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PACIFIC GAS AND ELECTRIC COMPANY

DEMAND RESPONSE RULE 24 COST RECOVERY

PREPARED TESTIMONY

PG&E®

PACIFIC GAS AND ELECTRIC COMPANY
DEMAND RESPONSE RULE 24 COST RECOVERY
PREPARED TESTIMONY

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CHAPTER 1
DEMAND RESPONSE DIRECT PARTICIPATION OVERVIEW

A. Introduction

This application requests authorization for Pacific Gas and Electric Company (PG&E) to recover costs associated with the limited-scale implementation of its Rule 24 tariffs as approved in Resolution E-4630 and as provided by Decision 12-11-025. PG&E has, over the past several months, developed this application to comply with Ordering Paragraphs (OP) 27 and 36 of Decision 12-11-025. These orders contemplate a wholesale energy market where significant amounts of Demand Response[1] (DR) are bid into the California Independent System Operator (CAISO) as a "Proxy Demand Resource" (PDR) or a "Reliability Demand Response Resource" (RDRR) to help the state meet its electric needs. PG&E's Rule 24 tariffs establish the ground rules under which retail customers and Demand Response Providers (DRP) can bid into the CAISO to utilize these products.

On May 23, 2014, the United States Court of Appeals for the District of Columbia Circuit (Electric Power Supply Association (EPSA) vs. Federal Energy Regulatory Commission (FERC)) vacated FERC's Order 745, likely introducing critical impacts to Direct Participation and the associated costs of full implementation as provided in Appendix B. In light of this decision and the current market uncertainties, PG&E is concerned that any large investment to implement Direct Participation at this time may not be prudent and may represent an unsatisfactory risk to its ratepayers. PG&E urges the California Public Utilities Commission (CPUC or Commission) to re-examine its current assumptions and timelines and consider a more deliberate approach for implementing Rule 24.

Consequently, rather than authorizing costs to implement Rule 24 at full scale, PG&E recommends that the Commission pursue a limited rollout of

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1 "Demand response can be defined as changes to electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, to incentive payments, or to reliability conditions." *Assigned Commissioner and Administrative Law Judges' Ruling Amending Scoping Memo*, issued in Rulemaking 07-01-041 on November 9, 2009.

Rule 24 which will predominately use manual processes to facilitate participation in CAISO demand response market. The guidelines and description for this measured approach are found in Chapter 2. PG&E believes that its proposal accommodates practical levels of wholesale market participation in the short term and affords valuable experience for DRPs. It also tests the viability of the market and could surface the need for market changes. This approach also comes without any major ongoing cost commitments, such as those described in Appendix B,[2] so that the risks of stranding premature investments in technology infrastructure are minimized.

The cost recovery request in this application is also limited only to those costs associated with implementing Rule 24 for third parties, or more specifically, Cases 2, 5, 6 and 8 in Table 1-1 below. This application does not contain the incremental costs needed for PG&E to bid its own DR programs into the wholesale energy market as a DRP. An estimate of PG&E costs for this activity is contained in Chapter 3, "CAISO Integration Costs," of PG&E's Opening Testimony for the 2013 DEMAND RESPONSE RULEMAKING 13-09-011, PHASES 2 AND 3. PG&E anticipates that these "PDR Phase 2" costs[3] can be recovered in Rulemaking 13-09-011 through a subsequent application.

Beyond this application, and in recognition of the Commission's stated desire to see more DR integrated as Proxy Demand Resources (PDR) in the short term, PG&E is still committed to integrating approximately 10-20 megawatts of DR as Supply Resource DR in 2014. This DR amount could potentially increase in 2015 and 2016, pending additional programmatic changes and absent any legal obstacles to the contrary.

PG&E also attaches Appendices A and B as part of this application. These appendices contain a detailed accounting of the process and system modifications required to accommodate the full-scale implementation of Rule 24. Appendix A describes the process to transition from a limited, manually driven Rule 24 process to an automated process that is able to accommodate large

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2 Describes IT modifications and costs to fully implement Rule 24

3 Real Time Products in Case 1 and all of Case 3, 4 and 7. Request made to recover costs to build systems for Case 1, day ahead products in MRTU. See Chapter 3 of DR Order Instituting Rulemaking Phase 2 and 3 Opening Comments.

volumes of participants bidding into all of the available CAISO markets under Rule 24. Appendix B contains the descriptions and costs of how the manual business specifications used in the Rule 24 process can be implemented within PG&E's information technology systems. If the Commission continues to believe that the investor-owned utilities (IOU) still need to prepare for full implementation of Direct Participation by 2017, the costs found in these two appendices are what PG&E estimates it would incur to implement at full scale the foundational systems and processes for Rule 24.

The Commission should note that costs contained in the appendices are estimates to implement Direct Participation prior to FERC Order 745 being overturned. These estimates also reflect current labor costs and PG&E system configurations which will change over time. If the Commission determines that Rule 24 should not be fully implemented at this time but later elects to direct PG&E to fully implement this Rule, PG&E requests that it be allowed to refile a new application with updated costs, within 90 days of such an order, for the full implementation of Rule 24.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
TABLE OF CASES AND PRODUCTS BY ROLE
SUPPORTED AS PART OF THIS APPLICATION

					Supported Day Ahead Products			Supported Real Time Products	
Case	**Customer**	**LSE**	**MDMA**	**DRP**	**Energy**	**A/S**	**RUC**	**Energy**	**A/S**
1	Bundled	PG&E	PG&E	PG&E	N	N	N	N	N
2	Bundled	PG&E	PG&E	3rd party	Y	N	N	N	N
3	CCA	3rd party	PG&E	PG&E	N	N	N	N	N
4	DA	3rd party	PG&E	PG&E	N	N	N	N	N
5	CCA	3rd party	PG&E	3rd party	Y	N	N	N	N
6	DA	3rd party	PG&E	3rd party	Y	N	N	N	N
7	DA	3rd party	3rd party	PG&E	N	N	N	N	N
8	DA	3rd party	3rd party	3rd party	Y	N	N	N	N

B. Background

FERC Orders 719[4] and 719-A[5] require Regional Transmission Operators (RTO) and Independent System Operators (ISO) to amend their market rules to permit retail customers to bid demand response services directly into the RTO's or ISO's organized wholesale markets. Specifically, these orders require that end use customers, either on their own or through a DRP[6] be allowed to bid directly into these wholesale markets to the extent that Commission laws or regulations do not prohibit a retail customer's participation. In the absence of intervening regulations from the Commission, the FERC orders allow for direct participation of DR in California's wholesale markets without any additional requirements or rules.

California's electric grid is operated by the CAISO. The CAISO has been engaged in efforts to integrate retail DR programs with its wholesale energy markets. As part of its Market Redesign and Technology Upgrade (MRTU),[7] the CAISO engaged stakeholders in designing market products where DR can be bid into wholesale energy markets similar to its generation-model. Through this stakeholder process, the CAISO developed two wholesale energy market products to comply with previously discussed FERC Order 719: PDR and RDRR.[8] PDR enables DR participation, as a single resource or an aggregation of resources, in the wholesale day-ahead and/or real-time energy markets and in the Ancillary Services market. The load of these end-use customers would

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4 *Wholesale Competition in Regions with Organized Electric Markets* (FERC Order 719), issued on October 17, 2008, in Docket Nos. RM07-19 and AD07-7, available at http://elibrary.ferc.gov/idmws/file_list.asp?document_id=13656106.

5 *Wholesale Competition in Regions with Organized Electric Markets* (Order 719-A), issued on July 16, 2009 in Docket No. RM07-19, available at http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-1.pdf.

6 FERC Order 719 and 719A use the term Aggregator of Retail Customers, or ARC. For the purposes of this decision, DRP is synonymous.

7 MRTU manages transmission congestion and dispatches generation based on a model that accurately depicts available capacity and constraints on the CAISO controlled grid across various market time frames to help ensure that market outcomes are consistent with real-time operation of the transmission grid.

8 As originally proposed to the FERC, RDRR would enable emergency responsive DR resources to integrate into the CAISO market and operations. On February 16, 2012, the FERC rejected the CAISO's proposed RDRR tariff and provision. The CAISO has since filed for approval at FERC a tariff for RDRR.

continue to be served by their respective Load Serving Entity (LSE) but the load reductions would be bid in by the DRP's scheduling coordinator. As proposed in the initial CAISO's tariff filing, when bids clear the market, a winning bid would receive the Locational Marginal Price (LMP) and the LSE would receive an uninstructed energy payment or debit. The originally proposed tariff also applied a Default Load Adjustment (DLA) to ensure that the LSE would not receive a payment for both the bid and the uninstructed energy.

However, on April 16, 2010, FERC issued a notice of deficiency regarding the CAISO's PDR tariff proposal, including three discrete areas of concern.[9] FERC subsequently found deficiencies in the original tariff and required revisions pursuant to FERC Order 745.[10] FERC Order 745-A denied rehearing of Order 745 and granted in part and denied in part clarification of certain provisions of Order 745. In order to comply with the Order 745, the CAISO submitted a revised PDR tariff to the FERC eliminating the DLA for any bids above the Net Benefits Test (NBT). Pursuant to FERC Orders 745 and 745-A, the CAISO relied on the FERC conclusion that bids above the NBT are cost-effective and thus paying the LMP reimburses cost-effective DR at the same level as generation, without any overcompensation.[11]

Simultaneous to FERC's review of the case, the Commission, on November 9, 2009, issued a scoping memo amending Rulemaking 07-01-041 to initiate a Direct Participation Phase of this proceeding. On June 3, 2010, Decision 10-06-002 of this rulemaking established the initial conditions under which the Commission oversees retail DR direct participation.[12] In this decision, several issues that still required resolution were identified, including Commission oversight of programs and policies that apply generally to LSEs. The utilities

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[9] Letter from the FERC Office of Energy Market Regulation to the CAISO, filed in Docket No. ER10-765.

[10] Demand Response Compensation in Organized Wholesale Energy Markets, Order No. 745, 18 CFR Part 35, March 15, 2011 (Order 745).

[11] CAISO *Tariff Amendment To Implement Proxy Demand Resource Product*, filed in Docket No. ER10-765 on February 16, 2010.

[12] Decision 10-12-016 denied rehearing of Decision 10-06-002 and confirmed the Commission's broad regulatory authority over energy matters and its jurisdiction, to a degree, over DR providers.

strongly recommended that the issue of financial settlement be resolved prior to the adoption of a direct participation rule.

Decision 12-11-025 pertaining to Rule 24 Implementation was issued on December 4, 2012. FERC through Order 745-A had denied rehearing of its initial Order 745 and the Commission had denied rehearing of certain jurisdictional issues in Decision 10-12-016. Commission Decision 12-11-025 incorporated the elements from both of these decisions and provided its own draft version of a Direct Participation tariff – PG&E Rule 24.[13] The decision also allowed for comments on the tariff which focus on recommendations for refinements to the rule, especially those technical matters not addressed in this decision and any inconsistencies with this decision.

As a result, a collaborative process was set up between the IOUs and the Joint Parties to develop a common tariff that could be most readily implemented by all parties. The collaborative worked diligently on identifying and resolving implementation difficulties within the decision and agreed upon tariff language to help clarify certain provisions in the Rule. The final product of this team was a joint Petition for Modification (PFM) to amend the then current rule to make it easier to implement; additional PFMs were also filed for issues that could not be resolved cooperatively. Additionally, on August 9, 2013, PG&E and the other IOUs submitted their own versions of Rule 24 in compliance with Decision 12-11-025, in most part containing mutually agreed upon language by the collaborative and in anticipation of an affirmative decision of its joint PFM. Decision 13-12-029 on December 5, 2013, resolved the outstanding policy issues identified in these various PFMs. On February 5, 2014, Resolution E-4630 approved the final Rule 24 language after incorporating decision elements from the PFMs and modifying the IOU's proposed tariff language as needed.

OP 36 of Decision 12-11-025 was not changed through the PFM process. This OP provides the opportunity for the IOUs to recover the costs they incur in implementing Rule 24. Specifically, OP 36 provides that *"{w}ithin 90 days of the adoption of Electric Rule 24, Pacific Gas and Electric Company (PG&E),*

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13 Draft tariff was created using elements of both the IOU and third parties Rule 24 tariffs filed on May 21, 2011.

San Diego Gas and Electric Company (SDG&E) and Southern California Edison Company (SCE) may file applications requesting recovery of costs incurred as a result of the implementation of Rule 24 and Demand Response Direct Participation in the California Independent System Operator's (CAISO) Wholesale Energy Market."

OP 27 of Decision 12-11-025 also was not changed through the PFM process. This OP requires the IOUs to file tariffs to recover the costs of Rule 24 related services that they might provide to a DRP. Specifically, its states, "*Within 90 days of the adoption of Electric Rule 24, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must submit applications requesting review and approval of tariffs for the recovery of costs incurred as a result of providing services to demand response providers.*"

OP 36 and OP 27 in Decision 12-11-025 serve as a basis for this filing.

The 90-day period was ultimately extended allowing the IOUs to file their cost recovery applications on June 2, 2014.

On May 23, 2014, the United States Court of Appeals for the District of Columbia Circuit (EPSA vs. FERC) vacated FERC's Order 745.

C. Description of PG&E's Role in Rule 24 Process

Rule 24 allows retail customers, individually or in aggregate, to be bid directly into the wholesale energy markets via the CAISO's PDR and RDRR products. At a high level, PG&E's role in facilitating these non-Utility bids is to verify customer registration information for participation in the CAISO market, to facilitate data exchange with DRPs so that they may correctly and efficiently enroll participants into their programs for bidding and settling events with the CAISO, and to integrate the load reductions associated with an accepted bid into its front and back offices so as not to devalue their current processes.

The primary objective in this application is to recover the costs to implement this Rule on a limited, and mostly manual, basis. PG&E has different Rule 24 responsibilities depending on whether it is acting as a Utility Distribution Company, as a Meter Data Management Agent or as a LSE for the retail customer. The following activities are required to implement this Rule:

1. Isolating PG&E staff that provide services to non-utility DRPs
2. Establishing and maintaining third parties as non-utility DRPs

3. Processing and maintaining a DRP's Access to customer specific data via the Customer Information Service Request DRP Form
4. Modifying PG&E systems to produce and track non-interval data necessary for Rule 24
5. Transferring interval data on an ongoing basis to DRPs
6. Transferring non-interval data on a periodic basis to DRPs
7. Reviewing CAISO registrations
8. Preventing customers from dually enrolling in utility DR programs and with a non-utility DRPs
9. Verifying wholesale settlements

The details requirements of these processes are contained in Chapter 2.

D. Dependency on PG&E's Customer Data Access Project and Other Technological Improvements

New Rule 24 processes will impact several departments within PG&E and the current systems they utilize. PG&E's desire is to leverage these systems and its current processes as much as possible to make efficient use of ratepayer dollars. It should be no surprise that several of these systems are currently undergoing modification, or are planned to be modified, with technological improvements pursuant to Commission orders or for overall service enhancement to our customers. For example, Commission Decision 13-09-025[14] adopted on September 19, 2013 authorizes PG&E to build a platform in which customers can easily authorize the release of their PG&E electric interval data to third parties and efficiently provide it to third parties via an Open Automated Data Exchange format. This work has been designated as PG&E's Customer Data Access (CDA) project.

Since one of PG&E's key roles in Rule 24 is to provide meter data to qualified DRPs, and CDA facilitates this exchange, Rule 24 implementation[15] is dependent on the completion of Phase 1 of the CDA project. PG&E anticipates that this project will be completed by early next year.

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14 Smart Grid – Customer Data Access Proceeding.

15 Limited implementation numbers in Chapter 2 assume Phase 1 of CDA is in place.

E. Fee Schedule E-DRP

PG&E has attached a proposed fee Schedule E-DRP (Appendix C) which provides for certain DRP services that might be needed by DRPs or their customers to facilitate their involvement in Direct Participation.[16] All but one of these costs and services have already been deemed reasonable by the Commission as they were taken directly from PG&E's Commission approved Schedule E-EUS pertaining to Direct Access services.

The new item included in E-DRP pertains to the remote reprogramming of a PG&E SmartMeter™ so that it may accommodate data intervals of increased granularity. PG&E estimates that it will take approximately twenty (20) minutes to make the appropriate reprogramming changes in its' billing and metering systems. Using the established meter labor rate of $125.69 per hour in Schedule E-EUS (and as proposed in Schedule E-DRP), this charge would amount to $41.90 as shown in the proposed tariff. Unlike other meter services established in these rate schedules, remotely reprogramming a SmartMeter™ can be done in the office and should therefore not include the flat Metering Service Base Charge of $174.03.

F. Conclusion

PG&E respectfully requests that the Commission, through its final decision of this application, deem that the estimated limited Rule 24 implementation approach and costs contained in this application are reasonable and approve the full amount of this cost recovery request.

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16 The list of services provided in Schedule E-DRP is not all inclusive. PG&E expects additional services may be needed as the market needs becomes clearer.

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CHAPTER 2

BUSINESS PROCESS REQUIREMENTS

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A. Introduction

1. Scope and Purpose

The purpose and scope of this chapter is to describe the Pacific Gas and Electric Company's (PG&E) incremental business needs and costs to implement a limited scope deployment for electric Rule 24 to support non-utility Demand Response Providers (DRP). These incremental business needs will require PG&E to incur incremental business costs.

In its testimony, PG&E demonstrates that the amounts it seeks to recover in this application will be reasonably incurred and shows that the amounts it seeks to recover are incremental to revenue requirements currently in rates.

2. Organization of the Remainder of This Chapter

The remainder of this chapter is organized as follows:

- Section B – PG&E's Limited Scope Deployment for Electric Rule 24
- Section C – Summary of PG&E's Incremental Business Activities to Implement a Limited Scope Deployment of Electric Rule 24
- Section D – PG&E's Incremental Costs to Implement a Limited Scope Deployment of Electric Rule 24 for Non-Utility Demand Response Providers
- Section E – Conclusion

B. PG&E's Limited Scope Deployment for Electric Rule 24

PG&E plans to implement electric Rule 24 in a limited scope to allow non-utility DRPs the opportunity to participate in the California Independent System Operator's (CAISO) wholesale markets. PG&E's proposal will allow non-utility DRPs to participate in the CAISO's wholesale markets using both bundled and non-bundled customers. During 2014 and 2015, PG&E will provide services to these DRPs using mostly manual processes while actively pursuing methods to streamline these manual processes. Starting in late 2015, PG&E will utilize these business process enhancements and the planned deployment in early 2015 of its Customer Data Access (CDA) Phase 1 to increase the maximum number of allowed customers and meters.

PG&E's Rule 24 implementation is intended to meet the forecasted volumes shown in Table 2-1. Further, PG&E expects to be able to support the 2016 forecasted volumes for an extended period.

TABLE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
PG&E'S PROPOSED LIMITED IMPLEMENTATION FOR THE INTEGRATION OF NON-UTILITY DRPS INTO THE CAISO'S WHOLESALE MARKET

Line No.	Limited Scope	2014	2015	2016
1	Maximum Non-Residential Customers:	20	100	500
2	Maximum Electric Meters:	30	150	750
3	Maximum Number of DRPs:	2	5	5
4	Maximum Wholesale Resources (PG&E as LSE):	6	6	6
5	Maximum Load Reduction (PG&E as LSE):	50 MW	50 MW	50 MW
6	Residential Participants Allowed:	N	N	N

C. Summary of PG&E's Incremental Business Activities to Implement a Limited Scope Deployment of Electric Rule 24

Integrating retail demand response into the CAISO's wholesale markets is complex partly due to the number of roles and the various CAISO markets and products. Table 2-2 illustrates the many different roles played by different parties combined with the numerous CAISO's markets and products. Those cells filled with a "Y" indicate the Cases and CAISO's markets and products that PG&E plans to implement as part of this application. Specifically, PG&E is seeking authorization to implement Cases 2, 5, 6, and 8 for Day Ahead Energy only. The business activities and associated costs as discussed in this chapter encompass functionality to support these items.

TABLE 2-2
PACIFIC GAS AND ELECTRIC COMPANY
TABLE OF CASES AND PRODUCTS BY ROLE
SUPPORTED AS PART OF THIS APPLICATION

					Supported Day Ahead Products			Supported Real Time Products	
Case	**Customer**	**LSE**	**MDMA**	**DRP**	**Energy**	**A/S**	**RUC**	**Energy**	**A/S**
1	Bundled	PG&E	PG&E	PG&E	N	N	N	N	N
2	Bundled	PG&E	PG&E	3rd party	Y	N	N	N	N
3	CCA	3rd party	PG&E	PG&E	N	N	N	N	N
4	DA	3rd party	PG&E	PG&E	N	N	N	N	N
5	CCA	3rd party	PG&E	3rd party	Y	N	N	N	N
6	DA	3rd party	PG&E	3rd party	Y	N	N	N	N
7	DA	3rd party	3rd party	PG&E	N	N	N	N	N
8	DA	3rd party	3rd party	3rd party	Y	N	N	N	N

This limited scope for Rule 24 requires PG&E to implement nine new manual activities[1] as shown in Table 2-3, below.

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1 See Appendix A and B for details regarding a more comprehensive deployment.

TABLE 2-3
PACIFIC GAS AND ELECTRIC COMPANY
INCREMENTAL ACTIVITIES NECESSARY TO
SUPPORT NON-UTILITY DEMAND RESPONSE PROVIDERS

Activity Number	Activity Description
1	Isolating PG&E Staff That Provide Services to Non-Utility Demand Response Providers
2	Establish and Maintain Third Parties as Non-Utility Demand Response Providers
3	Processing and Maintaining a DRP's Access to Customer Specific Data Via the Customer Information Service Request Demand Response Provider Form
4	Modifying PG&E Systems to Produce and Track Non-Interval Data Necessary for Rule 24
5	Transferring Interval Data on an Ongoing Basis to DRPs
6	Transferring Non-Interval Data on a Periodic Basis to DRPs
7	Reviewing CAISO Registrations
8	Preventing Customers From Dually Enrolling in Utility Demand Response Programs and With a Non-Utility Demand Response Providers
9	Verify Wholesale Settlements

Each of the new business related activities is discussed in further detail below:

1) **Isolating PG&E Staff That Provide Services to Non-Utility Demand Response Providers**

Electric Rule 24 requires that confidential, competitive information received by PG&E from unaffiliated DRPs (or from the CAISO about the DRPs or their customers) in connection with PG&E's performance of its duties to implement and administer the DRP's use of PG&E's bundled load for Demand Response (DR) Services shall be limited to PG&E staff who are responsible for performing PG&E's non-DRP responsibilities. Such confidential, competitive information shall not be used to promote PG&E's services to its customers or customers of its affiliates.

PG&E staff receiving such confidential, competitive information from the DRPs or the CAISO in the discharge of PG&E's roles and responsibilities as a non-DRP shall not share such confidential, competitive information with other individuals in PG&E who are also responsible for discharging PG&E's roles and responsibilities as a DRP.

This new requirement mandates PG&E to set up a new work group or identify an existing work group to manage and to provide services to unaffiliated DRPs. This work group will have to have access to all of PG&E's DR processes and the CAISO's Demand Response System (DRS) under the roles of Utility Distribution Company (UDC) and Load Serving Entity (LSE). However, PG&E's DR department cannot have access to any information that is related to an unaffiliated DRP. This work group will be separate from those individuals at PG&E who are responsible for discharging PG&E's roles and responsibilities as a DRP.

2) **Establish and Maintain Third Parties as Non-Utility Demand Response Providers**

In order to participate in the electric Rule 24, interested third parties need to register with possibly PG&E[2] but always with the California Public Utilities Commission (CPUC or Commission) and the CAISO. A non-utility DRP must use the Demand Response Provider Service Agreement (DRP Service Agreement – Form No. 79-1160) to register with PG&E. PG&E would supply the non-utility DRP with a portable document format (PDF) based agreement. The non-utility DRPs would return the completed PDF in paper format to the PG&E work group mentioned in Activity 1, above.

Once this form is received, PG&E would validate that the information is correct. Once validated, PG&E would respond to the DRP that the validation is complete. The DRP must also satisfy PG&E's credit requirements. Once the credit requirements have been satisfied, PG&E will return to the DRP a copy counter signed by an authorized PG&E employee.

The PG&E work group mentioned in Activity 1, above, would maintain all paper copies of the agreement within its work group. This work group must periodically verify that each of the DRPs is valid. If a DRP's registration with PG&E becomes invalid, then PG&E must stop all wholesale market activities

2 Non-utility DRPs planning to enroll bundled service customers need to register with PG&E (as the LSE), the CPUC, and the CAISO. All non-utility DRPs regardless of the types of customers they plan to enroll must register with the CPUC. All DRPs must register with the CAISO.

with the DRP and inform both the CPUC and the CAISO. If a DRP's registration with either the CPUC or CAISO becomes invalid, then PG&E must stop all wholesale market activities with the DRP.

3) **Processing and Maintaining a DRP's Access to Customer Specific Data Via the Customer Information Service Request Demand Response Provider Form**

One of the key new requirements of electric Rule 24 is providing information to non-utility DRPs. To support this requirement, Rule 24 includes a new form titled Customer Information Service Request Demand Response Provider (CISR-DRP) Form (79-1152). The majority of the work necessary to provide information to the non-utility DRPs will be performed by the work group mentioned in Activity 1, above.

The new CISR-DRP form is complex. It has 72 text boxes and 12 check boxes. These 12 check boxes allow 82 valid combinations. Each valid combination requires different setup and handling throughout the duration of the customer's authorization. Both non-utility DRPs and customers will require training on the proper use of the form. The effort needed to validate that the form has been completed properly will take a significant effort.

The CISR-DRP form requires the customer to provide a start date for the authorization. The form allows the customer to either specify an end date or have the authorization continue indefinitely. If the customer leaves the authorization end date as indefinite, then the customer must specify if the customer alone can terminate the authorization or if the non-utility DRP is able to terminate the authorization as well. During 2014 and 2015, the work group identified in Activity 1, above, will manually perform all of these activities. Phase 1 of PG&E's CDA (D.13-09-025) is expected to help PG&E to manage the CISR-DRP authorization process. CDA Phase 1 is planned to be operational early 2015.

4) **Modifying PG&E Systems to Produce and Track Non-Interval Data Necessary for Rule 24**

As mentioned in Activity 7, below, a customer's DRP needs confidential customer data to support its wholesale market integration. The majority of this data can change overtime, and these changes can affect the DRP's use of a customer. Three primary examples are a change-of-party, a change in a customer's LSE, and a change in a customer's Sub Load Aggregation Point (S-LAP). A change to any one of these items requires the DRP to terminate any CAISO registrations containing this customer. It is important that PG&E track and report these changes to the DRP. During the 2014 to 2016 time period, these data items will be manually checked for changes and manually communicated to the DRP.

5) **Transferring Interval Data on an Ongoing Basis to DRPs**

For those customers where PG&E is the Meter Data Management Agent (MDMA), PG&E will be required to send Revenue Quality Meter Data (RQMD) for each of the non-utility DRP's customers to the DRP (or its agent) in a timely manner after the conclusion of customer's monthly billing cycle. The DRP converts this RQMD to Settlement Quality Meter Data (SQMD), which the DRP then sends to its Scheduling Coordinator (SC). The DRP's SC then submits the SQMD to the CAISO via the CAISO's the DRS. The SQMD must be submitted to the CAISO no later than 48 business days after the trade date. The CAISO uses this data to produce final settlement statements that it produces 55 business days after the trade date.

It is important that the RQMD be provided to the DRP be as accurate as possible because the CAISO is able to impose penalties for any corrections. If the PG&E acting as the MDMA is found, through a remedy and dispute resolution process, to have failed to comply fully with the applicable requirements for submission of timely and accurate RQMD so as to be the sole fault for the ability for the DRP to comply fully with the applicable CAISO requirements, then the MDMA shall be held liable, limited to the penalties imposed by the CAISO upon the non-Utility DRP or its SC due to the non-compliance.

Prior to sending a customer's interval data to a DRP, PG&E, acting as the MDMA will validate that customer's CISR-DRP authorization is still active. PG&E will not send the DRP any interval data for any operating dates that are after the termination date specified in the customer's CISR-DRP. However, PG&E will periodically check if any of this previously transmitted interval data has changed. Any changes discovered within three years of the operational date will be communicated to the DRP. These corrections will be transmitted to the DRP even after the CISR has terminated because the DRP was entitled to receive interval and any subsequent corrections for the operational dates specified in the customer's CISR-DRP.

During 2014, all of the data exchange activities will be manually performed and transferred (via a secure process) to the DRP. These manual processes limit PG&E's ability to accommodate a relatively large set of customers and meters during the initial implementation of Rule 24 processes.

6) **Transferring Non-Interval Data on a Periodic Basis to DRPs**

PG&E is required, as part of the CISR-DRP process, to provide the following data to the non-utility DRP upon PG&E's approval of the CISR-DRP and, without charge, up to two times in a 12-month period per service account:

a. Customer Service Agreement information, name, mailing address, service address, electric rate schedule, etc.

b. Basic meter information including the meter number, the type of meter, and the intervals currently being collected by the meter.

c. Customer's Monthly Meter Read Cycle.

d. The identity and contact information of the customer's LSE, MDMA, and Meter Service Provider.

e. A Unique Customer Identifier (UCI) that the DRP enters into the CAISO's DRS. This UCI is used by the CAISO's systems to prevent a customer from being in two or more registrations that are active at the same time. This UCI would also be provided to the customer's LSE.

f. A maximum of the most recent twelve (12) months of customer billing data or the amount of data recorded for that specific service agreement.

g. Confidential end-user information such as the customer's service voltage, the Sub Load Aggregation Point (S-LAP), Pricing Node (P-Node).

h. If the customer is currently enrolled or in the process of becoming enrolled in any event-based utility DR program(s). If yes, then PG&E must provide (1) the earliest date that the customer can opt out of the program without a financial impact to the customer; and (2) the earliest date that the customer can opt out of the program regardless of financial impact to the customer.

i. Up to one year of historical electric interval data, as it is available for a specific service agreement.

As mentioned in Activity 5, PG&E will periodically check if any of these data elements have changed. Any changes will be communicated to the DRP after PG&E validates that the CISR-DRP is still active.

During the 2014 to 2016 time period, all of the data mentioned above will be manually collected, tracked, and transferred (via a secure process) to the DRP. These manual processes, including the periodic checking for changes, limit PG&E's ability to accommodate more than small set of customers and meters.

7) **Reviewing CAISO Registrations**

Each business day, the isolated work group mentioned in Activity 1, above, will log into the CAISO's DRS and determine if there are any registrations to be reviewed. If there are registrations to be reviewed, then the isolated work group will perform the new tasks described below.

PG&E as the UDC will validate the following items:

- Validate that PG&E is the UDC for each of the customers.
- Validate that the UCI is correct for each customer in the registration.
- Validate that each of the customer's service agreement are still active.
- Validate that a CISR-DRP exists and is still active between the DRP and each customer in the registration.
- Validate that the LSE for each of the customer's is the LSE shown for the registration.
- Verify that the customer name and service address closely match the values in PG&E's systems.
- Validate that the S-LAP is correct for each of the customers.
- Validate that the P-Node is correct for each of the customers.
- Validate that the Default Load Aggregation Point is correct for the UDC.
- Review each customer for participation in a PG&E retail DR program including Peak Day Pricing (PDP) and SmartRate™.

PG&E as the LSE will validate the following items:

- Validate that PG&E has an active LSE DRP agreement with the DRP.

- Validate that PG&E is the LSE for each of the customers.

PG&E as the MDMA will validate the following:

- Validate that RQMD is currently being sent to the DRP for each of the customers in registration.

If the registration and all of the customers in the registration pass validation, then PG&E will perform the following activities:

- PG&E will mark the registration as "Reviewed without findings" in the CAISO's DRS.
- PG&E will manually update its customer information systems with sufficient information necessary to indicate that the customer is an active participant in the CAISO's wholesale market.

If one or more the customers in the registration do not pass validation, then PG&E will mark the registration as "Reviewed with findings" and provide information to the CAISO and the DRP outlining why one or more of the customers did not pass.

The registration review process is an entirely new activity. The review process will require PG&E personnel to log into several PG&E systems to obtain the necessary information. The process is especially difficult if a one or more of the customers are found to be enrolled or in the process of being enrolled in a DR program, PDP, or SmartRate. This review process will be entirely manual.

8) **Preventing Customers From Dually Enrolling in Utility Demand Response Programs and With a Non-Utility Demand Response Providers**

Rule 24 states that a customer cannot be concurrently enrolled in a PG&E demand response program and be in a confirmed registration with a non-utility DRP. This requires that PG&E check each demand program customer enrollment to determine if the customer is currently in a confirmed or pending registration. Likewise, PG&E, as part of its review of the registrations, is required to determine if one or more of the customers in the registration is currently enrolled or is pending enrollment in a demand response program. This seemingly simple check is actually very complex because of the numerous decision points and branches.

The following are some high level examples of this logic:

If one or more of the customers in a pending registration is enrolled or in the process of becoming enrolled in a DR demand response program other than PDP, then PG&E will determine if all of these identified DR program participants have requested to terminate their DR program participation. If one or more of these identified DR program participants have not requested to terminate its DR program enrollment, then PG&E will mark the registration as “Reviewed with findings.” If all of these identified DR program participants have requested to terminate their DR program participation, then PG&E will determine the earliest date that each of the DR participants could be de-enrolled from its DR program without any financial impact to the customer. The greatest of these dates will be the earliest possible start date for the registration. If the proposed start date for the registration is after this greatest DR program end date, then PG&E will mark the registration as “Reviewed without findings.” If the proposed start date for the registration is prior or equal to this greatest DR program end date, then PG&E will mark the registration as “Reviewed with findings.”

If one or more of the customers in a pending registration is found to be on PDP and if none of the customers are on any other DR program, then PG&E will determine the earliest date that each of the PDP participants could opt out of PDP without any financial impact to the customer. The greatest of these dates will be the earliest possible start date for the registration. If the proposed start date for the registration is after this greatest PDP end date, then PG&E will mark the registration as “Reviewed without findings.” If the proposed start date for the registration is prior or equal to this greatest PDP end date, then PG&E will mark the registration as “Reviewed with findings.”

9) **Verify Wholesale Settlements**

When PG&E bundled service customers are included in a resource, PG&E as the LSE validates the CAISO’s wholesale settlement calculations for each resource that receives a market award. This validation is commonly referred to as shadow calculations. PG&E performs this activity whether or not it is the DRP for the resource.

In this limited implementation of the Rule 24, PG&E would manually export the data from the CAISO DRS to a temporary tool to perform the shadow calculations. This process is manually intensive so the number of resources will be limited to six.

D. PG&E's Incremental Costs to Implement a Limited Scope Deployment of Electric Rule 24 for Non-Utility Demand Response Providers

PG&E cost to implement a limited scope of electric Rule 24 for non-utility DRPs is shown in Table 2-4.

These costs are expense and cover the incremental labor to manage this limited scope deployment.

TABLE 2-4
PACIFIC GAS AND ELECTRIC COMPANY
PG&E'S COSTS TO IMPLEMENT ELECTRIC RULE 24
FOR NON-UTILITY DRPS

Line No.	Labor/Cost Component	2015	2016	Total
1	FTE			
2	Demand Response	1.5	3.5	
3	Back Office	0.5	0.5	
4	Total FTE	2.0	4.0	
5	Expense			
6	Business Labor	$455,000	$922,000	$1,377,000
7	Develop Business Process Improvements	$750,000	$500,000	$1,250,000
8	Rule 24 Meter Configuration migration	$250,000	–	$250,000
9	Total Expense	$1,455,000	$1,422,000	$2,877,000

E. Conclusion

In this chapter PG&E has demonstrated that the activities necessary to implement a limited deployment of electric Rule 24 to support non-utility DRPs are incremental to PG&E's current business activities. These incremental activities will require PG&E to incur incremental business costs. Further, in this chapter PG&E demonstrates that the amounts it seeks to recover will be reasonably incurred.

PG&E requests that the Commission approve PG&E's request for $2.9 million.

PACIFIC GAS AND ELEC TRIC COMPANY

CHAPTER 3

COST RECOVERY AND RE VENUE REQUIREMENTS

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COST RECOVERY AND REVENUE REQUIREMENTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
COST RECOVERY AND REVENUE REQUIREMENTS

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) proposal for cost recovery of costs and associated revenue requirements needed to implement Rule 24 business processes and Information Technology requirements.

In this chapter, PG&E:

- Provides forecasted revenue requirement.
- Describes the mechanisms to recover the authorized funding through existing revenue balancing accounts in electric rates.
- Proposes allocation of requested revenue requirements and expenses recorded in electric balancing accounts.

B. Summary of Revenue Requirement Results

The following table shows PG&E's 2015-2016 Rule 24 proposed revenue requirements.

TABLE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
RULE 24 2015-2016 PROPOSED REVENUE REQUIREMENTS

Line No.		2015	2016
1	Rule 24 Revenue Requirement	$1,472,785	$1,439,381

The revenue requirements presented in Table 3-1 are based on the expenses summarized in Table 2-4 of Chapter 2. Proposed electric funding shown in Table 3-1 includes franchise fees and uncollectibles.[1]

C. Proposed Cost Recovery

PG&E recommends, as a matter of policy, that it is appropriate to recover Rule 24 revenue requirements from all distribution customers via the Distribution Revenue Adjustment Mechanism (DRAM). Moreover, program expenses would be tracked via the Demand Response Expenditure Balancing Account. Recovery of Demand Response (DR)-related revenue requirements via distribution rates is appropriate, as DR programs are not generation-related, provide distribution grid benefits, and are available to both bundled electric customers and customers served by an Energy Service Provider or Community Choice Access provider.[2] In addition, the California Public Utilities Commission (CPUC or Commission) has consistently authorized recovery of DR expenses through distribution rates.[3]

The most recent CPUC decision authorizing 2012-2014 DR program expenses, Decision 12-04-045, maintains the current recovery of DR program expenses via DRAM. Further, Decision 12-04-045 deferred resolution of DR cost recovery:

> …until the Commission makes a final determination about the future structure of the DR market,[4]

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1 The calculated franchise fees and uncollectible factor of 0.010790 (electric) is based on factors included in PG&E's 2011 General Rate Case Settlement Agreement filed in Application 09-12-020, Motion of PG&E; Division of Ratepayer Advocates; The Utility Reform Network; Aglet Consumer Alliance; California City-County Street Light Association; California Farm Bureau Federation; Coalition of California Utility Employees; Consumer Federation of California; Direct Access Customer Coalition; Disability Rights Advocates; Energy Producers and Users Coalition; Engineers and Scientists of California, Local 20; Merced Irrigation District; Modesto Irrigation District; South San Joaquin Irrigation District; Western Power Trading Forum; and Women's Energy Matters for Adoption of Settlement Agreement, filed October 15, 2010, at Attachment 2, Tables 1-2 and 1-5.

2 A.11-03-001, *2012-14 Demand Response Programs and Budgets*, PG&E Rebuttal Testimony, pp. 11-2 to 11-4.

3 *Ibid*, p. 11-5.

4 *Decision Adopting Demand Response Activities and Budgets for 2012 Through 2014,* D.12-04-045, p. 204.

This decision also states that:

> …changing the current cost recovery and rate design process for DR is not ripe for discussion.[5]

Moreover, the Commission believes that Rulemaking 07-01-041 (now succeeded by R.13-09-011), the DR Order Instituting Rulemaking, is the "most appropriate forum…to establish overall rules" for DR cost recovery.[6] Subsequently, the DR cost recovery rules would be applied in PG&E's next rate design application.

In light of Decision 12-04-045's cost recovery directives, PG&E proposes, pending an outcome in Rulemaking 13-09-011, that 2015-2016 Rule 24 costs continue to be recovered by DRAM. In addition, the decision in this proceeding should find that the eventual cost recovery for such costs will be determined in Rulemaking 13-09-011.

D. Allocation of Revenue Requirement by Balancing Account

PG&E proposes to continue recovering its authorized Rule 24 revenue requirements from all customers through electric distribution rates. PG&E proposes to recover Rule 24 expenses from electric customers based on authorized revenue allocation and rate design methods in place at the time the CPUC issues its final decision in this application docket.[7]

E. Conclusion

PG&E requests recovery of the revenue requirements included in Section B of this chapter. PG&E also requests recovery of the associated revenue requirements authorized in this filing be recovered in the appropriate rate components for electric rates set in the Annual Electric True-Up. The revenue requirements presented in this chapter are based on incremental costs presented in this proceeding and are not included in any other PG&E cost recovery application.

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5 *Ibid.*

6 *Ibid.*

7 Electric revenue allocation and rate design was most recently authorized in Decisions 11-05-047 and 11-12-053.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

BUSINESS PROCESS REQUIREMENTS

(COMPLETE RULE 24 IMPLEMENTATION)

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PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX A
BUSINESS PROCESS REQUIREMENTS
(COMPLETE RULE 24 IMPLEMENTATION)

A. Introduction

1. Scope and Purpose

The purpose and scope of this appendix is to describe the Pacific Gas and Electric Company's (PG&E) incremental business needs and costs to fully implement electric Rule 24 to support non-utility Demand Response Providers (DRP).[1] These incremental needs will require PG&E to incur incremental business costs and incremental Information Technology (IT) costs. This appendix discusses the incremental business related costs while the incremental IT-related costs are discussed in Appendix B.

2. Organization of the Remainder of This Appendix

The remainder of this appendix is organized as follows:

- Section B – PG&E's Phased Approach to Implementing Electric Rule 24
- Section C – Summary of PG&E's Incremental Business Activities to Implement Electric Rule 24
- Section D – PG&E's Incremental Costs to Implement Electric Rule 24 for Non-Utility Demand Response Providers
- Section E – Conclusion

B. PG&E's Phased Approach to Implementing Electric Rule 24

PG&E plans to implement electric Rule 24 in three phases to allow non-utility DRPs the opportunity to participate, in a limited basis, while PG&E is readying its IT systems needed to support the mature market.

As mentioned in Appendix B, PG&E will need between one to two years to design, build, test, and deploy its IT systems. In the meantime, PG&E is proposing that non-utility DRPs be allowed to participate using both bundled and

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[1] Chapters 1 and 2 of PG&E's opening testimony proposes a limited rollout of business processes to implement Rule 24 requirements in light of recent judicial decisions and market uncertainties regarding direct participation of Demand Responses (DR) resources in California wholesale electricity markets.

non-bundled customers. During 2014 and 2015, PG&E will provide services to these DRPs using mostly manual processes while actively pursuing its IT development processes. In 2016, PG&E will utilize the new IT systems that have been deployed thus far.

Additionally, this approach allows non-utility DRPs an opportunity to participate while they develop and deploy their own systems. The processes needed by a DRP to integrate load reductions into the California Independent System Operator's (CAISO) wholesale market are complex, and these DRPs will require a significant amount of time and infrastructure to support even a moderate number of participants.

As shown in Table A-1, PG&E proposes a transition schedule that allows non-utility DRPs an opportunity to participate in the CAISO's wholesale market while both PG&E and the non-utility DRPs are implementing their systems to support a mature market.

PG&E's Rule 24 implementation is intended to meet the forecasted volumes shown in Table A-1. The forecasted volumes assume that the California Public Utilities Commission (CPUC or Commission) wants PG&E to fully implement Direct Participation by 2017. In the case that the market volumes are significantly in excess or well below these forecasts, PG&E will re-evaluate the project deliveries. Accordingly, PG&E will continue to monitor the market and will advise the Commission.

TABLE A-1
PACIFIC GAS AND ELECTRIC COMPANY
PG&E'S PROPOSED TRANSITION SCHEDULE FOR THE INTEGRATION OF LOAD REDUCTIONS INTO THE CAISO'S WHOLESALE MARKET FOR FULL IMPLEMENTATION

Line No.	Market Component	Phase 1		Phase 2	Phase 3
		2014	2015	2016	2017
1	Participating Customers:	20	100	500	100,000
2	Electric Meters:	30	150	750	102,000
3	Number of DRPs:	2	5	No limit	No limit
4	Wholesale Resources (PG&E as LSE):	6	6	No limit	No limit
5	Load Reduction (PG&E as LSE):	50 MW	50 MW	No limit	No limit
6	Residential Participants Allowed:	N	N	N	Y

C. Summary of PG&E's Incremental Business Activities to Implement Electric Rule 24

Integrating retail demand response into the CAISO's wholesale markets is complex partly due to the number of roles and the various CAISO markets and products. Table A-2 illustrates the many different roles played by different parties combined with the CAISO's markets and products. Those cells filled with a "Y" indicate the Cases and CAISO's markets and products that PG&E plans to implement as part of this application. Specifically, PG&E is seeking authorization to implement Cases 2, 5, 6 and 8 for Day Ahead Energy, Day Ahead Ancillary Services (A\S), Day Ahead Residual Unit Commitment (RUC), Real Time Energy, and Real Time A/S. The business activities and associated costs as discussed in this appendix encompass functionality to support these items.

TABLE A-2
PACIFIC GAS AND ELECTRIC COMPANY
TABLE OF DIFFERENT SUPPORT CASES AND PRODUCTS BY ROLE FOR FULL IMPLEMENTATION

					Supported Day Ahead Products			Supported Real Time Products	
Case	**Customer**	**LSE**	**MDMA**	**DRP**	**Energy**	**A/S**	**RUC**	**Energy**	**A/S**
1	Bundled	PG&E	PG&E	PG&E	Y	N	N	N	N
2	Bundled	PG&E	PG&E	3rd party	Y	Y	Y	Y	Y
3	CCA	3rd party	PG&E	PG&E	N	N	N	N	N
4	DA	3rd party	PG&E	PG&E	N	N	N	N	N
5	CCA	3rd party	PG&E	3rd party	Y	Y	Y	Y	Y
6	DA	3rd party	PG&E	3rd party	Y	Y	Y	Y	Y
7	DA	3rd party	3rd party	PG&E	N	N	N	N	N
8	DA	3rd party	3rd party	3rd party	Y	Y	Y	Y	Y

Rule 24 requires PG&E to implement 13 new activities. As shown in Table A-3, below, these activities are divided into business and IT categories. Of these activities, 8 activities are common between business and IT, 1 activity is specific to the business, and 4 activities are specific to IT.

TABLE A-3
PACIFIC GAS AND ELECTRIC COMPANY
INCREMENTAL ACTIVITIES NECESSARY TO
SUPPORT NON-UTILITY DEMAND RESPONSE PROVIDERS

Activity Number	Activity Description	Business Activity	IT Project Activity
1	Isolating PG&E Staff That Provide Services to Non-Utility Demand Response Providers	Y	N
2	Establish and Maintain Third Parties as Non-Utility Demand Response Providers	Y	Y
3	Processing and Maintaining a DRP's Access to Customer Specific Data via the Customer Information Service Request Demand Response Provider (CISR-DRP) Form	Y	Y
4	Customer Energy Portal Changes	N	Y
5	Modifying PG&E Systems to Produce and Track Non-Interval Data Necessary for Rule 24	Y	Y
6	Transferring Interval Data on an Ongoing Basis to DRPs	Y	Y
7	Transferring Non-Interval Data on a Periodic Basis to DRPs	Y	Y
8	California Independent System Operator Demand Response System Application Programmatic Interface (CAISO DRS API)	N	Y
9	Reviewing CAISO Registrations	Y	Y
10	Modifying PG&E's Customer Care & Billing	N	Y
11	Forecasting Load Reductions for PG&E Bundled Customers	Y	Y
12	Administration and User Access	N	Y
13	Manage Energy Procurement and Settlements	Y	Y

Each of the new business related activities are discussed in further detail below:

1) **Isolating PG&E Staff That Provide Services to Non-Utility Demand Response Providers**

Electric Rule 24 requires that confidential, competitive information received by PG&E from unaffiliated DRPs (or from the CAISO about the DRPs or their customers) in connection with PG&E's performance of its duties to implement and administer the DRP's use of PG&E's bundled load for DR Services shall be limited to PG&E staff who are responsible for performing PG&E's non-DRP responsibilities. Such confidential, competitive information shall not be used to promote PG&E's services to its customers or customers of its affiliates.

PG&E staff receiving such confidential, competitive information from the DRPs or the CAISO in the discharge of PG&E's roles and responsibilities as a non-DRP shall not share such confidential, competitive information with other individuals in PG&E who are also responsible for discharging PG&E's roles and responsibilities as a DRP.

This new requirement mandates PG&E to set up a new work group or identify an existing work group to manage and provide services to unaffiliated DRPs. This work group will have to have access to all of PG&E's DR processes and the CAISO's Demand Response System (DRS) under the roles of Utility Distribution Company (UDC) and Load Serving Entity (LSE). However, PG&E's DR department cannot have access to any information that is related to an unaffiliated DRP. This work group will be separate from those individuals at PG&E who are responsible for discharging PG&E's roles and responsibilities as a DRP.

2) **Establish and Maintain Third Parties as Non-Utility Demand Response Providers**

In order to participate in the electric Rule 24, interested third parties need to register with possibly PG&E[2] but always with the CPUC and the CAISO. A non-utility DRP must use the Demand Response Provider Service Agreement (DRP Service Agreement – Form No 79-1160) to register with PG&E. PG&E would supply the non-utility DRP with a portable document format (PDF) based agreement. The non-utility DRPs would return the completed PDF in paper format to the PG&E work group mentioned in Activity 1, above.

Once this form is received, PG&E would validate that the information is correct. Once validated, PG&E would respond to the DRP that the validation is complete. The DRP must also satisfy PG&E's credit

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2 Non-utility DRPs planning to enroll bundled service customers need to register with PG&E (as the LSE), the CPUC, and the CAISO. All non-utility DRPs regardless of the types of customers they plan to enroll must register with the CPUC. All DRPs must register with the CAISO.

requirements. Once the credit requirements have been satisfied, PG&E will return to the DRP a copy counter signed by an authorized PG&E employee.

The PG&E work group mentioned in Activity 1, above, would maintain all paper copies of the agreement within its work group. This work group must periodically verify that each of the DRPs is valid. If a DRP's registration with PG&E becomes invalid, then PG&E must stop all wholesale market activities with the DRP and inform both the CPUC and the CAISO. If a DRP's registration with either the CPUC or CAISO becomes invalid, then PG&E must stop all wholesale market activities with the DRP.

3) **Processing and Maintaining a DRP's Access to Customer Specific Data Via the Customer Information Service Request Demand Response Provider Form**

One of the key new requirements of electric Rule 24 is providing information to non-utility DRPs. To support this requirement, Rule 24 includes a new form titled Customer Information Service Request Demand Response Provider Form (79-1152). The majority of the work necessary to provide information to the non-utility DRPs will be performed by the work group mentioned in Activity 1, above.

The new CISR-DRP form is complex. It has 72 text boxes and 12 check boxes. These 12 check boxes allow 82 valid combinations. Each valid combination requires different setup and handling throughout the of the customer's authorization. Both non-utility DRPs and customers will require training on the proper use of the form. The effort needed to validate that the form has been completed filled out properly will take significant effort. The management of the customer's authorization to release data is one of the primary areas in which PG&E's IT department will be able to provide better and more streamlined services to our customers and to the non-utility DRPs.

For example, the CISR-DRP form requires the customer to provide a start date for the authorization. The form allows the customer to either specify an end date or to have the authorization continue indefinitely. If the customer leaves the authorization end date as indefinite, then the customer must specify if the customer alone can terminate the authorization or if the non-utility DRP is able to terminate the authorization as well. During 2014 and 2015, the work group identified in Activity 1, above, will manually perform all of these activities. Phase 1 of PG&E's Customer Data Access (CDA) (D.13-09-025) is expected to help PG&E to manage the CISR-DRP authorization process. CDA Phase 1 is planned to be operational early 2015.

4) **Customer Energy Portal Changes**

This is an IT only activity. See Appendix B for details.

5) **Modifying PG&E Systems to Produce and Track Non-Interval Data Necessary for Rule 24**

As mentioned in Activity 7, below, a customer's DRP needs confidential customer data to support its wholesale market integration. The majority of this data can change overtime, and these changes can affect the DRP's use of a customer. Three primary examples are a change-of-party, a change in a customer's LSE, and a change in a customer's Sub Load Aggregation Point (S-LAP). A change to any one of these items requires the DRP to terminate any CAISO registrations containing this customer.

It is important that PG&E track and report these changes to the DRP. During the 2014-2016 time period, these data items will be manually checked for changes and manually communicated to the DRP. It is important that this process be automated to support a mature wholesale market integration.

6) **Transferring Interval Data on an Ongoing Basis to DRPs**

For those customers where PG&E is the Meter Data Management Agent (MDMA), PG&E will be required to send Revenue Quality Meter Data (RQMD) for each of the non-utility DRP's customers to the DRP (or its agent) in a timely manner after the conclusion of customer's monthly billing cycle. The DRP converts this RQMD to Settlement Quality Meter Data (SQMD), which the DRP then sends to its Scheduling Coordinator (SC). The DRP's SC then submits the SQMD to the CAISO via the CAISO's DRS. The SQMD must be submitted to the CAISO no later than 48 business days after the trade date. The CAISO uses this data to produce final settlement statements that it produces 55 business days after the trade date.

It is important that the RQMD be provided to the DRP be as accurate as possible because the CAISO is able to impose penalties for any corrections. If the PG&E acting as the MDMA is found, through a remedy and dispute resolution process, to have failed to comply fully with the applicable requirements for submission of timely and accurate RQMD so as to be the sole fault for the ability for the DRP to comply fully with the applicable CAISO requirements, then the MDMA shall be held liable, limited to the penalties imposed by the CAISO upon the non-Utility DRP or its SC due to the non-compliance.

Prior to sending a customer's interval data to a DRP, PG&E, acting as the MDMA will validate that customer's CISR-DRP authorization is still active. PG&E will not send the DRP any interval data for any operating dates that are after the termination date specified in the customer's CISR-DRP. However, PG&E will periodically check if any of this previously transmitted interval data has changed. Any changes discovered within three years of the operational date will be communicated to the DRP. These corrections will be transmitted to the DRP even after the CISR has terminated because the DRP was entitled to receive interval and any subsequent corrections for the dates specified in the customer's CISR-DRP.

During 2014, all of the data exchange activities will be manually performed and transferred (via a secure process) to the DRP. These manual processes limit PG&E's ability to accommodate a relatively large set of customers and meters during the initial implementation of Rule 24 processes.

Certain activities such as modifying interval data to correct for interval gaps and failed meters, etc. will continue to be performed manually even after 2016. PG&E believes this is the least cost approach based on the total number of expected meters provided in Table A-1.

PG&E is currently implementing Phase 1 of its Customer Data Access project. This Phase 1 is expected to be completed by early 2015. This phase will include many aspects of providing a DRP with ongoing interval data but the manual process described in Activities 3 and 5, above, will continue to be completely manual for at least 12 months after CDA Phase 1 is released to production. For this reason, PG&E believes it is able to accommodate more DRPs, customers, and meters in 2015 than in 2014.

7) **Transferring Non-Interval Data on a Periodic Basis to DRPs**

PG&E is required, as part of the CISR-DRP process, to provide the following data to the non-utility DRP upon PG&E's approval of the CISR-DRP and, without charge, up to two times in a 12-month period per service account:

a. Customer Service Agreement information, name, mailing address, service address, electric rate schedule, etc.
b. Basic meter information including the meter number, the type of meter, and the intervals currently being collected by the meter.
c. Customer's Monthly Meter Read Cycle.
d. The identity and contact information of the customer's LSE, MDMA, and Meter Service Provider.
e. A Unique Customer Identifier (UCI) that the DRP enters into the CAISO's DRS. This UCI is used by the CAISO's systems to prevent a customer from being in two or more registrations that are active at the same time. This UCI would also be provided to the customer's LSE.
f. A maximum of the most recent 12 months of customer billing data or the amount of data recorded for that specific service agreement.
g. Confidential end-user information such as the customer's service voltage, the S-LAP, Pricing node (P-Node).
h. If the customer is currently enrolled or in the process of becoming enrolled in any event-based utility DR program(s). If yes, then PG&E must provide (1) the earliest date that the customer can opt out of the program without a financial impact to the customer; and (2) the earliest date that the customer can opt out of the program regardless of financial impact to the customer.
i. Up to one year of historical electric interval data, as it is available for a specific service agreement.

As mentioned in Activity 5, PG&E will periodically check if any of these data elements have changed. Any changes will be communicated to the DRP after PG&E validates that the CISR-DRP is still active.

During the 2014-2016 time period, all of the data mentioned above will be manually collected, tracked, and transferred (via a secure process) to the DRP.

These manual processes, including the periodic checking for changes, limit PG&E's ability to accommodate more than small set of customers and meters.

PG&E is developing plans for its Phase 2 of its Customer Data Access (D.13-09-025). The scope of Phase 2 has not been fully established at this time but PG&E hopes that most if not all of these data elements are able to be included as part of CDA's Phase 2. If all of these components are not included, then PG&E may have to restrict the number of DRPs, customers, and meters for 2016 and beyond.

8) **California Independent System Operator Demand Response System Application Programmatic Interface**

This is an IT only activity. See Appendix B for details.

9) **Reviewing CAISO Registrations**

Each business day, the isolated work group mentioned in activity 1, above, will log into the CAISO's DRS and determine if there are any registrations to be reviewed. If there are registrations to be reviewed, then the isolated work group will perform the following new tasks:

PG&E as the UDC will validate the following items:

- Validate that PG&E is the UDC for each of the customers.
- Validate that the UCI is correct for each customer in the registration.
- Validate that each of the customer's service agreement are still active.
- Validate that a CISR-DRP exists and is still active between the DRP and each customer in the registration.
- Validate that the DRP is within its credit limits for all registrations that will be concurrently active.
- Validate that the LSE for each of the customer's is the LSE shown for the registration.
- Verify that the customer name and service address closely match the values in PG&E's systems.
- Validate that the S-LAP is correct for each of the customers.
- Validate that the P-Node is correct for each of the customers.
- Validate that the Default Load Aggregation Point is correct for the UDC.
- Review each customer for participation in a PG&E retail DR program including Peak Day Pricing (PDP) and SmartRate™. This is a complicated process.

PG&E as the LSE will validate the following items:

- Validate that PG&E has an active LSE DRP agreement with the DRP.
- Validate that PG&E is the LSE for each of the customers.

PG&E as the MDMA will validate the following:

- Validate that RQMD is currently being sent to the DRP for each of the customers in registration.

If the registration and all of the customers in the registration pass validation, then PG&E will perform the following activities:

- PG&E will mark the registration as "Reviewed without findings" in the CAISO's DRS.
- PG&E will manually update its customer information systems with sufficient information necessary to indicate that the customer is an active participant in the CAISO's wholesale market.

If one or more the customers in the registration do not pass validation, then PG&E will mark the registration as "Reviewed with findings" and provide information to the CAISO and the DRP outlining why one or more of the customers did not pass.

The registration review process is an entirely new activity. The review process will require PG&E personnel to log into several PG&E systems to obtain the necessary information. The process is especially difficult if a one or more of the customers are found to be enrolled or in the process of being enrolled in a DR program, PDP, or SmartRate. This review process will be entirely manual during 2014 and 2015. Accommodating even a moderate sized number of customers will require PG&E to develop an IT infrastructure, which is dependent on the CAISO building and providing an Application Programmatic Interface (API) to their DRS.[3] PG&E needs the CAISO to design and to publish the API specifications on a timeline that allows PG&E to complete its development process no later than the end of 2015.

10) **Modifying PG&E's Customer Care & Billing**

This is an IT only activity. See Appendix B for details.

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[3] An API allows the CAISO's and PG&E's system to inter communicate which eliminates the majority of the manual processes. The CAISO's API will have three components: (1) Registration Setup and Management; (2) Baseline Calculation Details; and (3) Resource Performance Details.

11) **Forecasting Load Reductions for PG&E Bundled Customers**

PG&E's Electric Procurement (EP) Department forecasts the hourly load for its bundled customers on a daily basis. When a DR event occurs, it is important that PG&E's EP Department is aware of the event and be provided in a timely manner with an estimate of the forecasted hourly-load reductions. After the event, EP also needs to know the actual hourly-load reductions. EP needs to know this information because it uses, in addition to other inputs, Supervisory Control and Data Acquisition (SCADA) and actual meter data as inputs to its forecast. On event days, EP adds the forecasted and actual hourly load reductions to the SCADA and meter data prior to sending the SCADA and meter data to its load forecasting engine. It is important that the engine use the hourly load as if the event had not occurred. Not accounting for the event load reductions will make EP's hourly load forecast artificially low. There is a 50-megawatt (MW) threshold below which EP does not need to account for load reductions.

During Phase 1 of the Rule 24 rollout, PG&E needs to limit the total load reductions for its bundled service customers to less than 50 MW. During Phase 2 of the Rule 24 rollout, PG&E expects this limit to be removed because part of PG&E's Rule 24 implementation includes the ability to provide this event related data to EP for non-utility resources containing bundled service customers.

12) **Administration and User Access**

This is an IT only activity. See Appendix B for details.

13) **Manage Energy Procurement and Settlements**

When PG&E bundled service customers are included in a resource, PG&E as the LSE validates the CAISO's wholesale settlement calculations each the resource receives a market award. This validation is commonly referred to as shadow calculations. PG&E performs this activity whether or not it is the DRP for the resource.

PG&E implemented a portion of this Shadow Calculations when it implemented its Proxy Demand Response (PDR) integration of PeakChoice™ as Day Ahead Energy. This functionality was limited to Day-

Ahead Energy only.[4] The following CAISO markets and products have not been implemented: Day-Ahead Ancillary Services, Day-Ahead Residual Unit Commitment (RUC), Real-Time Energy, and Real-Time Ancillary Services:

In Phase 1 of the Rule 24 roll-out, PG&E would manually export the data from the CAISO DRS to a temporary tool to perform the shadow calculations. This process is manually intensive and so Phase 1 will be limited to six resources.

One of the primary limitations to developing a robust solution is that the CAISO DRS does not support an API to download the data necessary for PG&E to perform the shadow calculations.

Provided the CAISO provides an API, PG&E plans to develop for Phase 2 of the Rule 24 rollout its corresponding API to import the data exposed by the CAISO's DRS API. This will allow PG&E to utilize its vendor provided solution that PG&E currently is using to perform shadow calculations for the majority of its wholesale settlements. This vendor provided solution will also perform shadow calculations for the remaining CAISO markets and products, including the NBT, that were not included in PG&E's PDR integration of PeakChoice™ as Day Ahead Energy This additional functionality will allow PG&E to perform shadow calculations for a high number of resources.

D. PG&E's Incremental Costs to Implement Electric Rule 24 for Non-Utility Demand Response Providers

PG&E's cost to implement electric Rule 24 for non-utility DRPs is shown in Table A-4. This table has the two major cost categories.

The first is the Total Project Costs to implement an IT solution to automate portions of functionality necessary to support Rule 24. These project costs include IT development costs plus business costs that are necessary to support the project.

The second major cost category is for Operations and Maintenance. The business portion of this major category represents the business related costs to manually implement electric Rule 24 on a limited basis during 2015 and 2016.

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4 This functionality did not include the CAISO's Net Benefits Test (NBT) because the NBT was being litigated at the Federal Energy Regulatory Commission while PG&E was developing its PDR integration of PeakChoice™.

The IT portion of these costs represents 2016 costs to maintain the IT infrastructure that has been completed in 2015.

The costs for these two major categories are separate, and the tasks associated with these categories are incremental.

TABLE A-4
PACIFIC GAS AND ELECTRIC COMPANY
PG&E'S COSTS TO IMPLEMENT ELECTRIC RULE 24
FOR NON-UTILITY DRPS

	Project Implementation Cost Summary		
Line No.		Work Days	Total
1	**Project Costs**		
2	Capital		
3	Labor	9,689	$11,626,335
4	Hardware		2,082,500
5	A&G		930,107
6	Material Burden		20,825
7	AFUDC (Jan 1 2015 thru Jun 30, 2016)		712,660
8	**Capital Subtotal**	**9,689**	**$15,372,427**
9	Expense		
10	Training	208	$250,000
11	Business Project Costs	469	562,500
12	Plan/Analyze Project Stage Labor	1,018	1,221,614
13	Forecasting Service Expense		125,000
14	Hardware Licensing		37,500
15	**Expense Subtotal**	**1,695**	**$2,196,614**
16	**Total Project Costs**	**11,384**	**$17,569,041**
17	**Operations & Maintenance**		Total
18	IT O&M (2016)		$562,500
19	Business O&M (2015, 2016)		$723,755
20	**O&M Subtotal**		$1,286,255
21	**Total Project and O&M Costs**		**$18,855,296**

E. Conclusion

In this appendix, PG&E has demonstrated that the activities necessary to implement electric Rule 24 to support non-utility DRPs are incremental to PG&E's current business activities. These incremental activities will require PG&E to incur incremental business costs and incremental ISTS costs. Further, in this appendix, PG&E has demonstrates that the amounts it seeks to recover will be reasonably incurred.

PG&E requests that the Commission approve PG&E's request for $18.9 million.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

INFORMATION TECHNOLOGY (IT) REQUIREMENTS

(COMPLETE RULE 24 IMPLEMENTATION)

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APPENDIX B
INFORMATION TECHNOLOGY (IT) REQUIREMENTS
(COMPLETE RULE 24 IMPLEMENTATION)

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PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX B
INFORMATION TECHNOLOGY (IT) REQUIREMENTS
(COMPLETE RULE 24 IMPLEMENTATION)

A. Introduction

This appendix describes the Information Technology (IT) work and costs that Pacific Gas and Electric Company (PG&E) will incur to fully implement Rule 24 and its related supporting activities if the California Public Utilities Commission (CPUC or Commission) believes that the Investor-Owned Utilities (IOU) need to make ready for a complete implementation of Direct Participation by 2017.[1] Additional costs may be incurred to maintain these new systems and processes, or expand system capabilities as dictated by the CPUC or the market. Cost recovery for these charges will be requested in a separate, future application. Specifically, this project and its associated costs will encompass the creation of new systems and processes to: (1) manage Rule 24 resource registrations; (2) manage authorizations and establish data transfers to Non-Utility Rule 24 participants; and (3) integrate Rule 24 processes into current demand response, customer management, and energy procurement systems and processes.

These project costs should be distinguished from the costs for ongoing operations and maintenance of Demand Response (DR) systems that support the manual implementation of Rule 24 until such time the project is able to enable technology to supplement or replace the manual efforts. Such operations and maintenance costs are described in Appendix A, "Business Process Requirements (Complete Rule 24 Implementation)."

The Rule 24 Project described in this appendix primarily uses internally developed software. As such, the costs are capitalized consistent with guidelines adopted by the Commission.

The proposed operative date for the Rule 24 Project, provided in Appendix A Table A-1, is dependent on when regulatory and business requirements are

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1 Chapters 1 and 2 of PG&E's opening testimony proposes a limited rollout of business processes to implement Rule 24 requirements in light of recent judicial decisions and market uncertainties regarding direct participation of demand responses resources in California wholesale electricity markets.

known. As explained in Section C of this appendix, PG&E follows a defined delivery methodology to promptly complete the project within its' estimated costs. Upon issuing a final decision approving the Rule 24 Project, the Commission must allow sufficient lead-time to design, build, deploy, and test the IT functionality needed to implement the project by its proposed operative date. PG&E estimates that this work will take 18 months. If, upon approval, new business requirements are added or requirements are changed, there is risk of delay and extra costs.

The remainder of this appendix is organized as follows:

- Section B – Proposed Rule 24 Project
- Section C – IT Planning Process
- Section D – Rule 24 Solution Overview
- Section E – Summary of Estimated Costs
- Section F – Conclusion

B. Proposed Rule 24 Project

1. Overview

PG&E proposes to build and\or extend infrastructure to develop the processes and system enhancements needed to manage requirements as defined by Rule 24.

2. Project Objective

For purposes of this estimation, PG&E will assume a project start date of January 1, 2015 for purposes of planning and estimation. As this may not be reflective of the final decision, it should be noted that actual project timelines would need to be adjusted to reflect the actual Rule 24 approval date. PG&E proposes to develop and extend processes and platforms to address the following goals and objectives:

1) Manage Rule 24 resource registrations of Non-Utility Demand Response Providers (DRP).
2) Manage authorizations and establish data transfers to Non-Utility Rule 24 participants.
3) Integrate Rule 24 processes into current demand response, customer management, and energy procurement systems and processes.

3. Project Proposal

As described in Section B.2, PG&E will extend or create new systems and processes to meet the Rule 24 requirements. As shown in Table A-1 from Appendix A, the IT project costs will allow PG&E to meet the full Phase 3 volumes in 2017 as well as incrementally support growth in volumes for Phase 2 in 2016, where PG&E will utilize the new IT systems that have been deployed thus far.

The Rule 24 requirements were previously detailed in the Appendix A. A mapping of the Appendix A business activities to the corresponding IT efforts as shown in Table A-3 from Appendix A:

Specifically for the IT Project, the activities 2-13 noted in Table A-3 have an effort that would result in an IT project estimation:

2. Establish and Maintain Third Parties as Non-Utility Demand Response Providers (DRP)
3. Processing and Maintaining a DRP's Access to Customer Specific Data via the Customer Information Service Request Demand Response Provider (CISR-DRP) Form
4. Customer Energy Portal Changes
5. Modifying PG&E Systems to Produce and Track Non-Interval Data Items Necessary for Rule 24
6. Transferring Interval Data on an Ongoing Basis to DRPs
7. Transferring Non-Interval Data on a Periodic Basis to DRPs
8. California Independent System Operator Demand Response System Application Programmatic Interface (CAISO DRS API)
9. Reviewing CAISO Registrations
10. Modifying PG&E's Customer Care and Billing (CC&B)
11. Forecasting Load Reductions for PG&E Bundled Customers
12. Administration and User Access
13. Manage Energy Procurement and Settlements

C. IT Planning Process

PG&E has numerous inter-related IT systems that support the day-to-day operations of its gas and electric service and PG&E's interaction with its customers. Because of the necessarily complex nature of PG&E's IT infrastructure, PG&E's IT Program Office Group has developed a standard approach for delivering new functionality. It is called the Information Technology Method (ITM). Because PG&E will use its ITM to implement the Rule 24 Project, this section provides a brief overview of the process PG&E uses interdependent work streams in a logical manner to streamline the process. This is PG&E's standard IT delivery process used on virtually all PG&E IT application projects.

The PG&E IT Program Office is responsible for managing and maintaining IT governance for application development efforts. The IT Program Office governance framework is based on common IT industry standards—most notably Control Objectives for Information and Related Technology (CoBIT), Project Management Body of Knowledge (PMBOK), and Capability Maturity Model Integration (CMMI). The current IT governance framework comprises of an extensive library of standardized templates, processes, and reference materials—framed around a robust quality control process and several key enterprise project management systems and tools.

The IT Program Office is dedicated to continuous process improvement and as such adjusts its IT governance framework and best practices to reflect changes in organizational structure, compliance requirements, industry best practices, and technology standards. The IT Program Office has established a robust in-house training and communication program to continuously educate staff on internal and external standards and best practices.

1. PG&E IT Methodology Defined

The IT Methodology consists of the following key components:

a. Project Stages

The IT Methodology recognizes the following seven industry standard SDLC project stages: (1) Work Intake; (2) Plan/Analyze; (3) Design; (4) Build; (5) Test; (6) Deploy; and (7) Stabilize.

b. Key Deliverables

Following industry standards, the IT methodology provides for Key Deliverable Modules that reflect 'best practices' within the application development arena. Each of these Key Deliverable Modules can contain multiple deliverables. Standardized templates are provided as well as guidelines for preparing, reviewing, and approving deliverables.

c. **Deliverable Waiver Process**

In accordance with standard industry practices, and in order to match the project documentation requirements to project size, risk, and complexity, the IT Program Office executes a Deliverable Waiver procedure as part of the quality control/Project Success Check process.

d. **Deliverable Routing and Archival**

The IT Methodology incorporates a set of standards, guidelines, processes and systems for the review, approval, and archival of project documentation.

e. **Quality Control Through Project Success Checks**

The IT Methodology includes up to five project Quality Control touch points referred to as Project Success Checks. A Project Success Check is a 'point-in-time' quality control assessments of a project. Chaired by the IT Program Office, the Project Success check's objective is to review adherence and compliance to enterprise project management best practices as reflected in the IT Methodology, and the adequacy, appropriateness and completeness of the Technical Solution as it is being proposed, documented, designed, built, and deployed.

D. Rule 24 Solution Overview

1. Rule 24

Implementing the Rule 24 Project on the scale and timeline proposed will require:

a) An education process for customers and third parties and changes in the way PG&E communicates and interacts with a number of its customers and third parties.

b) Modifications to PG&E's IT systems and internet-based tools to support the changes reflected in the proposals.

c) New business processes to manage customer concerns related to potential misuse of data by third parties.

d) Other changes to PG&E's business processes to support the customers resulting from these new capabilities.

The Rule 24 Project will provide a platform to allow for DRP registration for customer data access, Authorization to release customer specific data,

Data Presentment, the validation of a DRP's resource registration at the CAISO, and integration with Energy Procurement Front and Back office systems.

Much of the complexity and need for system integration is tied to the multiple permutations of support cases where PG&E is not the DRP. Table A-2 from Appendix A below illustrates the many different scenarios by role and supported products for a full implementation: Day-Ahead Energy, Day-Ahead Ancillary Services (A\S), Day-Ahead Residual Unit Commitment (RUC), Real Time Energy, and Real-Time Ancillary Services. Each scenario introduces additional complication and cost to build and operate the platform. The support roles for Rule 24 are represented in Cases 2, 5, 6 and 8 where the DRP is described as a Third Party.

Rule 24 builds upon the services as implemented by PG&E for Proxy Demand Response (PDR) integration of PeakChoice™ as Day-Ahead Energy. The project was included in PG&E's Market Redesign and Technology Upgrade (MRTU) application and focused on building a portion of the IT platform to create the foundation on which PG&E's DR programs can be migrated to PDR and Reliability Demand Response Resource (RDRR). The costs incurred are in PG&E's MRTU memorandum account, awaiting the Commission's final decision. This project constituted only Phase 1 of the deployment of the PDR platform in which PG&E fulfills the role as the DRP, Load Serving Entity (LSE) and Meter Data Management Agent (MDMA), and the Scheduling Coordinator (SC) for both the LSE and the DRP. (This work is referred to in this Appendix as PDR1.) In Table A-2, the PDR1 case is depicted as a subset of Case 1 for a specific PG&E program (PeakChoice™), CAISO product (Energy), and market (Day Ahead). The IT project costs in this appendix will encompass functionality to support Rule 24 as depicted as Cases 2, 5, 6 and 8 in Table A-2.

The IT platform to support PDR encompassed various services which are similar to those needed for Rule 24 support and accordingly, where appropriate, were re-used or extended for use in the design and estimation of the solution for Rule 24. For additional combinations of products (i.e., Ancillary Services or RUC) or markets (i.e., Real Time) that would need Rule 24 support, services would need to be extended or newly developed.

For purposes of the Rule 24 estimation, it assumed dependencies on other enterprise initiatives that can be leveraged to reduce overall costs and provide functionality such as the Customer Data Access (CDA) project.[2]

2. Rule 24 Service Offerings

The main functions of the Rule 24 Project have been identified in two primary services (as shown in Table A-3, Appendix A):

- Pre-Resource Registration Set Up and Resource Registration Review and Pre-Event Set Up (Table A-3, Items 1 through 12)
- Post-Event Activities (Table A-3, Item 13)

a. Pre-Resource Registration Set Up, Resource Registration Review and Pre-Event Set Up

The services as defined in the Pre-Resource Registration Set Up include process to set up the DRP in order to manage the DRP agreement, the Rule 24 Customer Information Service Request (CISR-DRP) and the alignment of the data transfer to the non-Utility DRP. A high level illustration is shown in Figure B-1. PG&E proposes that the DRP registration, CISR authorization, Rule 24 customer data transfer, and usage data transfer requirements be met by extending the Customer Data Access (CDA platform beyond its currently approved CDA Phase 1 functionality and Phase 2 project scope). PG&E did not have clear visibility into the Rule 24 customer data needs at the time of filing its CDA application, and hence it was not included in the scope. Therefore, the Rule 24 Project will need to extend the scope of CDA to meet its requirements.

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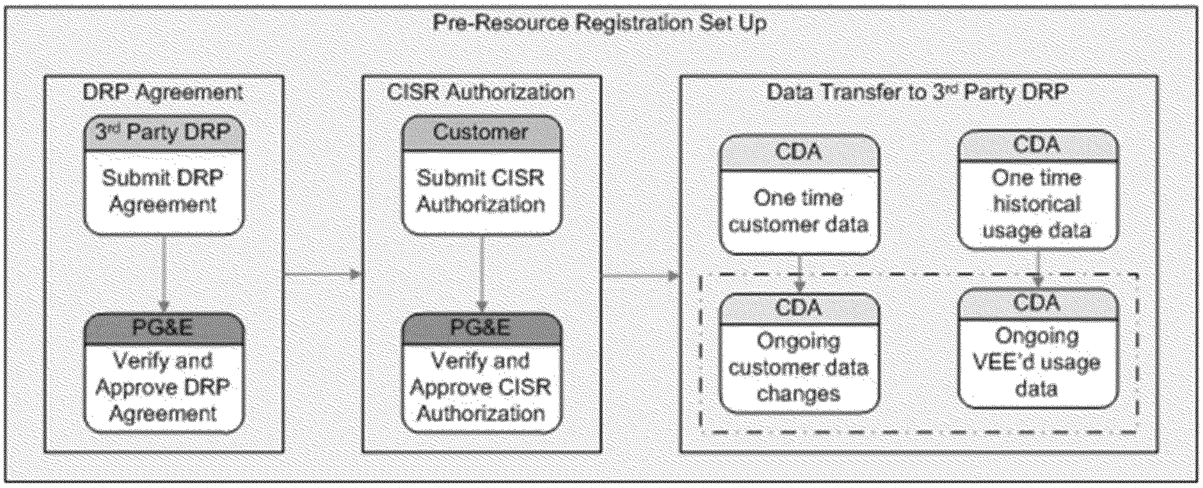
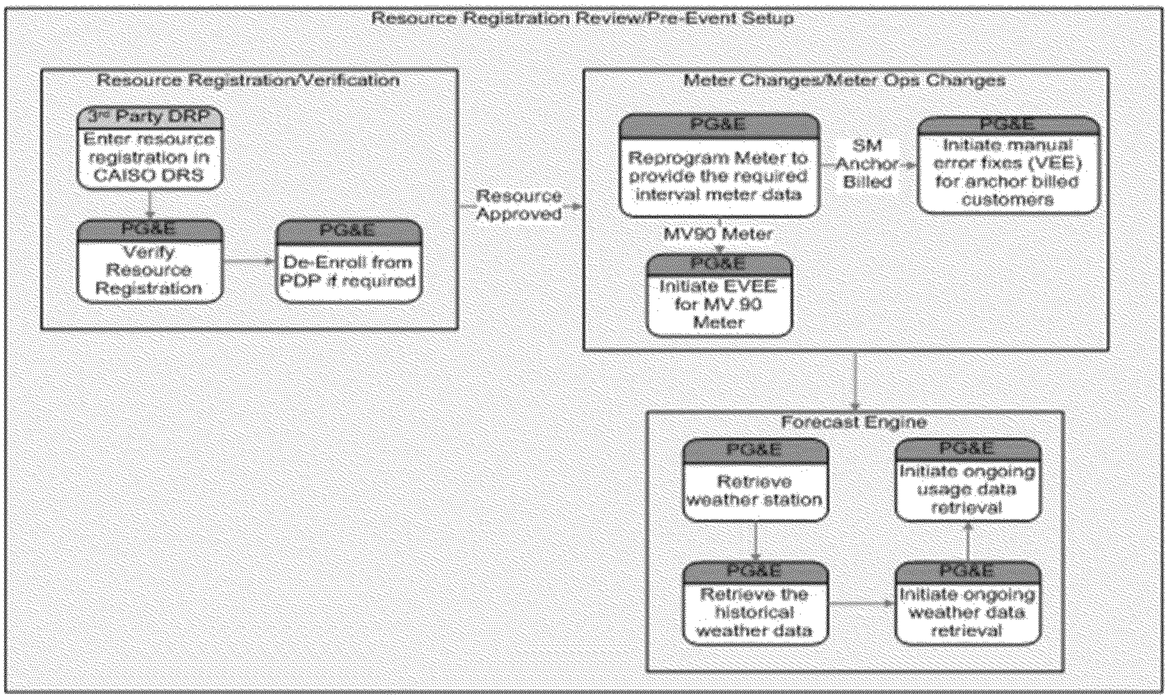
2 Customer Data Access project was approved in D.13-09-025 on September 23, 2013.

FIGURE B-1
PACIFIC GAS AND ELECTRIC COMPANY
PRE-RESOUCE REGISRATION SET UP



The services as defined in the Resource Registration Review and Pre-Event Set Up include processes to manage the DR resource registration from the CAISO through internal systems and processes and updating internal systems to conform with the DR resource metering needs and internal forecasting set up needs. A high level description is shown in Figure B-2. Please note that the CAISO DRS API must be in production at the point of project inception in order to allow for a scalable solution to be implemented. Any delays in the release of this interface into production will result in delays in this project being able to meet full scale requirements.

FIGURE B-2
PACIFIC GAS AND ELECTRIC COMPANY
RESOURCE REGISTRATION REVIEW AND PRE-EVENT SET UP



A description of impacted processes and systems are provided as follows:

1) **Isolating PG&E Staff That Provide Services to Non-Utility Demand Response Providers (DRP)**

This is a business only activity. See Appendix A for details.

2) **Establish and Maintain Third Parties as Non-Utility DRPs**

Processes will need to be developed and systems will need to be extended in order to allow for the DRP to contract with PG&E to help facilitate bundled service customer participation in the CAISO market. The process will allow for the submission of a DRS agreement into the PG&E systems where the DRS agreement will be validated, either approved or rejected, and communicated back to the DRP.

It is anticipated that this requirement may be done by extending the CDA platform beyond the current Phase 1 and Phase 2 scope to meet Rule 24 specific DRP registration functionality.

3) **Processing and Maintaining a DRP's Access to Customer Specific Data via the Customer Information Service Request Demand Response Provider (CISR-DRP) Form**

Processes will need to be developed and systems will need to be extended in order to allow for the appropriate authorization of the DRP by the customer for purposes of receiving data. In the course of the CISR authorization, PG&E must gather, validate, and assign a number of customer and meter data attributes in order to determine the appropriate customer attributes and corresponding meter data to provide for both a historical and on-going release. It is anticipated that this may be done by extending the CDA platform beyond the current CDA Phase 1 and Phase 2 scope to meet Rule 24 specific DRP CISR functionality.

4) **Customer Energy Portal Changes**

Changes to the Customer Portal will need to be made to allow for the facilitation of the CISR approval by the customer for the DRP authorization. These incremental changes will modify and extend the current portal to allow for Rule 24 specific functionality to be enabled. This would include the need to implement unique business rules and data presentation requirements in support of Rule 24 that are currently not implemented.

5) **Modifying PG&E Systems to Produce and Track Non-Interval Data Necessary for Rule 24**

Processes will need to be developed and systems will need to capture and align with Rule 24 defined customer data for purposes of data presentation. These changes will include mapping the customers to the appropriate DRP resources, aligning the customers data with the appropriate attributes (i.e., CAISO Sub-Load Aggregation Point and CAISO Pricing node), and collecting Rule 24 customer specific data (i.e., service voltage, contact information of a customer's LSE and MDMA, list of enrolled Utility Distribution Company (UDC) DR programs, etc.).

6) **Transferring Interval Data on an Ongoing Basis to DRPs**

Processes will need to be developed and systems will need to be extended in order to allow for the transfer of Rule 24 defined usage data. Rule 24 would need to extend CDA to meet the new requirements to provide on-bill cycle Revenue Quality Meter Data (RQMD) so it includes Multi-Vendor 90 (MV90) interval meter data. This will require a change to both upstream systems as well the data presentment platform of CDA. For the explicit task of providing electric interval data, it is anticipated that this may be done by extending the CDA platform beyond the current CDA Phase 1 and Phase 2 scope.

7) **Transferring Non-Interval Data on a Periodic Basis to DRPs**

Processes will need to be developed and systems will need to be extended in order to allow for the transfer of Rule 24 defined non-interval data. In order to provide the non-interval data to the authorized DRP(s), the authorization process and as data the delivery processes may be impacted as needed to provide customer data in addition to usage data. The presentation of customer data was not defined in the scope of CDA but it is anticipated that this may be done by extending the CDA[3] platform beyond the current CDA Phase 1 and Phase 2 scope to send the unique customer data as required by Rule 24.

8) **California Independent System Operator Demand Response System Application Programmatic Interface (CAISO DRS API)**

PG&E will integrate with the CAISO API to allow for the programmatic retrieval and processing of DR resource applications. Based on current project assumptions, this interface must be in production by January 1, 2015 in order to minimize delays to the project delivery timeline and project scope and budget. The CAISO API is essential to support volumes of scale for the DRP agreements, and DRP resource registrations. Supporting the volumes as described in Table A-1 is dependent on the ability to

[3] CDA Phase 1 pertains only to customer specific electric interval usage information.

integrate with the CAISO in a systematic manner allowing for timely management of larger volumes of complex transactions. Without this interface, the ability to support the Rule 24 volumes beyond what is described in Phase 1 and Phase 2 will not be feasible. The integration to the CAISO API is new incremental work as the CAISO API was not in production at the time of PG&E PDR PeakChoice™ as Day-Ahead Energy implementation.

9) **Reviewing CAISO Registrations**

Processes will need to be developed and systems will need to be extended in order to manage the DR resource registrations in a timely manner at scale. These systems and processes will manage a complex set of business rules and data sets to determine eligibility and assign respective customer attributes. The service will facilitate the tasks of interfacing with the CAISO Demand Response System Application Programmatic Interface (CAISO DRS API) to check if the DRP is actively registered with PG&E, validate locations, validate registrations, and validate resources. Upon completion of the DRP review, the system will update the CAISO DRS. The complexity of the solution is increased by the challenge associated with managing interdependencies between multiple resources with different DRPS(s) over time periods that may not overlap.

10) **Modifying PG&E's Customer Care and Billing (CC&B)**

Processes will need to be developed and the CC&B systems will need to be extended to create new interfaces to manage DR registrations, update metering characteristics, and manage Rule 24 customer attributes. The CC&B system is the Customer Information System (CIS) for PG&E and will need to be updated and queried against to find or provide the most current status and attributes for each customer as used in the DRP resource registration and customer data transfer. Interfaces will need to be created or modified to capture the data needed to support the Rule 24 customer data.

11) **Forecasting Load Reductions for PG&E Bundled Customers**

A forecasting process will need to be implemented to capture appropriate data to support the creation of forecasts. To facilitate this function, resources must be aligned with the appropriate weather station. Historical usage and weather data must be aligned and provided to the forecasting engine and a forecast at the appropriate granularity must be created in a timely fashion.

New processes will be created to automate scalable processes to allow for proper alignment of data feeds and processing of the corresponding forecast into PG&E systems.

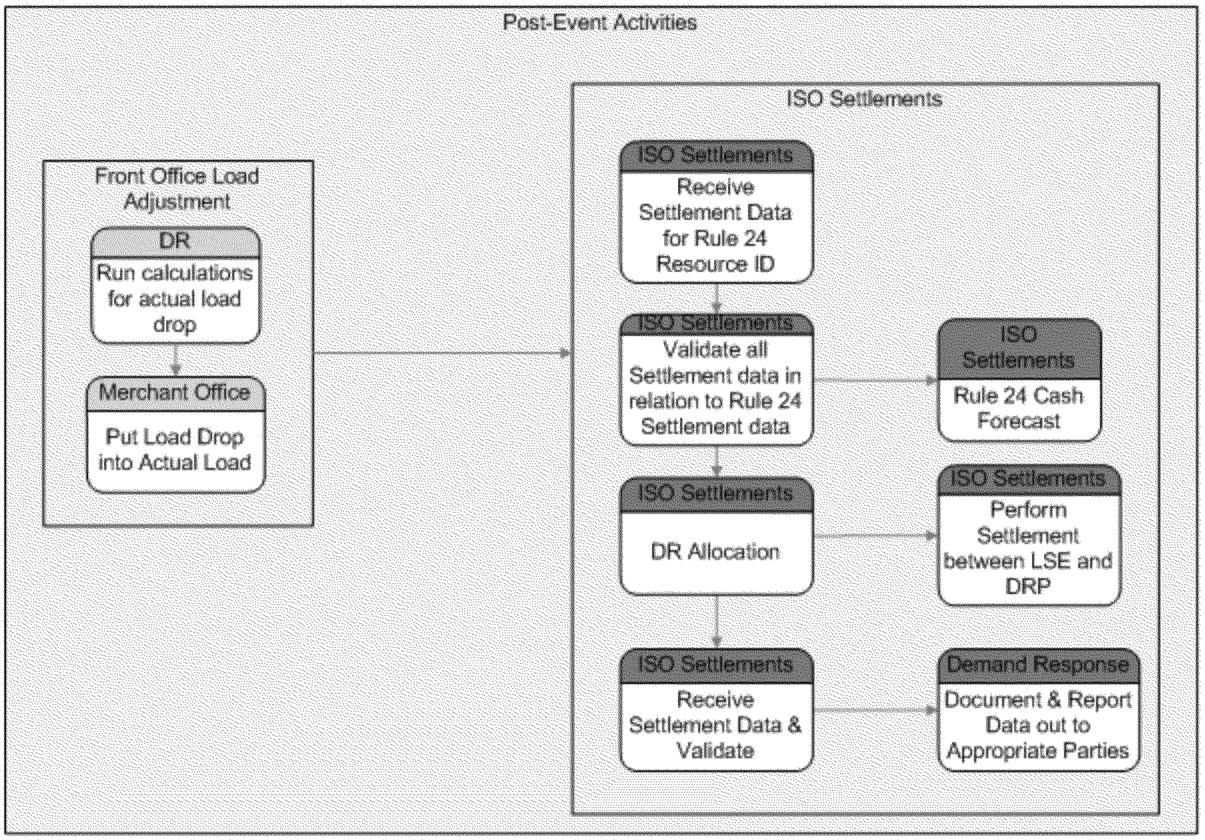
12) **Administration and User Access**

Processes will need to be developed and systems will need to be extended in order to allow for the appropriate administration of applications and to allow for appropriate user access. This would include enhancing existing systems to allow for appropriate segmentation of administration rights and Rule 24 customers and functionality.

b. Post-Event Activities

The services as defined in the Post-Event activities include processes to manage the results of a CAISO dispatch of a Rule 24 resource. A high level description is shown in Figure B-3.

FIGURE B-3
PACIFIC GAS AND ELECTRIC COMPANY
POST-EVENT ACTIVITES



The corresponding systems and processes to be modified include:

13) **Manage Energy Procurement and Settlements**

Processes will need to be developed and systems will need to be extended in order to integrate the DR resources, forecasts and CAISO market awards accordingly into the wholesale market energy procurement processes both from a front office procurement and back office settlement capacity. These processes will be unique for Rule 24 as they will be done for customers where PG&E is not the DRP. In the past, PG&E, as the DRP, managed all systems, all customers, and the deployment of PDR PeakChoice™ as Day-Ahead Energy.

E. Summary of Estimated Costs

The direct cost estimates for the projects discussed in this appendix are shown in Table B-1. As explained below, the estimates are based on high-level business requirements provided by individual PG&E departments to meet DR objectives. As these business requirements are further refined during actual project development, the resultant IT requirements will be defined in greater detail, which may affect the estimated project costs.

In addition to describing PG&E's overall approach to developing IT cost estimates, this section presents the cost estimates and assumptions used in preparing the costs.

1. PG&E's IT Cost Estimating Process

PG&E used its standard approach to develop the project cost estimates based upon high-level business requirements. The cost estimate is created as part of an iterative process as cost estimates are created and refined throughout the ITM intake (concept estimate) and plan/analyze phases (job estimate). This method first relies on the ITM process described in Section C to estimate the approximate cost of implementing the changes and then uses prior experience to refine the estimate for the DR project specifics.

The ITM process begins with assembling a list of assumptions that the estimate is based upon, followed quickly by defining the project's scope in the form of business requirements. From these business requirements, IT professionals with the necessary expertise in the affected areas develop IT requirements to deliver the business functionality. These IT professionals also assess where work will take place in parallel, thus reducing overall project costs.

Per the ITM process, PG&E IT employees met with various business units to identify the Rule 24 business requirements. As a result, PG&E identified approximately 15 major requirements with approximately 120 additional supporting requirements. These requirements and supporting requirements where then categorized and grouped into the 13 incremental activities as shown in Table A-3. Each of these requirements were confirmed with the business and then reviewed in depth with the various IT technology development groups. As each requirement could impact multiple IT development groups, a number of sessions were scheduled where the requirements were discussed and debated.
The corresponding IT development groups were then asked to estimate the impacts and effort needed to accomplish these requirements. This process

was followed for each individual major and supporting requirement to determine the appropriate scope and complexity of the work.

As part of the review and estimation process, PG&E IT development groups reviewed the existing technical architecture to determine what systems or processes needed to be modified, extended, or if needed, created to meet the business requirements. Where an existing system or process could potentially be re-used, it was integrated as part of the overall scope of work with reduced or no costs. Any costs estimated for re-usable existing processes or systems costs would typically involve regression testing, configuration or one time set up costs. Where existing functionality did not exist or required significant alteration, costs were estimated to ensure that the business requirements were met. Upon completion of the review and internal estimation, the individual IT groups were able to assess the work and identify the incremental effort needed to deploy a solution that could support the requirements defined for the Rule 24 Project.

Once PG&E had a sense of the magnitude of required IT changes, it analyzed the size and difficulty of developing those hypothetical software components to result in an estimate of workdays needed to deliver the required IT changes. At this point, PG&E used an estimated average daily rate to arrive at an initial cost estimate for the contemplated scope of work.

Using this initial estimate of effort and cost, PG&E then asked various IT and business users to recall prior experiences delivering similar functionality. PG&E used this feedback to update its estimate until it was considered reasonable for the proposed scope of work. The final step in the process is to classify the work for accounting and regulatory purposes, add overhead expenses to the appropriate categories, and add contingency if needed to account for risk and uncertainty.

This was the approach used to develop the Rule 24 Project cost estimates. It should be noted that PG&E expects to assess the market for commercially developed software as project development begins. At that time, PG&E will conduct build versus buy analyses to determine the most cost-effective way to meet all critical business requirements.

2. Assumptions Used for the Rule 24 Project Cost Estimates

Early cost estimates for IT projects are based on reasonable assumptions and informed judgment regarding the work to be performed. These assumptions may or may not properly forecast what will be involved in implementing a new solution within a complex systems blueprint such as PG&E's. Specific assumptions considered when estimating the Rule 24 Integration project costs, particularly with regard to functionality that is expected to already be in place when implementing the project, is that: (1) all online functionality will be an extension of the CDA platform as approved in Decision 13-09-025; (2) existing meter data Validation Editing end Estimation (VEE) processes will be available to be extended to meet new Rule 24 requirements: and (3) CAISO DRS API will be in production.

PG&E's Rule 24 implementation is intended to meet the forecasted volumes as defined in Appendix A in Table A-1. In the case that the market volumes are significantly in excess or well below these forecasts, PG&E will re-evaluate the project deliveries. PG&E will continue to assess the market and adjust project deliveries appropriately. Accordingly, PG&E will continue to monitor the market and will advise the Commission.

3. Estimated Costs for Rule 24 Projects

Table B-1 below provides a breakdown of the estimated direct IT project costs for Rule 24 for the period 2015-2016 assuming a project start date of January 1, 2015 with a project duration of 18 months. Please note that many of these costs rely on an interdependency of functionality requirements being completed in whole and cannot be abstracted as a stand-alone cost.

TABLE B-1
PACIFIC GAS AND ELECTRIC COMPANY
ESTIMATED RULE 24 IT PROJECT COSTS BY FUNCTIONAL REQUIREMENT
(THOUSANDS OF DOLLARS)

Activity Number	Activity Description	Business Activity	IT Project Activity	Capitalized	Expensed	Total
1	Isolating PG&E Staff That Provide Services to Non-Utility Demand Response Providers (DRP)	Y	N			
2	Establish and Maintain Third Parties as Non-Utility DRPs	Y	Y	$275,033	$43,094	$318,128
3	Processing and Maintaining a DRP's Access to Customer Specific Data via the Customer Information Service Request Demand Response Provider (CISR-DRP) Form	Y	Y	$835,695	$130,943	$966,638
4	Customer Energy Portal Changes	N	Y	$271,574	$42,552	$314,127
5	Modifying PG&E Systems to Produce and Track Non-Interval Data Necessary for Rule 24	Y	Y	$1,491,061	$233,631	$1,724,693
6	Transferring Interval Data on an Ongoing Basis to DRPs	Y	Y	$1,027,133	$129,818	$1,156,952
7	Transferring Non-Interval Data on a Periodic Basis to DRPs	Y	Y	$491,687	$77,042	$568,728
8	California Independent System Operator Demand Response System Application Programmatic Interface (CAISO DRS API)	N	Y	$635,690	$99,605	$735,295
9	Reviewing CAISO Registrations	Y	Y	$3,200,794	$501,526	$3,702,320
10	Modifying PG&E's Customer Care and Billing (CC&B)	N	Y	$1,441,503	$225,867	$1,667,370
11	Forecasting Load Reductions for PG&E Bundled Customers	Y	Y	$1,468,573	$358,428	$1,827,000
12	Administration and User Access	N	Y	$187,248	$29,340	$216,587
13	Manage Energy Procurement and Settlements	Y	Y	$237,844	$37,267	$275,111
	<u>Other Project Related Costs</u>					
	Training			$62,500	$250,000	$312,500
	Hardware and Licensing			$2,082,500	$37,500	$2,120,000
	Capital Overhead			$1,663,592	$0	$1,663,592
	TOTAL			**$15,372,427**	**$2,196,614**	**$17,569,041**

A summary of the total IT project costs by year is shown below in Table B-2.

TABLE B-2
PACIFIC GAS AND ELECTRIC COMPANY
ESTIMATED RULE 24 IT PROJECT COSTS
(THOUSANDS OF DOLLARS)

Line No.		2015	2016	Total
1	Rule 24 IT Project Forecast			
2	Expense	1,884	313	2,196
3	Capital Expenditures	8,919	6,454	15,373
4	Total Direct Costs	10,803	6,766	17,569

4. Rule 24 IT Operation and Maintenance (O&M) Costs

Upon completion of a deployment phase, the Rule 24 platform would be transitioned into the PG&E Production technology environment. Once part of PG&E Production technology environment, the Rule 24 platform would incur costs to support ongoing O&M. The Rule 24 O&M cost estimate assumes Rule 24 goes into the PG&E Production technology environment as of July 2016. These costs are outlined in Table B-3.

TABLE B-3
PACIFIC GAS AND ELECTRIC COMPANY
RULE 24 OPERATIONS AND MAINTENACE FORECAST
(THOUSANDS OF DOLLARS)

Line No.		2016	Total
1	Rule 24 IT O&M Forecast	563	563
2	Total	563	563

F. Conclusion

Significant effort will be required to implement the proposed Rule 24 Project and supporting activities. PG&E has and will continue to use its ITM process to implement the IT changes to ensure maximum success. The costs that are represented in this appendix are based upon the high-level business requirements explained in the appendix. Due to the high-level nature of the requirements, the cost and schedule estimates are preliminary, but represent PG&E's best estimates at this time. PG&E has taken care to ensure that the costs and work presented in this appendix do not include other previously funded functionality and are new and incremental.

PACIFIC GAS AND ELEC TRIC COMPANY

APPENDIX C

PROPOSED FEE SCHEDUL E E-DRP

ELECTRIC SCHEDULE E-DRP Sheet 1
DEMAND RESPONSE PROVIDER SERVICES

APPLICABILITY: This schedule applies to any Customer, or Demand Response Provider (DRP) acting on their behalf, who requests PG&E to render the following services below to facilitate their involvement in Direct Participation, as detailed in Electric Rule 24.

TERRITORY: The entire PG&E service territory.

RATES: If PG&E performs any metering service for a Customer or DRP pursuant to Rule 24, the following charges shall apply to the requesting party:

1. Interval Meter ....Cost

2. Per-Event Metering Service Charges

   a. Metering Service Base Charge, per meter..................... $174.03

      This charge is incurred when PG&E goes to the meter to perform all Rule 24 related metering service activity(ies) except the remote programming of a SmartMeter™. PG&E Meter Service Charges listed below that are incurred while PG&E is at the meter are added to this Metering Service Base Charge.

      Metering Service Charges:

   b. Meter Installation, per meter $193.37

      This charge is incurred each time PG&E installs an interval meter. This rate includes costs for the installation of the interval meter. This service does not include the interval meter cost, metering transformer material and installation cost, telecommunications equipment, installation or service costs. Meter removal, testing, and programming charges, described below, would also be charged for a typical meter installation.

   c. Meter Removal, per meter $87.01

      This charge is incurred each time PG&E removes an interval meter or a meter to be replaced by the interval meter. It includes costs for removal and processing of the existing meter.

   d. Meter Test, per meter... $116.02

      This charge is incurred when PG&E tests the interval meter.

   e. Meter Programming (On-site), per meter......................... $48.34

      This charge is incurred when PG&E programs or reprograms the interval meter during a site visit.

(Continued)

ELECTRIC SCHEDULE E-DRP
END USER SERVICE

RATES: (Cont'd.)

2. Per-Event Metering Service Charges (Cont'd.)

f. Meter Programming (Remote), per meter........................$41.90

This charge is incurred when PG&E reprograms a SmartMeter™ remotely.

g. Meter Battery Change, per meter....................................$58.01

This charge is incurred when PG&E replaces the interval meter battery.

h. Metering Inspection, per meter.....................................$ 106.36

This charge is incurred each time PG&E inspects the interval metering facility beyond what is required by its normal business practices.

i. Metering Services Hourly Labor Rate $125.69

Metering services performed by PG&E which are not covered by the above service charges or any other PG&E fees or contracts will be charged this hourly rate, plus the Metering Service Base Charge described above, plus materials costs.

Application of Per-Event Metering Service Charges:

When PG&E performs any of the above services, the Metering Service Base Charge and applicable service charge(s) apply. For example, if an interval meter malfunction requires repair and testing of the meter, the requesting party would incur the Metering Service Base Charge, Unscheduled Metering Maintenance Charge, and the Meter Test Charge. The Metering Service Base Charge does not apply to PG&E's remote programming of its' SmartMeter™.

Once the requesting party has communicated to PG&E that the interval meter site is ready for interval meter installation, if the interval meter site is not prepared at the time PG&E attempts to perform the interval meter installation, the requesting party will be charged the Metering Service Base Charge and the Metering Inspection Charge.

If conditions at the customer's meter site require an exceptional amount of material and/or time to perform meter services, the requesting party will be charged for the additional material cost and the hourly rate for the additional time.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX D

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEVEN J. DEBACKER

Q 1 Please state your name and business address.

A 1 My name is Steven J. De Backer, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a senior program manager in the Demand Response Department. I work with most aspects of demand response.

Q 3 Please summarize your educational and professional background.

A 3 I earned a bachelor of science degree in mechanical engineering from the University of California at Berkeley. I joined PG&E in 1983 as an energy management engineer in PG&E's East Bay Region.

Between 1983 and 1988, I worked through the East Bay as a load management representative. My responsibilities included working on PG&E's Appliance Metering, Group Load Curtailment, Commercial and Residential Time-of-Use, PURPA metering, and Summer Time Break programs.

Between 1988 and 1989, I worked as a major account representative in Hayward. In this position, I worked with large commercial and industrial customers. My areas of responsibility included energy management and load management including PG&E E-19/E-20 Non-Firm rate schedules.

Between 1989 and 1996, I worked as an industrial power engineer in Livermore. In this position, I coordinated the installation of gas and electric facilities to residential and commercial developments, and large industrial and commercial customers.

Between 1996 and 2006, I worked as a senior tariff analyst in San Francisco. Among other duties, I was the program manager for the Real-Time Pricing and E-19/E-20 Non-Firm programs. I also worked directly with PG&E's Transmission Operations Center in managing PG&E's Electric Emergency Plan.

In 2006, I assumed my current position. My responsibilities include demand response program development, implementation, and operations, which also includes transitioning PG&E's demand response programs into the California Independent System Operator's wholesale markets.

I have previously testified before this California Public Utilities Commission or the California Energy Commission.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Demand Response Rule 24 Cost Recovery Testimony:

- Chapter 2, "Business Process Requirements."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEVEN R. HAERTLE

Q 1 Please state your name and business address.

A 1 My name is Steven R. Haertle, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a principal case manager in the Customer Programs & Energy Management Proceedings Department managing regulatory cases related to Demand-Side Management (DSM) programs and electric rate design.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in agricultural and managerial economics from the University of California, Davis in 1982 and a master of business administration degree from the University of San Francisco in 1994. Since joining PG&E in 1983, I have held a variety of positions with increasing responsibility. I have managed PG&E's time-of-use metering projects and experiments; General Rate Case marginal costs, revenue allocation, rate design, and DSM showings; development of PG&E electric and gas revenue allocation and rate design; customer information systems conversion; and interval meter data acquisition and load research. I have previously testified before the California Public Utilities Commission on negotiated electric rate reasonableness, electric alternatives for agricultural customers, electric revenue allocation, and DSM program cost recovery. I assumed my current principal case manager position in August 2007.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Demand Response Rule 24 Cost Recovery Testimony:

- Chapter 3, "Cost Recovery and Revenue Requirements."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF COREY A. MAYERS

Q 1 Please state your name and business address.

A 1 My name is Corey A. Mayers, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a manager in the Demand Response (DR) Department within Customer Care. I have been in this position for 16 months. Prior to this assignment, I was the manager of Policy Implementation in the Integrated Demand Side Management Department within Customer Care for two years. I am currently responsible for supporting the DR organization in the development and implementation of products to facilitate third-party programs. My responsibilities include the development and implementation of the tariffs and processes required to facilitate Direct Participation for non-Utility DR Providers.

Q 3 Please summarize your educational and professional background.

A 3 I have a bachelor of science degree in mechanical engineering from the University of California at Santa Barbara. I am also a registered professional engineer with the state of California.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Demand Response Rule 24 Cost Recovery Testimony:

- Chapter 1, "Demand Response Direct Participation Overview."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.