutes, The SCE System Operator using via ADMS may open the breaker 5- The MCS configures SCE BESS inverter to go to Black start mode (e.g VSI mode) and begin to energize generation and loads 6- The MCS manages the load and generation resources (SCE's BESS is the primary resource) in order to maintain a locally balanced system. 7- Once the MCS senses that the grid is restored it will prepare the system to reconnect to the grid (e.g., optimize Voltage, Frequency, Phase Angle, etc.) 8- The MCS notifies the ADMS, through DERMS it is ready to reconnect to the grid 9- ADMS, through DERMS, signals the MCS to close the switch once other decisions/processes are completed by the SCE System Operator 10- MCS configures SCE BESS to return to Current Source Inverter (CSI) mode and default operation 11- MCS returns customer DERs to default mode
Scenario 1	For project demonstration purposes, the SC operator may use the ADMS to close the breaker in order to simulate an unplanned outage. Modified steps are detailed below:

	1. Project personnel notify SCE orgs, customers, vendors, CAISO and other necessary stakeholder of the date, time and duration of unplanned outage demonstration 2. After approval, project operator opens MGPOI circuit breaker via ADMS All other steps are the same as above.
Post condition	• The microgrid area is reconnected to the grid • The ESIP BESS is operating in default mode • Customer generation and loads are operating in default mode • The MCS is sending status and measurements to DERMS

7 Business Requirements

The following Smart City business requirements will be approved by project stakeholders and sponsors. They are intended to be maintained at a high level and will be used to derive technical requirements for procurement, testing, low level designs and other project execution activities.

Requirement ID	Business requirement
SCBR1	The Smart City MCS shall be able to support planned island, black start, and reconnection to the grid
SCBR2	The Smart City MCS shall be able to integrate with and optimize, control and schedule any or all MGPOI (meters, relays, breakers, etc.), SCE BESS, customer PV and ESS, EVs (V1G and V2G), controllable loads, other generation to support pre-island, island and non-island conditions
SCBR3	The Smart City MCS shall provide a local or remote (SCE Hosted) interface for SCE operators to access remotely in order to: • Configure modes and settings of the MCS, SCE's BESS and customer DERs • Access and download historical logs (measurements, alarms, status, analyses, etc.) • Configure asset types and communications • Access alarms • View Real time measurements and status
SCBR4	The Smart City MCS shall support, at minimum, a DNP3-2012 and IEEE 2030.5-2018 interface to SCE according to SCE's DNP point list and IEEE 2030.5 profiles
SCBR5	The Smart City MCS shall provide, at minimum, DNP3-2012, IEEE 2030.5, IEC 61850 and Modbus protocol support to interface with SCE's BESS and customer DERs (TBD)
SCBR6	The Smart City MCS shall conform to CA Rule 21, IEEE 1547, UL 1741, IEEE 2030.7, 2030.8, 2030.9 and P30 requirements unless conflicting with SCE's requirements
SCBR7	The Smart City MCS shall be able to account (e.g., integrate, optimize, control, etc.) for non-inverter based generation if present
SCBR8	The Smart City MCS shall be able to be configured to support the addition of new loads and distributed generation
SCBR9	The Smart City MCS shall be able to prioritize the power generation of renewable energy over non-renewable energy resources
SCBR10	The Smart City project team shall be able to notify project customers of upcoming planned outages necessary for demonstrations (non-PSPS)
SCBR11	The Smart City system shall comply with applicable state, local and federal regulations in regards to safety standards and cybersecurity
SCBR12	The Smart City system shall comply with SCE's cybersecurity standards (TBD)
SCBR13	The Smart City project shall maintain up-to-date operating and maintenance procedures, agreements/contracts and policies that include roles and responsibilities for SCE organizations, vendors, customers and project personnel that include the testing, demonstration and post-demonstration period

SCBR14	The Smart City MCS shall be able to store logs (measurement, alarms, modes, etc.) locally for a TBD duration
SCBR15	The Smart City project equipment (e.g., MCS, MGPOI, etc.) shall be able to communicate and be controlled (e.g., remain energized) during outage conditions (e.g., via UPS)
SCBR16	The Smart City MCS shall support zero or near zero resource/asset configuration (self-provisioning)
SCBR17	The Smart City MCS shall support real time and post island analysis of the microgrid event and DER operations
SCBR18	The Microgrid Project MCSs shall support adaptive protective schemes as specified in related microgrid standards (e.g., IEEE C30) and work in coordination with protection functions of individual components and assets
SCBR19	The Smart City system shall be able to support simulated planned and unplanned island scenarios
SCBR20	The Smart City MCS shall support SCE or customer's business rules and constraints

Workpaper Title:

Capital Pilot – Capable Programmable Automation Controller Project, EPIC 3 Project GT-19-0048 61850

Business Planning & Technology Strategy GT-19-0048 61850 Capable PAC Final Project Report

Developed by

SCE Transmission & Distribution, Business Planning & Technology Strategy

Version Date: 07/21/2022

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1 Executive Summary

The 61850 Capable Programmable Automation Controller (PAC) Demonstration ("Project") evaluated the feasibility of replacing a legacy programmable logic controller (PLC)—currently used in SCE substations to perform automated load restoration—with a modern 61850 capable PAC. The PLC is one of the last components of legacy technology that has not been fully transitioned into the modern International Electrotechnical Commission (IEC) 61850 standard within SCE's system.

This modern PAC operates on the IEC 61850 standard to communicate and control Intelligent Electronic Devices (IED) necessary to carry out automated load restoration schemes, bank testing and volt/var control within the substation. Once the PAC is integrated with other IEC 61850 IEDs, SCE will experience numerous benefits and be able to addresses key challenges posed by continued use of legacy PLCs. Benefits include:

- Enhances SCE's situational awareness with the ability to support a larger number of data points in a standardized format to monitor critical statuses and execute controls via IEC 61850.
- Accelerates the automation implementation on SCE systems using standard data models and service mapping. Allows 61850 PACs to execute existing restoration schemes, enables new applications and advanced schemes, such as allowing two or more IEDs to communicate for load restoration and/or control.
- Dramatically reduces the time to configure substation IEDs as data is organized consistently across all brands of devices and enables device autoconfiguration to reduce reduce risk of human error.
- Allows SCE to enable cybersecuirty applications, such as IEC 62351 security standards, authentication, role-based access control, communication. Existing PLCs communications use the legacy Modbus protocol.
- Addresses technology obsolescence as many IED manufacturers are migrating from Modbus to IEC 61850.
- Increases SCE's flexibility in choosing IED vendors for their substation needs through interoperability between devices.
- Eliminates need for short interval polling of Modbus registers through standard reporting, thereby freeing bandwidth for other communications.

2 Project Summary

The PLC is one of the last pieces of legacy technology that has not been fully transitioned into the modern IEC 61850 standard in SCE's system. An IEC 61850 PAC will increase the number of applications from a given IED, for example in cases where two or more IEDs are needed for load restoration and/or control. It will give SCE's Protection Asset Engineering and Monitoring & Control Engineering groups more flexibility in IED choice and substation design. SCE's reliance on current legacy equipment prevents us from enabling stronger cybersecurity controls and forces us to maintain reliance on legacy communications mediums. This project would demonstrate an IEC 61850 capable PAC that can communicate and control other IEC 61850 devices for automated load restoration.

This project advances these three strategic capabilities in the following ways:

B-3.10 Trans. Wide-Area Situational Awareness & Control: IEC 61850's Ethernet technology that can be prioritized *with* other message traffic. Coupled with the IEC 61850's annunciator functionality, this will provide SCE with enhanced situational awareness and control necessary to maintain stability.

B-3.8 Trans. Advanced System Protection: Provides the capability to perform automated restoration schemes for SCE systems through the use of standard data models and service mapping, which allow IEC 61850 PACs to perform the necessary automation and control to support existing protection schemes as well as enabling new applications and advanced schemes (e.g., allowing two or more IEDs to communicate for load restoration and/or control).

O-1.1 T&D Advanced Cyber Security: Implementing an IEC 61850 PAC will allow SCE to enable cybersecuirty applications across devices which support IEC 62351 features(e.g., authentication, role-based access control, communication encryption), which are currently limited by PLCs operating on the legacy Modbus protocol.

Figure 1 EPIC Investment Framework for Utilities

2.1 Project Objectives

The goal of a new IEC 61850 capable PAC is to allow interoperability between various vendors' IEDs that do not support the current legacy protocol or are currently limited by the legacy Modbus protocol. This project demonstrated that an IEC 61850 capable PAC can communicate and control other IEC 61850 devices for automated load restoration.

2.2 Problem Statement

Presently, PLCs operating on the legacy Modbus protocol are used to communicate and control various IEDs within SCE substations—e.g., protective relays, load tap changer, circuit breakers, capacitor bank switches, reclosers, voltage regulators—in performing load restoration for grid events. IEDs are hardwired to various substation equipment and PLCs through input/output connections that allow them to communicate sensing and control data. Today, IED vendors are migrating from the legacy Modbus protocol in favor of a new high speed interoperable IEC 61850 standard.

SCE has been phasing in IEC 61850 IEDs into its substations in support of SCE's Substation Automation version 3 "SA3" standard, which relies on 61850 MMS as its primary communication protocol, and it has yet to integrate an IEC 61850 capable PAC into substation designs. Presently, the automation controller operates on the legacy Modbus TCP/IP protocol to communicate and control various IEDs within SCE SA3 substations.

- SCE is committing to IEC 61850 standard, and vendors are phasing out Modbus TCP/IP.
- Some existing IEDs have discontinued support for the Modbus TCP/IP
- Some IED's Modbus register mapping shifted with latest firmware version
- Future Process Bus & Digital Substation projects requires a fully IEC 61850 compatible PAC

2.3 Scope

The scope of this project was to evaluate and demonstrate the interoperability between a new IEC 61850 capable PAC and IEDs from various vendors in a controlled lab environment. The test network was isolated from the existing Fenwick Substation Automation lab network except for a PC hosting the HMI application. This project validated the ability of an IEC 61850 PAC to communicate and control various IEDs. After network testing and successfully communicating with IEDs from multiple vendors, the substation restoration logic schemes were exercised. The logic was exercised by simulating fault scenarios and verifying IED and IEC 61850 PAC response was accurate. The project team also investigated cybersecurity features that became available after transitioning to IEC 61850.

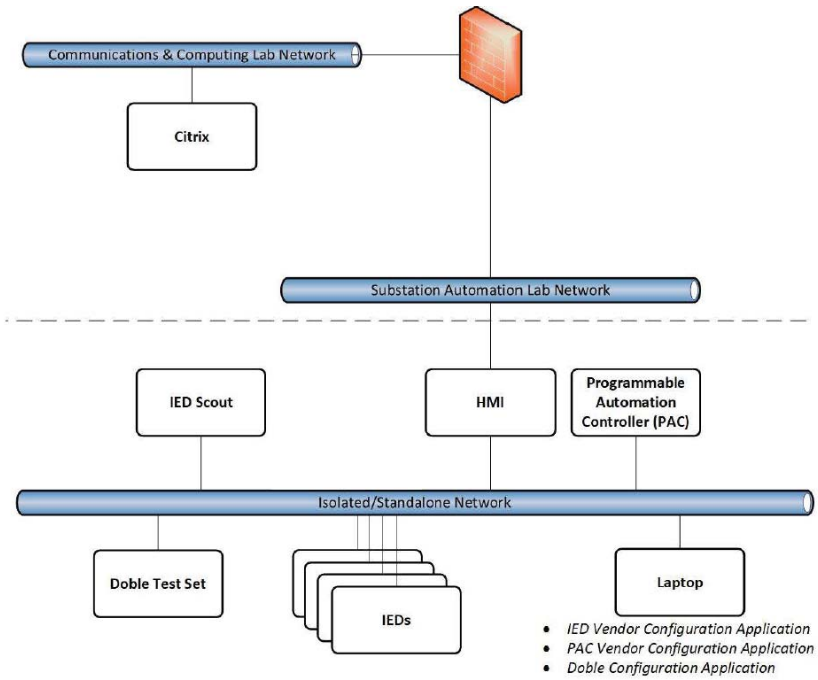

Figure 2 Test Network Diagram

The devices were connected to an isolated LAN (a single unmanaged switch) specific for this project testing. The team was able to have remote access to the LAN through the Lab Network.

2.4 Schedule

Table 1 Project Schedule

Project Schedule	Date
Project Start	Q1 2020
Detailed Demonstration Use Cases Complete	Q1 2020
Procurement Requirements Complete	Q2 2020
Preliminary System Design Complete	Q2 2020
61850 Capable PAC Vendor(s) Selected	Q3 2020
Lab Site and Equipment Procured	Q4 2020

Final System Design Complete	Q1 2021
Lab System is Ready for Demonstrations	Q2 2021
Demonstrations Complete	Q4 2021
Final EPIC Report to CPUC	Q2 2022
Project Complete	Q2 2022

2.5 Milestones/Deliverables

Table 2 Deliverables

Deliverable Name	Deliverable Description
Demonstration Plans	Detailed use cases, demonstration scripts, measurement and validation (M&V) plans.
61850 Capable PAC Vendor Requirements	Functional and non-functional requirements necessary to solicit a 61850 capable PAC from vendors.
Detailed System Design, Specifications, Test Plans	Detailed design and specifications for the integrated system (e.g., 61850 PAC, IED, HMI, LAN Switch, CB Simulator).
Demonstration Results	Document detailing demonstration test findings and results, including data obtained for each use case.
Annual Reports	Yearly EPIC progress reports (EOY 2021 – until the EPIC III Final report)
Final Project Report	Presentation of project detailed findings and results, including a summary of all data collected and how the data may be accessed.

The project team met all major milestones that lead to a successful demonstration for stakeholders and production teams to continue integrating this technology in a future pilot or field project.

In Q1 of 2021, the project team completed Milestone #1: Validate Communication Capability between PAC, IED, and HMI – where communication testing was performed to see how the devices interact on the network through various device failure tests and simulating some other disruption to the devices.

Testing was performed all throughout Q3 using the new Process Bus devices network where we exercised various logic functions to complete Milestone #2: Test Restoration Flows - Self-Restoring Loop (SRL). With the help of our technician and consultant assigned to the project, we safely performed these tests using Doble test sets and sampled values. Testing was officially completed at the start of Q4 of 2021.

One of the Use Cases was to test the security features supported by some IEDs and to determine how the implementation differs from SCE's standard IEDs. These security features could not previously be enabled due to incompatibility with the legacy Modbus PLC. Transitioning to a 61850 Capable PAC would allow SCE to enable the security features on these IEDs. We were able to successfully convert one relay to enable the security features and tested with that device all throughout the testing phases of the project. Our recommendations on configuration settings for the security features were completed in Q4 of 2021 at the end of device testing. The security features included role-based access and the ability to lock down firmware and settings versions.

Testing proved to be successful in terms of executing all functions necessary for an SA3 PLC. The program was coded in such a way that it will be increasingly manageable to add new devices or modify current ones.

3 Project Results

This project demonstrated the interoperability between an IEC 61850 capable PAC and various IEDs from multiple vendors. All the test scenarios and use cases were completed successfully. The project team also delivered documentation and presented findings to key stakeholders. The project was completed within the scheduled time frame and within budget.

3.1 Technical Results, Findings, and Recommendations

Technical Results:

Project work produced great results that can easily be reproduced and configured for any testing moving forward. Our stakeholders are extremely happy to benefit from the work we were able to prove as a concept and deliver as a lab demonstration. Prior to this project the PAC device was limited to the Modbus communication protocol, but we have successfully proven that the IEC 61850 communication protocol can be used for future PAC applications. As a result, a few files can be saved and repurposed for future PAC projects and applications.

A project file can be exported that contains all data necessary for client and server mapping, including CID data. Individual maps can also be exported and saved; it is recommended that the map files be used as a template for any future devices. The exported project file is what will be used as the base configuration for the master program template, with the program mapping already configured. From the project file, the server CID is also retained, which contains the 61850 settings, this file can also be a template.

Aside from the configuration of the NOP (name of module with 61850 support on M580 PAC system), the PAC master program was also updated to support the new module and individual sections were added for various IED manufactures, where individual device applications can be configured.

Findings:

When configuring devices from multiple vendors to communicate to the NOP, we ultimately exercised the interoperability aspect of 61850. The NOP was configured to connect up to 4 different IED manufacturers and we found that not every IED treated the standard reporting approach (URCB parameters) the same way. IEC61850 as written today leaves some aspects of implementation open to interpretation.

For example, a relay vendor does not support reservation of a URCB, but instead will allow up to 7 clients to connect to a report at any given time. Another vendor had a bug in their line relay, where indexing was not implemented correctly through their software. A fix was promised to SCE in future firmware release.

Recommendations:

The 61850 Server was also added and configured as part of the testing, but the server data has not been fully integrated into the Master Program. The Server model that was developed can be exported via CID. Any changes made to the model should also be reflected in the NOP mapping. However, instead of managing the two files (CID and map), transferring the single project file is the recommended best practice moving forward.

Along with the server implementation, the project team worked with the Substation Engineering Modeling Tool administrators to introduce the PAC as a new 61850 device to be used in future substation designs where the PAC's Modbus protocol module is replaced with the IEC 61850 module.

3.2 Technical Lessons Learned

- CID file configurations – managing file versions is key (CID on relay = CID for NOP)
    - SEMT should always be the source for CID files
    - A vendor had IP address issue on NOP Client – CPU communication port layout (port 1 & port 2)
- Visualizing IEC61850 with network diagnostic tools was necessary for troubleshooting and simulating controls
    - Scanning individual Report Control Block settings proved helpful for different relays (indexed vs non-indexed)
    - Separating the stream to enable and reserve a Report Control Block demonstrated how the standard is handled among various vendors
- Building IEC61850 server model with Common Data Classes (CDC)
    - Unable to use custom name
    - Identified configuration type requirement for control model to support SBO (select-before-operate) commands

3.3 Value Proposition

The IEC 61850 capable PAC will increase interoperability between substation devices by transitioning to a common communication standard. This will also mitigate technology obsolescence by ensuring that communication between the PAC and IEDs will be maintained as IED vendors phase out Modbus devices. In addition, an IEC 61850 capable PAC can be integrated with the existing Substation Engineering Modeling Tool (SEMT) to automate PAC configuration. Lastly, the transition to a 61850 Capable PAC will allow SCE to pursue implementation of advanced cybersecurity features which are not supported by the legacy Modbus protocol.

3.4 Technology/Knowledge Transfer Plan

The project team provided the following deliverables to the project stakeholder at completion of the project:

- Final Presentation at Quarterly All-Hands for Substation Automation, Operations, and Protection engineering groups
- Documentation on implementation of the PAC as it fits into the current substation design standards to replace legacy model(s)
- Documentation on processes for device configuration
- Documentation on processes for device firmware upgrades
- Initial PAC server model
  - Validating IEC 61850 standard reports allows for direct communication to current SA3 human machine interface applications and IEDs.
- PAC templates for IEDs
  - Data driven auto configuration templates based on standard IEC 61850 XML files reduce the risk of human error and time spent debugging. XML files allow sharing of structured information among people, computers and networks.
- Initial testing and validation of PAC Master Program

4 Benefits

The results of this project can be used as a step towards implementation of a 61850 capable PAC in a production environment. The completion of this project and transitioning to a 61850 capable PAC ensures continued interoperability between substation IEDs as vendors begin to phase out support for Modbus, and SCE will have the option to leverage additional cybersecurity features for certain IEDs which could not be used with the legacy Modbus PLC. Furthermore, moving towards a 61850 PAC allows SCE to pursue continued digitization of the substation and possible virtualization of this equipment.

4.1 Procurement

The project team procured the services of a technical consultant with expertise in SCE substation design, PLC testing, and IEC 61850. This procurement was a direct award to the vendor.

4.2 Stakeholder Engagement

The project team held weekly meetings with the project stakeholders throughout the duration of the project. These meetings kept the work and outcomes aligned with the expectations of the major stakeholders. Stakeholder engagement included:

- Weekly meeting to sync up on testing and documentation
- Testing with vendor input
  - Met with vendor when additional support was needed to debug project
- Integrator meetings
  - Kept in line with the current production code as it was released to reduce need for regression testing at the end of project timeline
- Presentations to all stakeholders and project committee meetings
- Coordination with other projects in the lab
- Bi-weekly project status meetings with IT and Cybersecurity
- Coordination with IT/Cyber for testing input and lab environment assessment.

List of Acronyms

CDC	Common Data Classes
CID	Configured IED Description (filetype)
EPIC	Electric Program Investment Charge
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Devices
MMS	Manufacturing Message Specification
M&V	Measurement and Validation
PAC	Programmable Automation Controller
PLC	Programmable Logic Controller
SBO	Select-before-operate
SCE	Southern California Edison
SEMT	Substation Engineering Modeling Tool
SRL	Self-Restoring Loop
TCP/IP	Transmission Control Protocol/Internet Protocol
URCB	Unbuffered Report Control Blocks

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Workpaper Title:

Capital Pilot – Virtual Relay Proof of Concept, EPIC 3
GT-19-0049

Concept of Operation

EPIC III Project: GT-19-0049

Virtual Substation Relay (SA3)

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Document Author *Jesse Silva*	Approved by: *Kevin Sharp*	Version **1.2**	**Page i**
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1 Document Control

1.1 Revision History

Version	Date Modified	Author	Brief Description of Change
1.0	2020-4-7	Sam Uyeno	Initial Draft
1.1	2020-4-21	Sam Uyeno	Added additional IT business requirements
1.2	2020-8-13	Teren Abear	Added IT Requirements (see section 6)

1.2 Approvals

Name	Title	Date	Signature
Jesse Silva	Technical Lead	9/10/2020	Jesse Silva
Teren Abear	Project Manager	8/28/2020	Teren Abear
Zeus Xioco	Engineering Manager	9/1/2020	Zeus Xioco
Kevin Sharp	Technical Lead Sr. Manager	8/31/2020	[illegible]
Andrea Haas	IT Program Manager	10/7/2020	Andrea Haas
Anthony Johnson	EPIC Chief Engineer	9/2/2020	Anthony Johnson
David Martinez	Technology Strategy Manager	9/8/2020	David Martinez
Jeff Shiles	Project Sponsor	9/1/2020	Jeff Shiles
Renee Cinar	PMO Manager	9/18/2020	Renee Cinar

1.3 Acronyms

CB	Circuit Breaker
CSP	Common Substation Platform
DMS	Distribution Management System
EMS	Energy Management System
GOOSE	Generic Object-Oriented Substation Event
HMI	Human Machine Interface
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
MEER	Mechanical-Electrical Equipment Room
MMS	Manufacturing Message Specification
MU	Merging Unit
P&C	Protection & Control
LAN	Local Area Network
PAC	Programmable Automation Controller
PLC	Programmable Logic Controller
POC	Proof-of-Concept
RAP	Research Administration Plan
ROA	Return on Asset
SA	Substation Automation
SCE	Southern California Edison
SEMT	Substation Engineering Model Tool
SMV	Sampled Measured Values

2 Scope

2.1 Document purpose

The purpose of this document is to communicate the users' need and expectations of the proposed system/project to the users, sponsors, stakeholders, project managers, procurement representatives, vendors, system developers, engineers, new team members, etc. It is intended to document the current system ("as is"), provide a description of the users' future need and how the proposed system ("to be") will operate to meet those need from the end users' point of view. This document also defines the business use cases and business requirements for the proposed system/project.

2.2 Introduction

The Virtual Substation Relay Proof-of-Concept ("Project") will demonstrate the feasibility of virtualizing a protection relay—a critical component for substation protection—through the use of a virtual relay software application (or virtual protection machine), merging unit (MU), and process bus network within a controlled lab environment. Through this lab demonstration, the Substation Demonstration team ("Team") will provide a recommendation on the viability of using a virtualized protection relay to execute existing SCE protection functions and new cybersecurity controls.

Traditional protection and control (P&C) systems, which have long relied on proprietary hardware, have been reliable, but there are considerable challenges with their continued use. They currently face high construction costs and long deployment times due to the hard-wired connections and trenching required to terminate and route wires to these P&C devices. A single substation consists of thousands of wires and terminations, and a control room must be large enough to accommodate this equipment and perform safe cable terminations. Modifications to these systems can also result in costly and long scheduled outages as a result of the complex relay connections and wiring. In addition, the proprietary design for individual P&C systems makes it difficult and costly to keep up with increasing cybersecurity and compliance updates. These updates require carefully planned outages and vast amounts of testing, which is becoming increasingly cost prohibited with today's technology.

Through a process bus implementation and virtualization of protection equipment, SCE can avoid complex relay connections and wiring within the substation. It enables standardization, and ease of updating. Additionally, by aggregating data from various devices within the substation into a single data model and allowing access to multiple applications, SCE can extract key information from data necessary to enable a wide variety of benefits. While this proof-of-concept will take place in a controlled lab environment, there are numerous possibilities and potential benefits once process bus and machine virtualization is deployed within the substation. Potential benefits include the following:

- Absence of complex relay connections and wiring has the potential to reduce capital and O&M costs associated with commissioning and maintaining physical protection assets within the substation.
- Virtual platform enables automated testing and monitoring that is not available with field hardware, which allows SCE to test an exact production system in QA before promoting to a production environment.
- Virtualization of protection devices on a standardized hardware platform makes it easier to update protection applications, reducing outage time and more quickly responding to new protection challenges.

- Virtualization potentially enables relatively low-cost redundancy (e.g., duplicate virtual relays and servers), which can improve overall substation reliability.
- A virtualized, interoperable platform allows for an optimized solution that includes only the required protection functions from desired vendors, thus reducing complexity and cost.
- Aggregation and analysis of data from devices enables SCE to extract key information necessary to enhance or create new protection schemes that help protect the grid against increasing renewables.
- Data and analysis from relay data enables more near real-time asset condition monitoring, predictive analytics, and health indices to support "just-in-time" asset replacement, thereby improving SCE's ROA.
- Virtualization provides more granular data from substation systems, which can be analyzed to help SCE better understand what is occurring within the substation where direct observation is not available.
- Enables advanced monitoring and behavior analysis of data from critical substation equipment to help identify and isolate anomalous behavior with automated responses in addressing cybersecurity risks.
- Virtualization on a standard server platform supports faster recovery of relays that might be damaged in a disaster (e.g., earthquake, electromagnetic pulse strike) by quickly replicating configuration from an archive.
- Enables SCE's broader vision for a fully automated digital substation.

2.3 Alignment with SPPS technology roadmap

2.3.1 SPPS capabilities addressed and how they will be advanced

This Project is aimed at cleaning SCE's power system, strengthening and modernizing its electric grid, and securing its computing and communications infrastructure. More specifically, this Project will help demonstrate and ultimately enable the following technological capabilities.

CLEANING THE POWER SYSTEM

- **[B-3.8] Transmission Advanced System Protection:** Developing protection technologies to accommodate changing resource mix (Need Date: 31 Dec 2025). The Project advances this capability by:

  Aggregation and analysis of data from substation devices enables SCE to extract key information necessary to enhance or create new protection schemes that help protect the grid with increasing renewables. Also, IEC 61850 standardization allows sharing of switchyard instrumentation to multiple Intelligent Electronic Devices (IED), which allows for advanced protection functions.

  Additionally, virtualization of protection devices on a standardized hardware platform makes it easier to update protection applications across the substation (even remotely), thereby reducing outage time and more quickly responding to new protection challenges.

GRID STRENGTHENING & MODERNIZATION

- **[D-2.3] Distribution Sensing & Monitoring:** Sensing and monitoring distribution grid conditions in real-time to determine status, and the potential for safety and reliability issues—e.g., hidden load, two-way power flows, etc (Need Date: 31 Dec 2025). The Project advances this capability by:

Virtualization provides more granular data from critical substation systems, which improves SCE's distribution sensing and monitoring capabilities and enables SCE to better understand what is occurring within the substation where direct observation is not available (hidden load, two-way power flows, etc).

- **[D-1.1] Distribution Optimize Infrastructure Replacement:** Assessing remaining asset life using condition-based maintenance technologies to extract full value from investments made and optimize infrastructure replacement decisions (Need Date: 31 Dec 2022). The Project advances this capability by:

  By aggregating data from various devices within the substation into a single data model that can be accessed by asset health analytic applications, SCE can transition from a preventative asset replacement strategy to that of a "just-in-time" asset replacement, thereby improving its return on assets (ROA).

  More specifically, machine virtualization technology paired with analytics enable more near real-time asset condition monitoring, predictive analytics, and health indices to support replacement of assets prior to failure as opposed to a predetermined useful life based on visual inspections or engineering analysis.

OPERATIONAL & SERVICE EXCELLENCE

- **[O-1.1] T&D advanced Cyber Security:** Protect SCE's computing and communications infrastructure against advanced persistent threats via cybersecurity platforms, controls, and services (Need Date: 31 Dec 2022). The Project advances this capability by:

  Machine virtualization, paired with analytics, enables advanced monitoring and behavior analysis of data from critical substation equipment, which enables SCE the ability to identify when a compromised system behaves anomalously and helps execute an automated response to isolate the system to minimize its potential impact to the grid operations.

  Additionally, virtualization of protection devices on a standardized hardware platform allows for faster security patching and other updates to ensure substations remain secure from emerging cybersecurity threats.

2.4 Alternatives considered

SCE's Substation Demonstrations Team also investigated relay virtualization using ABB's proprietary Smart Substation Control and Protection (SSC 600) solution. While ABB's SSC 600 solution is IEC 61850 compliant, the product only allows for use of ABB relays (i.e., not interoperable with other virtual relays from other vendors). This would require SCE to procure multiple proprietary vendor solutions to operate a complete substation, thereby, limiting the benefits of virtualizing IEC 61850-compliant relays—e.g., interoperability across relays to support advanced protection schemes, a standardized hardware platform for ease of updates, centralized data model for better visibility and analysis.

2.5 Proposed system overview

The proposed system contemplated for this virtual substation relay proof-of-concept consists of multiple MUs networked with several virtual protection relays via a digital interface using IEC 61850 process bus technology. The MU serves as an important interface between conventional switchyard instrumentation and the process bus. They will be used to convert analog voltage and current transformer signals into digital Sampled Measured Values (SMV) that will be merged into standard data packets and synchronized by a satellite clock before transmission to the appropriate protection relay or IED via process bus communication links.

In lieu of conventional protection relays, the Team will leverage virtual relay software applications from two (2) different vendors. Two vendors were chosen in order to demonstrate interoperability on its virtual machine platform, which consists of a server and real-time hypervisor software , which will be used to consolidate and run the virtual relay applications from the two different vendors.

A Doble® Test Set will be used by the Team to simulate various instrument recordings from various switchyard instrumentation, which will be communicated to the virtual relays via MUs and the process bus. Test signals from the Doble® will be inserted into the appropriate MU(s) or directly into the process bus in order to generate the SMVs necessary to trigger desired protection functions (e.g., instantaneous overcurrent, time overcurrent) to be performed by the vendor-procured virtual relays.

Lastly, a separate substation network will be developed within the lab to establish communications between the virtual protection relays and a human machine interface (HMI) to provide situational awareness and aid in evaluation measurement and validation. The team considered adding additional devices/systems to be connected via the substation network (e.g., EMS/DMS simulator, 61850-capable PAC) to enable other use cases (e.g., local and remote control, load restoration flows), however, the Team decided to focus the proof-of-concept on evaluating the virtual relay's core functionality—ability to execute various protection functions.

Please see Figure 1 in Section 5 for a conceptual diagram of the Virtual Substation Relay Proof-of-Concept and more detailed description of the proposed system.

2.6 References

- Project Charter
- Project GT PMO Site
- EPIC III CPUC Application
- EPIC III CPUC Research Administration Plan (RAP) Application
- Electrical Design Station Layout (EDSL) – SA-3 (Section: 62-20-40)
- IT Services Entry Level Checklist

3 Description of the current system

Each substation has a control room that houses various components, such as P&C devices. Relays contain secondary voltage and current inputs to protect the power system from abnormal system faults while automation devices automatically restore power to the grid.

Traditional P&C systems, which have long relied on proprietary hardware, have been reliable, but there are considerable challenges with their continued use. They currently face high construction costs and long deployment times due to the hard-wired connections and trenching required to terminate and route wires to these P&C devices. A single substation consists of thousands of wires and terminations, and a control room must be large enough to accommodate this equipment and perform safe cable terminations and maintenance. Modifications to these systems can also result in costly and long scheduled outages as a result of the complex relay connections and wiring. In addition, the proprietary design for individual P&C systems makes it difficult and costly to keep up with increasing cybersecurity and compliance updates. These updates require carefully planned outages and vast amounts of testing, which is becoming increasingly cost prohibited.

Furthermore, the maintenance of these systems is largely a manual process, which drives the need to explore new ways to automate and alert when device failure is approaching. When devices fail, it can be expensive and time consuming to upgrade them with the latest technology, so the short-term solution is to retain legacy technology. Unfortunately, this patchwork approach doesn't promote a more reliable and resilient grid.

4 Changes to current system and rationale

In order to address future protection needs associated with safely accommodating increasing renewables, SCE will require improved methods of sensing and monitoring distribution grid conditions to better understand the status and potential safety and reliability issues caused by a changing resource mix (e.g., hidden load, two-way power flows, etc). SCE will require an approach to quickly identifying and updating new (or enhanced) protection functions across its substations. Additionally, SCE will require access to more granular data from critical substation devices and systems necessary to achieve these challenges.

Machine virtualization helps address these capability gaps by digitizing protection relays and their associated input/outputs onto a standardized hardware platform that allows SCE the flexibility it needs to quickly respond to new protection challenged posed increasing renewables.

Additionally, by aggregating data from various devices within the substation into a single data model and allowing access to multiple applications, SCE can extract key information from data necessary to enable a wide variety of benefits.

5 Concept for the proposed system

5.1 Description of the proposed system

The proposed system contemplated for this virtual substation relay proof-of-concept (Figure 1) consists of multiple MUs networked with several virtual protection relays via a digital interface using IEC 61850 process bus technology. The MU serves as an important interface between conventional switchyard instrumentation and the process bus. They will be used to convert analog voltage and current transformer signals into digital SMVs that will be merged into standard data packets and synchronized by a satellite clock before transmission to the appropriate protection relay or IED via process bus communication links.

The process bus will be an ethernet-based Local Area Network (LAN) built upon the IEC 61850 standard and separate from the Substation Network discussed below. This digital interface enables mapping of measurements made in the switchyard to their associated protection relays located in the substation's mechanical-electrical equipment room (MEER) using secure fiber optic communications. The process bus will be used to enable process-level communications between the MUs and protection relays, which will leverage several communication protocols—Generic Object-Oriented Substation Event (GOOSE) and SMV—which provide for time-sensitive data exchange via a publisher/subscriber model.

For this proof-of-concept, the Team will leverage virtual relay software applications from two (2) different vendors (in lieu of conventional protection relays). Several vendors were chosen in order to demonstrate interoperability on its virtual machine platform, which consists of a server and hypervisor software, which will be used to consolidate and run the virtual relay applications from the two different vendors. The virtual protection relays will receive digital monitoring inputs in the form of SMV via the process bus, which they'll used to compute various protection functions and, as necessary, will transmit binary GOOSE messages to the appropriate IED (e.g., CB tripping).

A Doble® Test Set will be used by the Team to simulate various instrument recordings from various switchyard gear and instrumentation, which will be communicated to the virtual relays via MUs and the process bus. Test signals from the Doble® will be inserted into the appropriate MU(s) or directly into the process bus in order to generate the SMVs necessary to trigger desired protection functions (e.g., instantaneous overcurrent, time overcurrent) to be performed by the vendor-procured virtual relays.

A separate substation network will be developed within the lab to establish communications between the virtual protection relays and a human machine interface (HMI) to provide situational awareness and aid in evaluation measurement and validation. This substation network will leverage several communication protocols—namely Manufacturing Message Specification (MMS) and various IT management protocols—which are less time-sensitive as compared to process bus communication protocols (i.e., SMV and GOOSE).

The integrated system will be developed and tested in a controlled lab environment. The Team anticipates using the Substation Automation lab located at SCE's Fenwick facilities, which is where other similar SCE SA-3 standard-related projects are taking place.

Note: the Team considered additional devices/systems to support other use cases—i.e., an EMS/DMS simulator to evaluate local and remote control of the virtual relays, as well as a 61850-capable PAC to evaluate load restoration flows via virtual relays. However, the Team decided to focus this proof-of-concept on evaluating the virtual relay's core functionality (i.e., ability to execute various protection functions).

5.2 Context diagram

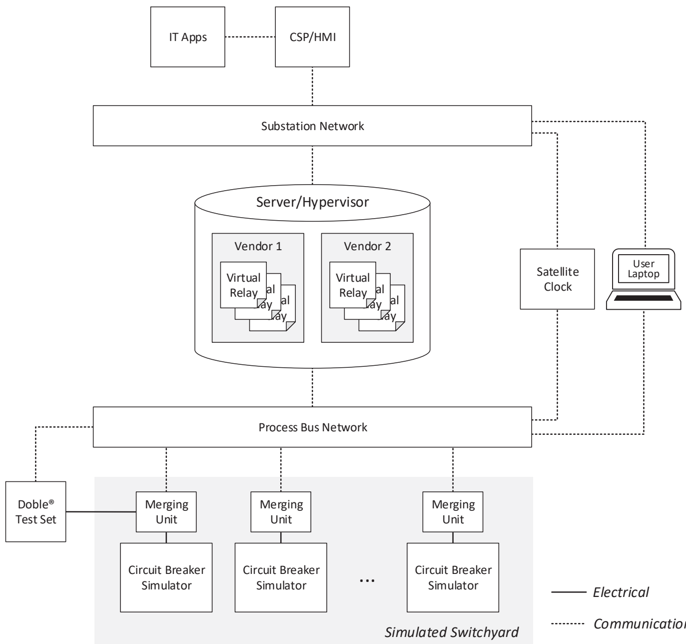

FIGURE 1: CONTEXT DIAGRAM FOR THE VIRTUAL SUBSTATION RELAY PROOF-OF-CONCEPT

5.3 Major system components and interconnections among them

Component	Description
Relay Hypervisor Software Application	Virtual machine monitoring (VMM) software application that will be used to create and run virtual machines (e.g., virtual relays).
Virtual Relay Server	Computer server used to run VMM software application.
Virtual Protection Relay	Virtual protection relay software application (i.e., guest virtual machine) running on the relay hypervisor software application.
Substation Network/ Ethernet Switch	Computer network used to connect relay hypervisor with other 61850 capable devices (e.g., CSP/HMI, Satellite Clock). Operates on MMS and various IT management communication protocols.
Process Bus Network/ Ethernet Switch	Computer network enables digital transmission of process measurements between the substation switchyard and digital protective relays in the control room. Operates on SMV and GOOSE communication protocols.

Merging Unit (MU)	Device that enables the implementation of an IEC61850 process bus by converting analog signals from the conventional CTs and VTs into IEC 61850 digital values.
CB Simulator	The CB simulator (e.g., Ice-Cube Relay) is a hardware component. The IED relay (virtual in this case) outputs a control signal that can open and close the CB simulator.
Doble® Test Set	Device used to input voltages and currents into a relay or MU to simulate fault scenarios. The test set can be used to implement test plans and record / evaluate results.
Common Substation Platform (CSP)/Human-Machine Interface (HMI)	Computing platform (HW/SW), which will serve as the communication and control hub between the operations center and substation equipment and distribution circuit equipment and sensors.
IED Configuration Tool	Vendor's IED configuration tool

5.4 Interfaces to external systems or procedures

The Substation Demonstration Team does not anticipate any interfaces to external enterprise network and/or controls systems networks for this demonstration. However, below are descriptions for some of the internal interfaces required for this demonstration.

Component	Description
Merging Units (MU) to Virtual Relay Server (via Process Bus Network)	Time-sensitive two-way network communication flow for binary GOOSE messaging (e.g., CB tripping, on-off status) and one-way for SMV messaging (e.g., current and voltage measurements) via ethernet-based LAN (process bus network). This network is intended to be developed in SCE's Substation Automation lab.
Virtual Relay Server to CSP/HMI (via Substation Network)	Two-way network communications via MMS and various IT management protocols via ethernet-based LAN (substation network). This network is also intended to be developed in SCE's Substation Automation lab.

5.5 Assumption and constraints

Assumptions:

- At least two (2) third-party vendors have the capability to provide interoperable virtual protection relay solutions that can easily be implemented in SCE's lab.
- There will be a suitable lab installation location for this demonstration.
- This project will need an IEC 61850 experienced personnel that will understand the overall standard and the SCE system.

Constraints:

- Potential resource constraints based on active EPIC II projects requiring similar expertise (i.e., IIM-15-015: System Intelligence & Situational Awareness).

5.6 System boundaries

This project will be demonstrated in controlled lab environment and does not require access to production systems. From a communication network perspective, the project is bounded by the CSP/HMI and MUs networked on the lab's two LANs (i.e., Substation Network and Process Bus Network). From an electrical perspective, this project is bounded by the Doble® Test Set and CB Simulators (i.e., ice-cube relays) also located within the demonstration lab.

6 IT Requirements

6.1 IT/Cyber Security

- Enterprise Architecture will be involved in the development/drafting of any architecture document.
- No connectivity to the vendor's website is expected to be needed.
- The specified system will not require connectivity to other labs, however it is likely that remote access utilizing Citrix or existing system will be required by vendors to provide remote support.
- The system is not expected to require connectivity to an external server.
- External users might requires connectivity into the device in the lab utilized means provided by IT (i.e. Citrix)
- This project is not intended to be funded beyond the lab environment.
- Cybersecurity will have the opportunity to review and provide feedback on the requirements.

7 High-level Business use cases

7.1 Use Case #1 Execute Existing Circuit Breaker Relay Protection Functions

Use case name	Execute Existing Circuit Breaker Relay Protection Functions

Description	This Use Case will demonstrate SCE's ability to execute several existing CB relay protection functions (e.g., instantaneous overcurrent, time overcurrent) using vendor-procured virtual relays.
Use case ID	UC1
Actors	▪ Substation Demonstration Team ▪ Protection and Automation ▪ Technical Support & Strategy ▪ Virtual Relay Product Vendors
Pre-condition	▪ Lab set-up is complete per integrated system design (e.g., communication networks, configuration of virtual relay software applications and MU, IT set-up, system integration and system testing) ▪ SCE familiarity with virtual relay vendor's software application (e.g., training)
Flow of events	Steps: 1.) Using a Doble® Test Set, execute appropriate test plan to insert signals via MU (or directly into the process bus) 2.) Subscribing virtual relay(s) receive sample values (voltage and/or current) created by the MU via the process bus 3.) Virtual relay(s) process received sample values and determines the appropriate action per SCE protection function and settings 4.) If action is required, the virtual relay publishes a control message (i.e., GOOSE) for subscribing MUs via the process bus 5.) MU(s) execute control message (e.g., operate contact necessary to open designated circuit breaker) 6.) Designated circuit breaker opens 7.) Adjacent MU senses open circuit breaker and publishes a status change message (i.e., GOOSE) 8.) Subscribing virtual relay(s) receive Circuit breaker status update 9.) Validate protection function was properly executing via Doble Test Set
Alternative Paths	▪ Repeat for other existing SCE protection functions ▪ Insert test plan signals from the Doble® Test Set into the MU or directly into the process bus in order to trigger protection functions ▪ Test redundancy by disabling primary relay and allowing secondary relay to receive and process test sample values
Post condition	▪ Doble® Test Set shows that CB tripped within expected time ▪ CB simulator shows CB open

8 Other potential high-level Business use cases

8.1 Use Case #2 Execute New Circuit Breaker Relay Protection Functions

Similar to Use Case 1, except that this will demonstrate SCE's ability to execute newly developed relay protection functions that are representative of those functions necessary to protect SCE substations against increasing renewables.

8.2 Use Case #3 Test Restoration Flows ("Self-Restoring Loop") Via Virtual Relay

This Use Case will demonstrate the ability to execute SCE's "Self-Restoring Loop" scheme with a 61850 capable PAC and virtual relays.

8.3 Use Case #4 Execute Local and Remote Control of Substation Switchgear

This Use Case will demonstrate SCE's ability to execute local and remote control of substation switchgear through use of a simulated Common Substation Platform (e.g., HMI) and EMS/DMS simulator respectively.

8.4 Use Case #5 Test Cybersecurity Controls and Features on Virtual Relays

This Use Case will demonstrate SCE's ability to configure and test designated cybersecurity controls and features on vendor procured virtual relays necessary to deploy this technology in SCE's operational substations.

9 Business requirements

Requirement ID	Business Requirement
BR-1	Virtual relay software application(s) are able to communicate and control connected 61850 capable devices per SCE's SA-3 standard.
BR-2	Vendor's virtual relay software application can be programmed to carry-out desired existing protection functions (e.g., instantaneous overcurrent, time overcurrent).
BR-3	Vendor's virtual relay software application can be programmed to carry-out new desired protection functions.
BR-4	Ability for virtual relay configuration to be standardized in SCE's SEMT (Substation Engineering Model Tool).
BR-5	Virtual relay software application(s) are able to fully accommodate IEC 62351 security standards.
BR-6	Project team shall verify lab environment is isolated prior to connecting devices to network.
BR-7	Project team shall ensure external connections from the lab to external vendor support do not exist, or that the appropriate cybersecurity controls have been applied.
BR-8	Project team shall ensure project's hypervisor is hardened.
BR-9	Project team shall ensure devices with known vulnerabilities, if used with this demonstration project, are identified, tracked, and the commensurate cybersecurity controls are applied.

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Email:	Access to a valid email account
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Workpaper Title:

Capital Pilot – Storage Based Distribution DC Link, EPIC 3 GT-18-003

Concept of Operation

EPIC 3 Project: GT-18-0003

Storage-Based Distribution DC Link

Document version: 1.0

Document version date: 10/31/19

Document Number: GT-18-0003 ConOp v1.0

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Table of Contents

1 Document Control

1.1 Revision History

Version	Date Modified	Author	Brief Description of Change
1.0	2019-10-31	Sam Uyeno	Initial Draft

1.2 Approvals

Name	Title	Date	Signature
Hayne Son	Technical Lead	12/5/2019	DocuSigned by: Hayne Son
Brian Jones	Project Manager	12/4/2019	Brian Jones
Josh Mauzey	Technical Lead Manager	12/7/2019	DocuSigned by: JOSH MAUZEY
Andrea Haas	IT Program Manager	12/6/2019	Andrea Haas
Anthony Johnson	EPIC Chief Engineer	12/4/2019	DocuSigned by: Anthony Johnson
Vishal Patel	Technology Strategy Manager		
Brandon Tolentino	Project Sponsor	12/9/2019	DocuSigned by: Brandon Tolentino

1.3 Acronyms

BESS	Battery Energy Storage System
DC	Direct Current
DNP3	Distributed Network Protocol 3
EMS	Energy Management System
GHG	Greenhouse Gas
GEI	Grid Edge Innovation, department within Technology Innovation division
RAP	Research Administration Plan
RT	Real-Time
SCE	Southern California Edison

2 Scope

2.1 Document purpose

The purpose of this document is to communicate the users' need and expectations of the proposed system/project to the users, sponsors, stakeholders, project managers, procurement representatives, vendors, system developers, engineers, new team members, etc. It is intended to document the current system ("as is"), provide a description of the users' future need and how the proposed system ("to be") will operate to meet those need from the end users' point of view. This document also defines the business use cases and business requirements for the proposed system/project.

2.2 Introduction

The storage-based distribution direct current (DC) link ("DC Link") project will demonstrate if it is feasible for a battery energy storage system (BESS) to manage controlled line loading on two adjacent circuits simultaneously, via a DC link, thereby preventing line overload or duct bank temperature violations, optimizing local voltage, and supporting the integration of renewable resources.

The demonstration will also evaluate the ability of this DC Link to enable controlled line loading between two circuits without a BESS. This enhances the operational flexibility currently provided by feeder parallel/tie switches, which only allows a fixed amount of load to continuously transfer, whereas a dynamic DC link allows the power transfer to be set to any value, up to the maximum rating of the Power Conversion System, and allows this power transfer to dynamically adjust based on the loading of the two circuits. As a result, a storage-based DC link system provides an opportunity for SCE to improve load management and minimize costly switching operations.

2.3 Alignment with SPOP technology roadmap

2.3.1 SPOP capabilities addressed

This Project is in alignment with SCE's Grid Strengthening & Modernization strategic pillar, which aims to modernize the distribution grid and its operations to enhance reliability while supporting and leveraging customers' distributed energy choices. More specifically, this project will demonstrate the following capabilities:

- **[D-2.7] Distribution Protection Automation & Control:** Controlling and coordinating increasingly complex protection and automation systems to improve reliability performance and to manage the operational complexities created by high volumes of DERs based on real-time analysis of system conditions (Need Date: 31 Dec 2019)
- **[D-3.8] Develop DSO platform:** Ability to support future-state DSO technical requirements via platform systems, communications, analytical tools, market transaction and grid management tools (Need Date: 31 Dec 2025)

2.3.2 How this project will advance the capabilities

This project advances these two strategic capabilities in the following way:

- **[D-2.7] Distribution Protection Automation & Control:** The DC Link will demonstrate the ability for SCE to implement dynamic load transfers between two circuits via a storage-based DC link in order to improve reliability performance and to manage the operational complexities created by high volumes of DERs based on real-time analysis of system conditions.

- **[D-3.8] Develop DSO platform:** This demonstration is intended to evaluate SCE's ability to leverage innovative control technologies to deliver enhanced levels of reliability, resiliency, safety, and security for energy delivery to consumers.

2.4 Alternatives considered

Two alternatives were considered in developing this project, see below:

- **ALTERNATIVE 1:** Traditional Energy Storage System – This alternative requires that each circuit have a dedicated BESS to manage individual line loads.
- **ALTERNATIVE 2:** Traditional Load Roll Method – This alternative leverages a parallel/tie switch to connect two circuits, enabling load transfer. However, this method does not provide the benefits of a storage device and it cannot dynamically control the amount of load that is transferred between the two circuits. Challenges of the load roll method include smaller conductors toward the end of circuit and lack of available capacity to accept load from another circuit. These factors can limit the amount of power being transferred.

2.5 Proposed system overview

The proposed concept will provide distribution system operators with enhanced flexibility in managing line loads by using a DC Link that enables controlled line loading from a BESS to two circuits simultaneously and between two circuits (without using batteries). A high-level illustration of the DC Link project is shown on the next page (Figure 1).

The project will require construction of a DC Link in SCE's lab facilities and connection of two electrical circuits. The DC Link is comprised of a set of battery modules, two inverters, two step down transformers, and a DC bus connecting the inverters.

During the lab demonstration phase, the system will be run by members of DER Demonstrations team. If the lab demonstration is successful, a possible future project will become a field demonstration pilot.

Expected list of stakeholders:

1. Distribution/Operations Engineers – determine the amount of load to be transferred through the DC Link, in order to resolve circuit or bank overloading conditions; determine whether duct bank temperatures can be decreased on the circuits connected to DC Link.
2. Grid control operators – implement load transfers through the control system interface.

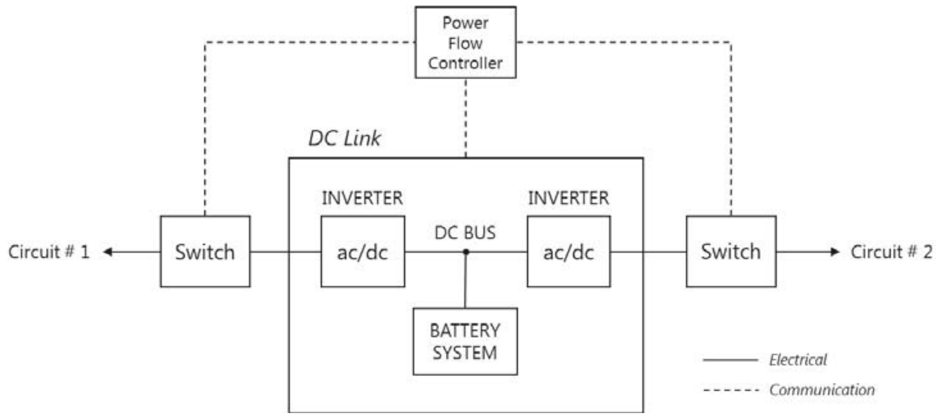

FIGURE 1: HIGH-LEVEL SCHEMATIC OF DC LINK

2.6 References

- Project Charter
- Project GT PMO Site
- EPIC III CPUC Application
- EPIC III CPUC Research Administration Plan (RAP) Application

3 Description of the current system

Currently, line load management is supported by two preferred methods—either using the Load Roll Method via a tie switch or by using a dedicated BESS to support line loading on an individual circuit (albeit an emerging approach for SCE).

The Load Roll Method requires operating a tie switch between two circuits in order to transfer some load from the overloaded circuit. This rudimentary approach does not allow for a dynamic load transfer and is subject to performing switching operations to determine the amount of load transferred.

A dedicated BESS may be used to support load management for an individual circuit, which allows operators to shift the time of energy use and control load management with fewer switching operations. However, each circuit requires its own BESS.

4 Changes to current system and rationale

In order to demonstrate the benefits of this project, a lab demonstration will be set up to simulate the addition of a DC Link in-between two circuits as shown in Figure 1. The current system has a BESS connected to a single circuit and the rules are established to limit the amount of charging or discharging on this single circuit only. New load management rules would need to be developed to discharge the BESS on two circuits simultaneously.

5 Concept for the proposed system

5.1 Description of the proposed system

The DC Link project will be tested in a lab environment, the proposed lab locations are potentially at the Equipment Demonstration and Evaluation Facility, Westminster or the SSID (Shop Services Instrumentation Division) test pad, located in the back of the transformer storage areas. Both of these locations and possibly others will be scouted during the execution phase to find a suitable location.

The DC Link system will have two possible configurations during the lab testing phase. If there are two 12kv distribution circuits located in a reasonable vicinity, then the DC Link will be connected to each of those circuits, and isolated through the use of 12kv standard gas switches. Otherwise, the DC Link will have one 12kv distribution circuit connection to one inverter, and the other connection will be a Utility Grid Simulator (procured as part of this project). In conjunction with the Grid Simulator, additional load banks will be required to simulate actual loads on the circuit.

At a high level, the DC Link system will perform the following basic functions:

1. Discharge the batteries to reduce line loading on one circuit.
2. Discharge the batteries to reduce line loading on two circuits, within the bounds of the electrical rating of the system.
3. Transfer power from circuit #1 to circuit #2, without discharging the batteries.
4. Charge the batteries using power from one circuit.

5.2 Context diagram – refer to section 5.3 for diagram.

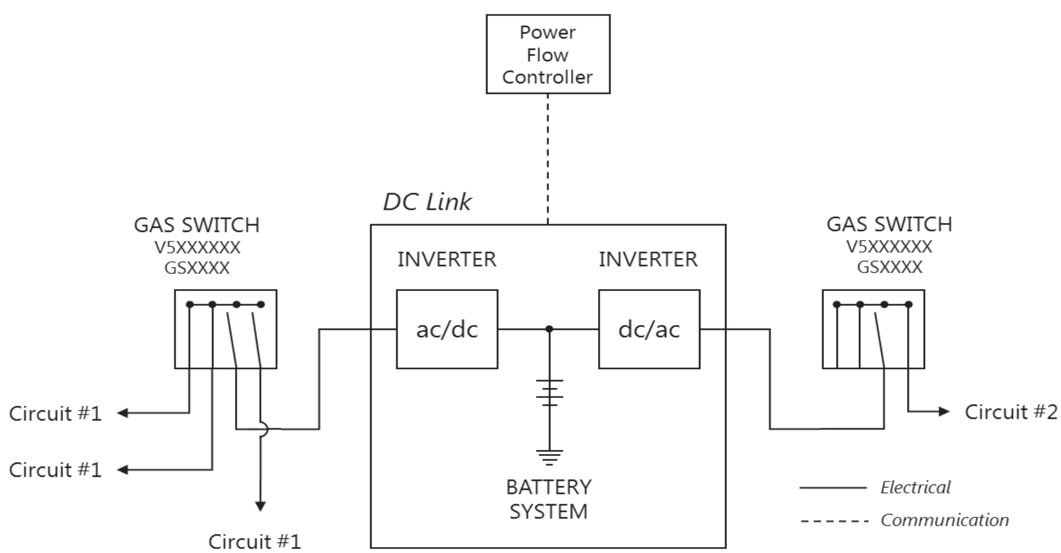

FIGURE 2: CONTEXT DIAGRAM FOR THE STORAGE-BASED DC LINK DEMONSTRATION

5.3 Major system components and interconnections among them

Component	Description
Inverter (x2)	Equipment that converts AC power to DC power, and vice versa. Also known as the Power Conversion System, or PCS. 150-250kw is the anticipated rating for each inverter.
Battery Modules	The individual cells are contained in a battery module housing, which allows mounting the modules into a rack configuration. Total system rating is expected to be 250 kWh or 1 hour runtime.
Battery Mgmt. System	Monitors parameters of each cell or rack of batteries, such as temperature, cell voltage, current, alarms, etc.
Power Flow Controller	Monitors voltage and phase angle of each circuit, controls the flow of power through the DC Link equipment.
DC Bus	Connects between the two inverters to provide DC path
Transformer	Steps the voltage down from 12kv to 480 volts, since the inverter is typically rated at 480 volts.
Gas Switches (x2)	Provides means of isolation for the DC Link from each circuit

5.4 Interfaces to external systems or procedures

Component	Description
Energy Mgmt. System (EMS)	Tracks real & reactive power output of DC Link
EDNA	Used to track/store all monitored points of DC Link system
SCE Lab Network	Separate network to communicate with DC Link components
Flexible Logic Controller	Common SCE interface used to control all Energy Storage systems
Vendor Control Software	Vendor-specific software used to control DC Link product

5.5 Assumption and constraints

Assumptions:

- A third-party vendor has the capability to provide a storage-based DC link system that can be implemented in a lab environment. The inverter technology itself is existing, however the unique connection of two inverters in series and then having the proper power flow control system is a novel feature that has not been tested by SCE.
- This project assumes that a control algorithm can accept inputs from a SCADA simulator using historical data and determine how to charge or discharge the batteries, including the rate of charge/discharge.
- There will be a suitable lab installation location that can be connected to two circuits simultaneously. In the event a lab does not have two available circuits for connection, the project will require additional time and cost to establish suitable connections.

Constraints:

- Depending on the length of the demonstration, a cybersecurity assessment or evaluation of connected devices may need to be performed.
- The amount of space required for the DC Link could limit the locations where it could be installed

5.6 System boundaries

From an electrical grid perspective, the project is bounded by the DC Link and the two gas switches that connect the individual circuits to the DC Link. The gas switches would be used as an isolation point if the DC Link became unstable or unsuitable to connect to the SCE grid.

From a communication perspective, this project is bounded by the Power Flow Controller and the network interface cards within the DC Link. The SCE line crews will maintain control over the gas switches, while Grid Edge Innovation (GEI) group will control the actual DC Link system operation.

5.7 System modes of operation

There are four modes of operation envisioned for the DC Link project:

- **Mode 1:** Charging the BESS within the DC Link from a single circuit
- **Mode 2:** Operating the DC Link to discharge the BESS onto one circuit
- **Mode 3:** Operating the DC Link to discharge the BESS onto two circuits
- **Mode 4:** Operating the DC Link, without the BESS, to transfer load between two circuits. The amount of load will be user adjustable up to the maximum power rating of the DC Link system.

6 High level Business use cases

6.1 Use Case #1 Charge BESS

Use case name	Charge BESS
Description	Once the DC Link's BESS state of charge lowers to a predefined threshold, a circuit will begin charging the BESS until predefined conditions are met.
Use case ID	UC1
Actors	▪ Distribution Engineering (simulated by SCE's DER Demo Team) ▪ Distribution System Operator (simulated by SCE's DER Demo Team)
Pre-condition	▪ Charging circuit has adequate capacity to charge BESS ▪ BESS state of charge is known ▪ BESS state of charge is below predefined threshold ▪ Specified load transfer is within the limits of the DC Link power electronics
Flow of events	Steps: 1.) Develop and program charging instructions for Power Flow Controller to initiate and secure charging the BESS 2.) Once BESS lowers to a predefined threshold, the Power Flow Controller will validate charging circuit capacity and begin charging BESS 3.) Once BESS is charged to a predefined threshold, a signal is sent to the Power Flow Controller to secure charging the BESS
Alternative Paths	▪ Secure charging early to support BESS discharging on an overloaded circuit
Post condition	BESS state of charge reaches predefined threshold (or other desired level)

6.2 Use Case #2 Discharge to One Circuit

Use case name	Discharge to One Circuit
Description	Once an overload condition is identified on an individual circuit, the BESS discharges via the DC Link onto the overloaded circuit to provide temporary relief.
Use case ID	UC2
Actors	▪ Distribution Engineering (simulated by SCE's DER Demo Team) ▪ Distribution System Operator (simulated by SCE's DER Demo Team)
Pre-condition	▪ Real-time load telemetry indicates overloading on a circuit ▪ BESS state of charge has adequate capacity to support the overloaded circuit ▪ Specified load transfer is within the limits of the DC Link power electronics
Flow of events	Steps: 1.) Develop and program discharging instructions for Power Flow Controller to initiate and secure discharging the BESS 2.) Measure circuit's existing real-time loading and compare with desired load 3.) Verify that BESS' current state of charge has adequate capacity to support overloaded circuit 4.) Calculate the level and duration of BESS discharge to support overloaded circuit 5.) Begin discharging BESS 6.) Discharging is secured once the circuit overload condition has elapsed, as evidenced by real-time load telemetry, or BESS is fully discharged
Alternative Paths	▪ None identified
Post condition	Circuit overload condition has elapsed, as evidenced by real-time load telemetry, or BESS is fully discharged

6.3 Use Case #3 Discharge to Two Circuits

Use case name	Discharge to Two Circuits
Description	An overload condition is identified on two adjacent circuits connected via a DC Link, requiring load management. The BESS discharges a specified load to both circuits simultaneously to provide temporary relief.
Use case ID	UC3
Actors	▪ Distribution Engineering (simulated by SCE's DER Demo Team) ▪ Distribution System Operator (simulated by SCE's DER Demo Team)
Pre-condition	▪ Real-time load telemetry indicates overloading on two circuits simultaneously ▪ BESS state of charge has adequate capacity to support both overloaded circuits ▪ Specified load transfer is within the limits of the DC Link power electronics
Flow of events	Steps: 1.) Develop and program discharging instructions for Power Flow Controller to initiate and secure discharging the BESS 2.) Measure both circuits' existing real-time loading and compare with desired load 3.) Verify that BESS' current state of charge has adequate capacity to support both overloaded circuits 4.) Calculate the level and duration of BESS discharge to support each overloaded circuit 5.) Begin discharging BESS 6.) Discharging is secured once the circuit overload condition has elapsed for both circuits, as evidenced by real-time load telemetry, or BESS is fully discharged
Alternative Paths	None identified
Post condition	Circuit overload condition has elapsed for both circuits, as evidenced by real-time load telemetry, or BESS is fully discharged

6.4 Use Case #4 Two Circuit Load Transfer, No BESS

Use case name	Two Circuit Load Transfer, No BESS
Description	When an overload condition exists on one circuit, an adjacent circuit with adequate capacity can be used to transfer a specified amount of load, via the DC Link, to the overloaded circuit without the BESS
Use case ID	UC4
Actors	▪ Distribution Engineering (simulated by SCE's DER Demo Team) ▪ Distribution System Operator (simulated by SCE's DER Demo Team)
Pre-condition	▪ Real-time load telemetry indicates overloading on a circuit ▪ Adjacent circuit has adequate capacity to support overloaded circuit ▪ Specified load transfer is within the limits of the DC Link power electronics
Flow of events	Steps: 1.) Measure overloaded circuit's existing real-time loading and compare with desired loading 2.) Measure adjacent circuit's real-time loading and determine if there is adequate capacity to support overloaded circuit 3.) If there is adequate capacity on adjacent circuit, program specified load transfer in the Power Flow Controller 4.) Begin transferring load from overloaded circuit to adjacent circuit 5.) Secure load transfer once overload condition has cleared or adjacent circuit no longer has excess capacity to support
Alternative Paths	None identified
Post condition	Overload condition is clear or adjacent circuit no longer has excess capacity to support

7 Business requirements

Requirement ID	Business Requirement
BR-1	BESS is capable of being charged through one or several circuits via DC Link
BR-2	BESS is capable of being discharged onto one or several circuits by a specified amount
BR-3	A specified amount of load can be transferred from one circuit to another via DC Link
BR-4	Power Flow Controller and DC Link can be connected via Distributed Network Protocol 3 (DNP3)
BR-5	BESS is capable of providing capacitive or reactive power within its nameplate rating
BR-6	BESS is capable of all nameplate power and duration combinations within the scope of work
BR-7	BESS can control the active and reactive power at the connected voltage level.
BR-8	BESS allows control through a remote command/control interface via DNP3 TCP/IP
BR-9	BESS allows control through a Local or Remote web based interface

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Workpaper Title:

Capital Pilot – Service Center of the Future, EPIC 3 GT-18-0017

Concept of Operations

EPIC 3 Project: GT-18-0017

Service and Distribution Centers of the Future

Document version: 1.3

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Document Number: GT-18-0017 ConOp v1.3

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Table of Contents

1 Document Control

1.1 Revision History

Version	Date Modified	Author	Brief Description of Change
0.8	2019-10-24	Joshua McDonald	Initial Draft
0.9	2019-11-07	Joshua McDonald	Revisions based on Jordan's comments
1.0	2019-11-12	Jordan Smith	Final Draft ready for Sponsor/Stakeholder Input
1.1	2019-11-25	Joshua McDonald	Comment resolution and addition of Resiliency use case
1.2	2020-07-13	Joshua McDonald	Added DNP/RTU information
1.3	xx-2021	Joshua McDonald	Full revision based on project scope updates

1.2 Approvals

Name	Title	Date	Signature
Jordan Smith	Technical Lead		
David Taylor	Project Manager		
Juan Castaneda	Technical Lead Manager		
Chris Lorimer	Project Sponsor		
Jun Wen	Project Sponsor		
Anthony Johnson	EPIC 3 Chief Engineer		
Vishal Patel	Technology Strategy		
Andrea Haas	IT Point of Contact		

1.3 Acronyms

AMI	Advanced Metering Infrastructure
CAISO	California Independent System Operator
CB	Circuit Breaker
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DNP	Distributed Network Protocol
DSO	Distribution System Operator
ESIP	Energy Storage Integration Program
ESS	Energy Storage System
EV	Electric Vehicle
EVSP	Electric Vehicle Service Provider
FEMS	Facility Energy Management System
GIPT	Grid Interconnection Processing Tool
GMS	Grid Management System
HVAC	Heating, Ventilation and Air Conditioning
IT	Information Technology
kW	Kilowatt
LAN	Local Area Network
M&V	Measurement and Verification
MGPOI	Microgrid Point of Interconnection
NMS	Network Management System
PCT	Programmable Controllable Thermostat
PKI	Public Key Infrastructure
PSPS	Public Safety Power Shutoff
PV	Photovoltaic

RTU	Remote Terminal Unit
S2S VPN	Site-to-site Virtual Private Network
SCADA	Supervisory Control and Data Acuisition
TE	Transportation Electrification
TOU	Time of Use
VArs	Volt-ampere reactive (Reactive Power)

2 Scope

2.1 Document purpose

The purpose of this document is to communicate the users' need and expectations of the proposed system/project to the users, sponsors, stakeholders, project managers, procurement representatives, vendors, system developers, engineers, new team members, etc. It is intended to document the current system ("as is"), provide a description of the users' future need and how the proposed system ("to be") will operate to meet those need from the end users' point of view. This document also defines the business use cases and business requirements for the proposed system/project.

2.2 Introduction

Southern California Edison (SCE), along with many of its commercial and industrial customers, are committed to moving their fleets towards electrification. However, the challenges of converting engine powered vehicles to electric power are considerable. On the customer side, there are costs and complexities with setting up and operating the new electric fueling system, concerns about their availability when there's an outage of the grid, and uncertainties about the cost of electricity as a fuel. On the grid side, the distribution infrastructure to fully electrify these fleets have significant local constraints, as large numbers of heavy-duty vehicles will need very high power and energy capacity - approaching 30 megawatts (MW) per location in some cases. In order to minimize or eliminate these issues and further the deployment of transportation electrification, the systems need to be designed to meet the customer needs, and the charging needs to be managed and optimized with new technical solutions to support their deployment.

The GT-18-0017 Service and Distribution Center of the Future project (project) will consist of electric transit busses, high powered direct current (DC) electric vehicle supply equipment (EVSEs), an SCE provided behind the meter (BTM) energy storage system (ESS), controllable loads such as electrified space and water heating, and an SCE provided Microgrid Control System (MCS). The project will demonstrate islanding capabilities to support EV charging resiliency and load management use cases for the electric vehicle (EV) and controllable loads.The project will integrate with an existing Charge Ready Transport[1] project site to inform beyond initial phase distribution and charging infrastructure deployment.

The project deliverables include:

- A demonstrated system to manage customer EV charging loads
- Demonstration of an EV charging sub-metering system
- A demonstrated conversion of a gas/electric building to full electric and integration with site controls
- A demonstrated technical solution for integration of Service Center systems into SCE's GMS
- A demonstrated customer resiliency solution for EV Charging using energy storage

[1] https://www.sce.com/business/electric-cars/charge-ready-transport

- Recommendations for enhanced GMS capabilities (services, interfaces, etc.) for similar charging-based management systems
- Final report showing results and providing recommendations to enable further deployment of such facilities
- Technical presentation: at least one technical conference

2.3 Alignment with SCE's SPOP Technology Roadmap

2.3.1 SPOP Capabilities Addressed

This project is intended to support the following Technology Roadmap objectives and capabilities[2]:

Customer Energy Choices

- Objective 1: Remove barriers to customer adoption of transportation and building electrification technologies
  - Capability 1: Space and water heating electrification technologies can meet customer needs
- Objective 2: Improve value of DERs to customers and grid by enabling load management capabilities and other services (e.g. volt/var support)
  - Capability 8: Ability to coordinate BTM resources to optimally meet customer and grid needs

Grid Strengthening & Modernization

- Objective 2: Improve visibility, control, planning, and operation of distribution grid to improve reliability and integrate DERs
  - Capability 7: Controlling and coordinating protection and automation systems to manage the operational complexities created by high volumes of DERs based on real-time analysis of system conditions

2.3.2 How This Project will Advance the Capabilities

The project will demonstrate transportation electrification charge management techniques to optimize operation and control costs, enabling large scale fleet electrification. It will also demonstrate methods of service of large scale, high power, high energy electric fleets and coordinated communication and control with grid management systems. It will show how building electrification can be accomplished to manage costs and how it can be integrated with other DER systems.

Today, customers don't have a way to fully exploit the capabilities of vehicles as DERs. This project also demonstrates the full integration of such DERs for the value of facility management, as well as an aggregation with potential for grid services. Distribution system operators will understand the potential value of such a facility, and planners will be able to adjust efforts based on the revised system impact of a managed facility versus base case.

2.4 Alternatives Considered

There are 2 possible alternatives for this project:

- Do nothing: SCE currently has no method to serve a full electrification scenario at Metro's site, and Metro has no understanding of how to implement full electrification. Doing nothing would result in higher costs and more uncertainty, along with complaints from internal and external transportation electrification (TE) customers as SCE would not have an ability to provide the most effective solution that fits SCE's grid and customer requirements.
- Let others work on solutions: External projects would likely be purely customer focused and thus not likely to lead to a fully grid integrated solution. SCE would lose the opportunity to develop expertise in serving fleet customers in the future.

[2] https://edisonintl.sharepoint.com/ourcompany/pages/strategy.aspx.

2.5 Proposed system overview

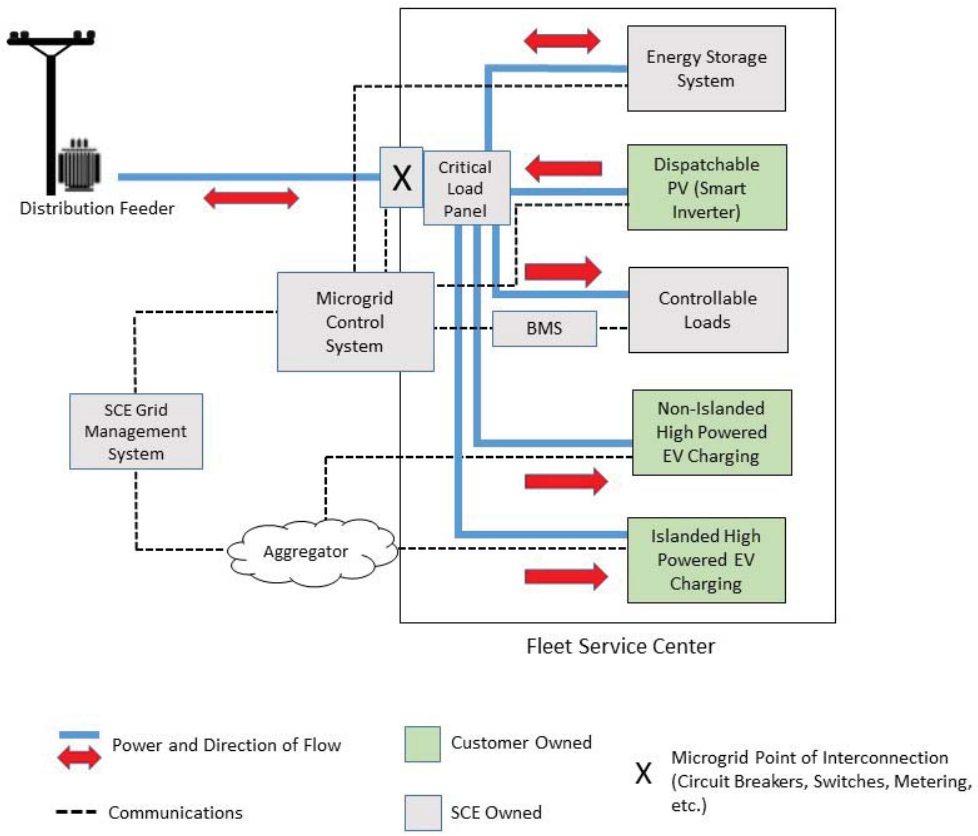


FIGURE 1- PROJECT CONCEPTUAL DIAGRAM

The high-level diagram above shows a fleet service center connected to an SCE feeder. An MCS is present to aggregate and manage a variety of controllable DERs based on grid and customer use cases. The exact technologies and capabilities being deployed by the project and customer for the demonstration are still to be determined. The overarching priority will be to ensure the EV charging needs are met. The individual charging circuits or entire project system may be islanded from the grid for the resiliency demonstrations. The project will first be tested and demonstrated in a lab setting before being deployed in the field.

2.5.1 Stakeholders

Stakeholder organizations and personnel include:

Name	Organization
Chris Lorimer (Co-Sponsor)	TEPM, New Development Planning
Jun Wen (Co-Sponsor)	DSO, Programs, & Strategies

Todd Carlson	Transportation Services Department
Mauro Dresti	TE-eMobility, Customer Service
Gary Barsley	Emerging Products & Technology, Customer Service
Terry Thien	T&D-Grid Operations: Substation Ops: Operations Engineering
Paul Anderson	Cybersecurity Risk Management
Craig Hammond	IT-Grid Services-Network & Telecom Engineering
Leon Machado	IT-Grid Services-Network & Telecom Engineering
Prakash Suvarna	IT-Grid Management System
Michael Schulte	IT-Solution Delivery (Prin Mgr)
Paul Anderson	Cybersecurity Risk Management
Nelson J Herrera	IT-Proprietary Telcom Sys
Anthony Johnson	T&D Technology Innovation
Triet Ho (Quincy)	IT - Smart Grid & Enterprise Networking
Gregory Tecson	IT Support
Warren Abatay	IT Support
Marc Rice	IT Policies, Standards & Governance
Aaron Renfro	GM&R-Integrated GRC & Governance Coord (EPIC 3 Manager)
Diego Hinojosa	T&D-GT Lab Operation
Tim Kedis	T&D Grid Control Management
Marcus Lotto	Grid Contracts Origination & Operation
Roger Salas	T&D Dist. Tech Studies & Tariff Support
Vishal Patel	T&D SPOP- Technology Strategy
Namrita Merino	CS Business Customer Division, DER Delivery
John Minnicucci	SCE Regulatory Affairs & Compliance
Ron Sellemi	IT-Enterprise Architecture
Andrea Haas	IT-GridTech
Josh Mauzey	T&D Technology Innovation

TABLE 1- PROJECT STAKEHOLDERS

2.6 References

The following documents will be input to the project.

- Project charter
- Project SharePoint site
- EPIC III CPUC application
- EPIC III CPUC Research Administration Plan (RAP) application
- GMS Presentation
- GMS & DERMS Use Cases
- Rule 21
- SAE J3105

- GT-18-0017 Use Case Document

3 Description of the current system

There are no fully integrated Service Centers as proposed that exist. The current deployment of the proposed components are standalone or electrically connected (e.g., PV + Storage, PV + EV charging), and are not integrated from a communications perspective. The existing processes for deploying aggregated high-powered charging systems are not well established. Control systems that manage high powered charging, storage, PV and other loads together do not exist. Resiliency use cases for charging have not been demonstrated.

4 Changes to current system and rationale

Higher powered charging will become necessary to both drive EV adoption and to support the charging of larger batteries as found in fleet heavy-duty vehicles; or for certain niche charging applications requiring frequent and quick charges such as on-route bus charging. As higher-powered charging facilities become more critical, SCE will need to:

- Create standard requirements and processes for connecting these high- powered systems onto SCE's grid and allowing their use for customer resiliency, while maintaining safe, reliable, and affordable energy delivery for these and other customers on the same circuit
- Demonstrate the integration of these systems into SCE's GMS and show how they should be used to support customer and distribution system operator (DSO) type services

5 Concept for the proposed system

5.1 Description of the proposed system

The project will deploy and test components of the Service Center system in the lab prior to field demonstrations at the El Monte Transit Center. For the demonstration, the project will provide an energy storage system (ESS), the MCS, the Microgrid Point of Interconnection (MGPOI) equipment, a building managements system (BMS), and controllable loads managed by the BMS. The customer and Charge Ready Transport project is providing the EVs, chargers and there may also be photovoltaics (PV) with smart inverter(s) installed by the customer. The charging systems will be Direct Current (DC) chargers with rated output power of 180 and 450 kilowatts (kW) and might have power sharing capabilities among the ports (e.., three ports per 180 kW charger).

The MCS will interface with the site DERs (except the EV chargers) and the GMS. The GMS in turn will be integrated with the cloud-based charging controller managing the chargers. The MCS will be able to manage chargers through the GMS to meet use case objectives. The MCS will be able to optimize DERs independently in order to reduce site demand or replace (e.g., shift) grid capacity used for charging and other site loads during high cost time periods while still ensuring vehicles have sufficient energy to complete their jobs. The MCS will also use the aggregated resources to support grid services such as voltage support or capacity deferral. Additionally, the MCS will manage the DERs to support planned and unplanned islanding use cases.

5.1.1 Major system components and interconnections among them

The following table shows the components being implemented for the demonstration.

Application/Component	Description
Microgrid Control System	For the demonstration, the facility energy management system will be SCE provided/managed, and interface with SCE's GMS and SCE and Customer DERs (PV, ESS, Curtailable loads). From the SCE operator's viewpoint, the GMS aggregates the

	site DERs (e.g., no single DER will be managed by SCE for the project[3]). The MCS will support capabilities to ensure charging occurs as required for fleet applications while 1- Systems are operated to reduce customer energy/demand costs to the extent possible; 2- DSO use cases are implemented, and; 3- the customer charging systems are islanded and able to charge EVs using the ESS when a grid outage occurs
ESS	The energy storage system will be an SCE owned and operated system during the project. It will be deployed and modeled as a behind the meter (BTM) customer owned and managed system. The battery will supply power to both the customer loads and the grid. It will support both grid following and grid forming.
PV	Solar generation may be installed by the customer and will be used to charge the battery, offset loads, and discharge to the grid depending on the programmed mode. As a Rule 21 connected system, the PV inverter will also support smart inverter Phase 1, 2 and 3 capabilities[5] based on the FEMS and GMS/DERMs use cases.
Controllable Loads	Controllable loads include the EV chargers and buses, and could consist of heating, ventilation, and air conditioning (HVAC) systems, water heating, lighting or other. Will interface with FEMS to support customer and grid use cases
EV Sub-meters	Revenue grade SCE meters will be deployed on chargers to evaluate their use for future Charge Ready and other SCE EV applications. These will communicate to the FEMS which will store the data for retrieval and analysis
GMS	SCE's Grid Management Systems are currently in the design phase. The GMS will manage DER's such as the Service Center FEMS among other things. The interface between the FEMS and DERMS will be DNP3
Communications Equipment (RTUs, radios, routers, firewalls, etc.)	Supports communications and security for SCE and customer communications, per Cybersecurity/Information Technology (IT) requirements. An RTU will most likely be required for DNP3 communications between the FEMS and the SCE SCADA systems
MGPOI	Synchronized Circuit Breakers (CBs), Switches and other infrastructure necessary to island one or more of the demonstration system's circuits in order to demonstrate resiliency. This would most likely be provided by the ESS vendor

TABLE 2- COMPONENTS AND INTERACTIONS

[3] The ESIP ESS may be managed by SCE apart from the project to meet other objectives
[5] ibid

5.2 Interfaces to external systems or procedures

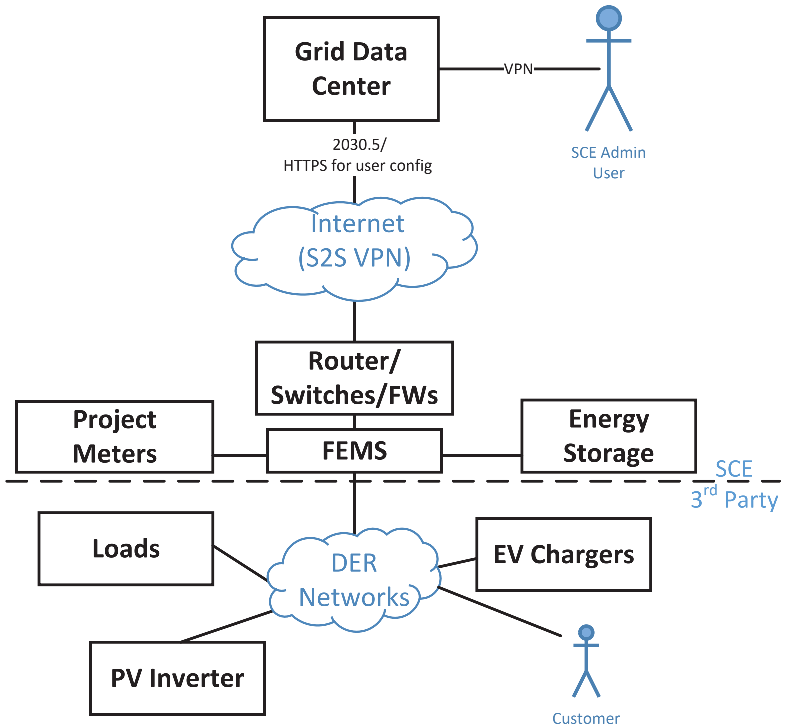


FIGURE 2- PROJECT COMMUNICATIONS

The above high level communications diagram depicts the project communications which is subject to change as the project interacts with SCE's IT and Cybersecurity organizations, the project and project customer, procures DERs, and the ownership/management models are determined. The project FEMS will support the customer application protocols (e.g., IEEE 2030.5, proprietary APIs, etc.). The FEMS applications will need to integrate with the existing customer local area network (LAN) if present (or other type of network), or a LAN will need to be set up to communicate to DERs.

The one expected external communications interface is between SCE's Controls Systems and the FEMS. This interfaces comprises two types of communications: 1-Between the DERMS (in the SCE Control System Network) and FEMS, and; 2-between the project User and the FEMS. The DERMS will send control and pricing signals and receive status and monitoring information using IEEE 2030.5 over a site to site virtual private network (S2S VPN). The project User to FEMS communications will be required for configuration, patching and similar services. Users would most likely be required to access SCE's production network from the Admin network (e.g., via Citrix) and then access the site network via a similar process over the broadband transport. The Communications would be secured using SCE's Public Key Infrastructure (PKI). Firewalls, switches, Routers, etc. will be present depending on the communications used and SCE requirements.

5.3 Assumption and constraints

Assumptions:

- Customer site participates and contributes their own planned elements such as vehicles, chargers, storage, PV
- Charge Ready infrastructure installed to support initial vehicles

- Required technologies and standards are available
- FEMS is SCE owned
- ESIP ESS is available to be deployed for the project, or this project acquires SCE owned ESS
- The project will be approved to island the demonstration system(s)

Constraints:

- Existing device support for local management system s communications and control standards
- Cybersecurity protocols and approvals
- Availability of appropriate versions of charging and safety standards needed to demonstrate
- Availability of GMS (ADMS and/or DERMS) to support communication and control

5.4 System boundaries

From a communications perspective, several networks will be utilized. These include:

- SCE's internal networks including the lab, QAS, PROD and Admin networks
    - Lab network will be used for acceptance/functional testing
    - QAS network will be used for integration testing
    - PROD network will be used for field demonstration
    - Admin network will be used by system users to access PROD networks
- The internet (data will be tunneled using a VPN)
- Customer networks where project systems are located

5.5 System modes of operation

While ensuring the primary objective that charging occurs as desired, the FEMS will most likely support various modes of operation (note that the Island Condition used to demonstrate resiliency is not a mode of operation of the FEMS). While the details will be determined during the technical design phase of the project, probable modes include:

- Grid Support Mode: The FEMS will interface with SCE's GMS systems and manage the available DERs as a single resource or the individual generation resources in order to support distribution reliability (e.g., voltage support, demand response, etc.). This could be enabled when receiving program signal and opting in. Depending on the program and needs, it could be day ahead, hour ahead or fast support.
- Economic Mode: Using pricing information (e.g., demand charge rates, dynamic or time-of-use (TOU) pricing, locational marginal prices, etc.) the FEMS attempts to optimize individual resources to achieve the lowest operating costs.
- Default Mode: The FEMS does not manage resources or manages resources using preferred or 'default' settings when not in another mode. Note that the ESS smart inverter, per Rule 21 Phase 1 autonomous requirements, provides power quality support through volt/Var curves

6 High level Business use cases

The following use cases specifies four management capabilities for the FEMS system. The reason for enabling these capabilities (e.g., the tariff or program) may be varied. From the grid standpoint, the FEMS aggregates the site DERs to meet the objectives of the program while ensuring that the EV charging requirements are met. To accomplish this, the FEMS will manage the controllable loads and ESS as the customer's fast charging is not appropriate for curtailment. Note that IEEE 2030.5 is an event based protocol and control signals include a start time and duration. If programs allow for unknown event durations, the IEEE 2030.5 duration may be sent with an excess (overly long) duration and would then have to be cancelled via IEEE 2030.5 at the conclusion of the issue.

6.1 Use Case #1- Demand Charge Mitigation

Use case name	Demand Charge Mitigation / Load Leveling
Description	Use a load-leveling strategy to reduce a customer's peak demand or energy at their utility meter, thereby reducing demand charges and overall energy costs.
Use case ID	UC1
Actors	• DERMS • FEMS • ESS • Fast Chargers • Customers • Controllable loads
Pre-condition	• The FEMS has been validated and tested (e.g., cybersecurity, lab testing, production integration, optimization schemes, etc.) • The systems have been interconnected via Rule 21 • The FEMS is registered with the DERMS and has SCE's SSL Cert • SCE orgs, customers, vendors and other necessary stakeholders have agreed to and documented project notification processes, roles and responsibilities • FEMS is continuously monitoring the local grid status, DER status (e.g., SOC, connection state, etc.) logging, and sending aggregate measurements to DERMs • FEMS programmed with or gets via IEEE 2030.5 DER nameplate ratings and capabilities • Customer/project operator programs FEMS with necessary demand and time constraints
Flow of events	1. Customer or project user places FEMS into a demand limiting mode 2. User plugs in vehicle(s) 3. System evaluates demand from vehicle(s) and other loads connected to it and ESS SOC 4. System compares current demand to target demand and determines if charging/discharging of the ESS (energy storage system) and curtailment of loads is required to meet target demand 5. System begins charging EVs 6. System periodically reevaluates and adjusts draw from ESS/manages loads 7. Vehicles complete charging 8. FEMS reverts (or is manually reverted by user) to default mode
Alternative Paths	• Fleet operator/FEMS initiates and implements strategies for ensuring specific charger/ESS systems charge at full power vs others based on specific desired EV state of charge while staying within programmed demand constraints
Post condition	FEMS reverts ESS, loads and EV Chargers default to normal operating condition

6.2 Use case #2- Rate-based Charging Management

Use case name	FEMS manages ESS to limit charging demand based on rates
Description	In order to reduce energy use and the customer utility bill, the FEMS limits power supplied by the grid by supplementing/replacing charging with ESS power and curtailing loads at certain high cost time periods as defined by TOU, Real Time Pricing (RTP), or other rate-based tariffs/programs.
Use case ID	UC2
Actors	• DERMS • FEMS • ESS • Fast Chargers • Customers • Controllable Loads
Pre-condition	• The FEMS has been validated and tested (e.g., cybersecurity, lab testing, production integration, optimization schemes, etc.) • The FEMS is registered with the DERMS and has SCE's TLS Cert • SCE orgs, customers, vendors and other necessary stakeholders have agreed to and documented project notification processes, roles and responsibilities • FEMS is continuously monitoring the local grid status, DER status (e.g., SOC, connection state, etc.), logging, and sending aggregate measurements to DERMs • FEMS programmed with or gets via IEEE 2030.5 DER nameplate ratings and capabilities • The systems have been interconnected via Rule 21 • Site host/ customer enrolls in rate program • FEMS System programmed with corresponding rate info (e.g., energy costs, time periods, seasonal changes or other parameters)
Flow of events	1. Customer or project user places FEMS into a specific rate mode 2. User connects vehicles to charger 3. Charging commences 4. FEMS uses ESS to supplement/replace demand from grid and curtails loads during certain time periods while continuing to charge vehicles 5. System periodically reevaluates and adjusts draw from ESS 6. Lower-rate time period comes into effect 7. FEMS reverts (or is manually reverted by user) to default mode
Alternative Paths	• Dynamic pricing (near real time) signals sent to the FEMS which manages system to limit costs (could be ignored) • Fleet operator/FEMS initiates and implements strategies for ensuring specific charger/ESS systems charge at full power vs others based on specific desired EV state of charge while reducing energy use as much as possible
Post condition	FEMS reverts ESS and EV Chargers default to normal operating condition

6.3 Use case #3- Demand Response

This use case utilizes ESS and controllable loads to support present or future grid-related demand response program. Managed charging and discharging (from ESS) may be used to balance circuit loading for constraint management, support renewable penetration, etc.

Use case name	FEMS manages charging based on grid operator demand response (DR) event
Description	When conditions on the grid warrant, a DR program is activated (e.g., Critical Peak Pricing (CPP)) and an event signal is sent to the FEMS or customer is notified. The user of the system chooses to participate and the FEMS is automatically or manually placed into a grid support mode based on the parameters of the event (e.g., charge/discharge, schedule, kW or % dispatch, etc.) or pre-programmed operation. The FEMS will then reduce energy use during the event based on charging needs and contractual obligations.
Use case ID	UC3
Actors	• DERMS • FEMS • ESS • Fast Chargers • Customers • Controllable Loads
Pre-condition	• The FEMS has been validated and tested (e.g., cybersecurity, lab testing, production integration, optimization schemes, etc.) • The FEMS is registered with the DERMS and has SCE's SSL Cert • SCE orgs, customers, vendors and other necessary stakeholders have agreed to and documented project notification processes, roles and responsibilities • FEMS is continuously monitoring the local grid status, DER status (e.g., SOC, connection state, etc.), logging, and sending aggregate measurements to DERMs • The systems have been interconnected via Rule 21 • FEMS programmed with or gets via IEEE 2030.5 DER nameplate ratings and capabilities • Site host/ customer enrolls in a capacity-based grid services program • FEMS System programmed with DR event parameters if contractual-based event
Flow of events	1. Grid operators note/project a capacity constraint on the grid 2. Grid operators, via GMS, send out DR event (parameters, start time, duration) via IEEE 2030.5 3. FEMS notifies customer of event 4. Customer opts in o FEMS notifies DERMS of opt in via IEEE 2030.5 if required 5. FEMS ensures ESS SOC at/near 100% for the start of event o For real time events, FEMS will use existing ESS SOC 6. EV drivers connect vehicles to chargers 7. FEMS manages loads and ESS to supplement/replace charging demand based on event parameters 8. FEMS reverts system to default state at the conclusion of the event

Alternative Paths	• Over-generation event- FEMS ensures low ESS SOC prior to event start and then charges ESS during event and adds load (e.g., heats water, cools building, etc.) • Events may be performance based (*reduce as much as possible and get compensated accordingly*) or contractual based (*reduce by this amount of kW or % of total system capacity)* • Events may be real time (fast), hour ahead, day ahead, etc. depending on the enrolled program • Discharge- FEMS dispatches ESS to discharge to the grid (may be used instead of or in parallel with reducing loads) • Fleet operator/FEMS initiates and implements strategies for ensuring specific charger/ESS systems charge at full power vs others based on specific desired EV state of charge while complying with DR event • Event notification is sent via text, email or call to customer. Customer programs FEMS with event parameters or enables event mode on FEMS if parameters are set by program (time, duration, operation). o May require an opt-in via IEEE 2030.5 or from customer • If the program allows and event duration is unknown, DERMS schedules IEEE 2030.5 event for very (overly) long duration. DERMS *Cancels* event via IEEE 2030.5 when conditions are rectified • Customer opts out and does not participate
Post condition	Utility M&V is conducted. FEMS reverts ESS and EV Chargers default to normal operating condition

6.4 Use case #4- Voltage Support

Use case name	FEMS supports over/under voltage conditions using ESS
Description	When significant abnormal grid voltage conditions occur (e.g., due to PV generation on feeders), the grid operator may call on the customer to support using the FEMS/ESS by absorbing or supplying reactive power.
Use case ID	UC4
Actors	• DERMS • FEMS • ESS • Fast Chargers • Customers
Pre-condition	• The FEMS has been validated and tested (e.g., cybersecurity, lab testing, production integration, optimization schemes, etc.) • The FEMS is registered with the DERMS and has SCE's SSL Cert • SCE orgs, customers, vendors and other necessary stakeholders have agreed to and documented project notification processes, roles and responsibilities • FEMS is continuously monitoring the local grid status, DER status (e.g., SOC, connection state, etc.), logging, and sending aggregate measurements to DERMs • Site host/ customer enrolls in a voltage support grid services program • FEMS programmed with or gets via IEEE 2030.5 DER nameplate ratings • FEMS System programmed with voltage event parameters if contractual-based event

Flow of events	1. Grid operators note/project a voltage issue on the grid
	2. Grid operators, via GMS, send out reactive power event (parameters/schedule) via IEEE 2030.5
	    ○ FEMS notifies customer if event signal is to FEMS
	3. Customer opts in
	    ○ FEMS notifies DERMS of opt in via IEEE 2030.5 if required
	4. FEMS manages ESS to supply or absorb reactive power
	5. Voltage constraint condition is rectified
	6. The systems have been interconnected via Rule 21
	7. Grid operator
	8. FEMS reverts system to default state at the conclusion of the event

Alternative Paths	• In addition to reactive power management, real power management may be used to support voltage constraints (add or reduce load) • Event notification is sent via text, email or call to customer. Customer programs FEMS with event parameters or enables event mode on FEMS if parameters are set by program (time, duration, operation). ○ May require an opt-in via IEEE 2030.5 or from customer • If the program allows and event duration is unknown, DERMS schedules IEEE 2030.5 event for very (overly) long duration. DERMS *Cancels* event via IEEE 2030.5 when conditions are rectified • Customer opts out and does not participate
Post condition	Utility M&V is conducted. FEMS reverts ESS and EV Chargers default to normal operating condition

6.5 Use case #5- Sub-Metering

SCE's Transportation Electrification group is exploring the use of advanced metering to support EV sub-metering needs. This use case explores using SCE sub-meters that can send EV charger data to the FEMS. This is a technical exploration of using SCE vs 3rd party integrated meters and no SCE billing or use of SCE systems is required.

Use case name	SCE Charger sub-meters send metering data to FEMS
Description	SCE EV sub-meter is sends EV charging data to FEMS to determine applicability for production use. SCE metering data is compared with the accuracy of integrated charger provided data.
Use case ID	UC5
Actors	• FEMS • Fast Chargers
Pre-condition	• The FEMS has been validated and tested (e.g., cybersecurity, lab testing, production integration, optimization schemes, etc.) • SCE orgs, customers, vendors and other necessary stakeholders have agreed to and documented project notification processes, roles and responsibilities • SCE meters have been installed on AC side of chargers • SCE meters are able to communicate to FEMS over an TCP/IP connection (protocol TBD) • The systems have been interconnected via Rule 21 • EV Charger metering data is provided to FEMS • Project personnel are able to access data on FEMS via SCE transport
Flow of events	1. EVs connected to DC chargers and start charging 2. SCE EV meters send charger metering data sent to FEMS periodically (TBD based on system requirements) 3. Charger integrated (3rd party) charger metering data sent to FEMS periodically (TBD based on system requirements) 4. Project personnel collects data from FEMS per charging session
Alternative Paths	• 3rd party and SCE metering data is sent to GMS for evaluation
Post condition	Utility analysis is conducted

6.6 Use case #6- Resiliency

The resiliency use case is meant to be conducted without the use of the FEMS.

Use case name	Charging continues from ESS during Grid Outage
Description	When a planned (e.g., PSPS) or unplanned outage occurs, the ESS will continue to support EV charging needs for as long as possible
Use case ID	UC5
Actors	• ESS • Fast Chargers • Customers • MGPOI Equipment
Pre-condition	• The FEMS has been validated and tested (e.g., cybersecurity, lab testing, production integration, optimization schemes, etc.) • The FEMS is registered with the DERMS and has SCE's SSL Cert • SCE orgs, customers, vendors and other necessary stakeholders have agreed to and documented project notification processes, roles and responsibilities • FEMS is continuously monitoring the local grid status, DER status (e.g., SOC, connection state, etc.), logging, and sending aggregate measurements to DERMs • The systems have been interconnected via Rule 21 and appropriate approvals and technologies are in place to support islanding
Flow of events	1. A planned or unplanned grid outage occurs

	2. The ESS MGPOI senses loss of voltage and opens switch(es) connecting project circuit(s) to grid 3. Project ESS enters grid forming mode 4. Charging from ESS(s) continues/commences 5. When ESS(s) reach lowest-allowed SOC, ESS stops discharging ○ If PV available, ESS may be charged form PV 6. Grid is restored 7. ESS MGPOI equipment senses restoration of grid 8. Switch(es) is closed and the circuit(s) is reconnected to the grid 9. ESS re-synchronizes and reconnects 10. After timer has elapsed the system will re-enter grid support mode 11. Grid charging/discharging commences
Alternative Paths	• A limited subset of the project chargers may be used to demonstrate resiliency • The FEMS may manage the DERs during the island condition (will need to be powered)
Post condition	Grid is stable and ESS is used for other use cases

7 Business requirements

The following requirements relate to the project scope, objectives and deliverables for this project. Lower level requirements are provided where known.

Requirement ID	Business requirement
BR1	The project shall evaluate and develop recommendations for the ability of similar facilities and technologies to participate in CAISO market programs
BR2	The project shall support regular sponsor/stakeholder updates on a regular or ad-hoc basis in their preferred formats and schedules. The updates shall include intermediate learnings if any
BR3	The project shall validate all requirements in a lab setting prior to field deployment and demonstrations
BR4	The project shall support knowledge transfer activities (e.g., training, recommendations, presentations, etc.) for users, sponsors and stakeholders during and at the conclusion of the project
BR5	The project shall coordinate with or leverage learnings from other SCE or external projects to the extent possible
BR6	If issues that affect the objectives or deliverables are found, the project shall confer with sponsors/stakeholders about issues, remediation efforts or de-scoping needs
BR7	The project FEMS shall integrate with and be able to optimize, control and schedule any or all DERs used for the demonstration
BR8	The FEMS shall provide a local interface for SCE project operators and Customers to access remotely in order to: • Configure modes and settings • Access and download historical logs (measurements, alarms, status, analyses, etc.) • Configure asset types and communications • Access alarms • Troubleshoot and patch • View Real time measurements and status
BR9	The FEMS shall support, at minimum, a DNP3-2012 and IEEE 2030.5 interface to SCE

BR10	The FEMS shall support SCE required DNP3 Point List and IEEE 2030.5 Function Sets (TBD)
BR11	The FEMS shall provide, at minimum, DNP3-2012, IEEE 2030.5 and Modbus protocol support to interface with ESS and DERs as determined by customer and SCE
BR12	The FEMS shall be able to account (e.g., integrate, optimize, control, etc.) for all inverter and non-inverter based generation if present
BR13	The FEMS shall be able to be configured to support the addition of new loads and distributed generation
BR14	The FEMS shall be able to prioritize the power generation of renewable energy over non-renewable energy resources
BR15	The project system shall comply with applicable state, local and federal regulations in regards to safety standards and cybersecurity
BR16	The project system shall comply with SCE's cybersecurity standards
BR17	The project leadership team (project manager and the technical lead) shall develop and maintain up-to-date operating and maintenance procedures, agreements/contracts and policies that include roles and responsibilities for SCE organizations, vendors, customers and project personnel that include the testing, demonstration and post-demonstration period
BR18	The FEMS shall be able to store logs (measurement, alarms, modes, etc.) locally for a TBD duration
BR19	The FEMS shall support zero or near zero resource/asset provisioning (e.g., plug n play)
BR20	The FEMS shall support real time and post analysis of the event and DER operations
BR21	The FEMS shall be able to support a variety of objectives and programs (e.g., Grid Services, Economic Optimization, ISO/DSO Markets, etc.)
BR22	The FEMS and related systems shall include and validate in the lab customer specific use cases and requirements
BR23	The FEMS shall be able to optimize and control individual resources and expose to SCE as a single aggregate resource
BR24	The FEMS shall provide the customer event and opt in/out notification and response capabilities
BR25	The FEMS shall be able to measure project DERs (in aggregate) real power, reactive power, frequency and voltage per phase
BR26	The FEMS shall provide instantaneous and average of measurements to DERMs at a TBD interval along with timestamps of readings
BR27	During Planning and Execution phases, the project team shall coordinate appropriate SCE Organizations (IT/Cybersecurity, Power Systems Control, Customer Programs, Interconnection, TE, GIPT etc.)
BR28	The project team shall ensure customer and vendor requirements are accounted for in system design specifications

BR30	Project personnel shall support analysis and recommendations for converting gas powered water and space heating to electrified-based loads
BR31	GMS and FEMS shall support IEEE 2030.5 Pricing function sets and others TBD in coordination with stakeholders
BR32	The FEMS shall be able to transition between Modes of Operation automatically (as opposed to manually)
BR33	During execution, the project team shall work with the appropriate internal (e.g., interconnection) and external organizations (e.g., vendors, jurisdictional authorities, etc.) in order to ensure successful resiliency demonstrations

(U 338-E)

2025 General Rate Case

A. 23-05-

Workpapers

SCE-02 Grid Activities
Volume 6 - Grid Modernization, Grid Technology, and Energy Storage
Energy Storage

May 2023

2025 GRC Summary

(Constant 2022 $000)

Beginning of Workpapers for:

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Energy Storage
Activity:	Energy Storage
Witness:	Jeff Shiles

Cost Type	Recorded/Adj. 2022	Forecast 2025
Labor	389	1,285
Non-Labor	248	1,010
Other	63	13,626
Total	**900**	**15,f21**

Due to rounding, totals may not tie to individual items.

Description of Activity:

Grid Scale Storage encompasses (1) the Distribution Energy Storage Integration activity (i.e., the DESI pilot program and ongoing post-pilot support for DESI systems that are operational), (2) the Long Duration Energy Storage activity (i.e., the LDES pilots), and (3) Generation (i.e., support for the Mira Loma energy storage systems and the RUOES procurement).

Forecast Methods - Summary o7Results o7Methods Studied

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Energy Storage
Activity:	Energy Storage
Witness:	Jeff Shiles

Cost Type	Recorded/Adj.				
	2018	201f	2020	2021	2022
Labor	215	316	288	257	389
Non-Labor	1,123	1,547	1,232	747	248
Other	3	58	74	68	63
Total	**1,3L0**	**1,f21**	**1,5fL**	**1,092**	**900**

Cost Type	Results o7Yinear Trending					
	3 : ears42020 - 2022		L : ears4201f - 2022		5 : ears42018 - 2022	
	$	r2*	$	r2*	$	r2*
Labor	513	0.54	396	0.18	437	0.49
Non-Labor	(1,225)	1.00	(1,029)	0.99	(296)	0.65
Other	47	1.00	70	0.04	119	0.52
Total	**(666)**	**N/A**	**(562)**	**N/A**	**260**	**N/A**

Cost Type	Results o7Averaging							
	2 : ears4		3 : ears4		L : ears4		5 : ears4	
	2021 - 2022	sd**	2020 - 2022	sd**	201f - 2022	sd**	2018 - 2022	sd**
Labor	323	66	311	56	312	49	293	59
Non-Labor	498	249	742	402	944	492	980	446
Other	65	3	68	4	66	6	53	26
Total	**886**	**N/A**	**1,122**	**N/A**	**1,322**	**N/A**	**1,325**	**N/A**

Cost Type	Yast Recorded : ear		
	2023	202L	2025
Labor	389	389	389
Non-Labor	248	248	248
Other	63	63	63
Total	**900**	**900**	**900**

Cost Type	Itemized Forecast		
	2023	202L	2025
Labor	0	0	0
Non-Labor	427	518	1,010
Other	53	53	13,626
Total	**L80**	**591**	**1L,636**

** r2 = R Squared (Based on recorded years data)*

*** sd = standard deviation (Based on recorded years data)*

2025 GRC Selected Forecast Method

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Energy Storage
Activity:	Energy Storage
Witness:	Jeff Shiles

Cost Type	Recorded/Adj.					Forecast			Selected Forecast		T: Forecast Incr/(Decr) 7rom 2022
	2018	201f	2020	2021	2022	2023	202L	2025	Method	($000)	
Labor	215	316	288	257	389	1,167	1,178	1,285	LRY + Adj	1,285	896
Non-Labor	1,123	1,547	1,232	747	248	427	518	1,010	Itemized	1,010	762
Other	3	58	74	68	63	53	53	13,626	Itemized	13,626	13,563
Total	**1,3L0**	**1,f21**	**1,5fL**	**1,092**	**900**	**1,6L9**	**1,9Lf**	**15,f21**		**15,f21**	**15,221**

Due to rounding, totals may not tie to individual items.

Analysis of Forecasting Methods

Analysis of Last Recorded Year:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have been relatively stable for three or more years, the last recorded year is an appropriate base estimate

Itemized Forecast:
Itemized Forecast Method

Other Forecast Methods not Selected

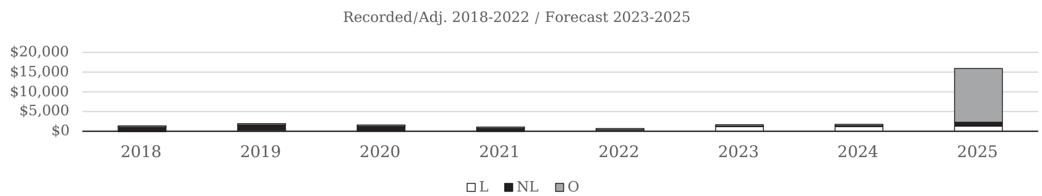
Linear Trending:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have shown a trend in a certain direction for three or more years, the last recorded year is an appropriate base estimate. Recorded expenses for this activity have not shown a strong trend, so the linear trending method is not appropriate to forecast the 2025 Test Year.

Averaging:
In D.89-12-057, and subsequently in D.04-07-022, the CPUC stated that if recorded expenses have significant fluctuations from year to year, or expenses are influenced by external forces beyond the utility’s control, an average of recorded-expenses is appropriate. Recorded expenses in this a activity have not shown significant fluctuations, therefore, the averaging methodology was not used as the basis for estimating the 2025 Test Year.

2025 GRC : ear Over : ear Variance

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Energy Storage
Activity:	Energy Storage
Witness:	Jeff Shiles



Cost Type		Recorded/Adj.					Forecast		
		2018	201f	2020	2021	2022	2023	202L	2025
Recorded / Forecast	Labor	215	316	288	257	389	1,167	1,178	1,285
	Non-Labor	1,123	1,547	1,232	747	248	427	518	1,010
	Other	3	58	74	68	63	53	53	13,626
	Total	**1,3L0**	**1,f 21**	**1,5f L**	**1,092**	**900**	**1,6L9**	**1,9Lf**	**15,f 21**
Yabor	Prior Year Total		215	316	288	257	389	1,167	1,178
	Change		102	(28)	(31)	132	779	11	107
	Total		**316**	**288**	**259**	**38f**	**1,169**	**1,198**	**1,285**
Non-Yabor	Prior Year Total		1,123	1,547	1,232	747	248	427	518
	Change		424	(315)	(485)	(499)	178	92	492
	Total		**1,5L9**	**1,232**	**9L9**	**2L8**	**L29**	**518**	**1,010**
Other	Prior Year Total		3	58	74	68	63	53	53
	Change		55	16	(6)	(5)	(10)	0	13,573
	Total		**58**	**9L**	**68**	**63**	**53**	**53**	**13,626**
Total Change	Prior Year Total		1,340	1,921	1,594	1,072	700	1,647	1,749
	Change		581	(327)	(522)	(372)	947	102	14,172
	Total		**1,f 21**	**1,5f L**	**1,092**	**900**	**1,6L9**	**1,9Lf**	**15,f 21**

Due to rounding, totals may not tie to individual items.

2025 GRC Forecast Commentary

(Constant 2022 $000)

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Planning Element:	Energy Storage
Activity:	Energy Storage
Witness:	Jeff Shiles

Summary of Changes: See Testimony

Cost Type		Recorded/Adj.					Forecast		
		2018	201f	2020	2021	2022	2023	202L	2025
Recorded / Forecast	Labor	215	316	288	257	389	1,167	1,178	1,285
	Non-Labor	1,123	1,547	1,232	747	248	427	518	1,010
	Other	3	58	74	68	63	53	53	13,626
	Total	**1,3L0**	**1,f 21**	**1,5f L**	**1,092**	**900**	**1,6L9**	**1,9Lf**	**15,f 21**

Due to rounding, totals may not tie to individual items.

Recorded (2018-2022)

See Testimony

Forecast (2023-2025)

See Testimony

Workpaper Title:

Grid Scale Storage (Energy Storage) - DESI Work Activities

DESI Pilot Program O&M Workpaper

2025 General Rate Case - O&M Workpaper

Project Element: Project Cost and Schedule

Total Forecast (Constant)						
		2023		**2024**		**2025**
Labor	$	1,167,393	$	1,177,972	$	1,284,614
Non-Labor	$	388,757	$	388,903	$	394,375
Total Forecast	**$**	**1,556,150**	**$**	**1,566,875**	**$**	**1,678,989**

Total Forecast (Nominal)						
		2023		**2024**		**2025**
Labor[1]	$	1,228,681	$	1,283,209	$	1,441,359
Non-Labor[2]	$	396,532	$	404,615	$	418,514
Total Forecast	**$**	**1,625,214**	**$**	**1,687,824**	**$**	**1,859,873**

Non-Labor Categories (Nominal)						
		2023		**2024**		**2025**
General Maintenance[3]	$	15,000	$	25,000	$	30,000
Vendor System Maintenance[4]	$	106,294	$	189,846	$	233,076
WDAT Fees[5]	$	18,238	$	32,769	$	33,438
Incidentials[6]	$	75,000	$	75,000	$	80,000
Technology Transfer[7]	$	170,000	$	70,000	$	30,000
Other Direct Costs (ODC)[8]	$	12,000	$	12,000	$	12,000
Total	**$**	**396,532**	**$**	**404,615**	**$**	**418,514**

Notes

[1]SCE labor for program management and closeout, technology transfer (training field personnel on how to operate and maintain the systems including operating bulletins, standards, and specifications via Organizational Change Management (OCM) and deployment readiness), engineering support, system monitoring and trouble shooting, and completing/closing the Measurement and Verification (M&V) phase. Starting in 2025, SCE labor begins performing routine maintenance and fixes. Includes adjustments for the Employee Compensation Program.

[2]Includes all other cost categories outside of labor.

[3]HVAC/filters and fire inspections, fire certifications (e.g., fire pump at Mercury 1 and Mercury 2 starting in 2024), CAISO meter certifications and verifications (for DESI 2, Mercury 1, and Mercury 2), and property maintenance (e.g., weed abatement, pest control).

[4]Contracted costs for maintenance, extended warranties, and availability guarantees to be performed by the system integrator for Mercury 1, Mercury 2, Gemini 1, and Gemini 2. Includes reserves for future maintenance work not yet negotiated with the system integrator for DESI 1, DESI 2, and Mercury 4 in 2024 and 2025. Doesn't include Apollo 1, Apollo 2, and Gemini 3 as those costs are forecasted to start outside this GRC period.

[5]DESI 2, Mercury 1, Mercury 2; final fee schedule for interconnection equipment hasn't been established for Mercury 1 and Mercury 2 and an estimate was used.

[6]Break fixes, software and hardware upgrades and refreshes, and reserves for costs not yet established with service providers and vendors. Includes reserves for pre-capital activities on Apollo 1, Apollo 2, and Gemini 3. Includes reserves for DESI 1, DESI 2, Mercury 4 maintenance in 2023 (delayed services with system integrator resulting from acquisition).

[7]Estimates for training development and materials, drawing updates, and equipment upgrades. Costs are expected to decrease as equipment is adopted by SCE skilled labor through OCM.

[8]Assumes $1k a month for work order allocations and other settlements.

Workpaper Title:

Grid Scale Storage (Energy Storage) - Generation Work Activities

SCE-02, Vol. 06
Workpaper Title: Grid Scale Storage (Energy Storage) - Generation Work Activities
Witness: Jeff Shiles

RUOES Site Faceplate Rating

RUOES Site	MW	%
Anode/Springville	225	42%
Cathode/Hinson	200	37%
Separator/Etiwanda	112.5	21%
Total	**537.5**	**100%**

Other

	2025 Fcst		2026 Fcst		2027 Fcst		2028 Fcst	
RUOES	**Nominal**	**Constant**	**Nominal**	**Constant**	**Nominal**	**Constant**	**Nominal**	**Constant**
Third Party Fixed Price Maintenance	12,307,811	12,307,811	12,307,811	12,307,811	12,307,811	12,307,811	14,842,799	14,842,799
Anode (Springville)	4,823,153	4,823,153	4,823,153	4,823,153	4,823,153	4,823,153	5,587,398	5,587,398
Cathode (Hinson)	4,626,761	4,626,761	4,626,761	4,626,761	4,626,761	4,626,761	5,779,540	5,779,540
Separator (Etiwanda)	2,857,897	2,857,897	2,857,897	2,857,897	2,857,897	2,857,897	3,475,861	3,475,861
Interconnection Fees	618,867	618,867	618,867	618,867	618,867	618,867	618,867	618,867
Anode (Springville)	259,061	259,061	259,061	259,061	259,061	259,061	259,061	259,061
Cathode (Hinson)	230,276	230,276	230,276	230,276	230,276	230,276	230,276	230,276
Separator (Etiwanda)	129,530	129,530	129,530	129,530	129,530	129,530	129,530	129,530
Total	**12,926,678**	**12,926,678**	**12,926,678**	**12,926,678**	**12,926,678**	**12,926,678**	**15,461,666**	**15,461,666**

	2025 TY Fcst
	Constant
Normalization	13,560,425
Anode (Springville)	5,273,275
Cathode (Hinson)	5,145,232
Separator (Etiwanda)	3,141,918

	2018 Rec	2019 Rec	2020 Rec	2021 Rec	2022 Rec
Mira Loma Peaker - Tesla CSA	**Constant**	**Constant**	**Constant**	**Constant**	**Constant**
Mira Loma Peaker - Tesla CSA	-	57,559	73,766	68,036	62,918

	2025 TY Fcst
	Constant
4 Year Average (2019-2022)	65,570

	2025 TY Fcst
	Constant
Total Generation Energy Storage - Other	13,625,995

Non Labor

SCE-02, Vol. 06
Workpaper Title: Grid Scale Storage (Energy Storage) - Generation Work Activities
Witness: Jeff Shiles

	1.0612		1.0824		1.1041		1.1262	
	2025 Fcst		**2026 Fcst**		**2027 Fcst**		**2028 Fcst**	
RUOES	**Nominal**	**Constant**	**Nominal**	**Constant**	**Nominal**	**Constant**	**Nominal**	**Constant**
RUOES Non Labor (generator modeling, site maintenance, mileage)	75,299	70,956	76,421	70,601	77,674	70,352	78,977	70,130
Anode (Springville)	31,520	29,702	31,990	29,554	32,515	29,450	33,060	29,357
Cathode (Hinson)	28,018	26,402	28,436	26,270	28,902	26,177	29,387	26,095
Separator (Etiwanda)	15,760	14,851	15,995	14,777	16,257	14,725	16,530	14,678
Total	**75,299**	**70,956**	**76,421**	**70,601**	**77,674**	**70,352**	**78,977**	**70,130**

	2025 TY Fcst
	Constant
Average	70,510
Anode (Springville)	29,516
Cathode (Hinson)	26,236
Separator (Etiwanda)	14,758

	2018 Rec	**2019 Rec**	**2020 Rec**	**2021 Rec**	**2022 Rec**
Mira Loma Peaker - Tesla CSA	**Constant**	**Constant**	**Constant**	**Constant**	**Constant**
Mira Loma Peaker - Tesla CSA Non Labor	483,396	1,152,265	525,349	559,897	7,160

	2025 TY Fcst
	Constant
5 Year Average (2018-2022)	545,613

	2025 TY Fcst
	Constant
Total Generation Energy Storage - Non Labor	616,123

Workpaper Title:

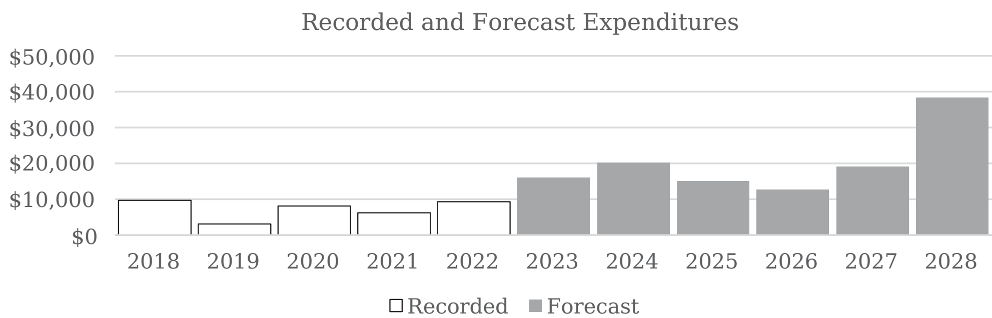
Grid Scale Storage (Energy Storage) Capital Expenditures

Southern California Edison - Capital Workpapers
Capital Workpapers Summary
SUMMARY BY GRC Volume
(Nominal $000)

Exhibit: SCE-02 Grid Activities
Volume: 6 - Grid Modernization, Grid Technology, and Energy Storage

	Recorded Capital Expenditures					Forecast Capital Expenditures					
Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Recorded and Forecast Expenditures	9,687	3,097	8,105	6,218	9,304	15,989	20,185	15,007	12,605	19,088	38,328
Total Expenditures					36,410						121,203

Due to rounding, totals may not tie to individual items.



	Forecast Capital Expenditures						
GRC Activity	2023	2024	2025	2026	2027	2028	6 yr Total
Energy Storage	15,989	20,185	15,007	12,605	19,088	38,328	121,203
GRC Total	15,989	20,185	15,007	12,605	19,088	38,328	121,203

Southern California Edison
2025 GRC Capital Workpapers

Exhibit:	SCE-02 Grid Activities
Volume:	6 - Grid Modernization, Grid Technology, and Energy Storage
Business Plan Group:	System Augmentation
Business Plan Element:	Energy Storage
GRC Activity:	Energy Storage

1. Witness:	Jeff Shiles
2. Asset type:	DS-LINE
3. In-Service date:	12\1\9999
4. RO Model ID:	901
5. Pin:	6424
6. CWBS Element:	CETOTOTAT642418
CWBS Description:	Energy Storage Deployment
7. SRIIM Eligible:	No

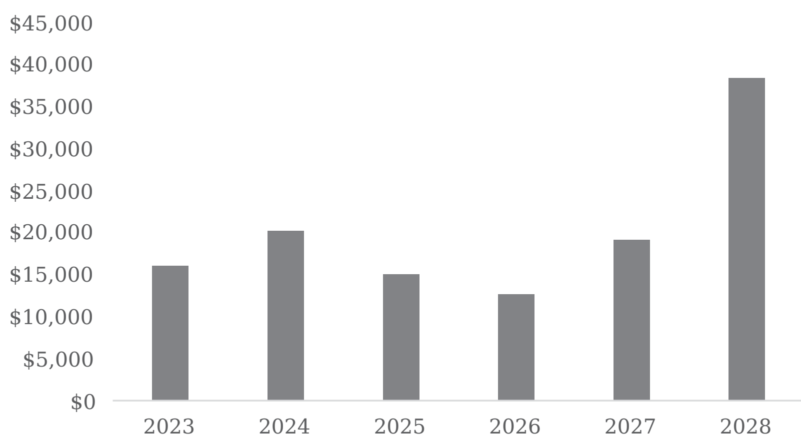
Cost Estimates - Nominal ($000)

2025 GRC - Capital Expenditures Forecast

Year	2023	2024	2025	2026	2027	2028
SCE$	15,989	20,185	15,007	12,605	19,088	38,328

2023 - 2028 Total
121,203

Due to rounding, totals may not tie to individual items.



Workpaper Title:

DESI Pilot Program Capital

DESI Pilot Program Capital Workpaper
2025 General Rate Case - Capital Workpaper

Project Element: Project Cost and Schedule

Total Forecast (,000)						
	2023	2024	2025	2026	2027	2028
Total Forecast	$ 15,989	$ 20,185	$ 5,811	$ -	$ -	$ -

Cost & Schedule							
Project	Avg. Cost	2023	2024	2025	2026	2027	2028
DESI 1	$ 3,338	$ 1,172	$ 2,166	$ -	$ -	$ -	$ -
DESI 2	$ 638	$ 638	$ -	$ -	$ -	$ -	$ -
Mercury 4	$ 608	$ 608	$ -	$ -	$ -	$ -	$ -
Mercury 1	$ 3,130	$ 3,130	$ -	$ -	$ -	$ -	$ -
Mercury 2	$ 3,578	$ 3,578	$ -	$ -	$ -	$ -	$ -
Gemini 1	$ 3,661	$ 3,661	$ -	$ -	$ -	$ -	$ -
Gemini 2	$ 248	$ 248	$ -	$ -	$ -	$ -	$ -
Apollo 1	$ 1,832	$ 159	$ 908	$ 765	$ -	$ -	$ -
Apollo 2	$ 11,371	$ 1,385	$ 7,311	$ 2,787	$ -	$ -	$ -
Gemini 3	$ 13,467	$ 1,409	$ 9,800	$ 2,258	$ -	$ -	$ -
Totals		**$ 15,989**	**$ 20,185**	**$ 5,811**	**$ -**	**$ -**	**$ -**

DESI Pilot Program Capital Workpaper
2025 General Rate Case - Capital Workpaper

Project Element: Project Cost and Schedule

DESI Capital By Project (Labor vs. Non-Labor)													
Project	**Category**		**2023**		**2024**		**2025**		**2026**		**2027**		**2028**
DESI 1	Labor	$	118	$	83	$	-	$	-	$	-	$	-
	Material/Contract/ Other	$	1,054	$	2,083	$	-	$	-	$	-	$	-
DESI 2	Labor	$	41	$	-	$	-	$	-	$	-	$	-
	Material/Contract/ Other	$	598	$	-	$	-	$	-	$	-	$	-
Mercury 4	Labor	$	40	$	-	$	-	$	-	$	-	$	-
	Material/Contract/ Other	$	568	$	-	$	-	$	-	$	-	$	-
Mercury 1	Labor	$	147	$	-	$	-	$	-	$	-	$	-
	Material/Contract/ Other	$	2,984	$	-	$	-	$	-	$	-	$	-
Mercury 2	Labor	$	151	$	-	$	-	$	-	$	-	$	-
	Material/Contract/ Other	$	3,427	$	-	$	-	$	-	$	-	$	-
Gemini 1	Labor	$	176	$	-	$	-	$	-	$	-	$	-
	Material/Contract/ Other	$	3,485	$	-	$	-	$	-	$	-	$	-
Gemini 2	Labor	$	111	$	-	$	-	$	-	$	-	$	-
	Material/Contract/ Other	$	137	$	-	$	-	$	-	$	-	$	-
Apollo 1	Labor	$	118	$	120	$	128	$	-	$	-	$	-
	Material/Contract/ Other	$	41	$	788	$	638	$	-	$	-	$	-
Apollo 2	Labor	$	158	$	170	$	163	$	-	$	-	$	-
	Material/Contract/ Other	$	1,227	$	7,141	$	2,625	$	-	$	-	$	-
Gemini 3	Labor	$	121	$	239	$	160	$	-	$	-	$	-
	Material/Contract/ Other	$	1,288	$	9,561	$	2,098	$	-	$	-	$	-
Labor Total		**$**	**1,182**	**$**	**612**	**$**	**450**	**$**	**-**	**$**	**-**	**$**	**-**
Material/Contract/Other Total		**$**	**14,808**	**$**	**19,573**	**$**	**5,360**	**$**	**-**	**$**	**-**	**$**	**-**
Totals		**$**	**15,989**	**$**	**20,185**	**$**	**5,811**	**$**	**-**	**$**	**-**	**$**	**-**