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Exhibit No.:  
Date: September 30, 2021  
Witness(es): Various

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**PACIFIC GAS AND ELECTRIC COMPANY**

**2023 GAS TRANSMISSION AND STORAGE**  
**COST ALLOCATION AND RATE DESIGN**

**PREPARED TESTIMONY**

**(PUBLIC VERSION)**

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PACIFIC GAS AND ELECTRIC COMPANY  
2023 GAS TRANSMISSION AND STORAGE COST ALLOCATION AND  
RATE DESIGN  
PREPARED TESTIMONY

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2023 GAS TRANSMISSION AND STORAGE COST ALLOCATION AND  
RATE DESIGN  
PREPARED TESTIMONY

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**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 1**

**INTRODUCTION AND SCOPE**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 1  
INTRODUCTION AND SCOPE

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 1**  
**INTRODUCTION AND SCOPE**

**A. Introduction**

This exhibit presents Pacific Gas and Electric Company's (PG&E) proposals for its 2023 Gas Transmission & Storage (GT&S) Cost Allocation and Rate Design Proceeding (CARD). The revenue allocation and rate design approved in this case will be used to implement rates based on the GT&S revenue requirement pending approval in PG&E's 2023 General Rate Case (GRC) Phase I Track I,<sup>1</sup> Application (A.) 21-06-021.

PG&E's Senior Vice President, Regulatory and External Affairs, Mr. Robert Kenney testifies in A.21-06-021, that PG&E's focus is on the people we serve, the planet we inhabit, and California's prosperity, with the GRC Phase I proposals to reinvest in infrastructure, improve operations, and adopt new innovations and advanced technologies to serve those principles.<sup>2</sup> In the CARD proceeding, PG&E makes throughput, cost allocation, and rate proposals to support implementation of the GT&S revenue requirement that aligns with the focus on people, planet and California prosperity.

PG&E provides customer billings and throughput forecasts for the electric generation, and other customer classes, to provide current information for cost allocation reflective of relative use of the gas transmission system,<sup>3</sup> and to minimize balancing account volatility which can result when the throughput underlying rates becomes too stale. Accurate cost allocation based on cost causation and minimalization of balancing account volatility serve the focus on people and prosperity. PG&E's customer billings and throughput forecasts includes impacts due to the electrification of end uses instead of natural gas consumption, which reflects the focus on planet.<sup>4</sup>

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<sup>1</sup> All other references to Track I refer to 2023 GRC Phase I Track I unless otherwise noted.

<sup>2</sup> A.21-06-021, Exhibit (PG&E-1), p. 1-1, line 4 to p. to 1-4, line 17.

<sup>3</sup> For more on cost allocation, please see Chapter 6 of this Exhibit.

<sup>4</sup> For more on throughput forecasts, please see Chapter 2A and 2B of this Exhibit.

PG&E's proposed GT&S rate design changes provide clearer price signals to customers for various services on the GT&S system, which will better align the rates with the costs for service.<sup>5</sup> PG&E's proposed rate design methodology would support more efficient use of the GT&S system, consistent with the focus on PG&E's customers, the planet, and California prosperity.

## **1. Purpose and Scope of the Chapter**

The purpose of this chapter is to present the background and scope for PG&E's first CARD filing and describe how the rest of this Exhibit is organized. This includes the regulatory background, guiding policy principals for GT&S revenue allocation and rate design and a brief introduction to the chapters that follow.

## **2. Summary of Proposals**

Proposals found within this chapter include the filing cadence of future CARD application and a request to update a Gas Cost Allocation Proceeding (GCAP) requirement dependent upon the previously known GT&S proceeding. Details of both proposals are detailed below.

## **B. Background**

On January 16, 2020, the California Public Utilities Commission (CPUC or the Commission) issued Decision (D.) 20-01-002, the final decision in the Commission's Rate Case Plan (RCP) proceedings.<sup>6</sup> In that proceeding, the Commission combined PG&E's GRC and the revenue requirement components of its GT&S into one filing in four year cycles.<sup>7</sup> However, D.20-01-022 also separated the cost allocation and rate design components of GT&S from the combined GRC/GT&S proceeding.<sup>8</sup> PG&E commented that the GT&S ratemaking components should be considered in a separate proceeding and the Commission agreed.<sup>9</sup> The Commission noted that D.07-07-004 and

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<sup>5</sup> In this case, costs for service are indicative of inventory management, local transmission, and backbone path differential costs.

<sup>6</sup> Order Instituting Rulemaking (OIR), R.13-11-006 (Nov. 14, 2013).

<sup>7</sup> D.20-01-002, p.78-79, Ordering Paragraph (OP) 4.

<sup>8</sup> D.20-01-002, pp. 41-44.

<sup>9</sup> "We agree with PG&E that, because this rulemaking proceeding focused on Phase 1 of the GRCs, we would benefit from a more robust record on whether to modify the filing requirements for Phase 2 applications." *Ibid*, p.44.

1 D.19-10-036 remain in effect as the controlling decisions for Electric and Gas  
2 cost allocation and rate design proceedings.<sup>10</sup> Therefore, the 2019 GT&S  
3 decision remains the controlling decision for the ratemaking for gas  
4 transmission, storage, customer billings and throughput forecasting. The GT&S  
5 decision required PG&E to file an application consistent with the schedule  
6 required for a 2023 test year,<sup>11</sup> which would be in 2021; therefore, PG&E is  
7 filing this application for all ratemaking components of the previously known  
8 GT&S proceeding for simultaneous implementation with the final decision in the  
9 2023 GRC Phase I.<sup>12</sup>

10 PG&E also believes this parallel timing with its 2023 GRC Phase I provides  
11 the gas marketplace and parties the most efficient opportunity for updating  
12 PG&E's GT&S rates, continuing as a second best solution under the new RCP  
13 to mimic the Gas Accord and GT&S Rate Case process in effect since 1998. In  
14 order to incorporate the parallel timing into the end-use rate presentation, PG&E  
15 enhanced the presentation table by first comparing present rates<sup>13</sup> to PGE's  
16 2023 GRC Track 1 revenue requirements as filed in Exhibit 3 of A.21-06-021 on  
17 June 30, 2021<sup>14</sup> and then the impact of the 2023 CARD proposals compared to  
18 the gas rates contained in PG&E's 2023 GRC Track 1.

## 19 **1. Rate Case Plan Workshops**

20 As part of D.20-01-002, the Commission ordered additional workshops  
21 to discuss the issues Investor Owned Utilities (IOU) and intervenors had  
22 raised in comments<sup>15</sup> to the Staff Report<sup>16</sup> and to the proposed decision.  
23 Regarding the ratemaking issues that PG&E raised (discussed above), the

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<sup>10</sup> D.20-01-002, p. 44.

<sup>11</sup> D.19-09-025, p. 338, OP 101.

<sup>12</sup> The request for simultaneous implementation with PG&E's 2023 General Rate Case was noted in the application to the filing, A.21-06-021, Application, p. 20.

<sup>13</sup> The traditional GT&S rate case presentation of present rates incorporates authorized 2022 base revenue requirement.

<sup>14</sup> A.21-06-021, Exhibit (PG&E-3), p. 1-2, lines 1-6.

<sup>15</sup> Opening Comments to the Staff Report were served by parties on April 5, 2018.

<sup>16</sup> Energy Division, General Rate Case Plan Workshop Report (Mar. 2018).

Commission ordered a workshop topic to address scheduling and filing requirements.<sup>17</sup>

Workshop 2 was held on October 7, 2020.<sup>18</sup> Agenda item 5 discussed Phase 2 Scheduling and Filings going forward. On behalf of the IOUs, PG&E presented a case schedule to mitigate the stacking of proceedings and the workload burdens of stacked proceedings.<sup>19</sup> As part of that proposal, the CARD filing is proposed as the successor to the GT&S rate case, which had both a) revenue requirements and b) throughput forecasts and cost allocation/rate design issues. CARD's scope would be limited to proposing new gas sales forecasts, cost allocation and rate design issues previously in scope for the GT&S proceedings, with the exception of revenue requirements and system capacity issues tied to those proposed revenue requirements as those issues are addressed in PG&E's 2023 GRC Track 1.

## **2. GT&S CARD Timing Versus GCAP Timing**

In keeping with the historical GT&S implementation of rates occurring simultaneously with the GT&S revenue requirement, PG&E is making this filing within 90 days of the 2023 GRC Phase I filing, in order to facilitate simultaneous implementation with the new GT&S revenue requirements approved in A.21-06-021. The ratemaking for gas transmission, storage, and sales forecasting do not fall neatly into scope or necessary timing with GCAP. If the CARD application were combined with PG&E's GCAP, the result would uncouple the GT&S rate making from the adoption of new GT&S revenue requirement, because the earliest possible filing per the GCAP decision (D.19-10-036) would have been late 2<sup>nd</sup> quarter 2022.<sup>20</sup>

In addition to the greater scope that addressing distribution and unbundled gas ratemaking in one proceeding would require in terms of

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<sup>17</sup> D.20-01-002, p. 71.

<sup>18</sup> On November 6, 2020, PG&E served a Workshop 2 Report on the service list of R.13-11-006 detailing the workshop, combining IOU and Party comments, and submitting the full presentation.

<sup>19</sup> Attachment A, Excerpts from the Rate Case Plan (Decision 20-01-002) Workshop #2 Presentation (Oct. 7, 2020).

<sup>20</sup> D.19-10-036, p. 84, OP 12.

1 preparation, several critical organizations in PG&E that support GRC  
2 Phase 2, GT&S CARD, and GCAP would have been occupied by PG&E's  
3 2020 GRC Phase 2 through hearings, briefs, and reply briefs through the  
4 first half of 2021.

5 With the creation of the GT&S CARD proceeding, PG&E maintains two  
6 separate proceedings for gas cost allocations and rate designs, CARD and  
7 the GCAP, as it has had since 1998's implementation of Gas Accord 1.  
8 A typical scope of the GCAP (previously known as a Biennial Cost Allocation  
9 Proceeding (BCAP)), is proposing and implementing cost allocation and rate  
10 design for gas distribution level customer classes, whereas the CARD  
11 addresses these types of issues at the transmission level and unbundled  
12 gas marketplace.

13 However, coordination of the customer billings and throughput forecasts  
14 for purposes of the two types of proceedings is desirable and efficient. In  
15 the 2018 GCAP Decision,<sup>21</sup> the adoption of the customer billings and  
16 throughput forecast was placed solely in the GT&S proceeding case. The  
17 GCAP Decision<sup>22</sup> authorized PG&E to submit a Tier 2 advice letter (AL)  
18 within 60 days from a final GT&S decision adopting a new customer billings  
19 and throughput forecast to update distribution rates based on adopted  
20 methods. With GT&S CARD being the successor to the former GT&S  
21 proceeding, PG&E will submit the AL with the new customer and throughput  
22 forecasts 60 days from a final decision issuance in GT&S CARD.

### 23 **3. Update to the 2023 CARD**

24 The showing in the testimony is based on the information available as  
25 the witnesses were developing the proposals. However, given the nature of  
26 the CARD proceeding, PG&E would need flexibility to revise testimony when  
27 any of the following occur: (1) a major revision in revenue requirement  
28 forecasts in PG&E's 2023 GRC; (2) after the entirety of this exhibit becomes  
29 public to Core Gas Supply (CGS), and/or; (3) a final decision is issued in

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<sup>21</sup> D.19-10-036, p. 82, OP 2.

<sup>22</sup> D.19-10-036, p. 82, OP 2.



OIR to Continue Electric Integrated Resource Planning (EIRP) and Related Procurement Processes, that adopts a new Preferred System Plan (PSP).<sup>23</sup>

### C. Organization of the Rest of This Exhibit

In this application, PG&E is presenting several proposals historically included in the GT&S proceeding related to cost allocation and rate design as well as the CGS portfolio.

Below are brief highlights of proposals found within this Exhibit by chapter and sponsoring witness. For details, please refer to each chapter.

The rest of the Exhibit is organized as follows:

- Chapter 2A – Electric Generation Gas Demand and Throughput (Todd Peterson). Chapter 2A presents the forecast for 2023 – 2026 for electric generation (EG).
- Chapter 2B – Non-Generation Demand and Throughput Forecast (Andrew Klingler). Chapter 2B presents the Non-EG sales and customer forecasts for 2023 – 2026.
- Chapter 3 – Backbone Rate Inputs (Carl Orr). Chapter 3 proposes the backbone load factor, the Baja-Redwood path differential, and miscellaneous backbone rate inputs including firm contract forecast, California production/Silverado path flows, off-system throughput and revenue forecast.
- Chapter 4 – Local Transmission Allocation Study (Annette Taylor). Chapter 4 presents analysis of various local transmission studies and proposes using a methodology of abnormal peak day.
- Chapter 5 – Electric Generation Local Transmission Rate Design Analytics (Todd Peterson). Chapter 5 presents analysis for alternate EG local transmission rate design.
- Chapter 6 – Cost Allocation and Rate Design (Patricia Gideon). Chapter 6 proposes inventory management recovery, volumetric EG rate design, and GT&S rates and illustrative end-use rates isolating impact of CARD proposals.
- Chapter 7 – Core Gas Supply (Pete Koszalka). Chapter 7 proposes the updated CGS portfolio and policy proposals for total core gas customers.

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<sup>23</sup> Rulemaking (R.) 20-05-003 was issued on May 7, 2020.

1 Due to Gas Rule 26,<sup>24</sup> CGS does not have access to PG&E's CARD filing  
2 position prior to service of the testimony. Therefore, once CARD is served  
3 and CGS is able to review the other chapters, CGS reserves the right to  
4 adjust its portfolio and, if needed, will do so in supplemental testimony.

- 5 • Chapter 8 – G-NGV1 and G-NGV4 Tariff Modifications (Stephen Sheridan).  
6 Chapter 8 proposes changes to PG&E natural gas vehicle tariffs G-NGV1  
7 and G-NGV4 to update the tariff language and presents redline versions of  
8 the proposed tariff revisions.

#### 9 **D. Conclusion**

10 PG&E respectfully requests the Commission approve and adopt PG&E's  
11 proposals to: (1) file future CARD Applications 90 days after a GRC Track I  
12 application filing and; (2) allow PG&E to submit a Tier 2 AL 60 days from a final  
13 decision in CARD as opposed to a final decision in the no longer existing GT&S  
14 case.

15 For the reasons stated herein, and in the succeeding chapters in this exhibit,  
16 the Commission should adopt PG&E's proposed forecasts, cost allocations and  
17 rate designs for 2023-2026.

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24 Gas Rule 26 (Sept. 13, 2012)  
<[https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_RULES\\_26.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_26.pdf)> (as of Sept. 3, 2021).

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 1**  
**ATTACHMENT A**  
**EXCERPTS FROM THE RATE CASE PLAN**  
**WORKSHOP 2 PRESENTATION, OCTOBER 7, 2020**

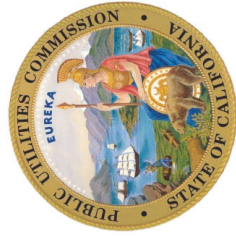


# **Excerpts From The Rate Case Plan (Decision 20-01-002) Workshop #2 General Rate Case Filing Standardization**

**October 7, 2020  
10am – 4pm**

**California Public Utilities Commission (CPUC)**

**CPUC Energy Division  
PG&E Lead**



# Rate Case Plan (RCP) Workshop #2

Efficient Scheduling of GCAPs, GRC 2s, GT&S  
CARDs, and TCAPS: Joint IOU Recommendations

October 7, 2020



Together, Building  
a Better California

# 1. Overview of Topic

- Allocation Cases, IOU Scheduling Concerns, and Proposed Guiding Principles
- More Efficient Scheduling
- GRC 2 Filing Standardization Requirements
- Outcomes Requested From Workshop
- Appendix

## 2. Allocation Cases, IOU Scheduling Concerns, and Proposed Guiding Principles

- IOU Allocation Cases to Schedule Within Four Year RCP
- PG&E GRC 1 versus GT&S CARD versus GCAP
- IOU Allocation Case Scheduling Concerns
- Proposed Guiding Principles for Allocation Case Scheduling Across California IOU's



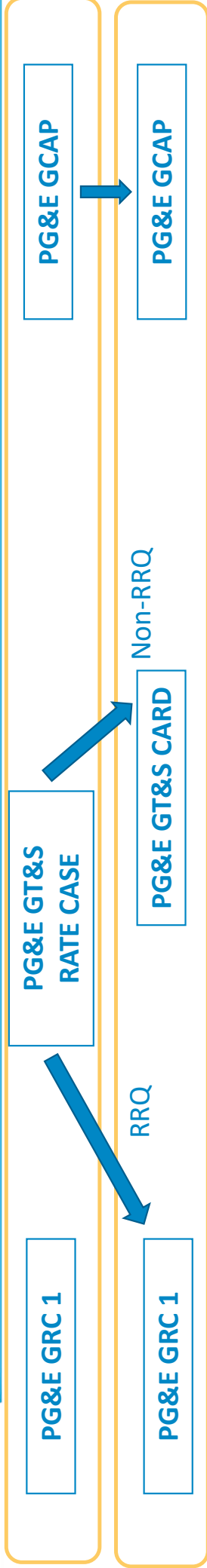
### 3. IOU Allocation Cases to Schedule Within Four Year RCP

Pacific Gas and Electric Company (PG&E)		Sempra (Southern California Gas and San Diego Gas & Electric) (SoCalGas/SDG&E)	Southern California Edison Company (SCE)
<b>Electric Rates</b>	<ul style="list-style-type: none"><li>General Rate Case Phase 2 (GRC 2)</li></ul>	<ul style="list-style-type: none"><li>General Rate Case Phase 2 (GRC 2)</li></ul>	<ul style="list-style-type: none"><li>General Rate Case Phase 2 (GRC 2)</li></ul>
<b>Gas Rates</b>	<ul style="list-style-type: none"><li>Gas Cost Allocation Proceeding (GCAP)</li><li>Gas Transmission &amp; Storage Cost Allocation and Rate Design (GT&amp;S CARD)</li></ul>	<ul style="list-style-type: none"><li>Triennial Cost Allocation Proceeding (TCAP)</li></ul>	





## 4. PG&E GRC 1 versus GT&S CARD versus GCAP



PG&E GRC 1	PG&E GT&S RATE CASE	PG&E GT&S CARD	PG&E GCAP
<ul style="list-style-type: none"><li>- Includes GT&amp;S RRQ beginning in 2023 GRC</li><li>- Limited to Authorizing Revenue Requirements for Four-Year Rate Case Period</li></ul>	<ul style="list-style-type: none"><li>- Filed for Simultaneous Implementation with PG&amp;E 2023 GRC 1 using GRC 1 Revenue requirement as present rates to see GT&amp;S rate case proposal impacts.</li><li>- Market Structure, GT&amp;S Services and related Gas Capacities, balancing rules, market concentration limits, long term contract limits</li><li>- Gas Billings and Throughput Forecasts</li><li>- Sharing Mechanism/Balancing Account Treatment of Revenues</li><li>- Gas Backbone, Local Transmission, and Storage Cost Allocation and Rate Design</li><li>- Backbone Transmission System Load Factors</li><li>- Core Gas Supply (c.f., chapter included in previous GT&amp;S Rate Cases)</li><li>- Core Transport Agent (CTA)-related issues</li></ul>	<ul style="list-style-type: none"><li>- Addresses all non-GT&amp;S PG&amp;E Gas Ratemaking;</li><li>- Incorporates Adopted GT&amp;S CARD Throughput and Billings Forecasts</li><li>- Cost Studies, Allocations, and Rate Design concerning Distribution, Public Purpose Program Surcharges, and Core Procurement</li></ul>	

## 5. IOU Allocation Case Concerns

1. Continue CPUC consideration of PG&E GT&S and GCAP issues in separate applications with GT&S CARD filed for Simultaneous Implementation with PG&E GRC 1 and GCAP Filed after CARD Decision
2. PG&E GRC 2 Future Filing Schedule Considers:
  - A. 2020 GRC 2 Decision Timing (Expected in 3<sup>rd</sup> Qtr 2021) and ability to implement, analyze and prepare for the following application,
  - B. SCE/SDG&E GRC 2 Timing to minimize overlap, and
  - C. PG&E Resource Constraints, particularly timing of preparation and litigation of PG&E GCAP
3. Transition/timing of Sempra TCAP on Four-Year Cycle instead of Current Three-Year Cycle that minimizes overlap to extent possible with PG&E GCAP and GT&S CARD
4. Maintain Historic Required GRC 2 Filing Schedule of 90-Days Following GRC 1 application for SCE and SDG&E with ability for requesting extension and opportunity within Rate Design Windows

## 6. Proposed Guiding Principles for Allocation Case Scheduling Across California IOU's

### 1. Minimize case delays with schedule to minimize overlap

- For each commodity across IOUs, that allows efficient oversight/participation by CPUC Staff, Public Advocates Office, and other parties within four-year rate case plan cycle
- Within each IOU, to enhance IOU's ability to (a) develop application and testimony on-time, and (b) provide more timely responses to data requests.

### 2. Provide sufficient time for implementation and subsequent post-implementation analysis prior to development of succeeding Applications (in transition and ongoing)

### 3. Schedule each IOU's Allocation Case(s) vs its RCP GRC 1 schedule, as warranted

A. SCE and SDG&E: File GRC 2 within 90 days of scheduled GRC 1 application

B. PG&E: Because PG&E's 2020 GRC 2 won't be decided until Fall '21, 90-day interval from 2023 GRC 1 is not workable. Due to linkage of gas wholesale market with GT&S CARD/GRC 1, PG&E should file GT&S CARD in 2021 (and every 4 yrs), and GRC 2 later.

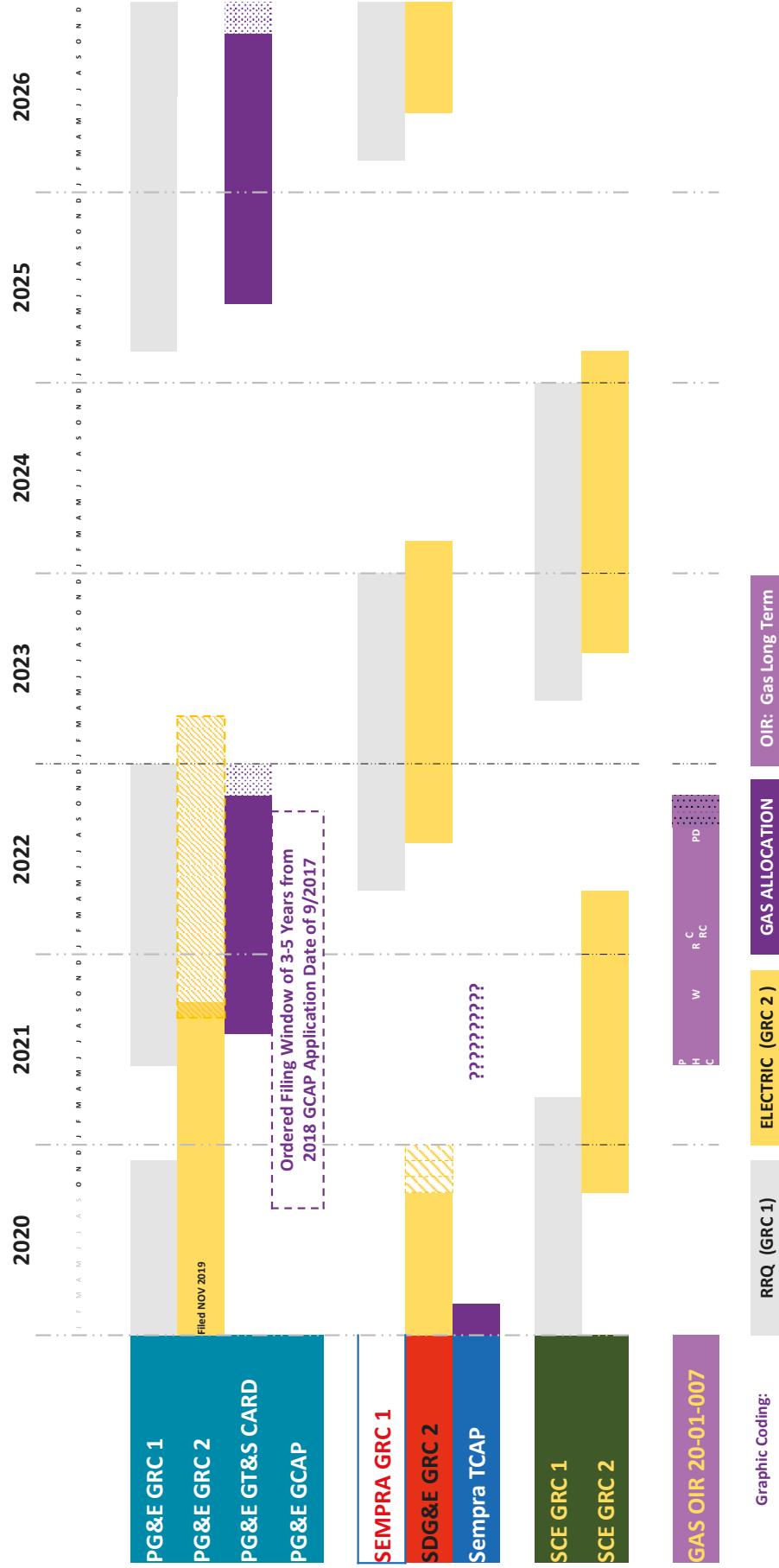
➤ GT&S CARD timed for simultaneous implementation with PG&E GRC 1 GT&S revenue requirement

C. For Sempra TCAP and PG&E GRC 2, schedule to avoid inefficient overlaps per (1)

## 7. More Efficient Scheduling

- Step 1: Known Schedules As Starting Point
- Step 2: When Should PG&E's GRC 2's Be Filed?
- Step 3: When Should PG&E's GCAPs Be Filed?
- Step 4: When Should Sempra's TCAP be Scheduled?
- Summary: Allocation Case Four-Year Filing Cadence

## 8. More Efficient Scheduling: Step 1: Known Schedules As Starting Point

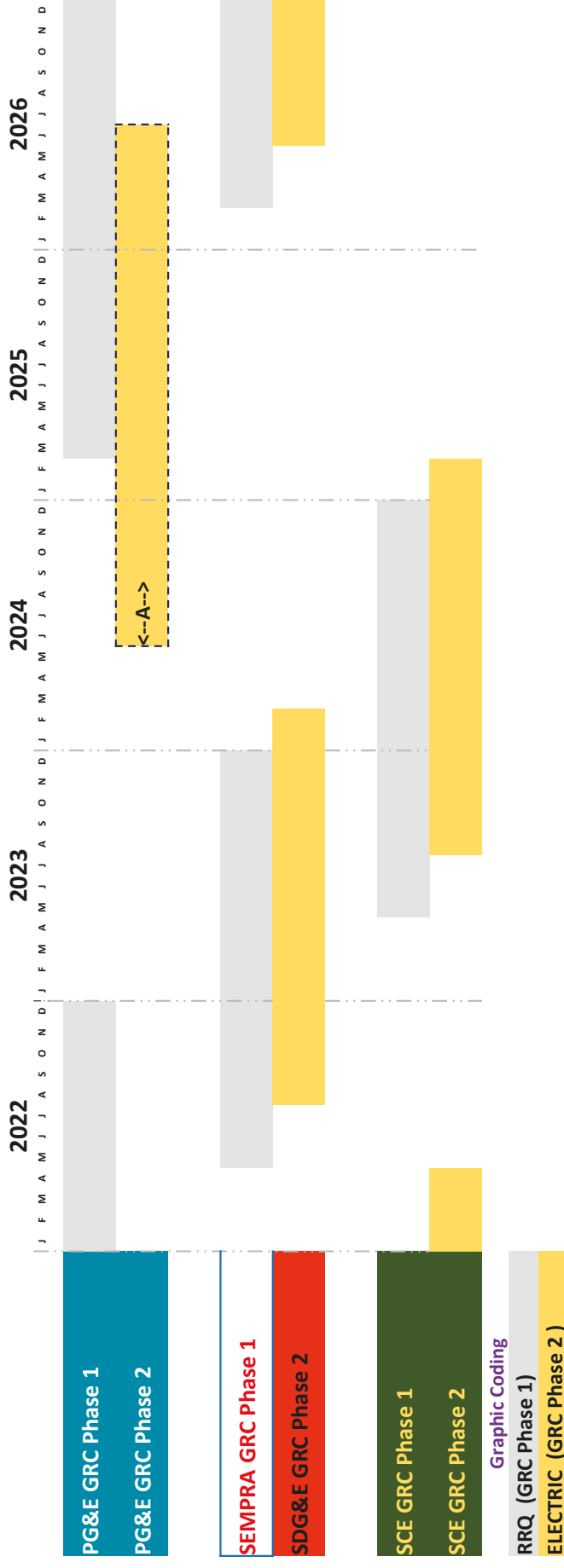




## 9. More Efficient Scheduling: Step 2: When Should PG&E's GRC 2's Be Filed?

### Filing PG&E's next GRC 2 in Summer of 2024 is most practical and expeditious timing:

- Allows for a full year of usage under phased 2020 GRC 2 implementation before beginning case preparation
- Avoids overlap with SDG&E or SCE GRC 2's in 2022 or 2023 that could cause delays
- Prevents an even longer gap and parallel demand on PG&E resources (GT&S CARD) from filing in Summer 2025
- File every four years subsequently

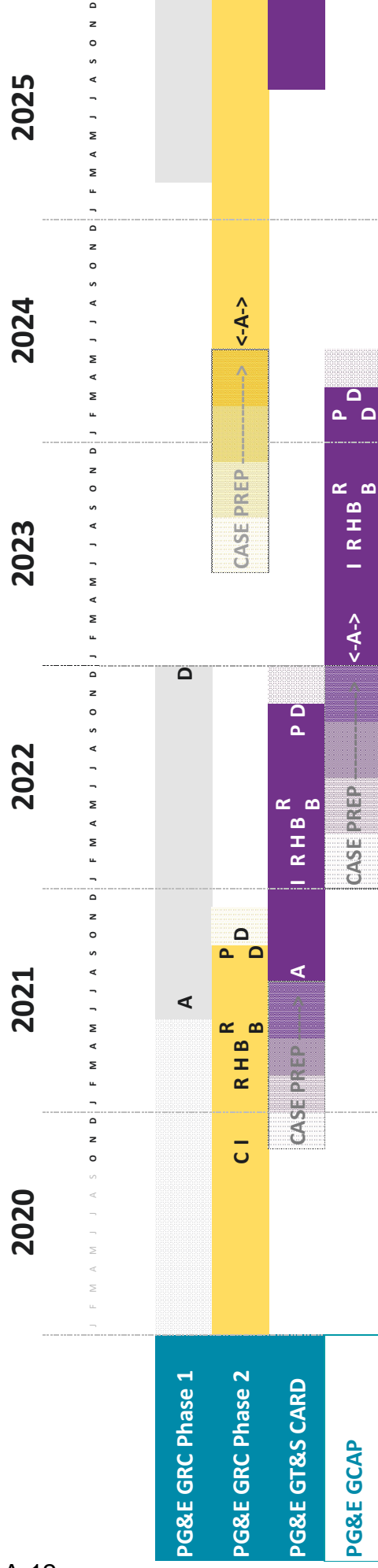




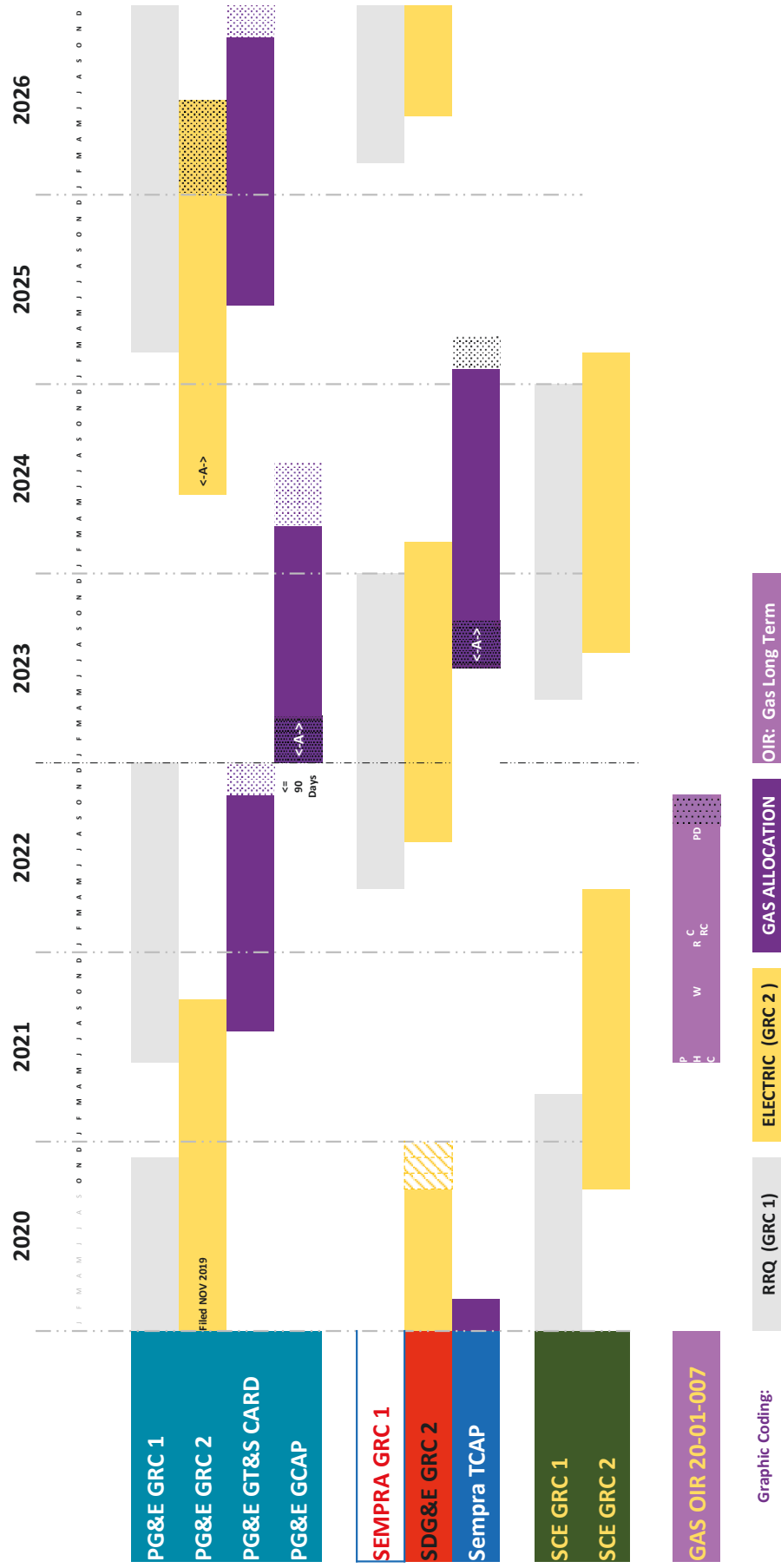
## 10. More Efficient Scheduling: Step 3: When Should PG&E's GCAPs Be Filed?

### Filing PG&E's Next GCAP within 90 Days of GT&S CARD decision is most practical:

- Allows Incorporation of Gas Throughput Forecast Adopted in 2023 GT&S CARD while still relevant
- Avoids overlap for PG&E Staff supporting GRC 2 in 2023/24 and GT&S in 2021/22
- One-time delay of ~5 months beyond the 3-5 year period from 9/2017 required in 2018 GCAP Decision
- Subsequently filed within 90 days of each GT&S CARD decision



# 11. More Efficient Scheduling: Step 4: When Should Sempra's TCAP be Scheduled?





## 12. Summary: Allocation Case Four-Year Filing Cadence

Utility	Case	Filing Timeframe	Transitional Scheduling Issues	Other
PG&E	GT&S CARD	<= 75 Days After GRC 1	< =60 Days in 2021	Implemented with GRC 1 RRQ's
	GCAP	<= 90 Days from GT&S CARD Decision	One-time delay from D.19-10-036 3-5 Year OP 12	Incorporates GT&S CARD Throughput
	GRC 2	Filed Summer of Year Prior to GRC 1 Application Filing	Filed Summer 2024 instead of 2021	Use RDW's as warranted
Sempra	TCAP	Next TCAP Filed 3 <sup>rd</sup> Qtr 2023		
SDG&E	GRC 2	File 90 Days After GRC 1	None	Use RDW's as warranted
SCE	GRC	File 90 Days After GRC 1	None	Use RDW's as warranted

## 13. GRC 2's Filing Standardization Requirements

While the methods and range of proposals vary across electric utilities and across applications, the following minimum elements would be included in all GRC 2 applications:

1. Cost of Service Methodology and Studies (including TOU period analysis)
2. Proposed Allocation of Revenue Requirement by Class/Service
3. Proposed Rate Design
4. Illustrative Bill Comparison Results
5. Electronic Work Papers

## 14. Outcomes Requested From Workshop

### Existing Authority confirmed

- GT&S and GD Ratemaking for PG&E will be addressed in separate applications to allow GT&S ratemaking to be implemented with GRC 1 RRQ (*OP 4*)
- Submission of SDG&E and SCE GRC 2's 90 Days from GRC 1 Filing continues on a four-year cycle parallel with GRC 1 under RCP D. 20-01-02

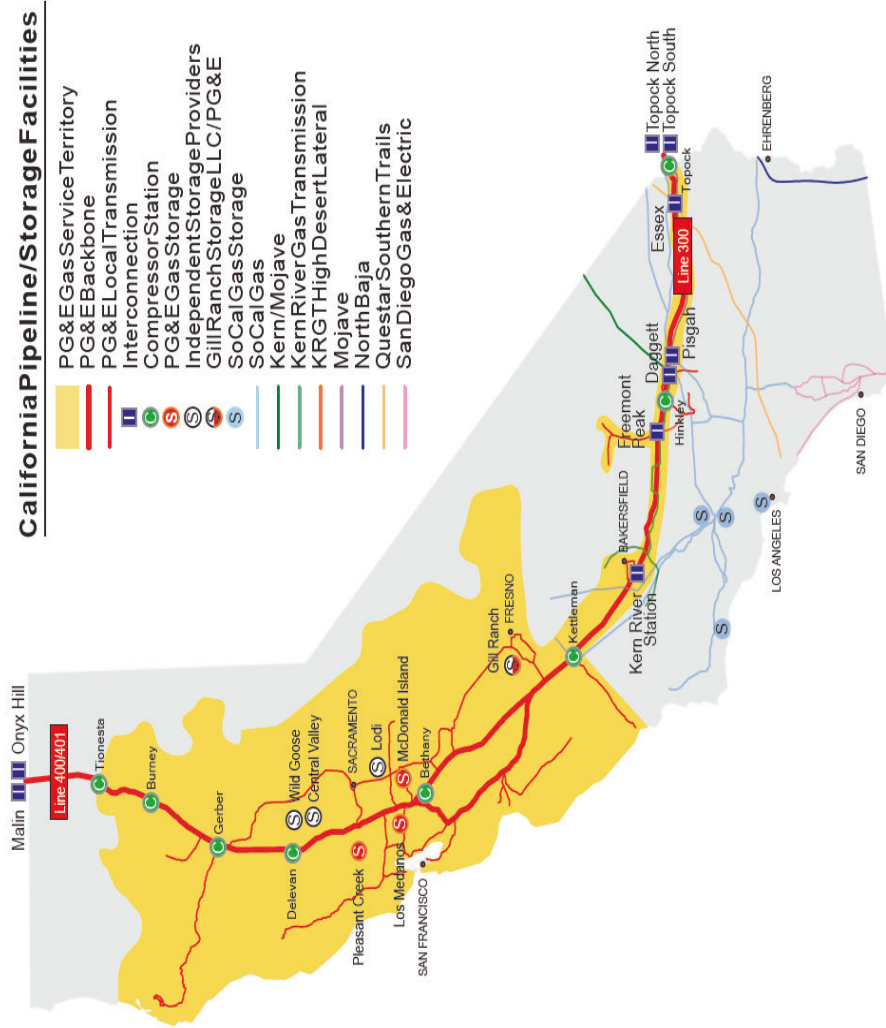
### Commission actions:

- Authorizes PG&E to file next GCAP within 90 days of 2023 GT&S CARD Decision, which would result in a one-time filing beyond the 3-5 year period authorized in D.19-10-036
- Authorizes PG&E's Next GRC 2 to be filed in Summer 2024 and every four years thereafter
- Authorizes Sempra to File TCAPs on Four-Year Cycle Commencing 3<sup>rd</sup> Qtr 2023

## 15. Appendix

- A. PG&E Gas Transmission System
- B. CPUC GT&S Scheduling Requirements
- C. Gas Marketplace and GT&S Ratemaking

# A. PG&E Gas Transmission System



## B. CPUC GT&S Scheduling Requirements

### **GT&S Ratemaking:**

- Because the Rate Case Plan Phase 1 decision (D.20-01-002) did not order GT&S ratemaking to be incorporated in PG&E's Gas Cost Allocation Proceedings (GCAP), and only ordered in (OP) 4 that GT&S Revenue Requirement proposals to be filed with PG&E's next GRC (in June 2021), the schedule for the rate design portion of PG&E's next GT&S is still governed by Ordering Paragraph (OP) 4 of D.19-09-025, which requires PG&E to file "in 2021" unless changed in the RCP proceeding.
- Accordingly, PG&E plans to file its GT&S rate design showing in Q3 2021, building from its GT&S revenue requirement to be filed in PG&E's 2023 GRC Ph 1 application in June 2021.

## C. Gas Marketplace and GT&S Ratemaking

- **PG&E's Gas Transmission system provides service similar to Interstate Pipelines**
  - From California's borders with Oregon to Arizona and with interstate/Canadian connections to Gas Basins of western Canada, Rocky Mountains, New Mexico, and Western Texas
  - For Producers/Shippers, Marketers/Brokers/Core Transport Agents including PG&E Core Gas Supply, other Utilities, and large end-user customers acting as their own gas procurement agent
  - With impacts on CAISO Market through gas-fired electric generation located inside and out of PG&E's service territory
- **Goal for Western Gas Marketplace via Gas Accords that became GT&S Rate Cases (1998 to 2019)**
  - infrequent rate changes with revenue requirement and ratemaking changing simultaneously and efficiently for rate case participants, particularly market participants
  - Timely updates of the throughput forecast are needed and appropriate in an era of dynamic changes to gas demand
  - Unlike most other electric and gas revenues, PG&E's GT&S revenue is partially at risk under the Sharing Mechanism\* and not subject to 100% balancing account treatment.

\* 50% of PG&E gas Backbone Transmission allocated to noncore and 25% of Local Transmission allocated to noncore is at risk

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 2A**

**ELECTRIC GENERATION GAS DEMAND AND THROUGHPUT**



PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 2A  
ELECTRIC GENERATION GAS DEMAND AND THROUGHPUT

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1 **PACIFIC GAS AND ELECTRIC COMPANY**  
2 **CHAPTER 2A**  
3 **ELECTRIC GENERATION GAS DEMAND AND THROUGHPUT**

4 **A. Introduction**

5 **1. Purpose and Scope of the Chapter**

6 This chapter presents Pacific Gas and Electric Company's (PG&E)  
7 forecast of on-system<sup>1</sup> electric generation (EG) gas demand for the 2023  
8 Gas Transmission and Storage Cost Allocation and Rate Design (CARD)  
9 Rate Case, for the period 2023-2026. This chapter includes details on the  
10 modeling methodology, assumptions, results, and key findings.

11 **2. Summary and Forecast Presentation**

12 PG&E's gas system transports and delivers natural gas to on-system  
13 EG customers. Annual throughput to serve the EG class is forecast to  
14 decline, but it remains a major component of total system throughput.  
15 Several factors related to natural gas and electric market conditions cause  
16 the throughput of EG customers to have high throughput variation as  
17 discussed in this chapter.

18 PG&E divides electric generators into two groups based on the  
19 generator's responsiveness to electric market prices. The  
20 market-responsive EG group consists of gas-fired electric generators whose  
21 output varies in response to prices in the wholesale electricity and gas  
22 markets. The market-responsive group is further divided by the level of  
23 service provided by PG&E. Local Transmission (LT) customers on PG&E's  
24 transmission or distribution systems pay different transportation charges  
25 compared to those taking service off of the Backbone (BB) system. The LT  
26 customers pay for the additional costs to transport gas further out on the  
27 system. The non-market-responsive EG group consists primarily of

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1 On-system refers to customers that connect to the PG&E gas system and are located in the PG&E Gas Service Territory.

1 gas-fired cogenerators<sup>2</sup> whose output is generally not sensitive to prices in  
2 the electricity and gas markets. This class's generation is primarily driven  
3 by onsite loads rather than electric wholesale prices. Below, Table 2A-1  
4 summarizes total annual average EG throughput for recorded year 2020 and  
5 forecast years 2023 through 2026.

**TABLE 2A-1**  
**AVERAGE-WEATHER ELECTRIC GENERATION COMPARISON TO 2020 RECORDED**  
**(MDTH/D)**

Line No.		2020 Recorded	2023 Forecast	2024 Forecast <sup>(a)</sup>	2025 Forecast	2026 Forecast
1	<u>Electric Generation</u>					
2	Non-market-responsive EG	163	155	156	155	155
3	Market-responsive EG	654	319	316	342	371
4	<i>Local Transmission</i>	287	60	58	59	60
5	<i>Backbone-only</i>	367	259	258	284	312
6	Total Electric Generation	817	474	472	497	527

(a) Since 2024 is a leap year, calculating an annual average value from monthly data results in throughput that is slightly higher than in other years.

6 Overall EG throughput is lower in the forecast period than recent history  
7 due primarily to several factors affecting market-responsive plants that bid  
8 into electric markets such as the California Independent System Operator  
9 (CAISO) market. Compared to 2020, these factors are: (1) an increase in  
10 the proposed transportation and forecast gas commodity prices that electric  
11 generators pay on PG&E's system relative to what other electric generators  
12 pay on other gas systems, (2) the addition of new non-gas resources  
13 (e.g., solar, wind, and battery storage), and (3) an forecast increase to  
14 average hydroelectric generation compared to 2020 dry conditions. Due to  
15 the planned retirement of the Diablo Canyon Nuclear Power Plant (DCNPP)  
16 in late 2024 through 2025, an increase in EG throughput is observed in

2 “[C]ogeneration is an efficient approach to generating electric power and useful thermal energy for heating or cooling from a single fuel source. Instead of purchasing electricity from the grid and producing heat in an on-site furnace or boiler, [cogenerators] provide both energy services in one energy-efficient step.” U.S. Energy Information Administration, Combined heat and power technology fills an important energy niche (Oct. 4, 2012), <<https://www.eia.gov/todayinenergy/detail.php?id=8250>> (as of Sept. 22, 2021).

these two years to meet the electric load previously served by this large resource. Non-market-responsive EG throughput is expected to decline slightly due to a reduction in use per customer.

### **3. Summary of Methodology**

PG&E's market-responsive power plant gas demand forecast is based on results from power system simulations conducted using the PLEXOS<sup>3</sup> production cost modeling tool. This application provides estimates of consumption of all fuels used for power generation on an economic basis. PG&E's forecast of non-market-responsive EG gas demand is based on the most recent available 12 months of actual deliveries.

### **4. Organization of the Remainder of This Chapter**

The remainder of this chapter is organized as follows:

- Section B – Forecast of Market-Responsive Electric Generation Gas Demand
- Section C – Forecast of Non-Market-Responsive Electric Generation Gas Demand
- Section D – Cold Year Electric Generation Gas Demand Forecast
- Section E – Conclusion

### **B. Forecast of Market-Responsive Electric Generation Gas Demand**

The market-responsive group consists of gas-fired electric generators whose output varies in response to clearing prices in the wholesale electricity market and their fuel cost in the gas markets. This group includes combined cycle power plants, gas turbine ("peaker") plants, and older steam boiler plants. It also includes two cogeneration plants connected to the PG&E system considered market-responsive because of their gas throughput behavior. Market-responsive power plants connected to the PG&E gas system operate within a wholesale electricity market that spans the western U.S. and parts of Canada and Mexico. Finally, the market responsive group includes gas deliveries to the Sacramento Municipal Utility District (SMUD) power plants in excess of SMUD's 88 thousand decatherms per day (MDth/d)<sup>4</sup> equity share of

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<sup>3</sup> PLEXOS is software licensed by Energy Exemplar Ltd.

<sup>4</sup> Deliveries to SMUD as of April 2021, above SMUD's equity share.

the Redwood and Baja path capacity. Gas deliveries to SMUD in excess of its equity share are subject to PG&E rates and are therefore included in PG&E's forecasts for rate-setting purposes.

Table 2A-2 summarizes PG&E's forecast for gas deliveries to market-responsive power plants for both plants on the LT and BB systems. PG&E's forecast of gas deliveries to market-responsive power plants is 319 MDth/d in 2023, 316 MDth/d in 2024, 342 MDth/d in 2025, and 371 in 2026.<sup>5</sup>

**TABLE 2A-2  
ELECTRIC GENERATION FORECAST,  
MARKET RESPONSIVE ELECTRIC GENERATION GAS DEMAND**

Line No.	MDth/d	2019	2020	2021	2022	2023	2024	2025	2026
1	Local Transmission	275	287	254	161	60	58	59	60
2	Backbone-Only	333	367	329	246	259	258	284	312
3	Total	608	654	583	407	319	316	342	371

Recorded billing data are utilized for the months of January 2019 through May 2021, the range that was available at the time of this filing. Monthly demand is then forecasted from June 2021 through December 2026. In 2021, the table above utilizes five months of recorded data and seven months of forecasted data.

Recent-year actual data indicates higher-than-average market-responsive gas-fired generation in 2019 and 2020. In 2021 through 2026, PG&E forecasts that this value will decline as more renewables are added to the system and hydro conditions return to average in 2022 onward. More details on these trends are provided below.

### **1. Key Forecast Drivers**

According to historic throughput data, market-responsive power plant gas demand in PG&E's service territory has been decreasing since at least 2015. However, an upward trend was observed in 2019 and 2020 due to the natural gas price environment and hydroelectric generation conditions in California. PG&E expects to see the historic trend of decreasing

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<sup>5</sup> These amounts have been reduced by PG&E's forecast of gas delivered to power plants by other pipelines.

1 market-responsive EG demand resume in the 2021 through 2026 forecast  
2 period.

3 Gas Prices: Prior to 2017, gas generators in the PG&E service territory  
4 typically paid higher burnertip gas prices relative to counterparts in Southern  
5 California. The burnertip gas price consists of gas commodity plus end-use  
6 transportation rates. In 2018 and 2019, this price differential decreased,  
7 becoming more favorable to Northern California generators. This increased  
8 gas-fired dispatch in the PG&E service territory. During 2020, the burnertip  
9 prices in both Northern and Southern California generally exhibited similar  
10 price levels. For 2021 and 2022, the burnertip prices in the Northern  
11 California are lower than those in Southern California. For 2023 through  
12 2026, burnertip prices in Southern California are less expensive than  
13 customer burnertip prices on the PG&E LT system but more expensive than  
14 BB system prices.

15 The PG&E LT system burnertip prices are more expensive than  
16 Southern California burnertip prices caused by higher LT transportation  
17 rates. The higher LT transportation rates proposed in Chapter 6<sup>6</sup> lowers  
18 forecasted demand from that group of generators in those respective years.  
19 The proposed EG BB transportation rates change very little. This lack of  
20 change does not have a material impact on the forecast.

21 Hydroelectric Generation: Additionally, lower-than-average  
22 hydroelectric generation in 2020 (dry hydro year) contributed to higher gas  
23 throughput. Gas-fired power plants make up most of the hydroelectric  
24 generation lost in dry years and generate less in wet years. PG&E also  
25 models 2021 as a dry hydro year before transitioning back to average  
26 hydroelectric generation conditions in 2022 through 2026, decreasing EG  
27 throughput.

28 Renewable Resource Additions: From 2021 through 2026, the forecast  
29 decreases in part due to an increase in installed renewable and storage  
30 capacity as additional solar, wind, and battery energy storage resources  
31 constructed throughout the state. This forecast is consistent with the  
32 California Public Utility Commission's (CPUC or Commission) Reference

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6 Ch. 6, p. 6-27, Table 6-13 Illustrative End-Use Class Average Rates (\$/Dth).

System Plan (RSP)<sup>7</sup> where most of these resources are added between 2021 and 2024 in advance of the retirement of DCNPP as discussed below.

DCNPP Retirement: Finally, the forecast shifts slightly upwards in 2024 through 2026 due to the planned retirement of the DCNPP,<sup>8</sup> one of the highest-capacity, highest-utilization<sup>9</sup> EG resources in the state. Its retirement will require other resources to compensate for previous DCNPP generation in every hour of the day. Even though gas generators are currently forecasted to make up for some of this generation, gas EG in PG&E's Service Territory in 2025 and 2026 is substantially lower than current levels. Furthermore, additional renewable and storage procurement by CAISO Load Serving Entities in the future could have the potential to displace the additional gas usage.

## 2. Modeling Methodology

PG&E's market-responsive power plant gas demand forecast is based on results from power system simulations conducted using the PLEXOS production cost modeling tool. This application provides estimates of consumption of all fuels used for power generation within the Western Electricity Coordinating Council (WECC) on an economic basis. PLEXOS is used by utilities and other organizations throughout the industry, including the California Energy Commission (CEC) in its Integrated Energy Policy Report (IEPR) forecasts.<sup>10</sup>

The model determines the least cost dispatch of generating resources to meet a given power demand. Least cost dispatch means finding the minimum cost to generate electricity among generation resources to meet electric demand. The gas-fired power plants on PG&E's system are included in the PLEXOS model used to project gas throughput.

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<sup>7</sup> D.20-03-028, p. 41, Table 5.

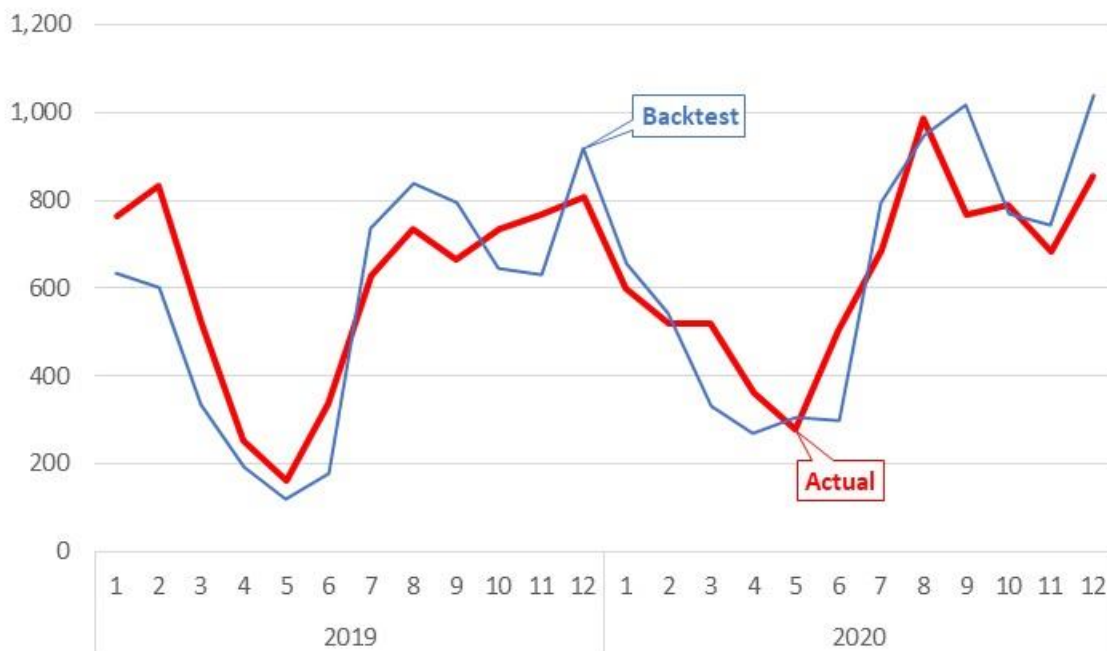
<sup>8</sup> D.18-01-022, p. 59, OP 1.

<sup>9</sup> The DCNPP consists of two reactors providing 2,280 MW of net-qualifying capacity (CAISO Resource IDs DIABLO\_7\_UNIT 1 and DIABLO\_7\_UNIT 2) and operate at nearly full power continuously unless offline for scheduled or unscheduled maintenance.

<sup>10</sup> CEC Staff Members, 2019 Natural Gas Market Trends and Outlook (Apr. 2020) p. 11, <<https://efiling.energy.ca.gov/GetDocument.aspx?tn=233661&DocumentContentId=66272>> (as of Sept. 7, 2021).

1 Since Northern California is part of a much larger wholesale electricity  
2 market, PG&E used PLEXOS to model the entire WECC area. Many  
3 assumptions are needed as input data and are discussed below. To assess  
4 the accuracy of the model, PG&E ran the historical period from January  
5 2019 through December 2020 and compared these results to actual  
6 demand. The results of this backtest<sup>11</sup> provide an indication of the accuracy  
7 of the modeling approach. Figure 2A-1 shows the actual power plant gas  
8 demand and the results from the PLEXOS backtest.

**FIGURE 2A-1**  
**MARKET-RESPONSIVE POWER PLANT GAS DEMAND (MDTH/D)**



9 Table 2A-3 compares throughput estimates from the backtest in  
10 PLEXOS with recorded actual throughput. In 2019, the model estimated  
11 lower annual average throughput than recorded data. In 2020, the model  
12 estimated higher annual average throughput than recorded data.  
13 Additionally, the backtest exhibits a high degree of correlation with historic  
14 actuals. Based on these results, the PLEXOS results are well-correlated to  
15 actual gas deliveries, with no consistent bias.

<sup>11</sup> Backtesting is the general method for seeing how well a strategy or model would have done ex-post.



**TABLE 2A-3**  
**SUMMARY OF MARKET-RESPONSIVE BACKTEST COMPARISON WITH ACTUALS**

Line No.	Value	2019	2020	2019-2020 Average
1	Actual Throughput (MDth/d)	600	632	616
2	Backtest Throughput (MDth/d)	553	646	600
3	Difference (MDth/d)	47	-14	17
4	% Difference	7.8%	-2.2%	2.7%
5	Correlation	0.88	0.90	0.89

### 3. Model Input Assumptions

To conduct the EG forecast, PG&E adapted a PLEXOS database provided by the CEC which was used for preliminary EG simulations for the 2019 IEPR to provide statewide EG gas demand forecasts. During this process, PG&E reviewed and updated assumptions in the CEC database as necessary. Key assumptions are described below.

WECC Modeling: In PLEXOS, PG&E represented the WECC electricity market as 26 sub-regions with transmission connections between them. The capacities of the transmission connections were obtained from the CEC's PLEXOS database.

Electric Load: PG&E used the final mid-case CEC forecast of annual California loads for the 2020 IEPR Update, including the impacts of incremental uncommitted electricity savings and behind-the-meter photovoltaic generation. The CEC publishes hourly forecasts for the three CAISO Transmission Access Charge areas which PG&E utilized directly. For non-CAISO California loads, PG&E received the hourly datasets that the CEC uses in their internal PLEXOS model. Since the CEC does not explicitly account for the electrification of buildings in the IEPR forecasts, PG&E added its internally developed electric load modifier to the IEPR forecasts. The methodology used to develop this forecast is consistent with the building electrification forecast in Chapter 2B.<sup>12</sup> These hourly values were scaled up from the PG&E Service territory to each California sub-region using that region's share of annual statewide load in the 2020

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<sup>12</sup> Chapter 2B, p. 2B-6.

1 IEPR Update forecast. PG&E's building electrification forecast adds about  
2 one half of one percent (0.5 percent) to California statewide electric load by  
3 2026. For regions outside California, PG&E utilized the forecast within the  
4 CEC's PLEXOS database.

5 Hydroelectric Generation: PG&E's forecast of hydroelectric generation  
6 is based on the 15-year average generation between water years 2003 and  
7 2017. 2021 was modeled as a "dry" hydro year using data from 2015 as  
8 configured within the CEC's PLEXOS database. The 15-year average  
9 assumption is consistent with the CEC's 2019 IEPR<sup>13</sup> and lower than the  
10 2020 California Gas Report (CGR) assumption of a 20-year average.<sup>14</sup>  
11 Since average hydroelectric generation has been trending downward over  
12 the last 20 years,<sup>15</sup> this results in lower hydroelectric generation than found  
13 in the CGR. This difference would have to be made up from other resources  
14 including natural gas and increases the EG forecast.

15 Existing Resources and Retirements: Data on existing and new power  
16 plants were obtained from the CEC's PLEXOS database. In addition to  
17 existing plants, PG&E confirmed all gas plants on the CAISO's 2020 Net  
18 Qualifying Capacity list<sup>16</sup> were present in PLEXOS. Gas fired steam plants  
19 in California with once through cooling were assumed to retire by their dates  
20 for compliance with the state water board, including the November 30, 2020

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13 CEC Staff Members, 2019 Natural Gas Market Trends and Outlook, (Apr. 2020) p. A-2,  
<<https://efiling.energy.ca.gov/GetDocument.aspx?tn=233661&DocumentContentId=66272>> (as of Sept. 7, 2021).

14 California Gas and Electric Utilities, 2020 CGR, Northern California, p. 42,  
<[https://www.pge.com/pipeline\\_resources/pdf/library/regulatory/downloads/cgr20.pdf](https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr20.pdf)>  
(as of Sept. 7, 2021).

15 Trend can be observed using Energy Information Agency data for conventional  
hydroelectric generation in California by year  
<[https://www.eia.gov/electricity/data/state/annual\\_generation\\_state.xls](https://www.eia.gov/electricity/data/state/annual_generation_state.xls)> (as of  
Sept. 7, 2021).

16 CAISO, Final Net Qualifying Capacity Report for Compliance Year 2020,  
<<http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx>> (as of  
Sept. 22, 2021).

amendments<sup>17</sup> to the compliance schedule affecting specific units at Ormond Beach, Alamitos, Huntington Beach, and Redondo Beach. Additionally, PG&E modeled DCNPP Reactor One planned to retire on November 2, 2024 and Reactor Two planned to retire on August 26, 2025.<sup>18</sup>

Renewable Generation and Storage: PG&E also included future renewable energy generation and energy storage projects consistent with the CPUC RSP finalized within the 2019-2020 Integrated Resource Plan for the relevant 2023-2026 timeframe of this proceeding.<sup>19</sup> Renewable energy generation is projected to reach approximately 50 percent of California retail sales by the end of the rate case period, on track to meet the requirements set by California Senate Bill 100.<sup>20</sup>

Natural Gas Burnertip Prices and Greenhouse Gas Emission Allowance Costs: The gas commodity price and greenhouse gas emission allowance cost forecasts use the August 2, 2021 contract settlement data and were obtained from PG&E's internal Market Data System. The end-use G-EG transportation rates were obtained from Chapter 6 CARD.<sup>21</sup>

### **C. Forecast of Non-Market-Responsive Electric Generation Gas Demand**

The non-market-responsive EG group consists primarily of gas-fired cogenerators whose output is generally not sensitive to prices in the electricity and gas markets. This class's generation is primarily driven by onsite loads rather than electric wholesale prices. Many of these plants have Qualifying

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<sup>17</sup> California Water Boards, State Water Resources Control Board, Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (last amended Nov. 30, 2020), <[https://www.waterboards.ca.gov/water\\_issues/programs/ocean/cwa316/docs/otc\\_policy\\_2020/otc2020.pdf](https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/otc2020.pdf)> (as of Sept. 22, 2021).

<sup>18</sup> D.18-01-022, p. 59, Ordering Paragraph (OP) 1.

<sup>19</sup> If the CPUC adopts a Preferred System Plan with higher amounts of renewable generation and battery storage, this could decrease the market-response EG throughput forecast presented here.

<sup>20</sup> The 100 percent Clean Energy Act of 2018 (SB-100) mandates that eligible renewable resources serve a specified fraction of total retail sales in California by the end of certain years. The relevant years for this forecast are 33 percent by the end of 2020, 44 percent by the end of 2024, and 52 percent by the end of 2027, and 60 percent by the end of 2030. Pub. Util. Code § 399.15(b)(2)(B).

<sup>21</sup> Chapter 6, Section E, p. 6-11, Table 6-28 Illustrative End-Use Class Average Rates (\$/Dth).

Facility contracts that require PG&E to purchase their power but do not allow PG&E to dispatch their power. This group currently consists of 384 accounts that have gas delivered by PG&E (as of May 2021) either at the distribution or LT service level.

PG&E's forecast of non-market-responsive EG gas demand is 155 MDth/d, based on the most recent available 12 months of actual deliveries (June 2020 through May 2021). This approach was used in previous Gas Transmission and Storage (GT&S) rate cases<sup>22</sup> and Gas Cost Allocation Proceedings.<sup>23</sup> Below, Table 2A-4 provides annual average non-market responsive throughput for recorded years 2017 through 2020 as well as the average of the most recent twelve months utilized in this forecast.

**TABLE 2A-4  
AVERAGE RECENT RECORDED THROUGHPUT COMPARED TO 2017 THROUGH 2020  
(MDTH/D)**

Line No.		2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	'23 - '26 Forecast
1	Non-market-responsive EG	175	175	172	163	155

The forecast is slightly less than calendar 2020 recorded demand and is also down from 2017 through 2019. This is due to a reduction in average demand per account. This forecast captures the decrease in gas throughput from this customer class by using the last 12 months of data. PG&E believes a reasonable forecast of non-market-responsive EG gas demand for the rate case period is the actual gas demand from June 2020 through May 2021, the most recent 12 months available.

If the Commission adopts a higher non-market-responsive EG gas demand forecast, the market-responsive EG and industrial gas demand forecasts should be reduced. Without this adjustment, EG would be over produced. Consequently, market-responsive gas throughput would need to be lowered. This would allow for a balanced electric supply and electric demand. A higher non-market-responsive EG demand forecast would increase industrial gas demand.

<sup>22</sup> D.16-06-056 and D.19-09-025.

<sup>23</sup> D.18-10-040.

Without an adjustment, the industrial gas demand forecast would exhibit a double counting of actual use. This implies that industrial gas use is higher than previously forecasted.

#### **D. Cold Year Electric Generation Gas Demand Forecast**

In the 2019 GT&S Final Decision, the Commission ordered PG&E to include a separate cold-year forecast of EG gas demand in its next GT&S application. This forecast is developed for a 1-in-35 cold year scenario. The cold year peak month (December in the 2019 GT&S Rate Case) demands are used to allocate LT costs between Core and Noncore customer classes. Pursuant to OP 86, PG&E provides the below forecast.

Table 2A-4 shows the total on-system throughput forecast for cold temperature conditions compared to recorded data for 2020. This forecast is developed for a 1-in-35 cold year scenario.

**TABLE 2A-5  
COLD-WEATHER ELECTRIC GENERATION COMPARISON TO 2020 RECORDED  
(MDTH/D)**

Line No.		2020 Recorded	2023 Forecast	2024 Forecast <sup>(a)</sup>	2025 Forecast	2026 Forecast
1	<u>Electric Generation</u>					
2	Non-market-responsive EG	163	155	156	155	155
3	<u>Market-responsive EG</u>	654	321	318	345	376
4	<i>Local Transmission</i>	287	61	58	59	60
5	<i>Backbone-only</i>	367	261	260	286	316
6	Total Electric Generation	817	477	474	500	532

(a) Since 2024 is a leap year, calculating an annual average value from monthly data results in throughput that is slightly higher than in other years.

#### **E. Conclusion**

This chapter has presented PG&E's forecasts for gas demand and throughput for core, noncore and wholesale customers that are used throughout this case in developing proposed rates. PG&E recommends the adoption of

1 these forecasts (Tables 2A-1 and 2A-5) for use in setting GT&S rates in this  
2 proceeding.<sup>24</sup>

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**24** In PG&E's most recent GCAP, D. 19-10-036, the CPUC adopted the proposal to no longer determine gas sales and customer billings forecasts in both the GCAP and in the GT&S Rate Case but instead to use the adopted forecast from the most recent GT&S Rate Case to update the previously adopted GCAP allocation methods and for the next GCAP application.

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 2B**

**NON-GENERATION DEMAND AND THROUGHPUT FORECAST**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 2B  
NON-GENERATION DEMAND AND THROUGHPUT FORECAST

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 2B**  
**NON-GENERATION DEMAND AND THROUGHPUT FORECAST**

**A. Introduction**

**1. Scope and Purpose**

This chapter presents Pacific Gas and Electric Company's (PG&E) forecast of on-system demand and wholesale throughput for the 2023 Gas Transmission and Storage (GT&S) Cost Allocation and Rate Design (CARD) Rate Case, for the period 2023-2026. The purpose of this testimony is to describe PG&E's forecast methodology, and PG&E's annual on-system demand for cost allocation and ratemaking.

The on-system throughput and billings consist of two market segments:

- 1) Core, which consists of residential, commercial, and Natural Gas Vehicle (NGV) customers, who can choose "bundled" natural gas commodity and transportation services, or unbundled transportation service, from PG&E.
- 2) Noncore industrial, which includes large manufacturing and refining customers, as well as non-manufacturing customers, such as large health, educational, governmental, food processing, and administrative facilities as well as NGV customers choosing noncore service. These customers purchase gas transportation-only services from PG&E and receive their natural gas supplies from third parties.

The electric generation forecast is described in the preceding Chapter 2A.<sup>1</sup> The off-system forecast is included in Chapter 3.<sup>2</sup>

**2. Forecast Summary**

PG&E proposes to revise gas transmission rates effective January 1, 2023, incorporating the current throughput projection for 2023. Table 2B-1 below compares PG&E's forecast for 2023-2026 to recorded data for 2020.

In the sections below, PG&E describes current economic conditions and the assumptions that underlie the forecast for 2023-2026. PG&E has

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<sup>1</sup> Chapter 2A, p. 2A-2, Table 2A-1.

<sup>2</sup> Chapter 3, p. 3-6, Table 3-1.

1 developed a throughput forecast that is reasonable and recommends that  
2 the forecast presented in this chapter be adopted for the CARD proceeding.

**TABLE 2B-1**  
**AVERAGE-WEATHER GAS THROUGHPUT FORECAST COMPARISON TO 2020 RECORDED**  
**(MDTH/D)**

Line No.		2020 Recorded <sup>(a)</sup>	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
1	<u>Core</u>					
2	Residential	513	483	467	453	436
3	Commercial	202	223	224	222	218
4	<i>Small Commercial</i>	184	205	206	204	201
5	<i>Large Commercial</i>	19	18	18	18	17
6	Interdepartmental	0.4	0.4	0.4	0.4	0.4
7	Core Natural Gas Vehicles	7	7	8	8	8
8	Total Core	723	714	699	683	663
9	<u>Noncore</u>					
10	Industrial	486	499	501	501	501
11	<i>Industrial Distribution</i>	69	70	70	69	69
12	<i>Industrial Transmission, Backbone and NGV4</i>	417	429	431	432	432
13	Non-market-responsive EG	163	155	156	155	155
14	Market-responsive EG	654	319	316	342	371
15	Total Noncore	1303	973	973	999	1027
16	Wholesale	8	9	9	9	9
17	Total Volumes	2034	1696	1681	1691	1699

(a) 2020 Recorded data is as recorded and not weather adjusted.

## 3 **B. Core and Noncore Gas Throughput Forecast (Other than Electric** 4 **Generation)**

### 5 **1. Forecasting Methodology**

6 PG&E forecasts gas demand by various means. The forecasts for  
7 residential, small commercial, large commercial, noncore industrial customer  
8 classes and wholesale customers were developed using econometric  
9 models, namely linear regression modeling with post regression adjustments  
10 for the impact of energy efficiency and building electrification. The  
11 econometric models rely on statistical analysis of historical data to derive  
12 relationships between economic and demographic data, prices,  
13 temperature, and seasonal-use patterns with gas throughput. The final

specification of a model is based on economic theory as well as the statistical significance and plausibility of its estimated coefficients and the reasonableness of the resulting forecast. Customers are grouped according to their economic role and usage type (these groupings may not correspond precisely to rate classes). These groups include residential, small and large commercial, and various types of industrial customers. Each of these classes has an associated regression model with several fitted coefficients. The throughput forecast is the sum of the throughput for each of these classes. Regression drivers such as economic and demographic variables are projected forward using estimates from third party data providers such as Moody's. Typical temperatures in the form of heating degree days are estimated from history and overlaid with a simple warming trend to capture climate change. Model equations and supporting data can be found in the workpapers supporting this chapter.

PG&E's forecast methodology is consistent with that used in gas proceedings and forecasts, including PG&E's 2019 GT&S Rate Case.<sup>3</sup> This methodology starts with base forecasts of customer usage obtained by regression against historical usage and economic and weather drivers. The base forecast is modified by forecast incremental energy efficiency and electrification impacts.

## **2. Forecasting Models Inputs and Assumptions**

### **a. Economic Activity**

PG&E populates its forecast models with economic projections developed by Moody's Analytics (Moody's). Specifically, forecasts of future economic and demographic activity for PG&E's service area, such as industrial and commercial output, employment, population, and household growth were taken from Moody's Analytics' December 2020 forecast of the PG&E service area economy.

Before the public health regulations related to the pandemic,<sup>4</sup> PG&E's service area was in economic expansion. But since the

---

<sup>3</sup> A.17-11-009, Exhibit PG&E-2, Chapter 16A.

<sup>4</sup> First California public health restrictions, such as San Francisco recommending restrictions on large gatherings, began in March 2020.

1 beginning of the pandemic, unemployment has spiked. Unemployment  
2 rates have come down substantially, but according to Moody's Analytics  
3 end of 2020 report, PG&E's service area economy is "precarious" and  
4 the pace of employment recovery lags national and regional averages.<sup>5</sup>  
5 The recovery is expected to continue and it remains to be seen whether  
6 California's relatively strong vaccination rates will accelerate the  
7 process.

8 Furthermore, prior to their 2020 end of year report, Moody's issued  
9 a report specific to COVID-19 impacts in summer 2020.<sup>6</sup> PG&E's  
10 economic modeling assumes that COVID-19-specific gas market  
11 impacts will follow approximately the timeline described by Moody's in  
12 their summer 2020 analysis: after arrival of vaccines, COVID-19-specific  
13 impacts will ramp down linearly until mid-2023, after which the only  
14 forecast impacts will be residual effects reflected in standard economic  
15 inputs.<sup>7</sup>

16 PG&E's only COVID-specific model adaptation was the inclusion of  
17 a COVID-19-dummy variable starting in March of 2020 whose forecast  
18 impact is ramped down to zero through mid-2023 following the Moody's  
19 timeline described above. While the arrival of the Delta and Lambda  
20 variants, additional uncertainty has been injected into the outlook, but  
21 the assumed COVID-19 trajectory still has almost two years of runway  
22 to play out and Moody's has not incorporated any specific fallout from  
23 the Delta variant in their baseline outlook for the economy in early  
24 August 2021.<sup>8</sup> We continue to monitor this issue and other economic  
25 developments that may substantially impact the forecast.

26 Core and noncore (non-EG) gas demand projections are  
27 determined, particularly in the longer run, by the economic outlook for

---

5 Moody's Analytics is an internationally recognized economic and demographic forecasting firm. As of September 22, 2021, the Moody's 2020 report remains their most current on possible COVID-19 scenarios.

6 Moody's Analytics, Regional Financial Review, "Forecasting COVID-19 Cases: An Update." (July 2020).

7 *Id.*

8 Moody's Analytics U.S. Macro Precis, August 2021, p. 2.

1 PG&E's service area. All other things being equal, the higher the growth  
2 rates of service area households and business activity—the latter  
3 reflected in commercial and industrial output and employment—the  
4 faster the growth of gas demand. In the case of the current forecast,  
5 modest household and economic growth is expected to increase gas  
6 demand, but energy efficiency and state-wide programs to address  
7 climate change will serve to temper this growth.

8 **b. Assumptions Regarding Weather**

9 Because residential and commercial customers use natural gas  
10 primarily for space-heating, temperature conditions are the single most  
11 important factor influencing winter and, by extension, annual Core gas  
12 demand.

13 For this proceeding, as with prior GT&S cases, PG&E has prepared  
14 throughput forecasts for two design temperature conditions--“average  
15 year” and 1-in-35-year “cold winter.” Average year demand is used for  
16 most rate-design purposes. It is the expected value of forecast demand  
17 (this is the standard point forecast) produced by applying forecast model  
18 driver values to regression coefficients. “Cold winter” demand is the  
19 currently adopted method for local transmission cost allocation. This is  
20 a “1 in 35” value in the sense that we have the standard deviation of  
21 historical monthly heating degree days (HDD) which we use to  
22 calculate percentile values for HDD in each month; the 1 in 35 scenario  
23 is approximately a 97th percentile HDD value. Each series of  
24 temperature conditions also employs a slight warming pattern to account  
25 for climate change. These patterns are based on work performed by the  
26 PG&E Meteorology Department. PG&E's Meteorology Department  
27 typically reviews and analyzes outputs from a series of peer-reviewed  
28 climate models and creates an expected weather forecast for the  
29 service area covering the test period.

30 **c. Assumptions Regarding Energy Usage: Conservation and**  
31 **Electrification**

32 PG&E incorporates the effects of electrification and energy  
33 efficiency into its gas throughput forecast. Energy efficiency

assumptions use savings totals from the 2019 Integrated Energy and Policy Report (IEPR) results for the PG&E service area developed by the California Energy Commission (CEC). PG&E's new energy efficiency programs and codes and standards are informed by the "Mid Additional Achievable Energy Efficiency (AAEE)" scenario while committed energy efficiency was provided separately by the CEC as it is embedded in the 2019 IEPR baseline forecast. The CEC's IEPR forecast is informed by recent energy-efficiency studies conducted in the state, most notably the California Public Utilities Commission's (CPUC or Commission) 2019 Potential and Goals Study produced by Navigant in 2019. PG&E's forecast draws from these studies and includes committed and uncommitted savings. PG&E has built these reductions into the forecast used in developing PG&E gas throughput for this GT&S rate case period.

Building electrification assumptions are derived from policy assumptions and subject matter expert likelihood estimates consistent with PG&E's electric sales forecast. Forecast electrification includes new construction and retrofit for residential and commercial customer classes.<sup>9</sup> Reduction in sales from building electrification in the rate case period are primarily from retrofit rather than new. The relatively small amount of new residential all electric construction is primarily driven by local energy codes and these values reduce the residential customer count forecast as well as sales.

### **3. Core Throughput Forecast**

Core demand is projected to average approximately 698 thousand dekatherms per day (MDth/d) during 2023-2026. The Core forecast demands are shown in Table 2B-1. A discussion of the forecast for the major customer groups composing the Core class follows.

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<sup>9</sup> Inputs and assumptions to this forecast are in general those available in early 2021. In particular, there is no change in assumptions made in response to the California governor's late July proclamation of the "California Comeback Plan", <https://www.gov.ca.gov/2021/07/30/governor-newsom-signs-emergency-proclamation-to-expedite-clean-energy-projects-and-relieve-demand-on-the-electrical-grid-during-extreme-weather-events-this-summer-as-climate-crisis-threatens-western-s/> (as of September 28, 2021).

1           **a. Residential Throughput**

2           Residential gas throughput is primarily driven by temperature, with  
3           smaller economic and price effects. It is the longer-term impacts of  
4           energy efficiency programs and California’s building standards that  
5           drove residential usage lower, both on a per-household basis, and total  
6           basis. California’s prolonged drought has also reduced demand for  
7           residential customers by reducing hot water use, resulting in lower  
8           average gas usage, especially in the peak winter months. The degree  
9           to which a substantial portion of this conservation continues under  
10          normal rainfall conditions remains to be seen.

11          For the CARD rate case period 2023-2026, under normal weather  
12          conditions, PG&E projects residential usage to average approximately  
13          464 MDth/d. This is about 9.3 percent below the recorded 2020  
14          amount.

15           **b. Commercial Throughput**

16          Similar to the residential class, throughput for the commercial class  
17          is primarily driven by temperature, economic, and price effects. The  
18          projected annual average usage for commercial gas throughput<sup>10</sup>  
19          during the CARD rate case period is approximately 226 MDth/d, about  
20          12 percent above the 2020 level. The 2020 throughput of about  
21          202 MDth/d followed about 233 MDth/d in 2019, a drop presumably due  
22          to COVID-19 and slightly warmer temperatures.

23           **4. Noncore Throughput Forecast**

24          Proposed noncore non-EG throughput is projected to be about  
25          500 MDth/d during the CARD rate case period. The forecast of noncore  
26          throughput is shown in Table 2B-1. A discussion of the major non-EG  
27          customer classes making up noncore follows.

28           **a. Industrial Distribution Throughput**

29          Industrial distribution customers are also primarily driven by  
30          temperature, economic activity, and gas pricing effects. The projected

---

<sup>10</sup> To qualify for this rate schedule, a core customer’s average monthly gas use must not have exceeded 20,800 therms in those months in the past year in which its usage exceeded 200 therms.

throughput for the industrial distribution<sup>11</sup> class of customers averages 69.3 MDth/d over the 2023-2026 CARD rate case period. This is 1 percent higher than the recorded 2020 amount of 68.7 MDth/d.

**b. Industrial Transmission, Backbone and Noncore Natural Gas Vehicles (NGV4) Throughput**

Due primarily to lower forecast economic activity in the fuels sector, the throughput for the industrial transmission customer class<sup>12</sup> had been projected to decline over time in previous forecasts. Here, the projected throughput is 422 MDth/d for the 2023-2026 CARD rate case period, or 3.7 percent higher than the 2020 recorded. However, throughput for this class had dropped almost 15 percent from 2019 to 2020, so this is a return to a lowering trend rather than a change in direction.

**5. Wholesale Throughput Forecast**

PG&E currently serves six wholesale customers: the City of Palo Alto, the City of Coalinga, West Coast Gas Castle Field, West Coast Gas Mather Field, Island Energy, and Alpine Natural Gas. The individual forecasts for these customers' loads are primarily driven by temperature. These regressions use weather data specific to the wholesale customer locations.

The proposed annual average gas throughput for these six customers is projected to be 9.4 MDth/d for the CARD rate case period—about 11 percent higher than the 2020 recorded amount (the 2020 recorded amount dropped about 8 percent from 2019).

---

<sup>11</sup> To qualify for the industrial distribution rate schedule, a customer's average monthly gas use must have exceeded 20,800 therms in those months in the past year in which its usage exceeded 200 therms.

<sup>12</sup> To qualify for the industrial transmission rate schedule, a customer must be of noncore status, which means that it must have maintained an average monthly usage in excess of 20,800 therms during the previous year, excluding those months in which usage was 200 therms or less. To the extent that its average monthly usage exceeds 250,000 therms, it is connected to facilities that are on transmission pressure (greater than 60 per square inch).



## **6. Impact of Chapter 8 Proposals**

Potential impacts on PG&E's proposed 2023-2026 throughput for G-NGV1 (core) and G-NGV4 (noncore) from the proposals in Chapter 8<sup>13</sup> will be included in the throughput forecast PG&E submits for its 2027 GT&S CARD in 3rd Quarter 2025 with an initial inclusion in the 2024 California Gas Report based on information available as these forecasts are developed. Prior to Commission approval, PG&E cannot move on the process of reviewing customer connection requests for service under the expanded applicability and, if the connection costs are accepted by the customer, beginning planning and then construction of the connections. In addition, the magnitude of customer connection requests for service under these proposed tariff changes are unknown prior to approval by the Commission. Therefore, such proposal impact is not included here because it would be speculative to forecast the cumulative impact on annual gas throughput under G-NGV1 and G-NGV4, including customer choice between core and noncore service, at this time.

## **7. Summary of On-System Cold Year Throughput Forecast**

Table 2B-2 shows the total on-system throughput forecast for cold temperature conditions. This forecast is developed for a 1-in-35 cold year scenario. The cold year peak month demands are used to allocate local transmission costs between Core and Noncore customer classes.

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<sup>13</sup> Chapter 8, Section C.

**TABLE 2B-2  
COLD YEAR GAS THROUGHPUT FORECAST (1-35 YEARS)  
(MDTH/D)**

Line No.		2020 Recorded	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
1	<u>Core</u>					
2	Residential	513	544	529	515	499
3	Commercial	202	238	238	237	233
4	<i>Small Commercial</i>	184	219	220	219	215
5	<i>Large Commercial</i>	19	19	19	18	18
6	Interdepartmental	0.4	0.4	0.4	0.4	0.4
7	Core Natural Gas Vehicles	7	7	8	8	8
8	Total Core	723	790	776	761	740
9	<u>Noncore</u>					
10	Industrial	486	501	503	503	503
11	<i>Industrial Distribution</i>	69	72	72	71	71
12	<i>Industrial Transmission,     Backbone and NGV4</i>	417	429	431	432	431
13	Non-market-responsive EG	163	155	156	155	155
14	Market-responsive EG	654	321	318	345	376
15	Total Noncore	1303	978	977	1003	1034
16	Wholesale	8	10	10	10	10
17	Total Volumes	2034	1778	1763	1774	1785

**1 C. Conclusion**

2           This chapter has presented PG&E's forecasts for gas demand and  
3 throughput for core, noncore and wholesale customers that are used throughout  
4 this case in developing proposed rates. PG&E recommends the adoption of  
5 these forecasts (Tables 2B-1 and 2B-2) for use in setting GT&S rates in this  
6 proceeding.<sup>14</sup>

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<sup>14</sup> In PG&E's most recent Gas Cost Allocation Proceeding (GCAP), D.19-10-036, the CPUC adopted the proposal to no longer determine gas sales and customer billings forecasts in both the GCAP and in the GT&S Rate Case but instead to use the adopted forecast from the most recent GT&S Rate Case (1) to update the previously adopted GCAP allocation methods, and (2) for the next GCAP application.

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 3**

**BACKBONE RATE INPUTS**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 3  
BACKBONE RATE INPUTS

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 3**  
**BACKBONE RATE INPUTS**

**A. Introduction**

This chapter describes various inputs to Pacific Gas and Electric Company's (PG&E) backbone rate design.<sup>1</sup> The most important of these inputs is the backbone load factor. Other inputs include the rate differential between the Baja and Redwood transportation paths, the forecast of off-system revenues and throughput, the forecast of backbone firm contracts, and the forecast of California production volumes transported on the backbone system.

**B. Backbone Load Factor**

**1. Summary**

PG&E employs a system average backbone load factor to design backbone transmission rates. The load factors underlying PG&E's proposed backbone rates in this rate case are: 65.20 percent for 2023; 61.26 percent for 2024; 63.84 percent for 2025; and 64.02 percent for 2026. By comparison, the backbone load factors adopted in the 2019 Gas Transmission and Storage (GT&S) Rate Case ranged from 62.45 percent to 63.36 percent for 2019-2022.<sup>2</sup> This section explains the computational details and rationale for the proposed 2023-2026 backbone load factors.

PG&E calculated the system average load factors in this case using the same methodology adopted by the California Public Utilities Commission (Commission) in the 2015 and 2019 GT&S Rate Cases. In Decision (D.)16-06-056, the Commission found that "PG&E's methodology for calculating the system average load factors for non-equalized rates is reasonable and should be adopted."<sup>3</sup> The Commission reached this conclusion despite several intervenors proposing changes to PG&E's methodology.<sup>4</sup> In D.19-09-025, the Commission found again that "PG&E's

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<sup>1</sup> The backbone rates themselves are presented in Chapter 6 of this testimony.

<sup>2</sup> D.19-09-025, Appendix H, Table 24.

<sup>3</sup> D.16-06-056, p. 233, Conclusion of Law (COL) 233; pp. 307-308.

<sup>4</sup> A.13-12-012, Exhibit CalCAPPGTNPalo1, p. 32.

1 methodology for its backbone rate design and load factor is just and  
2 reasonable. [W]e adopt PG&E's backbone rate design and load factor  
3 methodology."<sup>5</sup>

## 4 **2. Background**

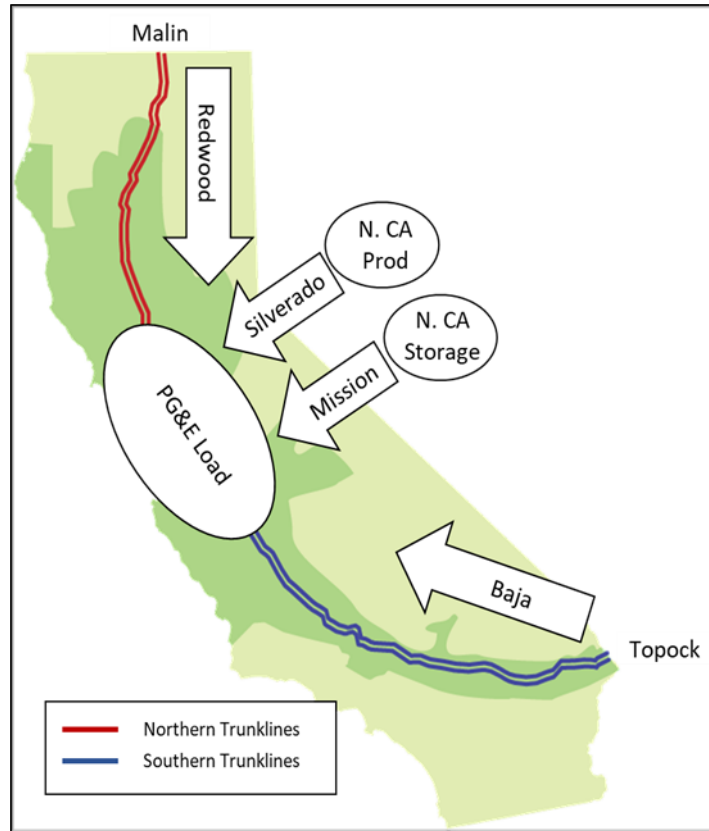
5 PG&E provides backbone transportation services on four paths:  
6 Redwood, Baja, Silverado and Mission. While the term "path" has long been  
7 used on PG&E's system, it is somewhat of a misnomer. It is more accurate  
8 to characterize PG&E's backbone services as being geographically  
9 differentiated by receipt point. Backbone customers receive their gas at  
10 specific receipt points (based on their path) but may deliver their gas to any  
11 point on PG&E's system (or any off-system interconnection point in the case  
12 of off-system services) regardless of their path.

13 The Redwood path receives gas principally at Malin (on the  
14 California-Oregon border) or points downstream of Malin. The Baja path  
15 receives gas principally at Topock (on the California-Arizona border) or  
16 points downstream of Topock. The Silverado path receives gas from  
17 California production sources, including renewable natural gas (RNG), in  
18 PG&E's service territory. The Mission path receives gas withdrawn from  
19 PG&E storage fields or independent storage providers in PG&E's service  
20 territory. The four paths are shown schematically in Figure 3-1 below.

---

5 D.19-09-025, p. 254; p. 318, COL 116.

**FIGURE 3-1  
PG&E BACKBONE TRANSPORTATION PATHS**



The Redwood path has three sub-paths: Core Redwood, Noncore Redwood, and Schedule G-XF. The Baja path has two sub-paths: Core Baja and Noncore Baja. The Silverado path is a single undifferentiated path, as is the Mission path. The rate design process considers the first three of these paths but disregards the Mission path. No costs are allocated to the Mission path because virtually all service on the path is provided under PG&E's as-available tariff (Schedule G-AA), for which the rate is zero.<sup>6</sup>

Under traditional utility rate design, rates for each backbone path might be determined by dividing the allocated costs for each path by the

<sup>6</sup> The Commission requires that “customer-owned gas transported to and from a storage facility...is assessed no more than one transportation charge on each utility system performing the transportation service.” (D.93-02-013, Appendix B, Adopted Rules: Gas Storage Service, Rule 4.1.) On PG&E's system, under the Gas Accord structure, gas is transported to storage on either the Baja, Redwood, or Silverado path and pays the applicable backbone rate. Gas is transported from storage on the Mission backbone path, for which the as-available rate is zero.

1 forecasted throughput on that path. However, since the beginning of the  
2 Gas Accord structure in 1998,<sup>7</sup> PG&E has designed backbone rates based  
3 on a system average load factor, not path-specific throughputs. The system  
4 average load factor is calculated as total backbone demand (on all paths)  
5 divided by total backbone capacity (on all paths) plus various adjustments:

$$\text{System Average Load Factor} = \frac{\text{Total Backbone Demand} + \text{Adjustments}}{\text{Total Backbone Capacity} + \text{Adjustments}}$$

6 For the reasons described below, PG&E uses the system average load  
7 factor as a substitute for throughput in the backbone rate calculation. The  
8 backbone rate for a given path is calculated by dividing the costs allocated  
9 to that path by the product of the path capacity multiplied by the system  
10 average load factor:<sup>8</sup>

$$\text{Path Rate} = \frac{\text{Allocated Path Costs (\$ '000)}}{\text{Path Capacity (MDth/d)} \times \text{System Average Load Factor (\%)} \times 365 \text{ d}}$$

11 In effect, this methodology assumes that the backbone paths are used  
12 proportionally to serve demand on PG&E's system. Another way to think  
13 about the methodology is that it averages demand across PG&E's various  
14 backbone paths for rate design purposes. The system average load factor  
15 methodology provides several benefits.

16 First, it contributes to backbone rate stability. The market's preference  
17 for the two primary backbone paths, Redwood and Baja, has changed in the  
18 past and may continue to change from time to time in the future. If PG&E  
19 used path-specific throughputs to design backbone rates, the result would  
20 be wild swings in the Redwood and Baja rates. The rate on a given path  
21 would decrease significantly when the path was favored by the market and  
22 increase significantly when the path went out of favor.

---

<sup>7</sup> See Gas Accord Settlement, which provides for rates and terms of service for 1997-2002, but which was not implemented until March 1, 1998.

<sup>8</sup> The actual backbone rate design is more complex than represented here in that separate calculations are performed for the reservation rate component and the usage rate component. Also, there are several types of services available on each path and sub-path, with attendant variations in rates.



1 Second, compared to path-specific throughputs, the system average  
2 load factor methodology enhances gas-on-gas competition. As discussed in  
3 the first point, path-specific throughputs would increase the rate on the  
4 out-of-favor path, thus perpetuating its out-of-favor status and disfavoring  
5 upstream suppliers. The converse would be true for the favored path and  
6 suppliers upstream of that path.

7 Third, the system average load factor methodology equitably allocates  
8 the costs of reserve/peaking capacity to all paths. On average, PG&E's  
9 backbone system operates at an approximately 65 percent load factor over  
10 the course of a year. The costs of the 35 percent reserve/peaking capacity  
11 should be borne by all customers because all customers benefit from the  
12 existence of this capacity. However, path-specific throughputs would result  
13 in rates on the favored path bearing relatively few of these costs, and rates  
14 on the out-of-favor path bearing a disproportionate share of these costs.

15 Importantly, the backbone load factor is not determined through a static  
16 calculation. As explained below, several of the throughput adjustments in  
17 the backbone load factor calculation rely on the backbone rates themselves.  
18 Thus, the backbone load factor and the backbone rates are interdependent.  
19 The backbone load factor model and the backbone rate model must be run  
20 in an iterative manner until the rates output from the rate model converge  
21 with the rates input to the load factor model.

22 Sections B.3 and B.4 below describe the backbone load factor  
23 calculation.

### 24 **3. Backbone Load Factor Calculation**

25 Table 3-1 below summarizes the backbone load factor calculations for  
26 2023 through 2026. These backbone load factors assume a "50 percent  
27 Baja-Redwood rate differential," a concept that is described in Section C of  
28 this this chapter.

**TABLE 3-1  
BACKBONE LOAD FACTOR  
50 PERCENT BAJA-REDWOOD RATE DIFFERENTIAL**

	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
1 <b>Backbone Demand (MDth/d)</b>				
2 Core	714	699	683	663
3 Core distribution shrinkage	18	18	17	17
4 Noncore industrial	495	497	497	497
5 Noncore natural gas vehicle (NGV4)	4	4	4	4
6 Noncore electric generation	474	472	497	527
7 Wholesale	9	9	9	9
8 Subtotal, on-system	1,714	1,698	1,709	1,716
9 G-XF off-system	80	80	80	80
10 Non G-XF off-system (full-rate-equivalent throughput) (See Table 3-2, Line 1)	113	103	113	106
11 Subtotal, off-system	193	183	194	186
12 TOTAL	1,908	1,881	1,902	1,902
13 Remove G-XF contracts	(86)	(86)	(86)	(86)
14 Adjust for Baja on-system discounts (See Table 3-2, Line 9)	0	0	0	0
15 Adjust for G-AA, G-SFT, and G-NFT premiums (See Table 3-2, Line 15)	57	63	56	67
16 Adjust for reservation charges for un-used firm contracts (See Table 3-2, Line 36)	138	61	68	27
17 Adjust for disproportionate usage of backbone paths (See Table 3-2, Line 42)	(83)	(90)	(97)	(91)
18 Subtotal, adjustments	26	(52)	(59)	(84)
19 TOTAL, ADJUSTED	1,934	1,829	1,843	1,819
20 <b>Backbone Capacity (MDth/d at Delivery Point)</b>				
21 Redwood Line 401	1,047	1,047	998	974
22 Redwood Line 400	1,064	1,064	1,014	990
23 Baja Line 300	958	958	958	958
24 Silverado "capacity"	69	88	86	87
25 TOTAL	3,139	3,158	3,057	3,009
26 Remove G-XF contracts	(86)	(86)	(86)	(86)
27 Remove SMUD equity capacity, Line 401	(48)	(48)	(45)	(44)
28 Remove SMUD equity capacity, Line 300	(38)	(38)	(38)	(38)
29 Subtotal, adjustments	(172)	(172)	(169)	(168)
30 TOTAL, ADJUSTED	2,967	2,986	2,887	2,841
31 Memo: Silverado flow forecast	45	54	55	56
32 <b>Backbone Load Factor</b>	65.20%	61.26%	63.84%	64.02%

1 The on-system demand forecast shown on lines 1 through 8 of  
2 Table 3-1 is taken from Chapter 2B (Demand and Throughput Forecast),  
3 except for Core distribution shrinkage (line 3). The Core distribution  
4 shrinkage quantities are based on the winter and summer base shrinkage  
5 allowances of 3.2 percent and 1.3 percent, respectively, that become  
6 effective November 1, 2020.<sup>9</sup>

7 Off-system demand is shown on lines 9 through 11. This forecast  
8 includes Schedule G-XF throughput and non-G-XF throughput. The  
9 Schedule G-XF throughput derives from a handful of long-term legacy

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<sup>9</sup> Advice 4310-G, which PG&E filed September 14, 2020 and the Commission approved October 8, 2020; A.21-06-021, Exhibit (PG&E-3), p. 11-65, lines 7-13 and Table 11-7.

contracts that pre-date the first Gas Accord.<sup>10</sup> The non-G-XF throughput, which is expressed as full-rate-equivalent throughput, is discussed further in Section B.4.b of this chapter.

Total backbone demand is shown on line 12. Various adjustments are shown on lines 13 through 18. First, on line 13, the off-system and on-system Schedule G-XF quantities are removed because G-XF shippers are subject to an incremental rate design<sup>11</sup> that does not employ the system average load factor. The remaining adjustments, shown on lines 14 through 17, are discussed in detail in Section B.4 of this chapter. Line 19 shows total adjusted backbone demand.

The backbone demand developed on lines 1 through 19 of Table 3-1 excludes Mission path throughput. The Mission path is used principally to transport gas withdrawn from on-system storage. Because no costs are allocated to the Mission path and no backbone revenues are derived from it, it is excluded from the backbone load factor calculation.

The backbone capacities shown on lines 20 through 25 of Table 3-1 are based on the firm backbone capacities PG&E proposed in its 2023 General Rate Case (GRC), Phase I, Track 1.<sup>12</sup> In the 2023 GRC, the backbone capacities are expressed in volumetric units (millions of cubic feet per day (MMcf/d)) at the receipt point. For purposes of the backbone load factor calculation and the backbone rate design, they must be expressed in energy units (thousands of dekatherms per day (MDth/d)) at the delivery point. The conversion from volumetric receipt point units to energy-based delivery point units was performed using the British Thermal Unit (BTU) Factors and the Shrinkage Rates PG&E proposed in its 2023 GRC.<sup>13</sup>

The exception to the foregoing discussion is the Silverado “capacity.” The Silverado path does not have an identifiable physical capacity;

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<sup>10</sup> The Schedule G-XF contracts are discussed further in Section D.3 of this chapter.

<sup>11</sup> An incremental rate design is a stand-alone rate design in which rates for a particular facility—in this case, Line 401—are developed using only the costs and capacities or throughputs of that facility.

<sup>12</sup> A.21-06-021, Exhibit (PG&E-3), p. 11-63, Table 11-5 (PG&E Pipeline Capacities). All references to PG&E’s 2023 GRC relate to Phase I, Track 1.

<sup>13</sup> A.21-06-021, Exhibit (PG&E-3), p. 11-65, Table 11-6 (BTU Conversion Factors for PG&E’s GT&S System) and Table 11-7 (Shrinkage Rates for PG&E Pipelines).

therefore, the capacity for this path is derived by dividing the Silverado throughput forecast (discussed in Section D.4 of this chapter, and shown on line 31 of Table 3-1) by the backbone load factor (shown on line 32 of Table 3-1).

Lines 26 through 29 of Table 3-1 show two adjustments to the total backbone capacities. First, the off-system and on-system Schedule G-XF contract quantities are removed from the total capacity for the same reason, explained above, that the Schedule G-XF quantities were removed from the total demand forecast. Second, the Sacramento Municipal Utility District (SMUD) equity capacities on Lines 401 and 300 are removed from the total because SMUD does not pay PG&E backbone rates for gas that flows on its equity capacity. (The SMUD load served by its equity capacity is also excluded from PG&E's electric generation demand forecast shown on line 6 of Table 3-1.) Line 30 shows the total adjusted backbone capacity.

Line 32 of Table 3-1 shows the system average backbone load factor, which is obtained by dividing line 19 by line 30.

#### **4. Details of Throughput Adjustments**

##### **a. Introduction**

This section provides details of the non-G-XF off-system throughput shown on line 10 of Table 3-1 and the various throughput adjustments shown on lines 14 through 17 of Table 3-1.

To understand the various throughput adjustments, it is necessary to understand how the system average load factor is used in the backbone rate setting process. It is used to calculate annual firm transmission (Schedule G-AFT) rates. All other backbone rates or rate caps—for seasonal firm, negotiated firm, as-available, negotiated as-available, and off-system services—are derived from multiples of the annual firm rate. For example, the as-available rate for a given path is 120 percent of the annual firm rate for that path. Thus, the “raw” system average load factor must be adjusted for transmission services that PG&E expects to provide at rates above or below the annual firm rate.

In addition, PG&E derives some backbone revenues from reservation charges under firm contracts that the contract holder only

1 partly uses. A load factor adjustment is necessary to account for these  
2 backbone revenues that are not associated with any backbone  
3 throughput.

4 Finally, a backbone load factor adjustment is necessary if the  
5 throughputs on PG&E's various backbone paths are expected to deviate  
6 from proportional throughputs (i.e., deviate from the adopted system  
7 average load factor applied to each path). Such a deviation, left  
8 uncorrected, would cause PG&E to either under- or over-recover its  
9 adopted backbone costs. For example, suppose throughput on a path  
10 with a relatively high rate exceeds the system average load factor, while  
11 throughput on a path with a relatively low rate is less than the system  
12 average load factor, but overall throughput on all paths matches the  
13 adopted system average load factor. In this case, PG&E would  
14 over-recover its backbone costs, absent a corrective load factor  
15 adjustment.

16 The goal of the throughput adjustments described in this section is  
17 to achieve full backbone cost recovery—no more and no less—while  
18 using a single, system average load factor to set backbone rates on all  
19 paths.

20 Table 3-2 provides details of the non-G-XF off-system throughput  
21 shown on line 10 of Table 3-1 and the various throughput adjustments  
22 shown on lines 14 through 17 of Table 3-1. As has already been noted,  
23 Schedule G-XF contracts have been removed from the numerator and  
24 the denominator of the load factor calculation because G-XF service is  
25 subject to a rate design that does not use the system average load  
26 factor. That throughput adjustment (shown on line 13 of Table 3-1) will  
27 not be discussed further. The remaining throughput adjustments are  
28 explained following Table 3-2.

**TABLE 3-2**  
**THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR**  
**50 PERCENT BAJA-REDWOOD RATE DIFFERENTIAL**

	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
<b>1 Calculate full rate equivalent non-G-XF off-system throughput</b>				
2 Forecasted Redwood revenues (\$ '000/yr)	\$20,208	\$21,532	\$25,424	\$25,424
3 Noncore Redwood G-AFT rate (\$/Dth)	\$0.570	\$0.663	\$0.695	\$0.745
4 Full rate equivalent throughput (MDth/d)	97	89	100	94
5 Forecasted Baja revenues (\$ '000/yr)	\$4,136	\$4,136	\$4,136	\$4,136
6 Noncore Baja G-AFT rate (\$/Dth)	\$0.707	\$0.824	\$0.859	\$0.921
7 Full rate equivalent throughput (MDth/d)	16	14	13	12
8 Total full rate equivalent throughput (MDth/d)	<b>113</b>	<b>103</b>	<b>113</b>	<b>106</b>
<b>9 Adjust for Baja on-system discounts</b>				
10 Quantity (MDth/d)	0	0	0	0
11 Contract rate (\$/Dth)	\$0.000	\$0.000	\$0.000	\$0.000
12 Noncore Baja G-AFT rate (\$/Dth)	\$0.707	\$0.824	\$0.859	\$0.921
13 Full rate equivalent throughput (MDth/d)	0	0	0	0
14 Throughput adjustment (MDth/d)	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>15 Adjust for G-AA, G-SFT, and G-NFT premiums</b>				
16 G-AA throughput - Core (MDth/d)	1	1	1	1
17 G-AA throughput - Noncore (MDth/d)				
18 Total on-system throughput	1,714	1,698	1,709	1,716
19 G-XF on-system throughput	5	5	5	5
20 Firm throughput excl G-XF	1,705	1,674	1,627	1,607
21 G-AA throughput - Core	1	1	1	1
22 G-AA throughput - Noncore (determined residually)	3	18	76	103
23 G-SFT throughput - Core				
24 Core G-SFT MDQ (annualized MDth/d)	179	179	179	179
25 Core G-SFT average utilization level	95.5%	95.5%	95.5%	95.5%
26 Core G-SFT throughput (MDth/d)	171	171	171	171
27 G-SFT and G-NFT throughput - Noncore				
28 Noncore G-SFT and G-NFT MDQ (annualized MDth/d)	116	125	30	56
29 Noncore G-SFT and G-NFT average utilization level	67.7%	83.8%	81.7%	91.7%
30 Noncore G-SFT and G-NFT throughput (MDth/d)	79	104	25	51
31 Total premium throughput (MDth/d)	253	294	272	325
32 Total premium unused reservation (MDth/d)	32	20	9	9
33 TOTAL (MDth/d)	285	314	281	334
34 Rate premium	20%	20%	20%	20%
35 Premium adjustment (MDth/d)	<b>57</b>	<b>63</b>	<b>56</b>	<b>67</b>
<b>36 Adjust for reservation charges for unused firm contracts</b>				
37 Total firm contract MDQ excl G-XF (MDth/d)	1,903	1,761	1,724	1,645
38 Average firm contract utilization level excl G-XF	89.6%	95.0%	94.3%	97.7%
39 Unused firm MDQ (MDth/d)	198	87	98	38
40 Average reservation portion of backbone rate	69.9%	69.6%	68.9%	69.4%
41 Unused firm contract adjustment (MDth/d)	<b>138</b>	<b>61</b>	<b>68</b>	<b>27</b>

(TABLE CONTINUED ON NEXT PAGE)

**TABLE 3-2  
THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR  
50 PERCENT BAJA-REDWOOD RATE DIFFERENTIAL  
(CONTINUED)**

	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
42 <b>Adjust for disproportionate usage of backbone paths</b>				
43 Core Redwood capacity (MDth/d)	716	716	716	716
44 Throughput at load factor (MDth/d)	467	439	457	458
45 Expected Core Redwood utilization level (incl brokering)	98.1%	98.1%	98.1%	98.1%
46 Expected Core Redwood throughput (MDth/d)	703	703	703	703
47 Throughput shift to Core Redwood capacity (MDth/d)	236	264	246	244
48 Core Redwood rate as percent of system average rate	90.2%	90.5%	90.9%	90.9%
49 Percent difference relative to system average rate	-9.8%	-9.5%	-9.1%	-9.1%
50 Throughput adjustment (MDth/d)	(23)	(25)	(22)	(22)
51 Core Baja capacity (MDth/d)	74	74	74	74
52 Throughput at load factor (MDth/d)	48	46	47	48
53 Expected Core Baja utilization level (incl brokering)	90.0%	90.0%	90.0%	90.0%
54 Expected Core Baja throughput (MDth/d)	67	67	67	67
55 Throughput shift to Core Baja capacity (MDth/d)	18	21	19	19
56 Core Baja rate as percent of system average rate	112.7%	113.2%	112.9%	113.0%
57 Percent difference relative to system average rate	12.7%	13.2%	12.9%	13.0%
58 Throughput adjustment (MDth/d)	2	3	3	3
59 Noncore Baja capacity (MDth/d; excl SMUD equity)	845	845	845	845
60 Throughput at load factor (MDth/d)	551	518	540	541
61 Expected Noncore Baja throughput (MDth/d; excl SMUD equity; incl discount adjusted off-system)	176	131	104	136
62				
63 Throughput shift to Noncore Baja capacity (MDth/d)	(375)	(387)	(436)	(405)
64 Noncore Baja rate as percent of system average rate	116.4%	116.4%	115.6%	115.4%
65 Percent difference relative to system average rate	16.4%	16.4%	15.6%	15.4%
66 Throughput adjustment (MDth/d)	(61)	(63)	(68)	(62)
67 Noncore Redwood capacity (MDth/d; excl G-XF and SMUD equity)	1,262	1,262	1,165	1,118
68 Throughput at load factor (MDth/d)	823	773	744	715
69 Expected Noncore Redwood throughput (MDth/d, excl G-XF and SMUD equity; incl discount adjusted off-system)	831	841	888	855
70				
71 Throughput shift to Noncore Redwood capacity (MDth/d)	9	68	144	139
72 Noncore Redwood rate as percent of system average rate	93.8%	93.6%	93.5%	93.3%
73 Percent difference relative to system average rate	-6.2%	-6.4%	-6.5%	-6.7%
74 Throughput adjustment (MDth/d)	(1)	(4)	(9)	(9)
75 Total throughput adjustment (MDth/d)	(83)	(90)	(97)	(91)
76 <b>Backbone Rate Inputs (AFT, \$/Dth)</b>				
77 System average rate (excl Silverado and G-XF)	\$0.608	\$0.708	\$0.743	\$0.798
78 Core Redwood rate	\$0.548	\$0.641	\$0.675	\$0.726
79 Core Baja rate	\$0.685	\$0.802	\$0.839	\$0.902
80 Noncore Redwood rate	\$0.570	\$0.663	\$0.695	\$0.745
81 Noncore Baja rate	\$0.707	\$0.824	\$0.859	\$0.921

**b. Full-Rate-Equivalent Non-G-XF Off-System Throughput**

Lines 1 through 8 of Table 3-2 show the derivation of non-G-XF off-system throughput. This calculation begins with the non-G-XF revenue forecast described in Section D.2 of this chapter. That forecast, divided by the annual firm rate, yields the full-rate-equivalent non-G-XF off-system throughput. PG&E expects actual non-G-XF off-system throughput to be greater than the quantities shown on line 4. However, these off-system sales are typically made at discounted rates. Thus, for

1 purposes of the backbone load factor calculation, it is necessary to  
2 discount adjust the actual throughput to obtain backbone rates that fully  
3 recover adopted backbone costs.

4 A simple example may be informative. Suppose the off-system  
5 market will pay \$0.20 per dekatherm (Dth) for 100 Dth of transportation  
6 service, resulting in revenues of \$20. Further suppose that the  
7 undiscounted rate for this service is \$0.80 per Dth. It would be incorrect  
8 to use 100 Dth of throughput in the load factor calculation because the  
9 100 Dth in question generates revenues corresponding to only 25 Dth of  
10 service at the undiscounted rate ( $\$20/\$0.80 \text{ per Dth} = 25 \text{ Dth}$ ). The  
11 correct throughput for purposes of the load factor calculation would be  
12 25 Dth. This is the methodology used in lines 1 through 8 of Table 3-2.

13 **c. Adjust for Baja On-System Discounts**

14 Lines 9 through 14 of Table 3-2 provide for the possibility of a  
15 discount adjustment for discounted on-system Baja path contracts.  
16 PG&E has provided, or contemplated providing, such discounts in the  
17 past. It is normally necessary to adjust the service quantities for  
18 discounted transactions downward to full-rate-equivalent quantities.  
19 However, because PG&E is not forecasting any on-system discounted  
20 transactions during the 2023 CARD Case period, this discount  
21 adjustment is zero.

22 **d. Adjust for Schedule G-AA, G-SFT, and G-NFT Premiums**

23 Lines 15 through 35 of Table 3-2 show the calculation of the  
24 adjustment for premium priced backbone services. PG&E charges  
25 premium rates for as-available service (Schedule G-AA), seasonal firm  
26 service (Schedule G-SFT), and certain negotiated firm services  
27 (Schedule G-NFT). These services pay a 20 percent rate premium  
28 compared to annual firm service. This adjustment is the mirror image of  
29 the discount rate adjustment discussed above. Just as the discount rate  
30 adjustment corrects throughput downward to account for discounted  
31 services, this adjustment corrects throughput upward to account for  
32 premium rate services. Lines 16 through 33 develop the total quantity of  
33 backbone service that pays premium rates. In lines 34 and 35 this



1 quantity is multiplied by the rate premium (20 percent) to determine the  
2 necessary throughput adjustment.

3 The quantities of service paying premium rates were developed  
4 as follows:

- 5 • Core Schedule G-AA service (line 16) is forecast to continue at the  
6 same average level that occurred during the 36 months ending June  
7 30, 2021.
- 8 • Noncore Schedule G-AA service (line 22) is forecast as a residual  
9 number: begin with total on-system demand; subtract the various  
10 categories of firm throughput and Core Schedule G-AA throughput;  
11 the remainder is Noncore Schedule G-AA throughput. The firm  
12 throughput shown on line 20 is derived by multiplying PG&E's  
13 forecast of firm contract quantities (described in Section D.3 of this  
14 chapter and shown on line 37 of Table 3-2) by the expected average  
15 utilization level of those contracts (shown on line 38 of Table 3-2).  
16 This average utilization level is in turn based on 36 months of  
17 recorded data ending June 30, 2021 except in instances where  
18 Noncore demand was insufficient to use Noncore firm contracts at  
19 levels as high as the 36-month recorded utilization level.
- 20 • Core Schedule G-SFT service (line 26) is forecast by multiplying the  
21 Core's Schedule G-SFT contract quantities (proposed in Chapter 7  
22 of this testimony and described in Section D.3 of this chapter) by the  
23 expected average utilization level of those contracts, which is based  
24 on 36 months of recorded data ending June 30, 2021.
- 25 • Noncore Schedule G-SFT and G-NFT services (line 30) are forecast  
26 by multiplying the forecast of Noncore contract quantities in these  
27 categories (described in Section D.3 of this chapter) by the expected  
28 average utilization level of those contracts, which is in turn based on  
29 36 months of recorded data ending June 30, 2021 except in  
30 instances where Noncore demand was insufficient to use the  
31 contracts at levels as high as the 36-month recorded utilization level.

32 **e. Adjust for Reservation Charges for Unused Firm Contracts**

33 Lines 36 through 41 of Table 3-2 show the calculation of the  
34 adjustment for reservation charges for unused (or partly-unused) firm

1 contracts. The backbone load factor is calculated as total backbone  
2 throughput divided by total backbone capacity (plus various  
3 adjustments). Because the numerator is throughput, and not total  
4 contract quantities, there is an implicit assumption that all firm contracts  
5 flow at 100 percent of the contract Maximum Daily Quantity (MDQ). But  
6 typically firm contracts flow at less than 100 percent of MDQ, resulting in  
7 PG&E collecting some reservation revenues for which there is not any  
8 corresponding throughput. PG&E would over-collect its backbone  
9 revenue requirement absent a throughput adjustment that recognizes  
10 the reservation revenues derived from firm capacity that is contracted,  
11 but not used.

12 PG&E calculated this adjustment by determining the quantity of  
13 subscribed but unused firm capacity and the percentage of the firm rate  
14 that is collected through the reservation charge. The product of this  
15 quantity multiplied by this percentage yields the appropriate throughput  
16 adjustment. Line 39 shows the quantity of subscribed but unused firm  
17 capacity. This quantity was developed from the data in lines 37 and 38,  
18 the source of which has already been discussed. Line 40 shows the  
19 average percentage of PG&E's backbone firm rates that is collected  
20 through the reservation charge. Line 41, which is the product of lines 39  
21 and 40, shows the final throughput adjustment.

22 **f. Adjust for Disproportionate Usage of Backbone Paths**

23 Lines 42 through 75 of Table 3-2 show the throughput adjustment  
24 for disproportionate usage of backbone paths. As mentioned earlier, the  
25 system average load factor methodology assumes that total backbone  
26 demand is served proportionally by PG&E's various backbone paths.  
27 If actual usage of PG&E's backbone paths is disproportionate (i.e., if  
28 throughput on one or more paths deviates from the system average load  
29 factor) PG&E will likely—absent a corrective adjustment—over- or  
30 under-recover the adopted backbone revenue requirement. This is true  
31 even if aggregate throughput on all paths equals the system average  
32 load factor. A throughput shift toward a low-rate path will decrease  
33 backbone revenues, while a throughput shift toward a high-rate path will  
34 increase revenues.

1           In the 2023-2026 rate case period, PG&E expects several such  
2 throughput shifts. First, the Core Redwood and Noncore Redwood  
3 paths are relatively low-rate paths that are forecast to be used at  
4 disproportionately high levels. The fact that these paths are low-rate  
5 paths is a result of the relatively lower costs of the Redwood facilities  
6 compared to the Baja facilities. The expectation that these paths will be  
7 used at disproportionately high levels is driven by the market's general  
8 preference for Redwood capacity (discussed further in Section D.3 of  
9 this chapter). In the case of the Core Redwood path, it is also driven by  
10 the fact that the path capacity is defined by the Core's firm contracts  
11 (whereas the capacities of Noncore paths simply equal all remaining  
12 backbone capacity not contracted by the Core). The utilization levels of  
13 the Core firm contracts have been historically high and can be predicted  
14 with confidence to be high in the future because the Core contracts are  
15 tailored to the Core load. Second, the Core Baja path is also expected  
16 to be used at disproportionately high levels. However, this relatively  
17 high-rate path has such a small capacity that it does not materially  
18 impact the adjustment described in this section. Third, if the Core  
19 Redwood, Noncore Redwood, and Core Baja paths are all used at  
20 disproportionately high levels, it follows that the Noncore Baja path, the  
21 highest rate path on PG&E's system, must be used at a  
22 disproportionately low level.

23           It is possible to adjust the backbone load factor for path throughputs  
24 that deviate from the system average load factor, while still using a  
25 single system average load factor to set rates for all backbone paths.  
26 The calculation of this adjustment is performed as follows. For each  
27 path, it is necessary to: (1) determine the expected deviation in  
28 throughput from the system average load factor; (2) determine  
29 the percentage deviation of the path rate from the system average  
30 backbone rate; and (3) multiply the quantity from the first step by  
31 the percentage from the second step to get the throughput adjustment  
32 for the backbone load factor calculation. This sequence of steps must  
33 be undertaken for each backbone path. It may yield positive or negative

1 adjustments. The sum of all these adjustments for all paths is the net  
2 adjustment used in the backbone load factor calculation.

3 An example of the adjustment for disproportionate usage of  
4 backbone paths may be informative. Attachment A to this chapter  
5 provides a simple illustration for a hypothetical utility with two backbone  
6 paths. This illustration demonstrates the revenue disparity that arises  
7 from disproportionate usage of the two backbone paths, performs an  
8 adjustment to the backbone load factor as described above to correct for  
9 the disproportionate usage of the two paths, and then performs a  
10 revenue check to confirm the mathematical validity of the adjustment.

11 As described in Section B.2 of this chapter, PG&E allocates costs to  
12 six backbone paths or sub-paths: Core Redwood, Noncore Redwood,  
13 Redwood Schedule G-XF, Core Baja, Noncore Baja, and Silverado.  
14 However, two of these paths may be disregarded for purposes of this  
15 throughput adjustment. The Redwood G-XF sub-path can be eliminated  
16 because it is subject to an incremental rate design that does not employ  
17 the system average backbone load factor. The Silverado path can also  
18 be eliminated because the definition of Silverado “capacity,” explained in  
19 Section B.3 above, ensures that Silverado throughput flows at the  
20 system average load factor, and therefore any Silverado adjustment  
21 would be zero.

22 Thus, the adjustment described in this section must be applied to  
23 four backbone sub-paths: Core Redwood, Core Baja, Noncore  
24 Redwood, and Noncore Baja:

- 25 • The Core Redwood path, consisting of Schedule G-AFT and G-SFT  
26 contracts, is forecasted to flow at a 98.1 percent utilization level.  
27 The G-AFT contracts flowed at a 97.9 percent utilization level during  
28 the 36 months ending June 30, 2021, and are projected to continue  
29 flowing at this level. The G-SFT contracts flowed at a 99.5 percent  
30 utilization level during the single winter that they have been in  
31 existence (November 2020 through March 2021), and are projected  
32 to continue flowing at this level. The weighted average utilization  
33 level for all of the Core Redwood contracts is 98.1 percent.

- 1           • The Core Baja path, consisting of Schedule G-SFT contracts, is  
2           forecasted to flow at a 90.0 percent utilization level. The Core has  
3           had various Baja G-SFT contracts over time. These contracts  
4           flowed at an average 90.0 percent utilization level during the  
5           36 months ending June 30, 2021. The Core Baja G-SFT contracts  
6           proposed in this case are projected to also flow at this level.
- 7           • The Noncore Baja path (excluding SMUD equity capacity) is  
8           forecasted to flow at an average 19 percent utilization level.<sup>14</sup>  
9           Flows on this path result from the minimal Noncore on-system firm  
10          contracts described in Section D.3 of this chapter, minimal  
11          off-system flows consistent with historic Baja off-system flows, and  
12          Noncore on-system as-available flows in periods when the Redwood  
13          path is flowing at capacity and additional demand remains to be  
14          served by the Baja path.<sup>15</sup>
- 15          • The Noncore Redwood Path (excluding SMUD equity capacity and  
16          Schedule G-XF service) is forecasted to flow at an average  
17          86 percent utilization level.<sup>16</sup> All remaining backbone throughput  
18          not discussed above must, by definition, flow on the Noncore  
19          Redwood path (the only exception being a small amount of  
20          Silverado path flows).
- 21          Lines 50, 58, 66, and 74 of Table 3-2 show the resulting  
22          adjustments for the Core Redwood, Core Baja, Noncore Baja, and  
23          Noncore Redwood paths, respectively. Line 75 shows the sum of these  
24          adjustments. This sum is the final throughput adjustment in the system  
25          average backbone load factor calculation.

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<sup>14</sup> This calculation employs actual off-system flows rather than discount-adjusted flows.

<sup>15</sup> The Noncore Baja and Noncore Redwood flows were determined by an analysis of monthly demands and throughputs that assumed a continuing strong preference for Redwood capacity, as discussed in Section D.3 of this chapter.

<sup>16</sup> This calculation employs actual off-system flows rather than discount-adjusted flows.

## C. Baja-Redwood Rate Differential

### 1. Summary

This section describes the Baja-Redwood rate differentials that PG&E proposes for its backbone transportation rates. In summary, PG&E proposes a rate differential equal to 50 percent of the natural rate differential that would result from the traditional backbone cost allocation. Based on this approach, PG&E proposes the following rate differentials: \$0.137 per Dth in 2023, \$0.161 per Dth in 2024, \$0.164 per Dth in 2025, and \$0.176 per Dth in 2026. By comparison, the Baja-Redwood rate differential adopted for the 2019-2022 GT&S Rate Case period ranges from \$0.10 to \$0.18 per Dth.<sup>17</sup>

### 2. Background

The Baja-Redwood rate differential is the difference between the Baja path transportation rate and the Redwood path transportation rate.<sup>18</sup> During the first 10 years of the Gas Accord structure (1998-2007), the rate differential was determined as the natural outcome of the traditional backbone cost allocation.<sup>19</sup> During the subsequent 15 years (2008-2022), the rate differential was set at levels significantly less than the natural rate differential, generally through settlement or stipulation, except for the 2015 GT&S Rate Case (2015-2018) where the rate differential was resolved through litigation.<sup>20</sup>

Table 3-3 summarizes the natural Baja-Redwood rate differentials based on traditional backbone cost allocation for the 2008-2022 period and the actual adopted Baja-Redwood rate differentials for the same period.

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<sup>17</sup> D.19-09-025, p. 254-256 and p. 320, COL 128.

<sup>18</sup> This difference is typically expressed as the difference between the Schedule G-AFT annual firm transportation rates for the two paths.

<sup>19</sup> Gas Accord settlement (1998-2002), Gas Accord settlement extension (2003), D.03-12-061 (2004), and the Gas Accord III settlement (2005-2007).

<sup>20</sup> Gas Accord IV settlement (2008-2010), Gas Accord V settlement (2011-2014), D.16-06-056 (2015-2018), and D.19-09-025 (2019-2022).

**TABLE 3-3**  
**2008-2022 BAJA-REDWOOD RATE DIFFERENTIALS**  
**(BAJA RATE HIGHER)**

Line No.	Settlement or Rate Case	Year	Natural Baja-Redwood Differential (\$/Dth)	Adopted Baja-Redwood Differential (\$/Dth)
1	Gas Accord IV (Settled differentials)	2008	N/A <sup>(a)</sup>	\$0.025
		2009	N/A <sup>(a)</sup>	\$0.025
		2010	N/A <sup>(a)</sup>	\$0.025
2	Gas Accord V (Settled differentials)	2011	\$0.061	\$0.025
		2012	\$0.071	\$0.030
		2013	\$0.071	\$0.035
		2014	\$0.078	\$0.040
3	2015 GT&S Rate Case (Litigated differentials)	2015	\$0.067	\$0.040
		2016	\$0.146	\$0.040
		2017	\$0.233	\$0.040
		2018	\$0.279	\$0.040
4	2019 GT&S Rate Case (Stipulated differentials)	2019	\$0.265	\$0.100
		2020	\$0.261	\$0.135
		2021	\$0.271	\$0.170
		2022	\$0.281	\$0.180

(a) The natural Baja-Redwood rate differentials are not available for the Gas Accord IV period (2008-2010) because that settlement did not develop a full revenue requirement and cost allocation. Instead, it applied negotiated rate escalators to adopted 2007 rates, as well as other negotiated elements such as the \$0.025 per Dth adopted Baja-Redwood rate differential.

As noted, the natural Baja-Redwood rate differential reflects the traditional backbone cost allocation that has been in place since 1998. This cost allocation generally allocates the costs of PG&E's southern trunklines (Lines 300A and 300B) to the Baja path and allocates the costs of PG&E's northern trunklines (Lines 400, 401, and 2) to the Redwood path. Each path also receives a proportionate allocation of common backbone costs (for example, the costs of PG&E's Bay Area Loop gas transmission pipelines and the costs of storage services recovered in backbone rates).<sup>21</sup>

As Table 3-3 shows, the natural Baja-Redwood rate differential has widened over the past dozen years. This widening is the result of relatively higher spending on the older Baja path facilities, relatively higher depreciation of the newer Redwood path facilities, and modest changes in the capacities of both paths. As the natural Baja-Redwood rate differential has widened, the issue of the appropriate rate differential has grown in

<sup>21</sup> The backbone cost allocation and rate design are described in detail in Chapter 6 of this testimony.

prominence. The Commission has consistently adopted a rate differential that is well below the natural differential. For the 12-year period ending 2022, the adopted Baja-Redwood rate differential averages 43 percent of the natural rate differential.

From a rate modeling perspective, the modified Baja-Redwood rate differentials are achieved by adding a step to the traditional backbone cost allocation. The traditional cost allocation (reflecting natural Baja-Redwood rate differentials) is modified by shifting a sufficient amount of costs from the Baja path to the Redwood path to achieve the desired Baja-Redwood rate differential.

### 3. PG&E Proposal

Table 3-4 below summarizes the natural Baja-Redwood rate differentials for the upcoming 2023-2026 CARD Case period, based on the revenue requirements PG&E proposed in its 2023 GRC<sup>22</sup> and the traditional backbone cost allocation. The table also shows the Baja-Redwood rate differentials that PG&E is proposing in this case, which equal 50 percent of the natural rate differentials.

**TABLE 3-4  
2023-2026 BAJA-REDWOOD RATE DIFFERENTIALS  
(BAJA RATE HIGHER)**

Line No.	Rate Case	Year	Natural Baja-Redwood Differential (\$/Dth)	PG&E Proposed (50 percent) Baja-Redwood Differential (\$/Dth)
1	2023 CARD Case	2023	\$0.273	\$0.137
		2024	\$0.321	\$0.161
		2025	\$0.328	\$0.164
		2026	\$0.353	\$0.176

PG&E is proposing the modified (50 percent) Baja-Redwood rate differentials shown in Table 3-4 because they better reflect cost causation than the natural Baja-Redwood rate differentials. Cost causation principles generally require that cost allocation corresponds to cost causation. In other words, to the extent feasible, the causers and beneficiaries of specific costs

<sup>22</sup> A.21-06-021, filed June 30, 2021.



1 should pay those costs in their rates. This in turn sends clear price signals  
2 to the market.

3 As described above, the traditional backbone cost allocation allocates  
4 PG&E's southern trunkline costs to the Baja path and PG&E's northern  
5 trunkline costs to the Redwood path. This cost allocation does not fully  
6 correspond to cost causation because all backbone transportation  
7 customers have contractual rights to deliver gas anywhere on PG&E's  
8 system (or anywhere off-system in the case of off-system contracts), not just  
9 to delivery points on the trunklines whose costs are included in their  
10 backbone rates.

11 PG&E's Baja and Redwood transportation contracts provide for *receipt*  
12 of gas at designated points along either the Baja path trunklines or the  
13 Redwood path trunklines. Baja path customers receive gas principally at  
14 Topock (on the California-Arizona border) but may also receive gas at other  
15 receipt points south of PG&E's Antioch terminal. Redwood path customers  
16 receive gas principally at Malin (on the California-Oregon border) but may  
17 also receive gas at other receipt points north of PG&E's Antioch terminal. In  
18 contrast to these limited receipt point options, backbone customers using  
19 either path may *deliver* their gas anywhere on PG&E's system, even to  
20 delivery points beyond the reach of the facilities whose costs are included in  
21 their backbone rates.<sup>23</sup>

22 Thus, the use of the term "path" to geographically differentiate PG&E's  
23 backbone services is somewhat misleading. It is more accurate to  
24 characterize PG&E's backbone services as being geographically  
25 differentiated by receipt point. When backbone customers contract for  
26 services on a specific path, they are in fact contracting to receive gas at a

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<sup>23</sup> See PG&E's backbone gas rate schedules (G-AFT, G-SFT, G-NFT, G-AA, G-NAA, G-AFTOFF, G-NFTOFF, G-AAOFF, and G-NAAOFF) for a description of backbone receipt points and delivery points. Backbone services generally deliver gas to the PG&E Citygate, to a storage facility, or to an off-system delivery point. Gas ultimately transported to an on-system end-use customer requires further downstream transportation under one of PG&E's end-user rate schedules. For additional discussion of backbone receipt points and delivery points, see California Gas Transmission Pipe Ranger, Paths and Choices, <[https://www.pge.com/pipeline/library/doing\\_business/paths\\_choices/index.page](https://www.pge.com/pipeline/library/doing_business/paths_choices/index.page)> (as of Sept. 24, 2021).

1 particular receipt point with virtually no limitation on where they may deliver  
2 the gas.<sup>24</sup> A Redwood path customer can receive gas at Malin and deliver  
3 it to the southern part of PG&E's service territory, say Bakersfield or even  
4 Topock, without having to pay any rate other than the Redwood path rate.  
5 PG&E does not charge such customers any sort of zone rate or backhaul  
6 rate for the backbone transportation service on its southern (Baja) facilities.  
7 Similarly, a Baja path customer can receive gas at Topock and deliver it to  
8 the northern part of PG&E's service territory, say Sacramento or Redding,  
9 without having to pay any rate other than the Baja path rate. Again, PG&E  
10 does not charge a zone rate or backhaul rate for service on its northern  
11 (Redwood) facilities.

12 Such long-haul backbone services are not merely theoretical. PG&E's  
13 Core gas load is served primarily (91 percent) by the Redwood path,<sup>25</sup> even  
14 though a significant part of that load exists in the southern part of PG&E's  
15 service territory. PG&E does not have as much visibility into how its  
16 Noncore gas load is served but projects similarly lopsided service  
17 (approximately 80 percent) by the Redwood path.<sup>26</sup> Also, PG&E provides  
18 significant Redwood off-system transportation service into the Southern  
19 California off-system market.<sup>27</sup> Thus, significant volumes of Redwood  
20 service are delivered to on-system or off-system customers served off of  
21 PG&E's southern (Baja) trunklines.

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**24** The only delivery point limitation for backbone contracts is that on-system contracts must deliver gas to on-system delivery points and off-system contracts must deliver gas to off-system delivery points.

**25** See Section D.3 of this chapter. On an annualized basis, Core firm Redwood contracts total 716 MDth per day while Core firm Baja contracts total 74 MDth per day. See also Chapter 7 of this testimony.

**26** Most Noncore end-users do not contract for backbone transportation services. Instead, they buy their gas at the PG&E Citygate without regard for the source of the gas or the backbone path used to deliver that gas to the Citygate. However, as described in Section D.3 of this chapter, PG&E projects, based largely on already-booked contracts, that approximately 80 percent of the Noncore load will be served by Redwood contracts.

**27** See Section D.2 of this chapter. Redwood off-system throughput (excluding Schedule G-XF service, which is priced at an incremental Line 401 rate) is forecast to average 268 MDth per day.

1           The nature of the contract rights on PG&E's backbone system supports  
2 a different cost allocation than the traditional cost allocation. Contractually,  
3 backbone customers have rights to and actually use PG&E's entire  
4 backbone system, not just the backbone facilities whose costs are included  
5 in their backbone rates. PG&E's backbone system does not function as a  
6 system of two isolated primary paths. Rather, it functions like a network or  
7 grid with contract rights differentiated by receipt point.

8           These facts support a cost allocation in which Redwood path  
9 transportation customers pay a share of the traditional Baja path costs and  
10 Baja path transportation customers pay a share of the traditional Redwood  
11 path costs. The maximum possible extent of such cost sharing would occur  
12 if PG&E treated *all* backbone costs, including the costs of the northern and  
13 southern trunklines, as common costs, resulting in equalized Baja and  
14 Redwood rates. However, PG&E is not proposing to equalize the Baja and  
15 Redwood rates. Rather, PG&E proposes to halve the Baja-Redwood rate  
16 differential that would result under the traditional cost allocation. This  
17 proposal continues to employ the traditional cost allocation methodology and  
18 thus recognizes the underlying cost differences between the Baja and  
19 Redwood paths. It also at least partly corrects the deficiencies in the  
20 traditional cost allocation described above by making the cost allocation  
21 more reflective of cost causation.

22           The concept of including some traditionally defined Baja costs in the  
23 Redwood rate and some traditionally defined Redwood costs in the Baja  
24 rate is not a new one. Since the beginning of the Gas Accord structure in  
25 1998, PG&E's Silverado path<sup>28</sup> rate has included an allocation of both Baja  
26 and Redwood path costs. The rationale for this allocation is Silverado path  
27 customers have contractual rights to transport their gas to any point on  
28 PG&E's system (or off-system in the case of off-system contracts), including  
29 points as far north as Malin and points as far south as Topock. Such  
30 transportation cannot occur in "thin air" but is only possible because of the  
31 existence of the northern and southern trunklines. Accordingly, the

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**28** PG&E's Silverado path is the backbone path used to transport California gas production located within PG&E's service territory.

1 Silverado rate includes an allocation of northern and southern trunkline  
2 costs.<sup>29</sup>

3 Finally, PG&E's proposed 50 percent Baja-Redwood rate differential has  
4 the advantage of continuity with past Baja-Redwood rate differentials  
5 adopted by the Commission. It is similar in percentage value to the average  
6 Baja-Redwood rate differential that the Commission adopted during the past  
7 dozen years (50 percent versus 43 percent). It is also similar in magnitude  
8 to the Baja-Redwood rate differential that the Commission adopted in the  
9 last GT&S Rate Case (average \$0.160 per Dth for 2023-2026 versus  
10 \$0.146 per Dth for 2019-2022).

#### 11 **D. Miscellaneous Backbone Rate Inputs**

##### 12 **1. Summary**

13 This section describes three miscellaneous inputs to the backbone load  
14 factor and backbone rate calculations: the forecast of backbone off-system  
15 revenues and throughput; the forecast of backbone firm contracts; and the  
16 forecast of Silverado path throughput.

##### 17 **2. Forecast of Backbone Off-System Revenues and Throughput**

18 PG&E's backbone off-system revenues and throughput derive from two  
19 sources: long-term Schedule G-XF contracts, which have been in place  
20 since before the Gas Accord structure was implemented; and non-G-XF firm  
21 and as-available contracts negotiated under Schedules G-NFTOFF and  
22 G-NAAOFF. The Schedule G-XF contracts have known contract quantities  
23 and are subject to an incremental, Straight Fixed Variable rate design.  
24 Therefore, they yield a predictable stream of revenues. They are discussed  
25 further in the next section. The remainder of this section describes the  
26 forecast of non-G-XF off-system revenues and throughput.

27 Historically, most of PG&E's backbone off-system services have  
28 occurred on the Redwood path, while only a small portion has occurred on  
29 the Baja, Silverado, and Mission paths. The level of and price for off-system  
30 services is heavily influenced by gas market conditions that in turn affect  
31 prices at various interconnection points on the California border. As a result,

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<sup>29</sup> Details of the backbone cost allocation for the Silverado path are provided in Chapter 6 of this testimony and the Chapter 6 workpapers.

off-system services fluctuate significantly from month to month but tend to be highest in the summer months.

PG&E proposes to forecast non-G-XF throughput and revenues using the same methodology it used in the 2019 GT&S Rate Case. Where off-system contracts have already been executed for the rate case period, PG&E relies on those executed contracts to develop the forecast. Where off-system contracts have not yet been executed, PG&E bases the forecast on the recorded 36-month average non-G-XF revenues and throughput.<sup>30</sup>

Table 3-5 below presents PG&E's non-G-XF off-system revenue forecast for the 2023-2026 period. Two-thirds of the forecasted revenues—specifically, the Redwood summer seasonal commitments—derive from negotiated firm contracts that have already been executed. The remaining forecasted revenues—for Redwood summer daily incremental, Redwood winter, Baja, and Silverado/Mission—are based on the average of 36 months of recorded revenues.

**TABLE 3-5  
NON-G-XF OFF-SYSTEM REVENUES  
(THOUSANDS OF DOLLARS)**

Line No.	Backbone Path	2023	2024	2025	2026
1	<u>Redwood</u>				
2	Summer (Apr-Oct) seasonal (executed)	\$15,435	\$16,759	\$20,651	\$20,651
3	Summer (Apr-Oct) daily incremental	1,489	1,489	1,489	1,489
4	Winter (Nov-Mar)	3,284	3,284	3,284	3,284
5	Subtotal	\$20,208	\$21,532	\$25,424	\$25,424
6	Baja	\$3,611	\$3,611	\$3,611	\$3,611
7	Silverado/Mission	525	525	525	525
8	Total	\$24,344	\$25,668	\$29,560	\$29,560

Table 3-6 below presents the non-G-XF off-system throughput forecast that corresponds to the non-G-XF off-system revenue forecast in Table 3-5. Again, this forecast is based on already executed contracts for Redwood summer seasonal services and based on the average of 36 months of

<sup>30</sup> The recorded 36-month period for developing the non-G-XF off-system throughput and revenue forecast is July 2018 through June 2021.

recorded data for Redwood summer daily incremental, Redwood winter, Baja, and Silverado/Mission services. On the Redwood path, PG&E does not contract for non-G-XF off-system firm services above 320 MDth per day. This amount plus the Schedule G-XF off-system contracts (80 MDth per day) represents the approximate limit (400 MDth per day) of the firm services PG&E can reliably provide into the southern California off-system market.

**TABLE 3-6  
NON-G-XF OFF-SYSTEM THROUGHPUT  
(MDTH/DAY)**

Line No.	Backbone Path	2023	2024	2025	2026
1	<u>Redwood</u>				
2	Summer (Apr-Oct) seasonal (executed)	320	313	320	320
3	Summer (Apr-Oct) daily incremental	18	18	18	18
4	Winter (Nov-Mar)	168	168	168	168
5	Average Annual	268	263	268	268
6	Baja	39	39	39	39
7	Silverado/Mission	3	2	3	3
8	Average Annual	310	305	310	310

### 3. Forecast of Backbone Firm Contracts

The forecast of backbone firm contracts is an input to the backbone load factor and backbone rate models. PG&E forecasts the Core backbone firm contracts based on the Core capacity proposals in this application. PG&E forecasts the Noncore backbone firm contracts based largely on contracts that have already been executed for the 2023-2026 CARD Case period and partly based on expectations for additional Noncore contracting during that period.

Chapter 7 of this testimony describes the firm backbone capacity that PG&E's Core Gas Supply (CGS) department proposes to hold. On the Redwood path, PG&E CGS proposes to continue holding 605.088 MDth per day of annual firm capacity, 100 MDth per day of seasonal firm capacity in November through March, and an additional 250 MDth per day of seasonal firm capacity in December through February. On the Baja path, PG&E CGS proposes to hold 150 MDth per day of seasonal firm capacity in November

1 through March and an additional 50 MDth per day of seasonal firm capacity  
2 in December through February.

3 PG&E proposes to offer corresponding Core backbone firm contracts to  
4 its wholesale customers. On the Redwood path, PG&E will continue to offer  
5 these customers a total of 6.834 MDth per day of annual firm capacity,  
6 1.129 MDth per day of seasonal firm capacity in November through March,  
7 and an additional 2.824 MDth per day of seasonal firm capacity in  
8 December through February. On the Baja path, PG&E will offer its  
9 wholesale customers 1.683 MDth per day of seasonal firm capacity in  
10 November through March and an additional 0.561 MDth per day of seasonal  
11 firm capacity in December through February. Based on past experience,  
12 PG&E expects its wholesale customers to accept the Redwood firm capacity  
13 and decline the Baja firm capacity offered to them.

14 As noted, the forecast of Noncore firm contracts is based largely on  
15 contracts that have already been executed for the 2023-2026 period. On  
16 the Baja path, PG&E did not forecast any additional firm contracts besides  
17 those that have already been executed. On the Redwood path, 98 percent  
18 of the annual firm contract volumes represent contracts that have already  
19 been executed, with the remaining 2 percent forecasted, and 47 percent of  
20 the seasonal firm contract volumes represent contracts that have already  
21 been executed, with the remaining 53 percent forecasted.

22 PG&E forecasted additional Noncore firm contracts, besides those  
23 contracts already executed, when demand existed that could not be served  
24 by the already executed firm contracts and when uncontracted firm capacity  
25 existed on the path in question. PG&E assumed a market preference for  
26 Redwood capacity over Baja capacity, consistent with the strong preference  
27 for Redwood service exhibited by the market in recent years. Finally, PG&E  
28 forecasted additional Noncore firm contracts only when demand was  
29 sufficient to use the contracts at a 95 to 100 percent utilization level,  
30 consistent with high historical utilization levels.

31 The Schedule G-XF contracts are legacy contracts that date back to the  
32 1993 in-service date of Line 401. These contracts are subject to  
33 incremental Line 401 ratemaking. Schedule G-XF has been closed to new  
34 customers since the start of the Gas Accord in 1998. The legacy contracts

will reach the end of their 30-year primary terms in 2023 but are renewable on a year-to-year basis thereafter. PG&E is forecasting that the customers holding these contracts will renew them due to their advantageous rate.

Table 3-7 below summarizes PG&E's forecast of Core and Noncore backbone firm contracts.

**TABLE 3-7  
FORECAST OF BACKBONE FIRM CONTRACTS  
(MDTH/DAY)**

Line No.	Contract Type	2023	2024	2025	2026
1	<u>Core</u>				
2	Baja – Annual	–	–	–	–
3	Baja – Seasonal	74	74	74	74
4	Redwood – Annual	612	612	612	612
5	Redwood – Seasonal	104	104	104	104
6	<u>Noncore</u>				
7	Baja – Annual	296	153	72	51
8	Baja – Seasonal	23	0	0	0
9	Redwood – Annual	656	639	777	692
10	Redwood – Seasonal	93	125	30	56
11	Silverado – Annual	45	54	55	56
12	Silverado – Seasonal	–	–	–	–
13	<u>Schedule G-XF</u>				
14	On-System	5	5	5	5
15	Off-System	80	80	80	80
16	<u>Totals</u>				
17	On-System	1,908	1,766	1,730	1,651
18	Off-System	80	80	80	80

Notes: Totals may not add due to rounding.

Seasonal contracts are expressed on an annualized basis.

Core contracts include Redwood quantities to be offered to (and presumed accepted by) wholesale customers and exclude Baja quantities to be offered to (and presumed declined by) wholesale customers.

Excludes non-G-XF off-system contracts.

#### 4. Forecast of Silverado Path Throughput

PG&E's Silverado backbone path transports gas that originates from northern California production sources. The throughput on this path is relatively small, serving only two to three percent of PG&E's total load. The backbone load factor and backbone rate models require a forecast of



Silverado path throughput. This forecast does not include California production transported directly to end-users on private pipelines.

Silverado path throughput depends on a number of variables, including northern California well drilling and well rework activity, the success of that activity, the production decline rates of existing northern California gas wells, and the portion of northern California production that flows on PG&E's gas system versus that which bypasses PG&E's system and flows on private pipelines. Drilling activity is in turn influenced by political considerations, regulatory and permitting issues, and expected future gas prices.

Additionally, Silverado path throughput depends on the pace of development of RNG in PG&E's service territory. Many RNG projects are in advanced stages of development. PG&E expects the first of these projects to begin production and flow on the Silverado path in the fourth quarter of 2021.

PG&E forecasted Silverado path throughput in two parts: conventional (fossil) throughput and RNG throughput. PG&E forecasted conventional throughput using the average decline rate of 6.7 percent recorded during the past five years.<sup>31</sup> PG&E forecasted RNG throughput on a project by project basis, using a combination of known projects and generic projects. Table 3-8 below summarizes PG&E's forecast of Silverado path throughput.

**TABLE 3-8  
FORECAST OF SILVERADO PATH THROUGHPUT  
(MDTH/DAY)**

Line No.	Production Source	2023	2024	2025	2026
1	Conventional (Fossil) Production	21	20	18	17
2	RNG	24	34	37	39
3	Total	45	54	55	56

## **E. Conclusion**

This chapter explains the calculation of and the rationale for the system average backbone load factors employed in the backbone rate design,

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<sup>31</sup> The decline rate for conventional Silverado throughput was determined from the 60-month period ending June 30, 2021.

1 presented in Chapter 6. These load factors are as follows: 65.20 percent for  
2 2023; 61.26 percent for 2024; 63.84 percent for 2025; and 64.02 percent for  
3 2026.

4 Additionally, this chapter proposes and presents a rationale for  
5 Baja-Redwood rate differentials that equal to 50 percent of the natural rate  
6 differentials that would be obtained from the traditional backbone cost allocation.  
7 Based on this approach, the proposed rate differentials are \$0.137 per Dth in  
8 2023, \$0.161 per Dth in 2024, \$0.164 per Dth in 2025, and \$0.176 per Dth in  
9 2026.

10 Lastly, this chapter presents three miscellaneous inputs to the backbone  
11 load factor and backbone rate calculations: the forecast of backbone off-system  
12 revenues and throughput; the forecast of backbone firm contracts; and the  
13 forecast of Silverado path throughput.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 3**  
**ATTACHMENT A**  
**BACKBONE LOAD FACTOR – ILLUSTRATION OF**  
**ADJUSTMENT FOR DISPROPORTIONATE USAGE OF**  
**BACKBONE PATHS**

1                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                   **CHAPTER 3**  
3                   **BACKBONE LOAD FACTOR – ILLUSTRATION OF ADJUSTMENT**  
4                   **FOR DISPROPORTIONATE USAGE OF BACKBONE PATHS**

5           Assume a hypothetical utility operates a gas transmission system with two  
6 backbone paths (Path A and Path B). Further assume that backbone rates are  
7 designed using the system average load factor method. The following backbone  
8 revenue requirement (\$225.0 million), backbone capacity (3,000 thousand  
9 decatherms per day (MDth/d)) and backbone throughput (2,000 MDth/d) are  
10 illustrative and yield the backbone load factor and backbone rates shown. Assume  
11 that no adjustments to the backbone load factor are necessary except the  
12 adjustment for disproportionate usage of backbone paths, which is discussed later in  
13 this illustration.

**TABLE 3-A-1**  
**BACKBONE LOAD FACTOR – THROUGHPUT ADJUSTMENT**  
**ILLUSTRATION PART 1**

	<u>Path A</u>	<u>Path B</u>	<u>Total</u>	<u>Units</u>
1 <b>Given</b>				
2 Backbone revenue requirement	\$75.0	\$150.0	\$225.0	\$ million
3 Backbone capacity	1,200	1,800	3,000	MDth/d
4 Backbone throughput			2,000	MDth/d
5 <b>Backbone Load Factor</b>			<b>66.67%</b>	
6 <b>Backbone Rates</b>	\$0.257	\$0.342		\$/Dth

14       Now consider revenues generated on this hypothetical backbone system.  
15 Revenue Scenario 1 shows that if throughput on each of the two paths equals the  
16 system average load factor used to set rates, then the utility will exactly collect its  
17 adopted revenue requirement. In contrast, Revenue Scenario 2 shows that if  
18 throughput on the low-rate path (Path A) exceeds the system average load factor  
19 and throughput on the high-rate path (Path B) is less than the system average load  
20 factor, then the utility will under-collect its adopted revenue requirement, even  
21 though combined throughput on both paths equals the system average load factor.

**TABLE 3-A-2  
BACKBONE LOAD FACTOR – THROUGHPUT ADJUSTMENT  
ILLUSTRATION PART 2**

	<u>Path A</u>	<u>Path B</u>	<u>Total</u>	<u>Units</u>
7 <b>Revenue Scenario 1:</b>				
8 <i>Each path flows at the system average load factor</i>				
9 Throughput	800	1,200	2,000	MDth/d
10 Revenues	\$75.0	\$150.0	\$225.0	\$ million
11 Over / (under) collection			<b>\$0.0</b>	\$ million
12 <b>Revenue Scenario 2:</b>				
13 <i>Disproportionate usage of backbone paths</i>				
14 Throughput	1,100	900	2,000	MDth/d
15 Revenues	\$103.1	\$112.5	\$215.6	\$ million
16 Over / (under) collection			<b>(\$9.4)</b>	\$ million

1 The solution to the under-collection in Revenue Scenario 2 is to reduce the  
2 system average load factor used to set backbone rates until the revenue under-  
3 collection is erased:

**TABLE 3-A-3  
BACKBONE LOAD FACTOR – THROUGHPUT ADJUSTMENT  
ILLUSTRATION PART 3**

	<u>Path A</u>	<u>Path B</u>	<u>Total</u>	<u>Units</u>
17 <b>Solution to Revenue Scenario 2:</b>				
18 <b>Adjust system average load factor</b>			<b>63.89%</b>	
19 <b>Recalculate backbone rates using adjusted</b>				
20 <b>system average load factor</b>	\$0.268	\$0.357		\$/Dth
21 <b>Revised Revenue Scenario 2</b>				
22 Throughput	1,100	900	2,000	MDth/d
23 Revenues	\$107.6	\$117.4	\$225.0	\$ million
24 Over / (under) collection			<b>\$0.0</b>	\$ million

4 However, it is not necessary to adjust the system average load factor through  
5 trial and error or by working backwards from a revenue calculation. The following  
6 shows the mathematical method for calculating the adjustment for disproportionate  
7 usage of backbone paths. For each path, it is necessary to: (1) determine the  
8 expected deviation in throughput from the system average load factor; (2) determine  
9 the percentage deviation of the path rate from the system average rate; and  
10 (3) multiply the quantity from the first step by the percentage from the second step to  
11 get the throughput adjustment. This sequence of steps must be repeated for each  
12 backbone path. The sum of the resulting throughput adjustments for all paths is the  
13 net throughput adjustment used in the backbone load factor calculation.

**TABLE 3-A-4**  
**BACKBONE LOAD FACTOR – THROUGHPUT ADJUSTMENT**  
**ILLUSTRATION PART 4**

	<u>Path A</u>	<u>Path B</u>	<u>Total</u>	<u>Units</u>
25 <b>Calculation of Adjustment for Disproportionate</b>				
26 <b>Usage of Backbone Paths</b>				
27 Backbone capacity	1,200	1,800	3,000	MDth/d
28 Throughput at system average load factor <b>(a)</b>	800	1,200	2,000	MDth/d
29 Expected throughput	1,100	900	2,000	MDth/d
30 Throughput shift <i>toward</i> path	300	(300)	0	MDth/d
31 Path rate as percent of system average rate	83.33%	111.11%		
32 Percent difference relative to system average rate	-16.67%	11.11%		
33 Throughput adjustment	(50)	(33)	<b>(83)</b>	MDth/d
34 Original backbone throughput			2,000	MDth/d
35 Adjusted backbone throughput			1,917	MDth/d
36 Adjusted system average load factor			<b>63.89%</b>	
37 Adjusted backbone rates	\$0.268	\$0.357	\$0.322	\$/Dth
38 <b>(a)</b> Note that "Throughput at system average load factor" can be calculated using either the original unadjusted system				
39 average load factor (66.67%) or the final adjusted system average load factor (63.89%). Either method yields the same				
40 throughput adjustment (-83 MDth/d).				

1 Note that the adjusted system average load factor calculated here  
2 (63.89 percent) is the same as that determined earlier to be necessary for revenues  
3 to equal the adopted revenue requirement under Revenue Scenario 2. This  
4 demonstrates the mathematical validity of the calculation. It also shows that the  
5 adjustment is consistent with the goal that rates should be designed to recover the  
6 adopted revenue requirement at adopted throughput levels.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 4**  
**LOCAL TRANSMISSION ALLOCATION STUDY**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 4  
LOCAL TRANSMISSION ALLOCATION STUDY

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 4**  
**LOCAL TRANSMISSION ALLOCATION STUDY**

**A. Introduction**

**1. Purpose and Scope of the Chapter**

In the 2019 Gas Transmission and Storage (GT&S) Decision, (D).19-09-025, the California Public Utilities Commission (CPUC) or Commission) found “that the cost allocation for PG&E’s local transmission service should be studied further to ensure the local transmission costs are being allocated consistent with cost causation principles.<sup>1</sup> Therefore, the Commission ordered that Pacific Gas and Electric Company (PG&E) complete the following steps:

- PG&E shall conduct workshops with Core and Non-Core customers to identify parameters for a credible transmission study;
- During the first workshop, PG&E shall deliver a presentation that identifies industry-standard methodologies used by other public utilities to study pipeline transmission costs so that workshop attendees can discuss which methodologies would be appropriate to study PG&E’s local transmission system;
- In a future rate case, PG&E shall execute a local transmission study using one of the methodologies identified in the workshops and submit the study results as its proposal for allocating local transmission costs; and
- Lastly, if PG&E deems it necessary to modify the selected industry-standard methodology so that it can accommodate a unique attribute of PG&E’s transmission system, PG&E shall justify the departure in its filing.<sup>2</sup>

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<sup>1</sup> D.19-09-025, p. 266.

<sup>2</sup> *Ibid*, p.267.

Accordingly, this chapter describes PG&E's compliance with these requirements regarding local transmission in D.19-09-025 and PG&E's proposed methodology for allocating local gas transmission costs.<sup>3</sup>

## 2. Summary of Proposals

After examining the gas industry standards for allocating local transmission costs and assessing the methodologies presented illustratively at the workshops by various parties, PG&E proposes to use the Abnormal Peak Day (APD) method to allocate local transmission costs between Core and Non-Core customers. This method allocates 63 percent of the local transmission costs to Core Customers and 37 percent to Non-Core customers. These results exclude the impact on allocation from incorporating discounted contracts, which are included in the final rate calculations in Chapter 6. As described below, the APD method was one of four methodologies recommended during the workshops by parties. Below, Table 4-1 shows the calculation details for the PG&E's APD method. Also, as shown in Table 4-1, this chapter will be using the 2023 local transmission revenue requirement from the 2023 General Rate Case (GRC) Phase I Track I proceeding.<sup>4</sup>

**TABLE 4-1  
APD METHOD SUMMARY ALLOCATIONS RESULT  
(BEFORE ADJUSTMENT FOR DISCOUNTED CONTRACTS)**

Line No.	APD Calculation Details	Values
1	LT Core Demand Served on APD (Mths/Peak Day)	30,139
2	LT Non-Core Demand Served on APD (Mths/Peak Day)	17,948
3	LT Core and Non-Core Demand Served on APD (Mths/Peak Day)	48,087
4	Estimated Local Transmission Revenue Requirement (\$)	\$1,547,393,000
5	Non-Core Local Transmission Revenue Requirement (\$)	\$577,544,012
6	Core Local Transmission Revenue Requirement (\$)	\$969,848,988
7	Non-Core Allocation percentage (%)	37.32%
8	Core Allocation percentage (%)	62.68%

<sup>3</sup> A description of PG&E's local transmission study is provided in Section F.

<sup>4</sup> A.21-06-021, Exhibit (PG&E-10), Appendix A, Table 17, line 1. All other references to Track I refer to 2023 GRC Phase I Track I unless otherwise noted.

**3. Organization of the Remainder of Chapter** This chapter is organized as follows:

- Section B – Overview of the Gas Transmission System
- Section C – Historical Background on Gas Local Transmission Allocation Methodology
- Section D – Overview of Cost Allocation Principles
- Section E – Local Transmission Workshop Presentations
- Section F – Evaluation of Local Transmission Allocation Methods
- Section G – Results of Local Transmission Allocation Study
- Section H – Conclusion

## **B. Overview of the Gas Transmission System**

PG&E operates one of the largest natural gas systems in the United States serving over 4.3 million gas customers and consisting of over 6,400 miles of backbone and local transmission pipelines, in addition to, 43,000 miles of distribution pipelines. The backbone transmission system consists of four major pipelines which import gas from interstate pipelines, as well as, from some California gas producing facilities.<sup>5</sup> The backbone pipeline system then delivers gas to the local transmission system or to the natural gas storage fields. The local transmission system, which is organized into twelve smaller systems, transports gas from the backbone system to the gas distribution pipelines. Also, a relatively small number (~600) of very large volume Non-Core customers, such as electric generators, refineries, and food processors, which account for about 93 percent of adopted Non-Core throughput and 56 percent of systemwide throughput, receive their gas directly from the backbone or the local transmission systems. Although PG&E's backbone system is located in mostly rural areas, a significant portion of PG&E's local transmission system is located in densely-populated areas.<sup>6</sup> While over 4.3 million Core and other Non-Core customers obtain their gas from connections to PG&E's distribution system, these customers also depend on the upstream local and backbone transmission

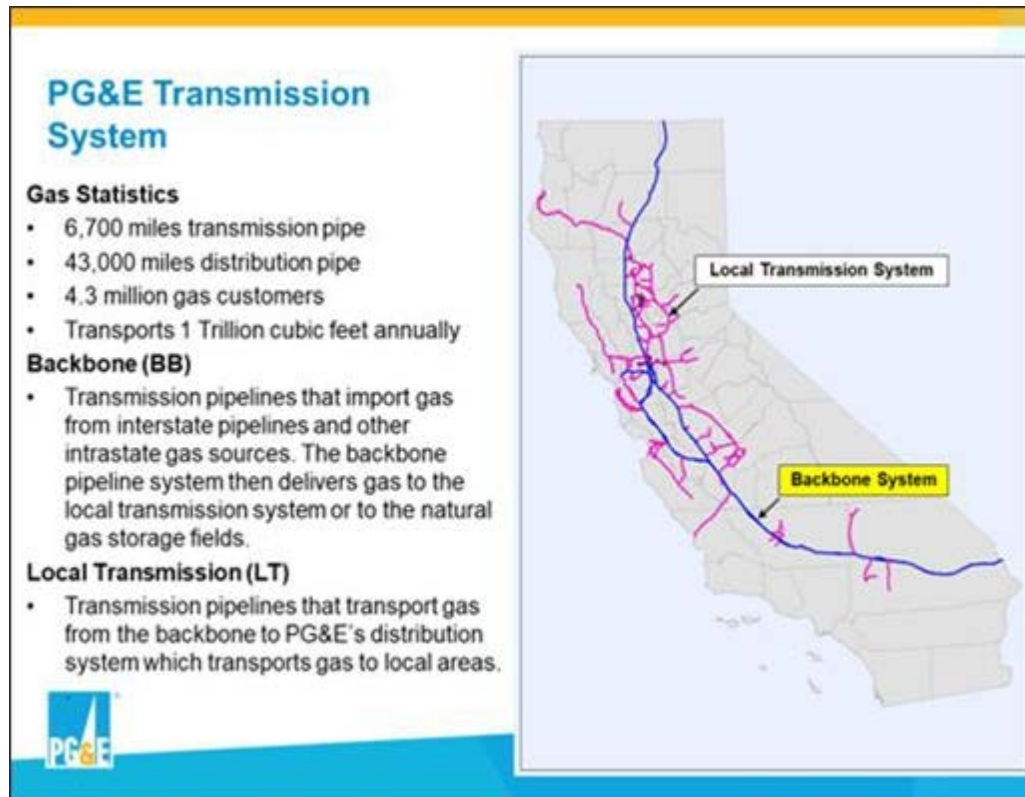
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<sup>5</sup> California Gas and Electric Utilities, 2020 Gas Report, Northern California, p. 36.

<sup>6</sup> A.17-11-009, Exhibit (PG&E-1), p. 5-13, line 1 to p. 5-14, line 1.

1 systems feeding their ultimate distribution system.<sup>7</sup> See Figure 4-1 for a map of  
2 the backbone and the local transmission systems.

**FIGURE 4-1**  
**PG&E'S GAS TRANSMISSION SYSTEM**



3 This chapter focuses on PG&E's local transmission system and how to  
4 allocate local transmission costs between Core and Non-Core customers.  
5 Transmission costs are typically allocated based on some measure of peak  
6 demand. PG&E uses hydraulic models to determine the capacity needs of the  
7 local transmission system. These models analyze operating pressure and  
8 demand changes and out of service events.<sup>8</sup> Each of the twelve local  
9 transmission systems has a separate model since they are hydraulically  
10 independent of each other.

11 Each hydraulic model uses a particular design day to model peak capacity  
12 demand. A design day is a set of temperature assumptions regarding the gas

<sup>7</sup> A.17-11-009, Exhibit (PG&E-1), p. 10-9, lines 24-30.

<sup>8</sup> A.17-11-009, Exhibit (PG&E-1), p. 10-10, lines 21-26.

capacity requirements under extreme weather conditions. The APD is used to determine gas capacity requirements for Core customers while Cold Winter Day (CWD) is used to determine capacity needs for Non-Core customers. The APD assumes that Non-Core customers demand will be curtailed to the extent necessary to service Core customers during an APD event; however, the CWD assumes that all customers will be served during a CWD event.<sup>9</sup> Table 4-2 lists the APD and CWD temperature assumptions.

**TABLE 4-2  
DEFINITIONS FOR APD AND CWD DESIGN DAYS**

Line No.	Design Day	Usage	Temperature Assumption	Service Criteria
1	APD	Use to determine gas capacity requirements for Core customers	Capacity requirement is based on providing Core customers with uninterrupted service on a one-day-in-90-year cold temperature design day	Assumes that Non-Core customers demand will be curtailed, if necessary, during a APD event
2	CWD	Use to determine gas capacity for Non-Core customers	Capacity requirement is based on providing Non-Core customers with uninterrupted service on a one-day-in-two-year area specific design day	Assumes all customers will be served during a CWD event

### **C. Historical Background on Local Gas Transmission Allocation Methodology**

The current methodology used to allocate local transmission cost, the Cold Year Peak Month (CYPM) methodology, has been used to allocate local transmission costs since D.92-12-058.<sup>10</sup> In D.92-12-058, the Commission also adopted the Cold Year Peak Season method for allocating backbone transmission costs and the Cold Year Peak Day method for allocation pipeline distribution costs.<sup>11</sup> Since the local transmission system is the bridge between the backbone and distributions systems, the Commission believed that the local transmission costs allocation methodology should be somewhere between the backbone and distribution methodologies, and therefore, adopted the CYPM

<sup>9</sup> A.17-11-009, Exhibit (PG&E-1), p. 10-10, line 32 to p. 10-11, line 20.

<sup>10</sup> D.92-12-058, Gas Long-Run Marginal Cost Proceeding, p. 23.

<sup>11</sup> D.92-12-058, pp. 21-22, 27.

1 method for local transmission costs.<sup>12</sup> The pipeline costs allocation methods  
 2 approved in D.92-12-058 are defined in Table 4-3 below.

**TABLE 4-3**  
**PIPELINE ALLOCATION METHODS APPROVED IN D.92-12-058**

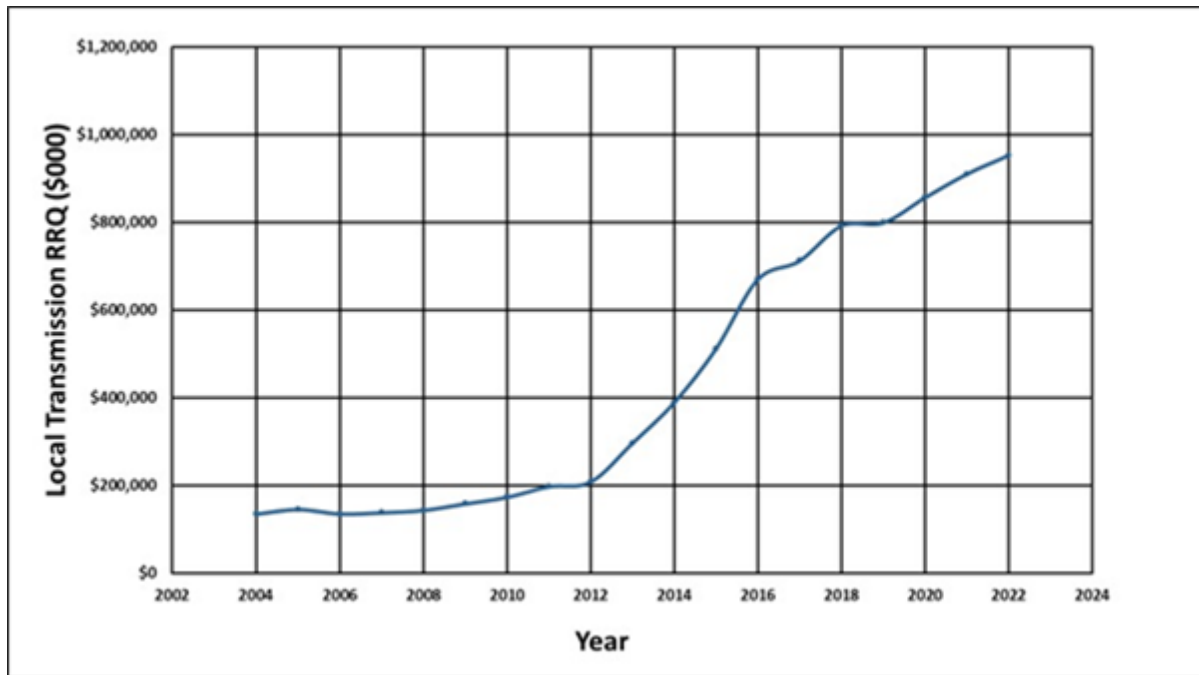
Line No.	Measure	Usage	Temperature Assumption	Service Criteria
1	CYPM	The current method for allocating local transmission cost that was first approved in D.92-12-058.	Local transmission allocation is based on a coincident peak of the coldest month in a 1-in-35-year cold year event.	All customers will be served under these methods.
2	Cold Year Peak Season	The method that was approved for allocating backbone transmission cost in D.92-12-058. <sup>(a)</sup>	Backbone allocation is based on a coincident peak of the coldest winter in a 1-in-35-year cold year event.	
3	Cold Year Peak day	The method that was approved for allocating pipeline distribution cost in D.92-12-058.	Distribution allocation is based on a coincident peak of the coldest day in January in an average temperature year event.	
(a) In D.98-06-073, the backbone allocation changed to a coincident peak based on the average temperature in January.				

### 1. Increasing Costs of the Local Transmission System

Beginning with the 2015 GT&S proceeding, due to the significant increases in safety standards and resulting improvement costs for the local transmission system, the local transmission allocation methodology became a widely debated issue between Core and Non-Core parties. Figure 4-2 shows the historical authorized local transmission revenue requirements beginning with the year 2004. As the graph shows, the revenue requirement between 2004 and 2012 remained at or below \$200 million with yearly increases being no more than \$25 million. However, after 2012, the yearly increases become significantly bigger with the authorized revenue requirement reaching \$952 million in 2022.

<sup>12</sup> D.92-12-058, p. 23.

**FIGURE 4-2**  
**HISTORICAL AUTHORIZED LOCAL TRANSMISSION REVENUE REQUIREMENT**  
**(THOUSANDS OF DOLLARS)**



## 2. New Divergent Views on Cost Allocation Methodologies

In the 2015 GT&S proceeding, certain Non-Core parties, Calpine and Indicated Shippers (IS), proposed allocating local transmission costs either based on classes receiving direct benefits of new safety improvements, i.e., residential and commercial customers located in proximity to local transmission lines, or using planning criteria of APD (Core) and CWD (Non-Core).<sup>13</sup> In addition, there were questions and suggestions from the various parties on how changes in some cost drivers, such as pipe diameter and length drove changes in costs.

For instance, The Utility Reform Network (TURN) disagreed with Calpine's and IS' assumption that pipe size is sole driver of local transmission costs. Using illustrative data from PG&E, TURN ascertained that PG&E's pipeline installation costs do not increase linearly with the size of a pipe since certain costs are fixed and do not vary by the size of the pipe. Moreover, the marginal costs of new pipeline capacity are primarily

<sup>13</sup> A.13-12-012, Exhibit Calpine/IS-001, p. 8, lines 10-21 and p. 10, lines 5-25.



1 caused by the need to transport the average daily demand for gas, not the  
2 peak day demand.<sup>14</sup>

3 Because of these divergent views, Commission in its 2015 GT&S Rate  
4 Case decision ordered PG&E to provide an analysis in the next GT&S case  
5 “demonstrating whether local transmission costs [w]ould be allocated more  
6 equitably by accounting for the actual relationships between pipeline  
7 capacity, throughput and costs.”<sup>15</sup> To fulfill the request for the study, PG&E  
8 performed a Local Transmission Engineering Study as part of the 2019  
9 GT&S proceeding.

### 10 **3. 2019 GT&S Local Transmission Engineering Study**

11 Below is a short overview of the 2019 GT&S Local Transmission  
12 Engineering study. Details of this study can be found in the workpaper  
13 (WP), WP 10-36.<sup>16</sup> The study was performed by PG&E’s gas planning  
14 engineers in 2017 and included in PG&E’s 2019 GT&S Rate Case  
15 application filed on November 17, 2017.

16 PG&E started the analysis with visualizing two stand-alone systems,  
17 one for Core customers and one for Non-Core customers. However, since  
18 building and analyzing the stand-alone systems for the entire local  
19 transmission system would be labor-intensive, the team decided to create  
20 stand-alone systems for two local transmission systems that together  
21 approximated the entire local transmission system’s mix of Core and  
22 Non-Core load. The East Bay local transmission system, which has a large  
23 geographic concentration of industrial, cogeneration, and electric generation  
24 use, was chosen to represent a system with relatively high Non-Core  
25 demand while the North Bay local transmission which has a relatively high  
26 residential and small commercial Core demand was chosen to represent a  
27 system with a relatively high Core demand. The two local transmission  
28 systems serve roughly one-third of the customer base, and contain a mix of  
29 urban, suburban, and rural customers and various commercial/industrial

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<sup>14</sup> A.13-12-012, TURN’s Opening Brief (Apr. 29, 2015), pp. 204-207.

<sup>15</sup> D.16-06-056, p. 316.

<sup>16</sup> A.17-11-003, Exhibit (PG&E-11), WP 10-36 to WP 10-47.

1 customers. Together the systems have a mix of Core and Non-Core  
2 demand that is relatively close to the system-wide mix.

3 For both the East Bay and North Bay the stand-alone Non-Core local  
4 transmission system was designed to only serve Non-Core customers and  
5 was designed to meet load requirements on a CWD, the current design  
6 standard. The Non-Core standalone system was designed with the needed  
7 pipe diameters and lengths to serve Non-Core customers only and excluded  
8 lengths of pipe that would otherwise exclusively serve Core customers.  
9 Likewise, the stand-alone Core local transmission system was designed to  
10 only serve core customers on an APD, the current Core design standard.  
11 The Core stand-alone system was designed with the needed pipe diameters  
12 and lengths to serve Core customers only and excluded the lengths of pipe  
13 that would otherwise exclusively serve Non-Core customers. The  
14 stand-alone designs incorporate the real hydraulic “stress” that each  
15 customer class hydraulically places on the design and therefore cost of the  
16 gas system under APD and CWD conditions. The resulting stand-alone  
17 designs and cost which use consistent design and cost methodologies  
18 throughout provide an engineering-based relative cost to serve Core and  
19 Non-Core.

#### 20 **4. Results of the Engineering Study**

21 In the 2019 GT&S proceeding, the results of the engineering study  
22 showed that Core customers local transmission cost allocation should be  
23 62 percent and Non-Core should be 38 percent. However, PG&E has  
24 adjusted these original results to address differences between the volume of  
25 Core and Non-Core load that exist systemwide versus for the total of the  
26 two representative systems. As equation 4-1 shows below, the adjustment  
27 prorated the East Bay and North Bay local transmission cost allocation to  
28 match the systemwide Core and Non-Core demand percentages. This  
29 change resulted in an adjustment of cost allocation from 62 percent Core  
30 and 38 percent Non-Core to 66 percent Core and 34 percent Non-Core.<sup>17</sup>

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<sup>17</sup> These allocation results are also before the impact of discounted contracts, which are applied by the Cost Allocation and Rate Design chapter. Please see Chapter 6, Section D, Local Transmission Rate Design.

**EQUATION 4-1**  
**ADJUSTED SYSTEMWIDE CORE COST ALLOCATION**

$$(EB + NB) \% \text{ Core Cost} \times \frac{\% \text{ Systemwide Core Load}}{\% (EB + NB) \text{ Core Load}}$$

$$61.58\% \times \frac{52.62\%}{49.29\%} = 65.74\% \text{ Core Cost}$$

**5. Commission Criticism of Engineering Study**

In its 2019 GT&S decision, the Commission did not approve the local transmission allocation method that was based on the engineering study and instead ordered the continuation of the CYPM method.<sup>18</sup> The Commission believed that the engineering study's hypothetical local transmission systems were overbuilt, and the construction costs used in the analysis were highly generalized, and therefore, did not meet what the Commission directed PG&E to consider, i.e., valid relationship between pipeline capacity and costs. Also, the Commission believed that using two standalone transmission systems is inconsistent with an important dynamic of PG&E's local transmission system that it is shared.

Despite the Commission's decision regarding the Local Transmission Engineering study,<sup>19</sup> the newly adjusted engineering study results can be used to validate other proposed methodologies. As the section on Cost Allocation Principles will explain, the stand-alone approach is an accepted and equitable method to apply to problems of allocating cost of a shared system, such as the local transmission system. Although the Commission stated the construction costs used in the engineering study were highly generalized, the engineering approach used by PG&E is driven by actual flow physics and is an accurate measure of the hydraulic "stress" each customer class puts on the system and therefore, reflects the costs each class imparts on the system. Moreover, as the final results will show, the allocation percentages from the engineering study are very close to the current method, CYPM, allocation percentages and also are nearly in the center of all the other proposed allocation percentages. Therefore, the

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<sup>18</sup> D.19-09-025, p. 266.

<sup>19</sup> D.19-09-025, pp. 265-267.

allocation results from the engineering study can at least be used to gauge what is an acceptable range of values for the allocations results and to spot any outliers. The need for validation of any proposed allocation method is further explained in the next section.

#### **D. Overview Cost Allocation Principles**

Cost allocation principles are common principles that define what constitutes an equitable division of cost among different groups that are served by some common facility or operation. Equitable division of cost is usually defined in terms of cost causation and how much each group benefits from the service.

As noted earlier, PG&E's proposed methodology for allocating local transmission cost should be consistent with cost causation principles.<sup>20</sup> Some of these cost causation principles include:

- Only those groups who cause costs to the system should pay for those costs;
- Two groups should pay the same costs, if the two groups cause equal increases in costs;
- If a group imposes larger cost, that group should pay more; and
- Groups who mitigate costs to the system should either incur a lower cost or be paid for helpful actions.

Rate design measures based on cost allocation methods that satisfy the above requirements can deliver transparent signals to customers and provide incentives for efficient customer behavior. However, if these requirements are not satisfied, inefficient signals can be sent to customers and increase the chances of cross-subsidization. Cross-subsidization happens when a cost allocation methodology or rate design measure unduly favors one group at the expense of others. Since both Core and Non-Core customers are concerned about being adversely impacted by cross-subsidization, it is important to find tools for assessing the various proposed methods for allocating local transmission costs.

##### **1. Applying Economic Game Theory to Cost Allocation**

This section discusses how cost sharing principles from economic game theory can be applied to problems of allocating cost of a shared facility such

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<sup>20</sup> D.19-09-025, p. 266.

as the local transmission system. Game theory is a theoretical framework for understanding the decision-making process of competing players in a strategic setting. Game theory early applications addressed zero-sum games where each player gains or losses are exactly balanced by those of other players. Since allocating local transmission costs between Core and Non-Core customers is also a zero-sum game, game theory's cost sharing principles can be used to gauge the appropriateness of different cost allocation methods. Furthermore, PG&E's discussion focuses on the cost allocation principles behind the Stand-alone and Incremental Cost tests, and the Shapley value.

## **2. Papers on Cost Allocation Principles and Pipeline Costs**

The theories and calculations discussed in this section were taken from the sources listed below:

- "Cost-Allocation Principles for Pipeline Capacity and Usage," D.J. Salant and G.C. Watkins, Attachment B: Gives a clear and concise overview of cost allocation principles as they relate to shared resources;
- "Cost Allocation and Rate Design for Unbundled Gas Services," Mohammad Harunuzzaman and Sridarshan Koundinya, Attachment C: Includes a discussion on how the stand-alone and incremental test can be use as theoretical benchmarks for inter-customer cross subsidies; and
- "Game Theory Cooperative Games: The Shapley Value," Giacomo Bonanno, Attachment D: Includes an illustrative calculation of the Shapley value, named after Lloyd Shapley, American mathematician and Nobel Prize-winning economist.

As Dr. Salant and Watkins cite in their paper, "there exists no way of allocating pipeline costs, [i.e., shared systems,] which is immune to criticism."<sup>21</sup> As these authors have done in their paper, PG&E will also try to summarize some of the main principles that most would agree a cost-allocation method should satisfy to be considered fair and reasonable.

The Stand-alone and the Incremental Cost tests are referenced in the "Cost Allocation and Rate Design for Unbundled Gas Services" paper as the

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<sup>21</sup> Attachment B, p. 91.

standard for examining the economics of cross subsidization. The paper also states that the stand-alone and incremental costs are not generally used as cost allocation methods in and of themselves in actual regulatory applications, but they remain of considerable value as they can be used as theoretical benchmarks to specify the upper and lower limits in cost allocation of a shared system to each of the customer segments sharing the service of that system.

On the other hand, the Shapley value is a unique solution that results in a fair distribution of both gains and costs to the parties working in coalition. The Shapley value is also the average of all the marginal contributions to all possible outcomes between parties. There have been several papers written on how the Shapley value can be used to address certain issues in the utility industry. For example, the Shapley value can be used to allocate transmission cost, to analyze the power losses in the transmission lines, and to determine fair compensation for energy exchanges between the micro-grids and utility grids.<sup>22</sup>

### 3. Illustrative Example of Stand-Alone Test

To illustrate an application of the stand-alone cost test, this test will be applied to the Postage-stamp cost allocation method,<sup>23</sup> where all users pay the same amount per unit of capacity regardless of transport distance. The stand-alone cost test requires that the allocation costs borne by each group cannot exceed that group's stand-alone costs. To illustrate this concept, column A in Table 4-4 shows the stand-alone costs of group A and B being \$11 and \$7 million dollars, respectively. For example, Group A's stand-alone cost is equivalent to the transmission costs that a utility would incur if all its customers were from Group A and Group B customers did not exist. The last row in column A shows that the total cost for serving both Groups A and B is \$15 million. Therefore, the utility saves \$3 million by building a combined transmission system that can accommodate both Groups A and B instead of building two stand-alone systems. And if costs are fully passed through to customers for recovery, the totality of customers

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<sup>22</sup> See Attachment E for links to related papers.

<sup>23</sup> In gas-ratemaking the typical description of this method is "equal cents per therm."

also then save \$3 million under a shared system than under two distinct systems. This is also a fundamental aspect underlying efficiency of single set of natural gas or water pipes in a neighborhood versus multiple and separately owned and operated sets of pipes.

Column B shows the results of allocation costs using the Postage-stamp method. Both Group A and B are allocated 50 percent of the total costs of serving both groups. However, this allocation method violates the stand-alone cost test since Group B allocated costs are greater than its stand-alone cost. The Postage-stamp allocation method generally fails to pass most common standards of fairness and reasonableness. The Postage-stamp allocation method is especially inefficient if total costs are distance-sensitive or if there is significant variation in demand between customers.

**TABLE 4-4  
STAND ALONE TEST**

Line No.	Stand-alone and Combined Costs for Group A and B (\$Mil)	A	Results of Post-Stamp Allocation	B
1	Cost of Serving Only Group A	\$11.00	Group A Allocated Costs	\$7.50
2	Cost of Serving Only Group B	\$7.00	Group B Allocated Costs	\$7.50
3	Cost of Serving Both A and B	\$15.00	Cost of Serving Both A and B	\$15.00

#### **4. Illustrative Example of Incremental Test and Shapley Value**

The Incremental Cost Test is a variation of the Stand-Alone Cost Test that establishes a priority among users and allocates common costs to the primary party up to the amount of that user's stand-alone costs. The remaining common costs are then allocated to the incremental party or parties. The Incremental Test is satisfied if no single group is subsidizing another. Also, the allocation to any group must be at least as large as the incremental costs of the group. However, the resulting allocation of the Increment Cost Test depends on the choice of the primary and incremental party. Moreover, one-sided incremental treatment tends to distort the cost allocation in favor of the customer class that receives incremental treatment.

1 An example of the possible different outcome of the Incremental Cost  
2 test can be seen in Table 4-5. The first 3 rows of Column A show the  
3 Incremental Cost Test where Group A is chosen as the primary party;  
4 therefore, Group A is allocated \$11 million, the equivalent of its stand-alone  
5 costs. Since the total costs is \$15 million, Group B is allocated the  
6 incremental costs of \$4 million. The last three rows of Column A show the  
7 results when Group B is the primary party which results in an allocation of  
8 \$7 million for Group B and \$8 million for Group A. Furthermore, if Group B's  
9 allocated cost were less than \$4 million, then Group B would be the recipient  
10 of a cross subsidy. Likewise, the threshold for Group A receiving a cross  
11 subsidy would be \$8 million.

**TABLE 4-5**  
**INCREMENTAL TEST AND SHAPLEY VALUE**

Line No.	Incremental Cost Test (\$Mil)	A	Shapley Value (\$Mil)	B	
1	<b>Group A Primary Cost</b>	<b>\$11.00</b>	<b>Group A Cost</b>	<b>\$9.50</b>	Avg of A
2	<i>Group B Incremental Cost</i>	<u>4.00</u>	<i>Group B Cost</i>	<u>5.50</u>	Avg of B
3	Total Cost	\$15.00	Total Cost	\$15.00	
4	<b>Group A Incremental Cost</b>	<b>\$8.00</b>			
5	<i>Group B Primary Cost</i>	<u>7.00</u>			
6	Total Cost	\$15.00			

Notes: Group A's contributions are shown in Column A, Rows 1 and 4.  
Group B's contributions are shown in Column A, Rows 2 and 5.  
The average of Group A's contributions is shown in Column B, Row 1.  
The average of Group B's contributions is shown in Column B, Row 2.

12 Column B of Table 4-5 shows the results of calculating the Shapley  
13 Value which requires taking each group's average contributions from  
14 multiple calculations where each group takes a turn being the "primary"  
15 party. Therefore, the Shapley Value does not change regardless of which  
16 party is chosen as the primary or incremental party. Therefore, Rows 1  
17 shows Group A's Shapley Value, the average of Group A's contributions  
18 from the two scenarios from Column A, \$11 and \$8 million which totals  
19 \$9.50 million. Likewise, Group B's Shapley Value is \$5.5 million, the



average of \$4 and \$7. The Shapley value is a unique cost allocation rule that has the following desirable properties.

- It is symmetric (equals are treated the same and does not change when the order in which groups are added to the system is changed);
- It is monotonic (it allocates all users larger cost shares whenever the total costs of serving everyone increases);
- It is additive (if groups of users are combined, the cost allocation for these users is the sum of the individual user);
- Nothing is charged to groups who do not contribute to cost;
- It always exists; and
- It identifies a unique cost allocation.

This section has introduced some cost allocation principles and some related quantitative tools that can be used to help gauge the fairness and reasonableness of pipeline cost-allocation methods. Therefore, in the outcoming sections, some of these allocation principles will be used to measure the appropriateness of the allocation methods presented at the workshop.

## **E. Local Transmission Workshop Presentations**

### **1. First Workshop**

Pursuant to D.19-09-025, PG&E held two local transmission study workshops. The first workshop occurred in December 2019. The workshop was open to the public. PG&E also invited CPUC's Energy Division and noticed the service list for PG&E's gas transmission and storage rate cases. The workshop included attendees from Energy Division, Shell Energy, IS, Sacramento Municipal Utility District, and TURN. Furthermore, in compliance with D.19-09-025, Ordering Paragraph 96, PG&E timely submitted both its 60-day and six-month status reports to the Commission. PG&E expects to submit its two-year status report in December 2021.

#### **a. The Black and Veatch Study**

During this workshop, PG&E presented a timeline of historical local transmission allocation issues and presented the results of a study commissioned by PG&E from Black & Veatch in 2014. Black and Veatch's tasks included the study of the national landscape of gas

1 transmission cost allocation methods. Black & Veatch investigated the  
2 gas transmission cost allocation methods used by eight distribution  
3 utilities that have system characteristics that are reasonably similar to  
4 PG&E's system. Black and Veatch's survey of the eight transmission  
5 costs allocation methods resulted in the following tally:

- 6 • Three utilities used some form of coincident peak design day;
- 7 • Two utilities used average and peak demand;
- 8 • One used coincident peak month;
- 9 • One used coincident peak day; and
- 10 • One used non-coincident peak day.

11 Figure 4-3 gives a description of the three common allocation  
12 methods used by the eight utilities.

FIGURE 4-3  
COMMON DEMAND ALLOCATION METHODS



## Common Demand Allocation Methods

### **Coincident Peak Demand Method:**

- Allocation is based on the demand of each customer class at the time of system peak, where each class allocation percentage is equivalent to its share of the system peak demand.
- This method favors high load factor customers with a relatively constant usage throughout the year.
- A greater percentage of costs is assigned to lower load factor heating customers whose consumption is greatest in winter, the time that system peaks usually occur
- Non-Core customers that have their services curtailed during the system peak will have no allocation of costs.

### **Noncoincident Peak Demand Method:**

- Allocation is based on a composite peak which is the sum of each customer classes actual peak regardless of the time of its occurrence. Each class allocation percentage is equivalent to its share of the composite peak.
- This method assigns cost to all customer class including classes that can be curtailed during system peaks
- Costs are spread more evenly among all customer classes; therefore, the cost allocation percentage for heating customers will be lower under this method than the Coincident Peak method

### **Average Usage and Peak Demand Method:**

- Allocation is a two-part allocation where the first allocation is first based on costs due to average usage and the second allocation based on costs attributed to peak demand.
- The costs based on average usage, which is derived by multiplying total cost by the system's load factor, is allocated based on the customer classes annual usage.
- The remaining costs associated with peak demand is allocated based on the coincident peak of each customer class.
- This method, which is a compromise between the Coincident and Noncoincident Peak methods, allocate costs to all classes and moderates the costs between the high and low load factor customers.

1           **b. PG&E's New Concept for Allocation Local Transmission Cost**

2           PG&E presented a new concept for allocating gas local transmission  
3           costs similar to the methodology used by PG&E to allocate electric  
4           distribution and generation costs. This method was a customer class  
5           specific model where each customer class was assigned an allocation  
6           weighting based on the classes' level of usage beyond a threshold  
7           usage. The threshold usage was a model parameter that could be  
8           chosen by the model user and was equal to a certain number of highest  
9           demand days in the year 2018, such as the top 10 highest demand  
10          days. Although no other alternative methodologies for allocation  
11          transmission costs were suggested by the workshop participants in this  
12          initial workshop, PG&E received comments from five participants about  
13          PG&E's new concept presented. As most comments were unsupportive  
14          of the new concept, PG&E discontinued further development.

15          **2. Second Workshop**

16          In August 2020, PG&E held a second public workshop to give  
17          intervenors an opportunity to present their proposed methodology for  
18          allocating local transmission costs. PG&E invited the same list of  
19          participants from the first workshop. The highlights of the second workshop  
20          included an overview of the 2019 GT&S Local Transmission Engineering  
21          Study which was described in Section C and four intervenors' presentations  
22          on their recommended methodologies for the allocation local transmission  
23          costs. The slides from the workshop presentations are included in  
24          Attachments A1–A4.

25          Table 4-6 shows a summary of a comparison of three out of four  
26          recommended methodologies that were presented at the workshop. The  
27          following four methods for allocating local transmission cost were presented  
28          at the last workshop:

- 29          • APD Method (TURN and IS);  
30          • CYPM (Southern California Generation Coalition (SCGC));  
31          • Top Peak Days of Year (SCGC); and  
32          • Alternative Version of the Engineering Study (Calpine).

**TABLE 4-6  
COMPARISON OF RECOMMENDED METHODOLOGIES**

Line No.	Metrics	IS	TURN	SCGC	Calpine
1	Allocation Method	APD	APD	CYPM <sup>(a)</sup>	Engineering Study
2	% of Non-Core Demand Served	50%	81%	100%	100%
3	Core Allocation %	74.0%	59.8%	65.8%	76.0%
4	Non-Core Allocation %	26.0%	40.2%	34.2%	24.0%

(a) Based on Current CYPM Forecast before adjusting for discount contracts

### 3. Workshop Presentations

Both IS and TURN recommended the APD method; however only TURN presented an illustrative calculation of its method at the workshop. SCGC recommended two methods, the CYPM Method and an allocation based on recorded data by customer class of the top demand days in the winter season, which is similar to the proposal PG&E made at the first workshop. However, SCGC did not present any detail of the calculations of either method or an approach to determine how many top demand days would be appropriate. Calpine recommended an alternate version of the 2019 GT&S Local Transmission Engineering Study. Calpine recommendation was based on a method it developed for the 2019 GT&S proceeding. Each of the 4 presentations are described and evaluated below to determine if any of the methods need to be updated or more precisely calculated either because the parties used illustrative data or because of incorrect assumptions.

#### **a. Indicated Shippers: APD Method with 50 percent of Non-Core Served**

##### **Indicated Shippers' Assumption:**

- Used APD data from the 2016 and 2018 California Gas Reports; and
- Assumed 50 percent of Non-Core demand can be served under APD conditions.

##### **PG&E's Evaluation:**

- IS used outdated data, so PG&E updated the APD method using data from the Gas System Planning Engineering team's 2020–2021 winter APD capacity plan for Core customers;

- IS' assumption of 50 percent of Non-Core Demand being served under APD conditions was incorrect; and
- Gas System Planning Engineering team's 2020-2021 APD capacity plan shows that 92 percent of Non-Core demand can be served under APD conditions.

IS recommended the APD method for allocating local transmission costs and assumed that 50 percent of Non-Core demand can be served during an APD event. As Table 4-6 shows, IS' allocation split was 74 percent Core and 26 percent Non-Core. IS supported the APD method as an alternative to PG&E's current local transmission costs methodology because they believed using the APD method to allocate local transmission costs reflects PG&E's system design planning criteria for Core customers and as a result, the APD method of allocation satisfies class cost causation.

#### **b. Indicated Shippers' Survey of Allocation Methods**

IS' presentation also included its survey of twenty gas distribution companies' allocation methods for the costs of mains. IS observed that:

- Sixteen of the companies used solely design day demand allocation.
- The other four companies used:
  - Non-coincident peak day;
  - Multiple methods including design day demand;
  - Multiple methods including coincident peak demand; or
  - Average & Excess Demand.

#### **c. TURN: APD Method with 81 percent of Non-Core Served**

##### **TURN's Assumption:**

- TURN's APD calculation used average annual throughput data.
- Assumed 81 percent of Non-Core demand can be served under APD conditions.
- TURN believes local transmission rates should reflect the difference in service priority levels for Core and Non-Core.
- TURN's APD calculation assumes 100 percent service level at peak capacity which includes the 19 percent of Non-Core demand that is usually curtailed under APD conditions.

- TURN separates the 100 percent service level at peak capacity demand into:
  - Baseload demand, the Core and Non-Core demand that usually can be served under APD conditions.
  - Non-Baseload demand, the 19 percent of Non-Core demand that is usually curtailed under APD conditions.
- TURN separated the local transmission revenue requirement into Baseload revenue requirement and Non-Baseload revenue requirement :
  - TURN allocated the Baseload revenue requirement to both Core and Non-Core based on equal cents per dekatherm; and
  - TURN allocated the total Non-Baseload revenue requirement to Core.

**PG&E's Evaluation:**

- TURN used illustrative annual data so PG&E updated APD method to data from the Gas System Planning Engineering team's 2020-2021 winter APD capacity plan for Core customers;
- TURN's assumption of 81 percent of Non-Core Demand being served under APD conditions is outdated;
- Gas System Planning Engineering team's 2020-2021 APD capacity plan shows that 92 percent of Non-Core demand can be served under APD conditions; and
- TURN's 100 percent service at peak capacity assumption violates cost causation principles; therefore PG&E's APD calculation only used the Core and Non-Core demand that can be served under APD conditions.

**d. Detailed Analysis of TURN's APD Calculation**

TURN recommended the APD method for allocating local transmission costs but assumed that 81 percent of Non-Core demand can be served during an APD event. TURN's APD method allocated 60 percent for Core and 40 percent to Non-Core. Using information from a PG&E data response, TURN cited the increases in capacity of PG&E's local transmission system since PG&E originally designed the system to serve only Core load during a APD event to justify its APD

1 assumption of 81 percent for Non-Core demand. TURN also mentioned  
2 that “[o]ver the past ten years, 99.9996 percent of noncore load has  
3 been served without curtailment.”<sup>24</sup> However, TURN believes that local  
4 transmission rates should reflect the difference in robustness of service  
5 for Core and Non-Core customers.

6 Table 4-7 shows the illustrative calculation details for the TURN’s  
7 APD allocation. TURN’s analysis used average yearly demand as a  
8 proxy for the daily demand under APD conditions. The calculation steps  
9 are on the right. For example, on Line 3, the total baseline demand is  
10 equal to sum of the lines 1 and 2, the Core and Non-Core demand  
11 served under APD conditions. Listed below are some details of TURN’s  
12 APD calculations:

- 13 • The demand on line 3 represents the baseload demand, the total  
14 Core and Non-Core demand that can be served under APD  
15 conditions;
- 16 • The non-baseload on Line 4 is the additional demand needed to  
17 serve the Non-Core demand that is curtailed during an APD event;
- 18 • On line 5, TURN assumed 100 percent service level at peak  
19 capacity, so the total local transmission throughput includes the total  
20 Core and Non-Core demand served on APD plus the Non-Core  
21 demand that is usually curtailed;
- 22 • The baseline revenue requirement on Line 8, will be allocated to  
23 both Core and Non-Core based on equal cents per dekatherm;
- 24 • The rest of the revenue requirement which is on Line 12 and is  
25 associated with the cost of building the additional capacity needed  
26 to reach 100 percent service level at peak capacity is only allocated  
27 to Core; and
- 28 • Core is allocated this additional cost to account for Core’s higher  
29 priority of service over Non-Core which is responsible for Non-Core  
30 curtailment.

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<sup>24</sup> Attachment A4, p. 4-Atcha4-2.



**TABLE 4-7  
TURN'S APD ALLOCATION**

Line No.	TURN's APD Calculation	(Demand in 1000 Dth )	Calculation Steps
1	LT Core Demand Served on APD	273,045	Input
2	LT Non-Core Demand Served on APD	217,547	Input
3	LT Total Demand Served on APD (Total Baseload)	490,592	L1+L2
4	LT Total Non-Core Curtailment on APD	51,030	(L2/.81) - L2
5	LT Total Core and Non-Core Demand Served on APD plus APD Non-Core Curtailment	541,622	L1+L2+L4
6	% of LT Revenue Requirement to be Allocated by Equal Cents per Dth	90.60%	L3/L5
7	Estimated LT Revenue Requirement	\$799,286,000	Input
8	LT Baseload Revenue Requirement	\$724,153,116	L6xL7
9	LT Baseload Revenue Requirement /Dth	\$1.48	L8/(L3x1000)
10	Non-Core Baseload LT Revenue Requirement	\$321,116,810	L9 x L2 x 1000
11	Core Baseload LT Revenue Requirement	\$403,036,306	L9 x L1 x 1000
12	Core Only: Peaking Capacity at 100 percent Service Level	\$75,132,884	(1 – L6) x L7
13	Total Core LT Revenue Requirement	\$478,169,190	L11 + L12
14	Non-Core Allocation percentage	40.18%	L10/L7
15	Core Allocation percentage	59.82%	L13/L7

**e. Southern California Generation Coalition: CYPM and Top Demand Day Methods**

SCGC presented two proposals for allocating local transmission cost. First, SCGC presented the CYPM, and cited D.92-12-058, the decision in which the Commission approved CYPM method for allocation local transmission costs. However, SCGC believes this method has its limitations since not all 30 of the coldest days will be in a single month and they typically occur over the calendar months of December and January as Heating Degree Days and resulting system demand for these two months are very close. Therefore, SCGC suggested that PG&E should investigate using the top demand or flow days of the winter season to allocate transmission costs instead of using the peak month. Since SCGC did not calculate CYPM Core and Non-Core allocation percentages, the CYPM allocation results in Table 4-6 are based on the most current CYPM forecast.

**f. Calpine Alternate Engineering Study**

**Calpine's Assumption:**

- Calpine created a joint Core and Non-Core systems instead of two Core and Non-Core stand-alone systems.

- Calpine assumed that the hypothetical Core stand-alone system had excess capacity under CWD conditions to serve 25 percent of Non-Core demand.
- Calpine created a Core system that was partially shared with Non-Core customers.
- Calpine also created an incremental Non-Core system that served the Non-Core load that could not be accommodated on the Core system.
- Calpine used the average of two Methods to allocate Core and Non-Core local transmission costs.
- In the first Method:
  - Core paid for the capacity it used on the Core system.
  - Non-Core paid for the capacity that Non-Core used on the Core system, in addition to, the Non-Core incremental system.
- In the second Method:
  - Core paid for the entire Core System.
  - Non-Core only paid for the cost of the incremental system.

**PG&E's Evaluation:**

- Calpine's engineering study is flawed because its calculations for its joint Core and Non-Core system do not use pipeline flow hydraulics and flow physics to determine costs;
- Calpine's one-sided incremental treatment in its second method unfairly distorts cost allocation in favor of the customer class that pays incremental costs; and
- PG&E recalculated Calpine's second method by calculating the "Shapley" value which takes the average contribution of the Core and Non-Core contributions from both incremental calculations.

**g. Detailed Analysis of Calpine's Engineering Study**

Calpine presented an alternate version of PG&E's 2019 GT&S Engineering Study as its proposed allocation method which resulted in a 76 percent allocation for Core and a 24 percent allocation for Non-Core. The description of Calpine Alternate Engineering Study can be found in

Calpine's GT&S opening testimony<sup>25</sup> and in the related WP.<sup>26</sup> Calpine believes its alternate version of the PG&E's Local Transmission Engineering Study addresses two weaknesses in PG&E's original study. Calpine believes its study addresses the following flaws:

- The study's two stand-alone hypothetical systems ignore the joint services that the system provides to both Core and Non-Core customers; and
- The study ignores Core customers' higher service priority over Non-Core customers.

For instance, instead of having Core and Non-Core stand-alone systems, Calpine created a Core system that was partially shared with Non-Core customers and an incremental Non-Core system that served the Non-Core load that could not be accommodated on the Core system. Calpine calculations are based on the assumptions that the hypothetical Core stand-alone system, which was designed to serve Core customers under APD conditions, has excess capacity under CWD conditions to serve 25 percent of Non-Core demand. Then Calpine calculates the Core's and Non-Core's allocations using two methods.

**First Method:**

- In Table 4-8, Columns B, C and D, shows the first calculation.
- The total cost of the Core System is \$1,661 million;
- Core pays for the capacity it used on the Core system (83 percent of \$1,661 Management Measures (MM) = \$1386 MM);
- Non-Core pays for the capacity it uses on the Core system (17 percent of \$1661 MM = \$275 MM); and
- Non-Core also pays for 100 percent of the incremental Non-Core system that provides the additional capacity that cannot be provided by the Core system (\$433 MM).

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<sup>25</sup> A.17-11-009, Exhibit Calpine-1, pp. 11-17.

<sup>26</sup> A.17-11-009, Calpine's response to PG&E Data Request PGE-Calpine001-Q001 and PGE-Calpine001-Q001-Atch01.

**Second Method:**

- In Table 4-8, Columns E, Core pays for 100 percent of the Core System (\$1,661 MM); and
- Non-Core pays for only 100 percent of Non-Core incremental system (\$433 MM).

The final steps to Calpine calculations are:

- Averaging the Core allocation percentages from Method 1 and Method 2;
- Averaging the Non-Core allocation percentages from Method 1 and Method 2; and
- Making an adjustment to account for the total systems Core and Non-Core throughput to get a final local transmission of 76 for Core and 24 for Non-Core.

Tables 4-8 and 4-9 shows a summary of Calpine's calculations.

**TABLE 4-8  
CALPINE ENGINEERING CALCULATION  
(MILLIONS OF DOLLARS)**

Line No.	A	B	C	D	E	F	G
1			Method 1		Method 2		
2		Core and Non-Core System split on CWD	With Noncore Assigned a Share of Core System		Incremental Non-Core System only		Average Split for Core and Non-Core Systems
3	Core share	83%	\$1,386	66%	\$1,661	79%	73%
4	NC use of Core	17%	275		—		
5	Incremental NC		433		433		
6	Total NC		\$708	34%	\$433	21%	27%
7	Total Combined		\$2,094		\$2,094		

**TABLE 4-9  
CALPINE'S ALLOCATION FOR LT SYSTEM**

Line No.	A	B	C
1	Average		
2	Split for Core and Non-Core Systems	Adjustment to account for the total system's Core/Non-Core throughput	Total System Allocation
3	73%	3%	76%
4	27%	3%	24%

## **F. Evaluation of the Local Transmission Allocation Methods**

As mentioned at the beginning of this chapter, PG&E proposed methodology for allocating local transmission cost is the APD method. In this section PG&E will give the details of its proposed APD methodology. PG&E will also give the details of the evaluation and adjustment of each model discussed in the previous section.

### **1. APD Model**

Column A in Table 4-10 shows TURN's APD calculation updated with data from the Gas System Planning Engineering team's 2020-2021 winter APD forecast. The updated inputs include:

- The Core demand served under APD conditions is 30,130 thousand dekatherms per day (MDth/d);
- The Non-Core demand served under APD conditions is 17,948 MDth;
- Ninety-two percent of Non-Core demand will be met during APD event, leaving 1,556 MDth being curtailed; and
- The local transmission revenue requirement has been updated to the 2023 GRC Phase I forecasted local transmission revenue requirement of \$1.5 billion.<sup>27</sup>

With the updated data, TURN's methodology allocates 64 percent to Core and 36 percent to Non-Core.

#### **a. Charging Core for additional demand and costs that do not exist**

However, TURN's assumption of 100 percent service level at peak capacity under APD violates the cost causation principles. First,

<sup>27</sup> Chapter 6: Attachment A, Table 6-2, Line 42.

1 TURN's calculation does not include the additional revenue needed to  
2 increase the capacity so that the service level is at 100 percent. If there  
3 is no additional cost, why should Core pay more. TURN is assuming  
4 that the local transmission throughput is 49,643 MDth/d on an APD  
5 while the actual maximum throughput during a APD event is actually  
6 48,087 MDth/d. Therefore, as Table 4-10, Column A, lines 4 and line 12  
7 show, TURN is charging Core for additional non-existent 1,556 MDth/d  
8 in demand which results in \$48 million in additional local transmission  
9 costs.

10 **b. PG&E's APD Methodology Only Includes Demand Available on**  
11 **APD**

12 PG&E's proposed APD methodology, shown in Column B, only uses  
13 the Core and Non-Core demand served under APD conditions to  
14 calculate local transmission allocation rates and excludes the amount  
15 that Non-Core is curtailed. PG&E proposed methodology allocates  
16 63 percent to Core and 37 percent Non-Core which is one percent  
17 different than TURN's allocation. However, under TURN's APD method,  
18 this one percent translates into almost \$18 million premium Core would  
19 have to pay due to Core's higher priority of service over Non-Core.  
20 However, as TURN stated in its workshop presentation, over the past  
21 ten years, 99.9996 percent of Non-Core load has been served without  
22 curtailment. This is a significant premium for an event that statistically is  
23 defined to happen one day in 90 years. Additionally, with the potential  
24 that increased electrification targeting PG&E's gas distribution system  
25 would result in decreasing Core gas sales, the possibility of Non-Core  
26 curtailments will become even more unlikely than they have already  
27 been.

**TABLE 4-10**  
**PG&E'S APD CALCULATIONS**

Line No.		A	B
	APD Calculations	TURN's Method	PG&E's Method
1	LT Core Demand Served on APD	30,139	30,139
2	LT Non-Core Demand Served on APD	17,948	17,948
3	LT Total Demand Served on APD (MDth) (Total Baseload)	48,087	48,087
4	LT Total Non-Core Curtailment on APD	1,556	
5	LT Total Core and Non-Core Demand Served on APD plus APD Non-Core Curtailment	49,643	
6	% of LT Revenue Requirement to be Allocated by Equal Cents per Dth	96.87%	
7	Estimated LT Revenue Requirement	\$1,547,393,000	\$1,547,393,000
8	LT Baseload Revenue Requirement	\$1,498,896,652	
9	LT Baseload Revenue Requirement/Dth	\$31.17	
10	Non-Core Baseload LT Revenue Requirement	\$559,443,390	\$577,544,012
11	Core Baseload LT Revenue Requirement	\$939,453,262	
12	Core Only: Peaking Capacity at 100 percent Service Level	\$48,496,348	
13	Total Core LT Revenue Requirement	\$987,949,610	\$969,848,988
14	Non-Core Allocation percentage	36.15%	37.32%
15	Core Allocation percentage	63.85%	62.68%

## 2. Cold Year Peak Month methodology

The CYPM allocation results are taken from the Gas Rate Design model discussed in Chapter 6 as the status quo method.<sup>28</sup> The CYPM on average allocates 65.8 percent of the local transmission cost to Core and 34.2 percent cost to Non-Core. These allocation percentages are based on the average of 2023–2026 CYPM forecast. Please note that CYPM allocations and all allocation discussed previously are before adjusting for discount contracts in order to provide transparent comparisons in this chapter.

## 3. Calpine Engineering Study

### a. Calpine's Method is Fundamentally Flawed

Calpine's engineering study is fundamentally flawed because its calculations for its joint Core and Non-Core system does not use pipeline flow hydraulics and flow physics to determine costs. Therefore, Calpine Engineering Study should not be used to allocate local transmission cost.

<sup>28</sup> Chapter 6, Section D, p. 6-10, line 6 to p. 6-11, line 4.

1           **b. Calpine's Second Method Distorts Cost Allocation**

2           However, in addition to this fundamental flaw, Calpine introduces  
3           another flaw by using a one-sided incremental treatment in its second  
4           method for allocating local transmission costs. Thus, Calpine's second  
5           method's one-sided incremental treatment unfairly distorts cost  
6           allocation in favor of the customer class that receives incremental  
7           treatment.

8           For example, the second method that Calpine uses to allocate  
9           transmission costs allocates the primary cost to Core and the  
10          incremental cost to Non-Core. As a result, this method allocated only  
11          23 percent of the costs to Non-Core and 77 percent to Core. Using  
12          one-sided incremental cost treatment for either Core or Non-Core  
13          customers places an excess amount of the costs on the non-incremental  
14          customer class and significantly understates the costs for the  
15          incremental customer class. Moreover, one-sided incremental  
16          treatments violate the symmetric cost allocation principle - results do not  
17          change when the order in which groups are added to the system is  
18          changed.

19          To illustrate the distortion of costs of one-sided incremental cost  
20          treatment, PG&E used Calpine's methodology but made Core the  
21          incremental customer. Using the Calpine approach but treating Core as  
22          the incremental customer the cost allocation becomes 53 percent for  
23          Core and 47 percent for Non-Core. Table 4-11 shows the  
24          allocations percentages from both the Core and Non-Core incremental  
25          cost calculations. Note that both of these Core and Non-Core  
26          allocations results become large outliers compared to the allocation  
27          results from other methods, such as APD or CYPM.

28           **c. Using the Shapley Value to Correct Calpine's Method 2**

29          However, if the Core and Non-Core contributions are averaged from  
30          both incremental calculations, consistent with the accepted Shapley  
31          method, as shown in Table 4-11, Row 7-9, the resulting  
32          allocation percentages are 66 percent Core and 34 percent Non-Core  
33          which equal the results from Calpine Method 1, as shown in Table 4-12.  
34          The fundamental flaw of ignoring pipeline flow hydraulics and flow



1 physics in an “engineering” study remain but Method 1 on its own  
2 reflects the averaging of the two properly performed incremental  
3 methods, instead of being averaged with the flawed Calpine Method 2  
4 which results in an outcome outside the reasonable range.

**TABLE 4-11  
INCREMENTAL COSTS**

Line No.	Incremental Allocation	Contributions (\$MM)	%
1	<b>Core primary cost</b>	<b>\$1,661</b>	<b>79%</b>
2	<i>Non-Core incremental</i>	433	21%
3	Total Cost	\$2,094	
4	<b>Core incremental</b>	<b>\$1,172</b>	<b>53%</b>
5	<i>Non-Core primary cost</i>	1,036	47%
6	Total Cost	\$2,208	
7	Average Core and Non-Core Contributions (Shapley Method)		
8		Contribution	%
9	<b>Core cost</b>	<b>\$1,416</b>	<b>66%</b>
10	<i>Non-Core cost</i>	734	34%
11	Total cost	\$2,151	

**TABLE 4-12  
PG&E ADJUSTED CALPINE STUDY  
UPDATED CALPINE ENGINEERING CALCULATION  
(MILLIONS OF DOLLARS)**

Line No.	A	B	C	D	E	F	G
1			Method 1		<b>PG&amp;E's Method 2</b>		
2		Core and Non-Core System split on CWD	With Noncore Assigned a Share of Core System		<b>Incremental Non-Core System only</b>		Average Split for Core and Non-Core Systems
3	Core share	83%	\$1,386	66%	<b>\$1,416</b>	<b>66%</b>	66%
4	NC use of Core	17%	275		—		
5	Incremental NC		433		—		
6	Total NC		\$708	34%	<b>\$734</b>	<b>34%</b>	34%
7	Total Combined		\$2,094		<b>\$2,151</b>		

**TABLE 4-13**  
**PG&E'S ADJUSTED ALLOCATIONS**

Line No.	Updated Allocation for Total System		
1	A	B	C
2	Average Split for Core and Non-Core Systems	Adjustment to account for the total system's Core/Non-core throughput	Total System Allocation
3	66%	3%	69%
4	34%	-3%	31%

## **G. Results of Local Transmission Allocation Study**

### **1. Finding a Range of Acceptable Models**

As mentioned earlier, there exists no way of allocating pipeline costs, i.e., shared systems, which is immune to criticism. As indicated by the two presentations of methods used across the U.S., there are many versions or combinations of methods. Therefore, in addition, to proposing a method for allocating transmission costs, PG&E selected a range of models that PG&E deems suitable for allocation transmission costs. Tables 4-14 and 4-15 show the allocation results of different methods presented above.

Table 4-15 is sorted in ascending order by the percentages for Core allocations percentages. As discussed earlier, the currently adopted statewide method of CYPM and the PG&E's Engineering Study (as adjusted to match systemwide Core vs Non-Core load) Core allocation percentages are in the middle. There are 4 models that have allocation percentages that are higher than these two models, and four models with lower percentages.

Figure 4-4 shows a one-dimensional line graph of the Core allocation percentages. Looking at the plotted allocations in Figure 4-4, there are clearly are some allocations that are outliers. For example, models that are farthest away from the center include:

- Calpine Study: Method 2 using Incremental Core;
- IS APD (presented at workshop);
- Calpine Study: (presented at workshop); and
- Calpine Study: Method 2 using Incremental Non-Core.

As discussed earlier, the Calpine Study uses a flawed underlying pipe capacity method, in addition; the Calpine Study uses one-sided incremental

1 cost that distorts cost allocation in favor of the customer class that gets  
2 incremental treatment. Moreover, IS' APD method assumes that 50 percent  
3 of Non-Core demand can be served under APD conditions. However,  
4 50 percent is actually much lower than the actual percentage, which is  
5 closer to 90 percent. Therefore, the models that tend to be the most flawed  
6 also have allocations that are outliers or furthest from the center. The most  
7 acceptable models tend to have Core or Non-Core allocation percentages  
8 within +/- 6 percent of each other. These models include PG&E's and  
9 TURN's APD methods, the CYPM method, PG&E's Engineering Study, the  
10 Calpine's Study with PG&E corrections. Table 4-15 shows these models  
11 allocation percentages shaded.

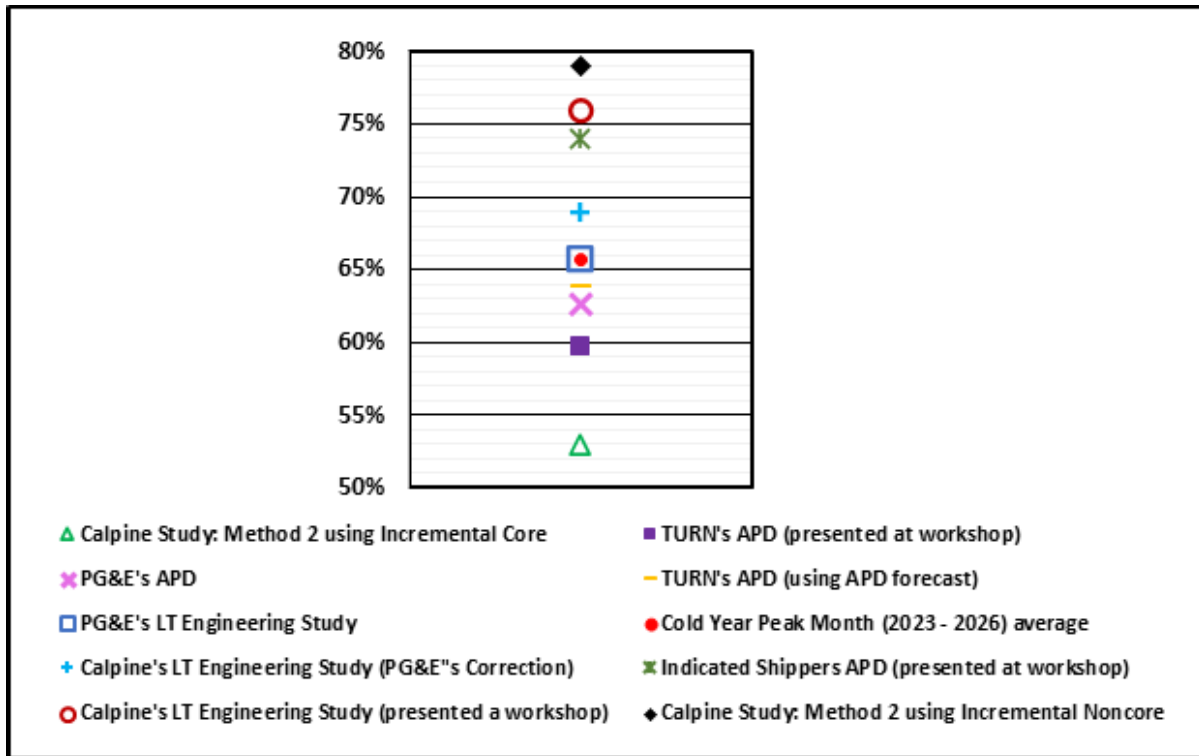
**TABLE 4-14**  
**SUMMARY OF PROPOSED ALLOCATION METHODS**

Line No.	Allocation Methods	Allocation% <sup>(a)</sup>		Allocation Dollars	
		Core	Non-Core	Core	Non-Core
1	PG&E's APD	62.7%	37.3%	\$940,200,000	\$559,800,000
2	IS APD (presented at workshop)	74.0%	26.0%	\$1,110,000,000	\$390,000,000
3	TURN's APD (presented at workshop)	59.8%	40.2%	\$897,000,000	\$603,000,000
4	TURN's APD (using APD forecast)	63.9%	36.1%	\$957,750,000	\$541,500,000
5	CYPM (2023-2026) average	65.8%	34.2%	\$1,018,338,449	\$529,054,551
6	PG&E's LT Engineering Study <sup>(b)</sup>	65.7%	34.3%	\$986,100,000	\$513,900,000
7	Calpine's LT Study (presented a workshop)	76.0%	24.0%	\$1,140,000,000	\$360,000,000
8	Calpine Study: Method 2 using Incremental Non-Core	79.0%	21.0%	\$1,185,000,000	\$315,000,000
9	Calpine Study: Method 2 using Incremental Core	53.0%	47.0%	\$795,000,000	\$705,000,000
10	Calpine's LT Engineering Study (PG&E's Correction)	69.0%	31.0%	\$1,035,000,000	\$465,000,000

(a) Before Discounted Contract Adjustment.

(b) Adjusted to address the differences between the volume of Core and Non-Core load systemwide vs for the two representative systems.

**FIGURE 4-4  
ONE DIMENSIONAL LINE GRAPH OF CORE ALLOCATION PERCENTAGES**



**TABLE 4-15  
CORE ALLOCATIONS SORTED IN ASCENDING ORDER  
(ACCEPTABLE PERCENTAGES SHADED: LINES 3-7)**

Line No.	Allocation Methods	Allocation% <sup>(a)</sup>	
		Core	Non-Core
1	Calpine Study: Method 2 using Incremental Core	53.0%	47.0%
2	TURN's APD (presented at workshop)	59.8%	40.2%
3	<b>PG&amp;E's APD</b>	<b>62.7%</b>	<b>37.3%</b>
4	<b>TURN's APD (using APD forecast)</b>	<b>63.9%</b>	<b>36.1%</b>
5	<b>PG&amp;E's LT Engineering Study<sup>(b)</sup></b>	<b>65.7%</b>	<b>34.3%</b>
6	<b>CYPM (2023-2026) average</b>	<b>65.8%</b>	<b>34.2%</b>
7	<b>Calpine's Study (PG&amp;E's Correction)</b>	<b>69.0%</b>	<b>31.0%</b>
8	IS APD (presented at workshop)	74.0%	26.0%
9	Calpine's Study (presented a workshop)	76.0%	24.0%
10	Calpine Study: Method 2 using Incremental Non-Core	79.0%	21.0%

(a) Before Discounted Contract Adjustment.

(b) Adjusted to address the differences between the volume of Core and Non-Core load systemwide vs for the two representative systems.

## 2. PG&E's Proposed Local Transmission Allocation Methodology

PG&E proposes to use the APD method to allocate local transmission costs rather than the CYPM method. However, as noted, earlier, no method is immune from all criticism and that is true for both the APD and CYPM method despite the many points in their favor. As ordered in the 2019 GT&S Rate Case, PG&E must propose a nationally used method proposed at the workshops. As the Black and Veatch study and IS survey discovered, most of the utilities they investigated used some form of coincident peak design day to allocate pipeline costs and only a few utilities used coincident peak month to allocate these costs. Therefore, PG&E has chosen to use the most common method for allocating local transmission cost, the APD method which is a coincident peak design day method.

The APD method is used to determine gas capacity requirements for Core customer. Yet less than 2 percent of PG&E's proposed 2023-2026 capital expenditures budget for gas transmission is driven by the need for additional capacity, whether for new customers or to serve the needs of existing customers with growing loads.<sup>29</sup> On the other hand, the CYPM method is not used as capacity planning criteria. Although the CYPM method assumes 100 percent service level for both Core and Non-Core, currently 90 percent of Non-Core load can be served during an APD event, which statistically would occur by definition only one day in 90 years or 1 day in 32,873 days. As noted above, in the last ten years 99.99 percent of Non-Core load has been served without curtailment. APD method is based on a 1-in-90 year day forecast while the CYPM method is based on 1-in-35 year forecast. With the increase occurrence of extreme weather events due to global warming, the APD method could provide a more robust forecast accounting for these events compared to peak month methods if average temperatures rise but very cold peak days remain. Lastly, both Core and Non-Core intervenors proposed the APD method for allocating local transmission costs which may be an indicator that some variation of the APD method can be accepted by both groups.

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<sup>29</sup> A.21-06-021, Exhibit (PG&E-3), p. 2-59, Table 2-15, lines 2, 3, and 4.

### 3. Discounted Contract Adjustment

There are currently five customers that receive discounts applied to their local transmission rates.<sup>30</sup> The Rate Design models adjust the local transmission allocation to account for these customer's discounts. However, the APD allocation does not change much after the discounted contracts as the terms under discounted contracts has decreased significantly since the last GT&S case. Before accounting for discounted contracts, the PG&E's APD allocation percentages were 62.7 percent for Core and 37.3 percent for Non-Core. However, the current, post-discounted contract percentages are only Core: 62.8 percent, Non-Core: 37.2 percent. The discounted contract calculation for the APD method can be found in Chapter 6 Local Transmission workpaper.

### H. Conclusion

In this chapter, PG&E discussed its compliance with the requirements regarding local transmission in D.19-09-025. Furthermore, PG&E vetted all the models that were presented at the ordered workshops and chose a method to allocate local transmission costs consistent with cost causation principles. Therefore, PG&E proposes the APD as its 2023 GT&S CARD method for allocating local gas transmission costs. PG&E respectfully requests that the Commission approve its proposed local transmission allocation estimates along with the methodology presented in this chapter.

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<sup>30</sup> A.17-11-009, Exhibit PG&E-2, p. 16C-20, lines 1-9.

**PACIFIC GAS AND ELECTRIC COMPANY CHAPTER 4**  
**ATTACHMENT A1**  
**SOUTHERN CALIFORNIA GENERATION COALITION**  
**PRESENTATION**

# Cold-Year Peak Month and Other Measures of Coincident Demand

Catherine E. Yap  
Barkovich & Yap, Inc.

On Behalf of

Southern California Generation Coalition

August 11, 2020



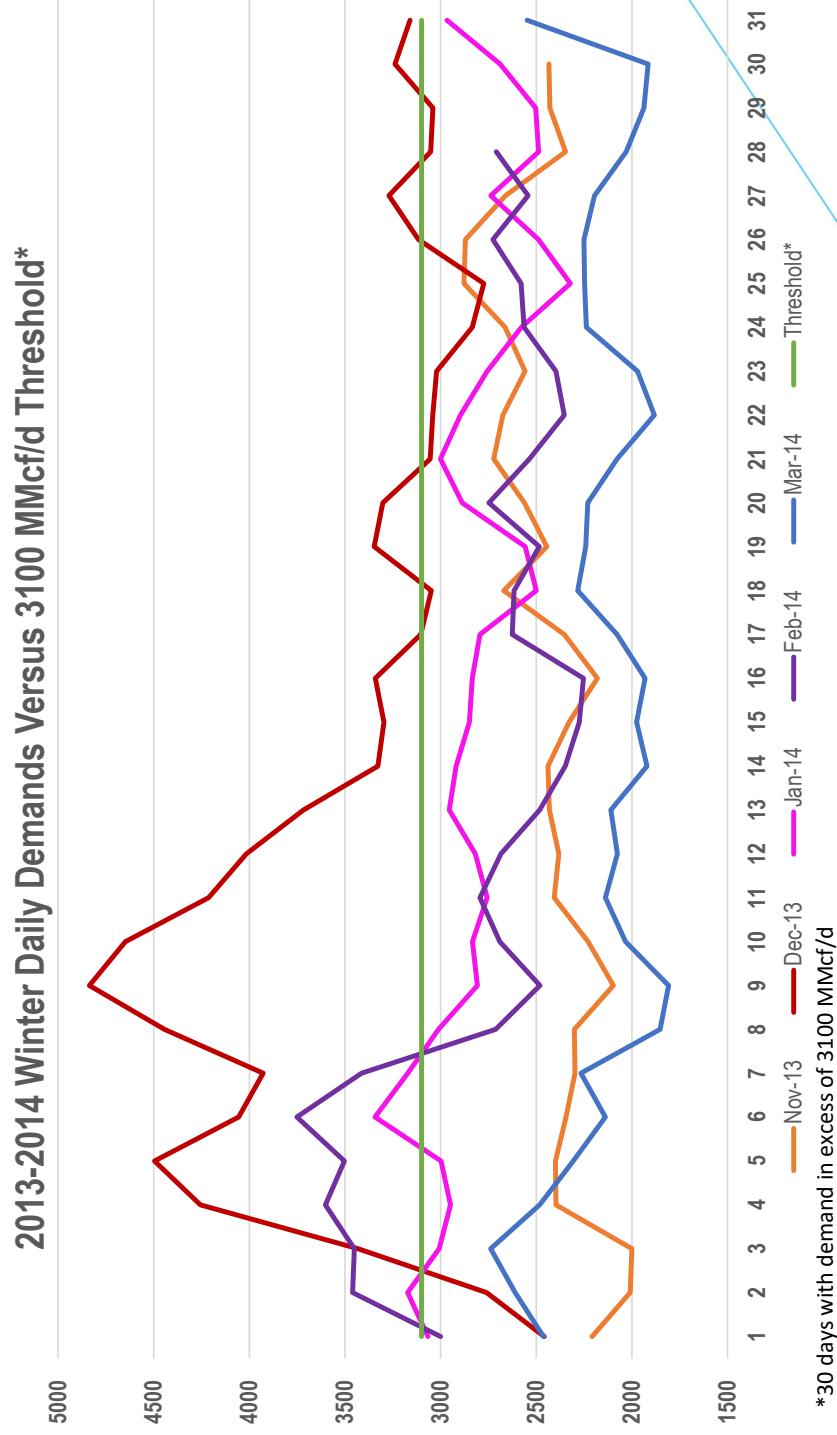
# Commission Decision 92-12-058 Established a Fundamental Costing Methodology

- ▶ “For each function of a utility’s gas system, the demand measure used to calculate that function’s marginal cost should be the one that reflects cost causation for that function.” (p. 20)
- ▶ “The criterion that causes a utility to need more capacity [is a] marginal demand measure (MDM).” (p. 21)
- ▶ “Logically, local transmission would be taking gas from both flowing supplies and storage withdrawal, and transporting that gas to local areas. Essentially, the MDM should be somewhere between transmission and distribution.” (p. 23)
- ▶ Decision chose cold year peak month for local transmission (p. 23)

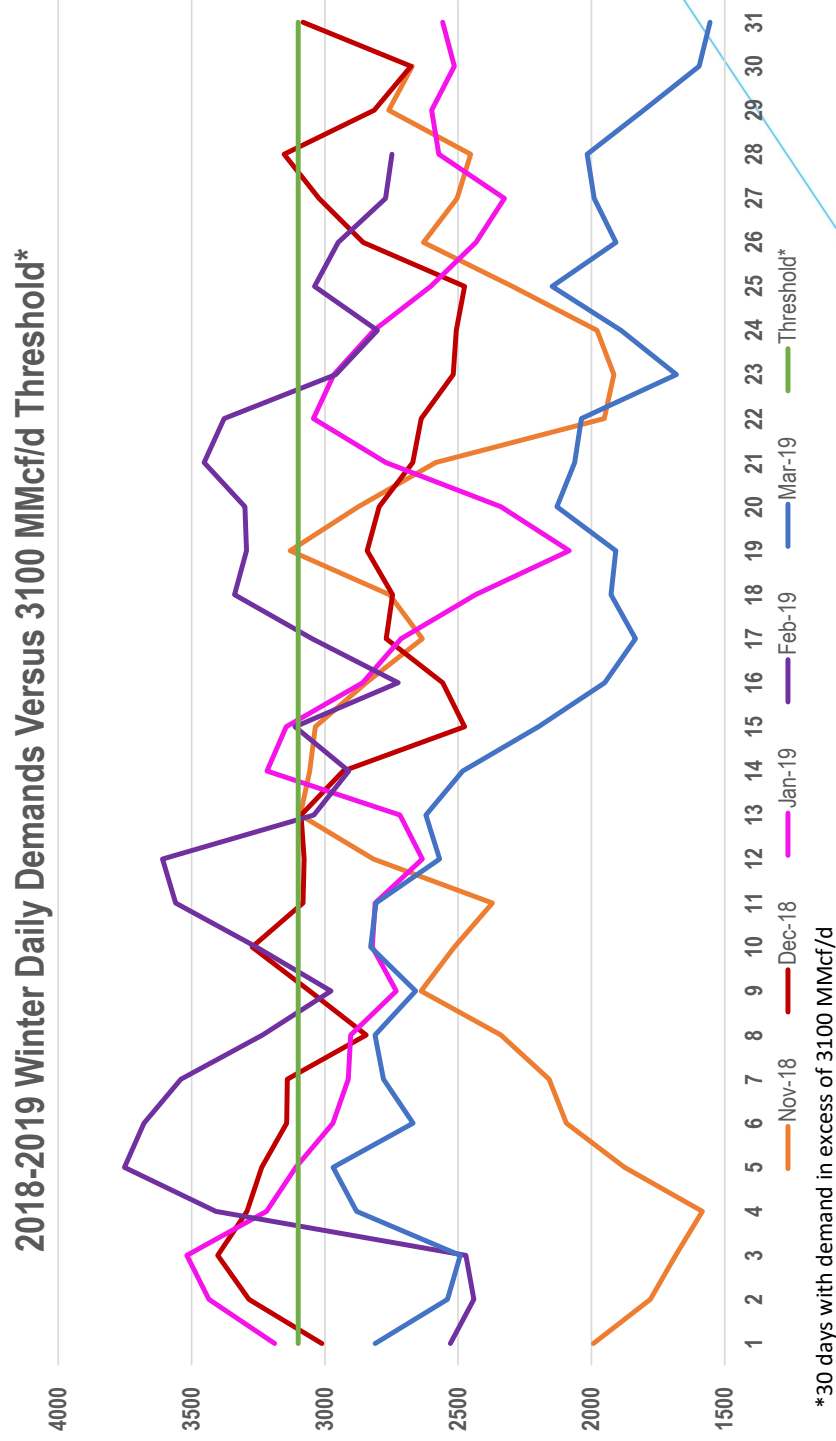
# Coincident Demand Drives Peak Requirements of the Shared System

- ▶ D.19-09-025 recognized local transmission is shared system and kept a coincident demand measure: cold year peak month.
- ▶ Peak demands drive the need to expand the system.
- ▶ Coincident demand measures the amount each customer class contributes to the peak demands.
- ▶ Cold year peak month is a reasonable measure but it has a limitation since not all 30 of the coldest days are within a single month.

# A Single Winter Month Does Not Contain the 30 Highest Flow Days



# A Single Winter Month Does Not Contain the 30 Highest Flow Days (cont.)



## **The Commission Has Previously Used a Similar Type of Coincident Demand Measure on the Electric System: Top 100 Hours**

- ▶ **Top 100 Hours represents about 1.3 percent of all (8760) hours in a year**
- ▶ **Peak month represents about 8.5 percent of the days in a year**
- ▶ **Peak 5 days represents about 1.4 percent of the days in a year**
- ▶ **Peak day measure could use top 5, 10, 20, or 30 days**

# Analysis of Demand Shares Using Recorded Data (2013-2020) Shows Moving to a Smaller Number of Peak Days Places More Cost Responsibility on Core Customers

4-AtchA1-7

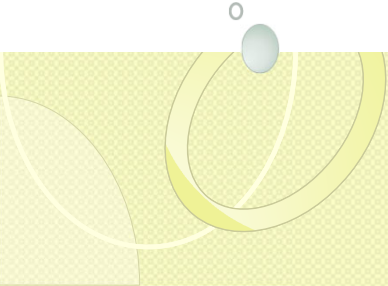
Relative to peak month allocation	Core	Noncore
Peak month	100%	100%
Peak 30 days	104%	95%
Peak 20 days	105%	94%
Peak 10 days	108%	91%
Peak 5 days	109%	90%

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 4**

**ATTACHMENT A2**

**CALPINE PRESENTATION**



# Proposal for a Local Transmission Cost Allocation Study

## Presentation to PG&E Workshop

Tom Beach

Crossborder Energy on behalf of Calpine

August 11, 2020





## Proposal: Use PG&E Study Method from A. 17-11-009 Modified to Correct CPUC-identified Issues

- PG&E compared the costs of two local T systems:
  - One to serve the core on an APD
  - Second to serve the noncore on a CWD
- Major issues identified in D. 19-09-025 (pp. 265-267):
  1. PG&E's actual local T system is one system to serve the higher of core demand on an APD or core and noncore demand on a CWD.
  2. Core customers have a higher priority of service.
  3. Lack of support for PG&E's cost formulas.

## Calpine's Revision to PG&E's Study

- Addresses the first two issues with PG&E's method
- Based on cost causation and local T design criteria
- Start with a "core system" serving the core on an APD.
- Assign to noncore the facilities that serve 100% noncore loads.
- Equal core/noncore sharing of the costs of the "core system" facilities that the noncore uses on a CWD.
- Adjust result to overall PG&E system core/noncore throughput.
- Result was an allocation of 76% core, 24% noncore.

## Further Improvements

- Noncore use of the core system on a CWD
  - Use a more sophisticated method than Calpine's volumetric split
  - Hydraulic modeling of common facilities used on a CWD
- Cost formulas
  - Benchmark using recent pipeline construction data

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 4**  
**ATTACHMENT A3**  
**INDEPENDENT SHIPPERS PRESENTATION**

# PG&E Local Transmission Study Workshop

Comments of  
BRUBAKER & ASSOCIATES, INC.  
On Behalf of:  
**INDICATED SHIPPERS**

## Indicated Shippers' (IS) Concerns with PG&E Proposed PCAF Methodology

- Many hours that are not peak hours are weighted in the PCAF cost allocation process, resulting in dilution of 'peak requirements'
- PG&E's data indicates its system is winter peaking
- 2018 data is not weather normalized
- Anonymity concerns makes it impossible to evaluate the implications of the PCAF model using real load data
- Concerned that PCAF does not best reflect class cost causation

## Results of IS Survey of Other LDC Cost Allocation Methods

- IS survey indicates that the use of design day demands/non-coincident class maximum demands in the allocation of transmission costs are more prevalent than indicated by PG&E's survey
- 20 LDCs in IS survey – 16 use design day demands and 1 uses non-coincident class maximum demands for cost allocation
- No utility in IS survey uses the PCAF method
- PCAF vastly different from what other utilities use for cost allocation

# IS Survey Results

## Most Frequently Used Cost Allocations for Mains

<u>Line</u>	<u>State</u>	<u>Utility</u>	<u>Docket No.</u>	<u>Allocation Method for Mains</u>
	(1)	(2)	(3)	(4)
1	Arkansas	Arkansas Oklahoma Gas	07-026-U	Design Day Demand
2	Georgia	Atlanta Gas & Light	42315	Design Day Demand
3	Idaho	Intermountain Gas Company	INT-G-16-02	Design Day Demand
4	Indiana	NIPSCO	Cause No. 43894	Design Day Demand
5	Kentucky	Columbia Gas - Kentucky	2013-00167	Design Day Demand
6	Minnesota	CenterPoint Energy (Minnesota Gas)	G-008/GR-15-424	Design Day Demand
7	Missouri	Laclede Gas	GR-2017-0215	Design Day Demand
8	Missouri	Missouri Gas Energy	GR-2017-0216	Design Day Demand
9	New Jersey	New Jersey Natural Gas Company	GR19030420	Design Day Demand
10	New York	Consolidated Edison	13-G-0031	Design Day Demand
11	North Dakota	Montana Dakota Utilities - ND	PU-17-295	Design Day Demand
12	Ohio	Vectren	18-0298-GA-AIR	Design Day Demand
13	South Dakota	Montana Dakota Utilities - SD	NG15-005	Design Day Demand
14	Tennessee	Chattanooga Gas Company	18-00017	Design Day Demand
15	Colorado	Public Service Company of Colorado	20AL-0049G	Design Day Demand
16	Montana	NorthWestern Energy	D2016.9.68	Design Day Demand
17	Maryland	BG&E	9326	Design Day Demand
18	Virginia	Columbia Gas - Virginia	PUE-2014-00020	NCP
19	Wisconsin	Wisconsin Public Service	6690-UR-123	Multiple Studies including Design Day Demand Multiple Studies including Coincident Peak Demand
20	Iowa	Alliant Energy (Interstate Power & Light)	RPU-2019-0002	Average & Excess

### Notes:

LDCs in lines 1-14 and 20 also classify a portion of mains as customer-related



## IS Alternatives Recognize Abnormal Peak Day (APD) Design Basis\* for Core Customers and Inferior Quality of Service to Noncore Customers

- PG&E system designed to meet Core Abnormal Peak Day (APD) demand
- Noncore demand is not planned to be met on an APD, which makes it an inferior service
- California Gas Report provides estimate of Noncore demand expected on an APD
- Possible LT cost allocation alternative based on Core APD plus 50% of potential Noncore demand on an APD

\* Industry standard Design Day Demand

# 

<u>Possible Allocators for PG&amp;E Local Transmission Costs</u>			
<u>Line</u>	<u>Description</u>	<u>Core</u>	<u>Noncore</u>
<u>PG&amp;E GT&amp;S A. 17-11-009</u>			
1	Cold Winter Day (CWD)		-
2	PG&E Proposed: 50% cold-year/ 50% average year	53%	-
3	Current PG&E Allocator: Cold-year peak-month	62%	47%
4	Calpine Revised Study: Noncore Contribution to Core-APD	67%	38%
5	Calpine Revised Study: Core-APD/ Incremental Noncore	66%	33%
6	<b>Calpine: 50% #4 / 50% #5, with adjustment</b>	79%	34%
		<b>76%</b>	<b>21%</b>
<u>Possible Alternatives</u>			
7	2016 Ca. Gas Report: Core APD Plus 50% of Potential Noncore Demand	72%	28%
8	2018 Ca. Gas Report: Core APD Plus 50% of Potential Noncore Demand	74%	26%

## Possible IS LT Cost Allocation Alternatives

- The IS LT cost allocation alternatives reflect PG&E system design to meet Core APD and as a result, class cost causation
- IS LT cost allocation alternatives include a reasonable financial contribution of Noncore demand toward LT system fixed costs
- PG&E no different from other LCDs with respect to system design (design day load conditions)
- Current PG&E Noncore cost allocation (33%) is larger than the alternative allocations based on system design and class cost causation (26% - 28%)

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 4**  
**ATTACHMENT A4**  
**THE UTILITY REFORM NETWORK PRESENTATION**

# TURN PRESENTATION

PG&E Local Transmission Cost Allocation



# Facts and Principles

- The PG&E LT system was originally designed to serve only core load on a 1-in-90 year systemwide APD (which has never occurred), and all noncore load on a 1-in-2 year Cold Winter Day, with noncore curtailment if weather is colder than 1-in-2 Cold Winter Day.
- Much has changed since the system was initially designed.
- Based on the most recent analysis by PG&E for the 2017-18 gas year, 81% of noncore demand would have been served had a systemwide APD occurred. (GT&S Ex. SCGC-Palo Alto-01, Attachment B: PG&E's Response to SCGC-Palo Alto DR-02, Q&A 2.5).
- Over the past ten years, 99.9996% of noncore load has been served without curtailment. (GT&S Ex. PG&E-31, pp. 10-25 – 10-26).
- LT rates should reflect the difference in firmness of service for core and noncore.

## TURN Proposed Allocation – Base Load and Peaking

All core and 81% noncore can be served on an APD =	273,045 MDth core
81% of 268,577 Mdth =	<u>217,547 MDth noncore</u>
	490,592 MDth Total Baseload
	<u>51,030 MDth Total Non-Baseload</u>
	541,622 MDth Total LT Throughput
Baseload to be Allocated by Equal Cents per Dth: 490,592/541,622 = 90.6% total	
2019 LT Rev Req = \$799,286,000 X .906 = \$724,153,000 / 490,592 MDth baseload -= \$1.4761/Dth	
Noncore Baseload	217,547 MDth X \$1.4761 = \$321,117,000 <b>NONCORE TOTAL</b>
Core Baseload --	273,045 MDth X \$1.4761 = \$403,036,000
Plus Peaking:	9.4% of Total \$799,286,000 = <u>\$75,133,000</u>
	<b>\$478,169,000 CORE TOTAL</b>
Core plus Noncore = Revenue Requirement --	\$799,286,000

# RESULTS AND COMPARISONS

	<u>Core</u>	<u>Noncore</u>
Proposed =	\$478,169,000	\$321,117,000
Current =	\$551,497,000	\$247,789,000
Difference	- 73,328,000	+ 73,328,000

	<u>Percent Core</u>	<u>Percent Noncore</u>
Current Allocation	69.0%	31.0%
TURN Proposal	59.8%	40.2%
PG&E LT Study	62.0%	38.0%
LT Throughput	50.4%	49.6%



## **Data Requirements**

- LT revenue requirement and throughput forecasts by core and noncore
- PG&E Curtailment Plan study for most recent gas year.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 4**  
**ATTACHMENT B**  
**COST ALLOCATION PRINCIPLES FOR PIPELINE CAPACITY**  
**USAGE**

*This paper applies principles from game theory to the problem of allocating the cost of a shared facility, such as a pipeline. The theory of cooperative games strongly suggests that no method exists for allocating costs that will achieve all major policy goals. We apply results from the theory of cooperative games and principles of cost allocation to assess some commonly adopted rules for allocating costs and defining unit charges. Most notably, the postage-stamp toll is found to fail a minimal set of commonly applied principles.*

*Cet article applique les principes tirés de la théorie des jeux au problème de la répartition des coûts d'une installation partagée telle qu'un pipeline. La théorie des jeux coopératifs suggère fortement qu'il n'existe pas de méthode de répartition des coûts qui puisse satisfaire tous les objectifs principaux en matière de politique. Nous appliquons les résultats tirés de la théorie des jeux coopératifs et des principes de répartition des coûts pour évaluer certaines règles d'usage adoptées pour répartir les coûts et définir les frais unitaires. En particulier, il ressort que le droit timbre-poste ne satisfait pas à un ensemble minimal de principes d'usage.*

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D.J. Salant and G.C. Watkins are with the Law & Economics Consulting Group, Emeryville, California.

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## **Cost-Allocation Principles for Pipeline Capacity and Usage**

D.J. SALANT and G.C. WATKINS

### **I. Introduction**

Transmission facilities, such as pipelines, lead to debates about cost sharing whenever there are multiple users of large segments. The cost-allocation literature strongly suggests that there exists no way of allocating pipeline costs which is immune to criticism. And a system of uniform rates (postage-stamp rates), for example, is no exception.<sup>1</sup> Our intent in this paper is two fold. First, to outline some of the main principles that most would agree a cost-allocation system should serve to satisfy the oft-cited statutory admonition of being "fair and reasonable." Second, to explain the implications of those principles.

To provide suitable focus initially we discuss postage-stamp systems in the context of a natural gas pipeline system and explain its pros and cons. Then we take a more analytical approach, but with no predetermined bias as to what constitutes the optimal way in which to allocate pipeline network costs among users. Instead, we work from first principles. Over the past decade or so there have been developments in economic techniques that apply notions of fairness and equity, as well as

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1/ Postage-stamp rate design has been applied by Nova Gas Transmission Limited in the Province of Alberta, Canada for most of that system's life.

efficiency, to cost allocation. There has been increased recognition of the need to look at the role that various fairness criteria play in allocating costs. Our paper makes it apparent how some current schemes such as postage-stamp rates can conflict with commonly accepted fairness standards.

We examine the so-called axiomatic approach in order analytically to examine alternative concepts of fairness, or "just and reasonable," for determining how to allocate costs. Our analysis is based on axiomatic social choice theory developed over the past twenty or so years, and in particular on axiomatic cost-allocation theory. Axiomatic cost-allocation approaches have been applied to water systems, airport landing fees, managerial accounting, flood control, navigation, and power systems. We apply this theory to identify a formula for allocating costs. We find that a postage-stamp rate generally fails to pass most commonly used standards for fairness and reasonableness, and could induce both inefficient bypass and inefficient resource development. Application of the axiomatic approach can provide some assurance that hidden implications of commonly proposed notions of fairness have not been overlooked.

The paper is organized as follows. Section II briefly discusses postage-stamp schemes. Basic cost-allocation and fairness principles are outlined in Section III. Additional fairness criteria are discussed in Section IV, including the nucleolus and the Shapley value. Section V discusses how the Shapley value can be used as a guide for cost allocation. Section VI addresses other equity and efficiency issues. Section VII is a summary.

## II. Postage-Stamp Schemes

In North America, regulated pipeline tolls are normally set to yield a total revenue requirement. There is typically some latitude for the regulator in determining how these tolls are set. These may consist of fixed and variable charges, be distance related, or fixed within zones, or may be uniform throughout: the so-called postage-stamp system.

A postage-stamp system is one in which all

users pay the same amount per unit, or parcel, of capacity, independent of transport distances. This type of rate structure is most appropriate when: (a) there are high fixed connection costs, so that the total costs are not so distance-sensitive; (b) there is little variation in the distances among the different users' shipments; (c) there are large transaction costs associated with distance-related tolls<sup>2</sup> when users have similar average distances of haul; and (d) when system complexity and cost interdependence make cost causation nebulous.

However, a postage-stamp tariff is inherently inefficient if total costs are distance-sensitive and/or if there is a significant variation in the sources of demand.<sup>3</sup> For instance, if one user wishes to use only a small part of the pipeline and many others use most of its entire length, the stand-alone cost of the one short-haul firm could be much less than  $1/n^{\text{th}}$  of the pipeline cost, where there are  $n$  firms that use it in total. This situation would encourage a potential contributor to the network costs to incur the cost of building bypass facilities. Such incentives can persist even if these bypass facilities were more costly than the incremental cost of allowing the short-haul firm access to, and use of, the pipeline system. And it is here that bypass is inefficient.

Furthermore, even when the postage-stamp rates do not initially create incentives for inefficient bypass, circumstances can change, which could cause such incentives to emerge. Technology can change, new fields can come on line, and a host of other factors can alter demand patterns in such a way as to create incentives for inefficient bypass. Moreover, the rate structure can affect incentives to bring new areas on line in the first place. We introduce principles for cost allocation that take into account the possibility that conditions can change over time.

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2/ This may be manifest in high administrative savings for the utility itself or for the users of the facility with a postage-stamp regime.

3/ Also, see the later discussion of the indirect impacts of postage-stamp rates on the efficiency of resource allocation.

### III. Basic Cost-Allocation Principles

We start by considering two commonly accepted minimal properties that a cost allocation should satisfy: (a) the stand-alone cost test; and (b) the incremental cost test. We explain why some simple approaches, such as the postage-stamp system, fail to meet these two principles.

The *stand-alone cost* test has two parts. First, it requires that the cost share borne by each user not exceed that user's stand-alone costs. If the proposed cost-allocation rule satisfies the condition that no single pipeline user can do better on his or her own than under the proposed cost allocation, then it satisfies the *individual rationality condition*. The second part of the stand-alone cost test applies to *subsets* or *groups of users*; it requires that the cost allocation satisfy a *group rationality condition*. The group rationality condition requires that no *group* of users be able to self-supply for less than their combined costs under the proposed allocation rule. If an allocation fails the stand-alone cost test for *any* coalition, or group of users, then any such group would have an incentive to bypass the system and self-provide. Together, the individual and group rationality conditions constitute the *stand-alone cost test*. The stand-alone cost test is a condition for all parties to cooperate voluntarily and use the system. It also means that each user will find it individually rational to remain on the system and pay his assigned cost share.

The other minimal condition for fairness is the *incremental cost test*. This test is satisfied if no single group of users is subsidizing another. The incremental cost test also means that the allocation of costs to any group of users must be at least as large as the incremental costs of including that group on the system. Both the stand-alone and incremental cost tests are *equity*, or *fairness*, conditions.

The incremental cost test is equivalent to a stand-alone cost test whenever joint costs are fully allocated. When costs are fully allocated and the cost allocation fails a stand-alone test, it is necessarily the case that cross-subsidies exist, in the sense that one group's contribution to the total costs is less than the incremental

costs of serving it. To see this, suppose there are two groups of pipeline users, and that the costs allocated to the first group were to exceed its stand-alone costs. The allocation of the total costs to this group and the remaining group will sum to the total system costs, assuming all costs are allocated. Thus, the costs of the entire system less the stand-alone costs of serving only the first group will then exceed the costs allocated to the second group. In other words, if the costs allocated to one group exceed its stand-alone costs, the costs allocated to everyone else are less than the incremental costs of serving them, where these are represented by the system costs less the stand-alone costs of serving everyone not in the first group.

A seemingly minimal requirement for a cost allocation is that it be fair at least in the sense that it passes both stand-alone and incremental cost tests. Then it would provide incentives for all interested parties to cooperate, would not allow cross-subsidies to exist, and would allocate all the costs among all users. The set of all such cost allocations is called the *core*. This basic, if somewhat abstract, concept is helpful in limiting discussion of how costs should be allocated and can eliminate some allocations, such as postage-stamp rates, that might otherwise seem reasonable.

Consider a simple example adapted from Young (1994), in which the costs of serving firm A alone is \$11 million, firm B alone is \$7 million, and the costs of serving the two together is \$15 million — which provides savings of \$3 million over separate systems serving each firm. Such savings are precisely what a pipeline system is intended to offer users. It is not obvious what is the right way to allocate costs or cost savings in this situation. An equal division of costs (which is how postage-stamp rates are usually set up) would set the price at \$7.5 million each, and firm B would not wish to participate in a joint project because it would be better off on its own. Thus, an equal division of costs fails the stand-alone cost test. Further, suppose that firm A uses three times the capacity that firm B does, at least over the part of the system they both use. Then a cost allocation in proportion to capacity, such as would be the case with a purely demand-re-

lated toll, would result in a price to firm A of \$11.25 million and \$3.75 million to firm B. This is another instance in which what seems to be a sensible cost-sharing rule fails to be in the core, that is, it does not pass a stand-alone test, given A's stand-alone costs of \$11 million.

However, a number of cost-sharing rules will be in the "core" for this example. An equal division of the savings above their respective stand-alone costs will result in cost shares of \$9.5 million and \$5.5 million for A and B, respectively. Division of savings in proportion to demand will result in a cost allocation of \$8.75 million and \$6.25 million. Division of savings based on opportunity, or stand-alone, costs implies a cost allocation of \$9.17 million and \$5.83 million. All three of these allocations are in the core, since both firms have allocated costs below their respective stand-alone costs. More generally, the core includes all cost allocations which fall in a particular range of values. That is, there will typically be upper and lower bounds on each firm's cost share for any cost allocation in the core. Although the core can rule out some harmless sounding cost-sharing schemes, such as equal splits of costs or postage-stamp schemes, it does not identify a unique split. Notice too that the logic of the stand-alone criteria can also be used to characterize the potential problems with cost-sharing arrangements such as a postage-stamp scheme, which indeed does fail the crucial stand-alone test.

Aside from non-uniqueness, another difficulty with the core is that it could be empty: it is possible that no cost allocation will satisfy the core conditions. Suppose, for example, the costs for a stand-alone system for each of firms A, B, or C were \$6 million, the costs of serving any two firms was \$7 million, and the costs of serving all three were \$11 million. In this case, the core would be empty.<sup>4</sup> Whether or not

4/ Here, the constraints for a cost allocation to be in the core cannot all hold instantaneously. In other words, the costs allocated to any pair of firms cannot exceed \$7 million, and there are three such constraints, which in aggregate imply that the total costs allocated to the three firms cannot exceed \$10.5 million. Moreover, the \$11 million total costs must be split among the three. These two conditions are contradictory. To put it another way, simultane-

ously supplying all three is obviously most economical, and would require that each user pay \$3.67 million on average (one may pay less than \$3.67 million, but then the other two will have to pay more than \$7.33 million, or (\$11 million - \$3.67 million), violating the stand-alone cost test. In any case, one pair of buyers will end up being assessed for more than their \$7 million stand-alone costs. So there will be a pair of buyers who will prefer to build their own system rather than paying their share of the total system costs. The core is empty, as it requires that the stand-alone test hold for all coalitions as well as individuals.

#### IV. Additional Fairness Criteria

There are a number of other fairness conditions that a cost-allocation mechanism should probably satisfy. Not all of them can always be satisfied simultaneously. Policy makers' choice of a formula for allocating costs will depend on which fairness criteria they judge to be the most important at the time. Here, we first present a heuristic discussion of the major standards that have been analyzed in the theoretical literature. We then explain, at least in the context of a theoretically ideal world with no uncertainty and no administrative or compliance costs, how these principles can nail down specific cost-sharing formulae.

One condition we shall want to impose on a cost-allocation rule is that it "work" in changing environments. That is, the principles laid out one day should not be revised the next due to a change in circumstances. In the case of Nova Gas Transmission Limited (NGTL), the Alberta Energy and Utilities Board has upheld the postage-stamp toll with the justification that the system should encourage gas development in remote areas of Alberta. By doing so the Board, at least implicitly, made the decision that it was worth sacrificing the stand-alone cost test for the sake of this other policy objective. Over time, with the development that has occurred, the justification for the cross-subsidy embodied in postage-stamp

ously supplying all three is obviously most economical, and would require that each user pay \$3.67 million on average (one may pay less than \$3.67 million, but then the other two will have to pay more than \$7.33 million, or (\$11 million - \$3.67 million), violating the stand-alone cost test. In any case, one pair of buyers will end up being assessed for more than their \$7 million stand-alone costs. So there will be a pair of buyers who will prefer to build their own system rather than paying their share of the total system costs. The core is empty, as it requires that the stand-alone test hold for all coalitions as well as individuals.

5/ One condition for the core to be non-empty is that the cost function be concave in the sense defined in Young (1994) and discussed below.

rates has much less force and now might discourage development elsewhere or encourage excess development in remote areas.

Moreover, it is not clear how strong are the merits of a system that creates incentives to develop facilities in regions that would otherwise not be economically viable. Basic economic principles imply that any subsidies embodied in the postage-stamp regime are not justifiable on grounds of economic efficiency. Even if remote regions were economically viable, the effect of a uniform postage-stamp system is effectively to tax production in low-cost, not-so-remote areas and subsidize production in remote, high-cost areas. Both the tax and the subsidy create deadweight losses. This is because regions with above-average costs produce at higher-than-optimal (*i.e.*, efficient) rates, while those with below-average costs produce at lower-than-optimal rates.<sup>6</sup>

There are a number of other fairness criteria that policy makers might wish to apply in allocating costs. Below we describe several which have been analyzed and discuss some of their implications. One fairness criterion that most would agree is desirable is that equals bear equal cost shares. So if two firms affect system costs in the same way, they should be allocated the same costs. In addition, this *symmetry* condition requires that the cost allocation be invariant to the labelling of the firms and to the order in which users are added to the system. One significant objection to imposing a symmetry requirement is that, in some cases, an asymmetric cost allocation will induce some to stay on the system and contribute to total costs in excess of stand-alone costs, whereas a symmetric scheme will lead to bypass. Thus, the symmetry condition can conflict with the stand-alone cost test.

Three other fairness and reasonability properties that cost-allocation rules should satisfy are a decomposition principle, a monotonicity principle, and consistency. The *decomposition principle* requires that each user bears an equal share of the costs of the compo-

nents it uses. It also implies that no one should have to contribute to portions of the system that they do not use at all. In other words, only those who use some components should have to pay for them. *Monotonicity* implies that as total costs increase, allocated costs should also increase, or at least not decrease. *Consistency* in cost allocation says that the principles used in determining cost shares for the entire set of users should apply equally to subsets of users.

In combination, the decomposition principle and symmetry have strong implications for cost allocation. They essentially nail down a unique allocation in which everyone benefitting from a component pays essentially the incremental costs of satisfying their demands.

The fairness criteria we have listed above satisfy the condition that they continue to apply as the environment changes. However, they do sometimes conflict, and different sets of criteria imply different cost-allocation rules. In what follows we try to outline what, in our view, are some of the more important criteria, and explain potential conflicts and their ramifications.

In particular, we consider two cost-allocation rules that have been well analyzed in the economics literature: the nucleolus and the Shapley value. These are two alternative views of what constitutes an ideal cost-sharing rule. Subsequently (Section V), we explain how these two ideals can be applied to determine pipeline rates.<sup>7</sup>

#### *IV.1 The Nucleolus: Consistent, Symmetric, and Homogeneous Cost Allocations*

The *nucleolus* is derived from a set of axioms. In particular, the nucleolus is the *unique* cost allocation that is: (a) symmetric, in that it treats equals equally and does not change when agents are re-labelled, or when the order in

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6/ A technical appendix, which illustrates the economic losses associated with uniform tolls, is available from the authors on request.

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7/ Under certain circumstances, setting rates using "Ramsey prices", in which rates are inversely proportional to the elasticity of demand for pipeline use, will be efficient. However, as noted by Young (1994) and by Lewis (1949), Ramsey prices are inherently inequitable since they penalize those with least resort to alternatives. This aspect also makes Ramsey prices politically unpalatable. They are not discussed in this paper.

which they are added to the system is changed; (b) passes through costs directly incurred by shippers; (c) is homogeneous, in that if all costs go up or down by some proportion,  $\alpha$ , all users' cost allocations go up or down by the same proportion  $\alpha$ ; and (d) is consistent for sub-groups of the entire set of pipeline users.

The nucleolus can be calculated by splitting the costs equally among the users of a common facility, or a portion thereof. It is essentially the cost allocation that is the mid-point of the core. The nucleolus also has the property that it maximizes the cost savings of the group of users that has the smallest cost savings among all possible groupings of facility users.

The notion here is that various individual or groups of users of a system may enjoy various degrees of savings in using it. For example, a large-scale user may obtain fewer economies of scale or scope in relation to the relevant stand-alone costs compared with those obtained by a small-scale user (at least on a per-unit basis). The nucleolus maximizes the savings enjoyed by those enjoying the least advantage from being in the system compared with the best alternative available for that grouping. The main problem with the nucleolus is that it is not *monotonic*. What this means is that the cost share of a user could fall even though he were using a component of the system whose costs have increased.<sup>8</sup>

#### IV.2 The Shapley Value: Symmetric, Additive, and Monotonic Cost Allocations with No Cross-Subsidies

The Shapley value yields another cost-allocation

8/ This problem could be overcome by the *per capita* (or *per user*) nucleolus, which is also the maximum of the series of cost savings for all possible groupings of users and which will be monotonic. However, it is not consistent. Consistency is an important criterion when, for example, in the case of a pipeline the set of receipt and delivery points is changing over time. Consistency requires that the cost allocation for any coalition not change when the cost-allocation problem is confined to one involving only those in the given group. Note, too, that neither the nucleolus nor the per capita nucleolus will be easy to measure. What would be desirable is a cost-allocation rule that is relatively easily computed and satisfies the principles of consistency, homogeneity, and symmetry.

rule that satisfies many desirable properties. Like the nucleolus, the Shapley value can be derived from a set of axioms. These axioms differ slightly from those that identify the nucleolus. The Shapley value has the additional property that it is also a fairly natural extension of a simple rule that applies in special circumstances. This simpler concept, which is the *decomposition principle* mentioned earlier, roughly speaking says that a firm that uses several pieces of the system should pay a suitable share of those pieces it uses.

To apply the decomposition principle, the stand-alone cost of serving any group of users must be decomposable into the costs of the components, or the cost elements, used by that group. If the cost function were decomposable, then the decomposition principle would merely allocate the costs of each component suitably among each component's users. So, for example, if there were three firms using a given pipeline link, the decomposition principle would allocate the costs of that link in proportion to the decomposed costs among those three firms. This allocation of costs should be based on both usage and each firm's fraction of the reserve capacity for that link. In other words, the allocation of costs should be based on those factors that contribute to costs.

The decomposition principle does yield outcomes that are in the core, that is, outcomes that satisfy stand-alone and incremental cost tests. But the principle can only be applied when costs can be decomposed into elements that are additive. However, the same type of idea can be extended to cases in which the cost function cannot be decomposed so readily. The Shapley value is the resulting cost allocation. The exact expression for the Shapley value is somewhat complicated, but it essentially states that each firm will contribute an equal proportion of the total costs allocated to each possible group it could join.

More precisely, consider the incremental costs of serving a given user when that user is added to a group of users. Now, suppose that system costs are calculated incrementally when adding users to a group one at a time in a random order. The Shapley value for a given user is just the average of the incremental costs



for that user among all possible ways in which the incremental costs can be calculated for him. Thus, the Shapley value is a cost allocation for each user that is based on a measure of each user's average incremental costs.

As discussed in Young (1994), the Shapley value has a number of desirable properties:

1. It is the unique cost-allocation rule that is: (a) symmetric; (b) additive;<sup>9</sup> and (c) charges nothing to firms who do not contribute to costs.
2. It is also the unique cost allocation that is symmetric and strongly monotonic, that is, it allocates *all* users larger cost shares whenever the total costs of serving everyone increases.
3. The core of every case in which the cost function satisfies a concavity condition (that can be explained in terms of the number of nodes and the length of the links) is non-empty and contains the Shapley value.

The conditions that the cost-allocation rule is additive and charges nothing to users who do not impose costs on the system constitute, what some would view, an important fairness condition. Suppose, for example, that a system component (sub-system) were built exclusively to serve one small group of users. These fairness conditions essentially imply that no one outside that group would have to bear any of the costs of that sub-system. Symmetry, as we have discussed above, requires equal treatment of firms that contribute equally to costs and have equal usage. The concavity condition, can be also expressed as a *submodularity condition*, and essentially means that the costs of serving two groups plus the stand-alone costs of serving those who are in both is less than the sum of the stand-alone costs of each of the groups. When costs are concave, the incremental costs of adding users at new receipt points or delivery points will be decreasing.

The Shapley value has one significant drawback in that it need not be in the "core." In other words, the Shapley value need not satisfy the stand-alone cost test that we discussed

above. However, the Shapley value has two advantages: (1) it always exists; (2) it identifies a unique cost allocation.

## V. Implementation Issues

### V.1 Implementation of the Shapley Value

The nucleolus and the Shapley value provide benchmarks for devising a toll system which best approximates, as much as is practical, fairness and reasonableness standards. Neither can be directly applied with ease. To use either of them requires that some possibly costly administrative procedures be set up to impute incremental costs for each shipper, receipt meter station, and delivery sales station.

To appreciate how a multi-zone system, in which tolls are based on the zones corresponding to pipeline receipt and delivery points, can approximate the theoretical benchmark of the Shapley value, it is useful first to describe the steps that would be needed to implement it. We focus our discussion on implementing or approximating the Shapley value, although most of it applies to the nucleolus as well.

In cases where costs can be decomposed, it is relatively straightforward to compute the Shapley value. It is possible that costs can be decomposed in an appropriate manner for many pipeline projects. In such cases, the use of the Shapley value or the decomposition principle would eliminate the need for debate about whether rates should be based on the average distance to the delivery or the receiving point. The Shapley value would impose costs on those firms that use the relevant components of the network. Debate might still occur as to how to measure incremental costs. However, the Shapley value would essentially evenly divide costs of components shared by multiple gas producers or shippers. And all incremental capacity costs would be directly allocated to those shippers on the basis of for whom that capacity was constructed.

### V.2 Pitfalls in Implementing the Shapley Value

The Shapley value is a theoretical ideal. For large and complex pipeline systems it is likely

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<sup>9</sup>/ A cost allocation is additive when, if two users or groups of users are combined, the cost allocation for these users is the sum of the individual user cost allocations.

to be difficult to apply directly. Here, we describe some of the difficulties in applying the Shapley value, and provide some suggestions for surmounting them. One problem, which we have noted above, is that the core need not exist, and even if it does, the Shapley value need not be in it. In such instances, there would be groups of pipeline users who would wish to break away to avoid the cost allocations imputed to them by the Shapley value.

Circumstances change, and so at some points in time the Shapley value will be in the core and at others it will fall outside of it. Changes are always occurring in the potential demands placed on the system. It would be helpful if the cost-allocation rule were to remain viable for any likely scenario. The Shapley value, which always exists, can always be imposed; however, coalitions would, at times, have incentives to break away. How likely, or how often, this would occur is an empirical question.

Another problem in implementing the Shapley value, even in a simple case in which costs are decomposable, is in measuring the incremental costs attributable to each user. The appropriate way to decompose and attribute costs is likely to be in terms of the capacity planned for each user. To appreciate the ease, or difficulty, that would be encountered in attempting to impute costs based on the Shapley value, it is useful to examine the types of cost attribution required. This will, in part, help guide how best to implement a cost-sharing rule in practice.

Incremental costs are based on the planned capacity requirements that drive them. Direct costs — the costs of actually moving the commodity in the transmission system — based on the fairness principles embodied in the Shapley value would be directly passed through. Indeed the decomposition principle, in conjunction with the principle that shippers imposing no costs on the system (or separable portion thereof) are not allocated any costs, requires that direct costs be passed through. Thus, implementing the Shapley value would require separation of direct costs, which are passed directly through, from common or joint costs. And then the common capacity costs, or

the costs of building the capacity to meet projected demand, would be allocated among users.

Of course not all capacity need be used, and not all anticipated demand need be realized. Conversely, in other instances, more demand may be placed on the system than anticipated. It is also the case that there could be considerable differences in the percentage of anticipated throughput that would actually occur. This means that some users would effectively have reserved more capacity than they needed and others less. Unused capacity could then be traded on a capacity-release market among the potential users. Such a market would alleviate potential shortages and enhance the efficiency and utilization of the system.

On the administrative side, there is a question of how to go about measuring component costs and capacity costs. In particular, use of the Shapley value requires that incremental capacity be imputed for each user. It could be difficult to obtain such measures based solely on accounting data. Accounting data are not intended to report the calculations made in capacity planning. Such calculations would be needed to reconstruct fully the capacity costs for each cost element. In particular, it can be difficult to reconstruct precisely how capacity planning and investment decisions were based on projected demands and to decompose those plans on an incremental basis. The best that might be possible is to allocate costs proportionally to what were the initial projections of demand or requests for services. Of course, those data might not be available, and then actual usage averaged out over some appropriately lengthy period would probably be the most appropriate procedure.

### V.3 Practical Solutions

The discussion above indicates that it would likely be difficult to allocate costs based on the Shapley value. This is not to suggest it would be impossible, but rather more that it would be less practical the greater the complexity of the network. The Shapley value is difficult to explain. However, for simpler systems, or com-

plex ones that have been aggregated in zones, the Shapley value essentially reduces to the cost allocation determined by the decomposition principle, which is reasonably straightforward. So, to a large extent the practicality of the Shapley value will depend on the degree of cost decomposability and on the extent to which costs can be aggregated.

There would likely be difficulties in applying the Shapley value or decomposition principle to a complex system arising from a large number of pipeline delivery and receipt nodes. One example is the NGTL system in Alberta. Here there are a plethora of receipt and delivery points with a great deal of common costs. In such a case, it would be more practical to aggregate various sets of users which are similar in some dimension, such as geographic proximity, and then to employ a weighted version of the Shapley value to the groups in partitioning the entire set of users. Such weighted versions of the Shapley value would continue to satisfy many equity conditions as well. This also leads to the notion of zonal charges.

Breaking up the system into zones, so that all users who share more or less equally in the use of the system contribute equally to its costs, can approximate tolls that would be determined by the Shapley value. In other words, the average distances for shippers who use many of the same facilities can be used to determine the tolls. So, if two shippers require use of transport facilities through some region, the average distance of transport, as well as the cost per mile or kilometre of the facilities, can be used to set tolls, or charges, for shipments in, through, or out of that zone.

## **VI. Other Equity and Efficiency Concerns**

The cost-allocation rule used in setting tolls for a pipeline system has an effect on user incentives to participate, to bypass, and to invest in the development of new and existing fields. Here we discuss how these factors can affect the optimal design of a cost-allocation scheme.

### *VI.1 Incentive Compatibility for Shippers and the Pipeline*

One specific problem that is typically a concern of regulatory agencies when allocating costs is the fact that the costs allocated to a firm might not exceed that firm's stand-alone costs (and therefore satisfy the stand-alone and incremental cost fairness criteria) and yet exceed the firm's willingness to pay. For example, a gas producer might prefer to shut down some wells rather than pay its allocated share of the costs of serving those sites, and yet be willing to pay the incremental costs for the pipeline to provide service to those wells. The regulatory authority will not generally know the gas producers' minimum or "choke" prices, nor will the authority know the incremental costs of providing service to each receipt point.

The notions of fairness and efficiency embodied in the incremental cost test imply that the cost allocation should not establish tolls in such a way that a user ever faces a cost allocation exceeding his willingness to pay when that willingness to pay is more than his incremental costs. Additionally, the system operator should face incentives to provide service to every gas producer whose willingness to pay exceeds the incremental costs of service. However, these fairness and efficiency goals typically cannot be fully realized in practice. A regulator will not know each shipper's "choke" price, that is, there is incomplete information. In addition, the pipeline company will not know that price either. Similarly, neither the regulator nor the shippers will know the pipeline company's costs.

The optimal tariff scheme will maximize fairness and efficiency goals subject to incentive compatibility and constraints, that is the pipeline and the shippers will respond to the tariff rule so as to maximize their own objectives (such as long-run profits) given their costs (which are known only to them). However, a toll system which meets these incentive-compatibility conditions imposes tolls, which in some cases will deter the pipeline from providing service to wells where willingness to pay exceeds incremental costs. This follows because in practice the regulatory au-

thority will not know the willingness to pay, choke prices, or incremental costs, and neither the pipeline nor the gas producers have much of an incentive to report these values accurately. So, rather than over-pay the pipeline, the regulator might, for instance, wish to allow some situations to arise in which some gas that should be shipped is not.<sup>10</sup>

There is a sizable literature on these types of incentive problems. Price-cap and incentive-regulation schemes are designed, in part, to provide a utility operator with the appropriate incentives under regulation to provide service to every user for which incremental costs are less than willingness to pay. Such pricing flexibility will typically lead to distance-sensitive tolls.

Additionally, some incentive schemes that can be implemented present each user with a menu of choices. The choices would effectively allow each user to reveal its valuations.<sup>11</sup> These mechanisms need not satisfy many of the fairness criteria discussed above. However, it is also the case that the participation constraint, that tolls not exceed choke prices because the cost allocation assigns them too large a cost share, might not be a pressing issue when transport costs are a relatively small share of the total costs of marketing gas.

### *VI.2 Static and Dynamic Efficiency*

Another concern is that any cost-allocation result be as efficient an outcome as possible. Trade-offs between efficiency and equity can arise. In choosing between policy measures it is useful to keep both in mind, and certainly options that adversely affect both efficiency and equity should be avoided.

In terms of static efficiency, one of the main concerns is that gas be delivered to users at

minimum total costs — including extraction and shipping costs. A postage-stamp scheme, or any other cost-allocation scheme that is not distance-sensitive, will effectively cross-subsidize output from remote and more costly sites (as already noted). Moreover, non-distance-sensitive cost-allocation mechanisms, and any other cost-allocation mechanism that provides cross subsidies, have effects on investment incentives that could accentuate welfare losses from cross subsidies over time.

For example, cross-subsidization of remote sites at the expense of nearby ones could lead to increasingly larger output at the remote sites than would have been the case without subsidies. Without a cross subsidy, a firm might invest in new facilities in a location closer to delivery points than would be the case if a cross subsidy existed. This means that the social cost of extraction and delivery will be higher than optimal in the long run. The short-run effects of the postage-stamp scheme will simply tend to alter extraction rates between facilities, but could also cause some locations that should remain open to shut down.

### *VI.3 Complexity*

Strict adherence to many of the principles discussed above can impose significant costs on both the regulatory agency and the pipeline. However, the principles do have practical value. For instance, as noted above price-cap schemes are, in some sense, simplified incentive-compatible mechanisms. Similarly, a simple system of zonal changes can be used to approximate the Shapley value or the nucleolus. The practical problem facing a regulatory agency is to balance theoretical performance with administrative and compliance costs arising from possible complexity.

## **VII. Summary**

We have examined various ways in which a fair and reasonable pipeline cost-allocation scheme can be implemented. Uniform charges such as those reprinted by postage-stamp cost allocations will not usually satisfy most concepts of fairness and reasonableness. In addi-

---

10/ Other concepts of fairness, such as those embodied in the Shapley value, or a desire to subsidize development in some regions over others, can also conflict with the application of the incremental cost test.

11/ It has been shown that mechanisms can be constructed that are: (a) efficient; (b) incentive-compatible; (c) individually rational (*i.e.*, pass a stand-alone cost test); and (d) allocate costs exactly. See Young (1994).

	Fairness and Equity Criteria					
	Symmetry	SAC/IC	Decomposable	Determinable	Monotonic	Consistency
Postage Stamp	Y	N	N	Y	Y	N
Nucleolus	Y	Y	N	Y	N	Y
Shapley Value	Y	Y	Y	Y	Y	Y

Notes: SAC/IC = Stand-Alone/Incremental Cost Tests; Y = Yes; N = No.

tion, postage-stamp cost allocations can result in inefficient production patterns and in inefficient bypass.

We have argued that cost allocations should pass a stand-alone cost test and an incremental cost test. In other words, no one should pay costs in excess of their stand-alone costs and no one should pay less than their incremental costs. These criteria can rule out many obvious cost allocations, such as postage-stamp rates, but do not identify a unique outcome.

We then proposed that a cost allocation in which each party pays its proportional share of the parts of the network it uses would meet most of the criteria for fairness and reasonableness considered. In particular, such a cost scheme would be symmetric, in that it would treat equals the same, pass through direct costs, be consistent when the set of users and load patterns change, and be monotonic, in that no one's cost share could fall if total costs were to increase.

We explained how such a rule might be implemented. The main difficulty is in determining the appropriate manner in which to decompose the cost elements when there is no

direct contract between the parties at the receiving node and the delivery node. In such cases, those involved in determining the tolls at the two ends would need to identify which system components are being used to provide service to the parties involved. We argued that a system of zonal charges can approximate the ideal cost allocation, and can involve much lower administrative costs. Our results are summarized in the table (above).

One of the cost-allocation methodologies, the postage-stamp scheme, fails to respond to more than half the six fairness and equity criteria considered. The nucleolus responds favourably to four of these six criteria, while the Shapley value will in most cases address all six.

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 4**  
**ATTACHMENT C**  
**COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED**  
**GAS SERVICES**

**COST ALLOCATION AND RATE DESIGN FOR  
UNBUNDLED GAS SERVICES**

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## **EXECUTIVE SUMMARY**

About half of the state public utility commissions (PUCs) in the United States have introduced unbundling of gas services for residential and commercial customers. Most of these states currently offer pilot choice programs for a selected sample of small customers for a limited number of services. A number of states have introduced state-wide unbundling and choice for all customers, and for a relatively larger menu of services.

The success of the unbundling programs depends critically on the accompanying regulatory policy choices. Among the policy choices, allocation of costs for unbundled gas services and designing of end use tariffs have significant impacts on whether and how much customers benefit from the unbundling process. Regulators face the twin tasks of facilitating a market for services that are believed to be competitive or potentially competitive, and adjudicating fair and reasonable rates for the remaining services. To perform these tasks, regulators are confronted with decisions about which services to unbundle, how to allocate and separate costs of unbundled services, which services to deregulate, and how to establish rates for regulated services.

To assist state regulators in developing rate-making policies for unbundled gas services, this report provides a comprehensive study of these issues. The report examines considerations that would dictate the identification of services to be unbundled and identifies services that can be unbundled. It provides overviews of cost allocation, cost separation, and rate design principles, and discusses how these principles can be applied to the design of rates for unbundled gas services. It also provides a comparative evaluation of alternative cost separation and tariff design options, based on selected criteria of regulatory



objectives. Finally, the report offers recommendations on rate-making policy options for unbundled gas services.

The study focuses on the application of the principles of cost allocation, cost separation and end-user tariff design to unbundled gas services. It discusses how the traditional rate design process needs to be changed to address the rate design of unbundled services (see Figures ES-1 and ES-2).

The study concludes that no combination of cost separation and end-use tariff design options can be unambiguously recommended to state regulators.

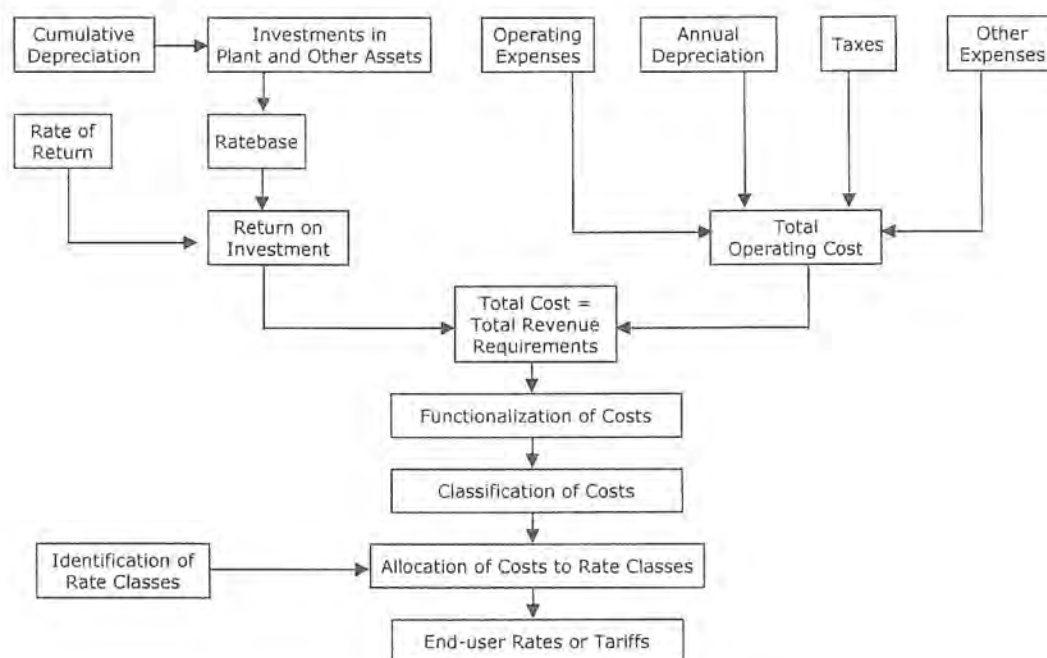


Fig. ES-1. Overview of the traditional rate design process.  
Source: Author's Construct.

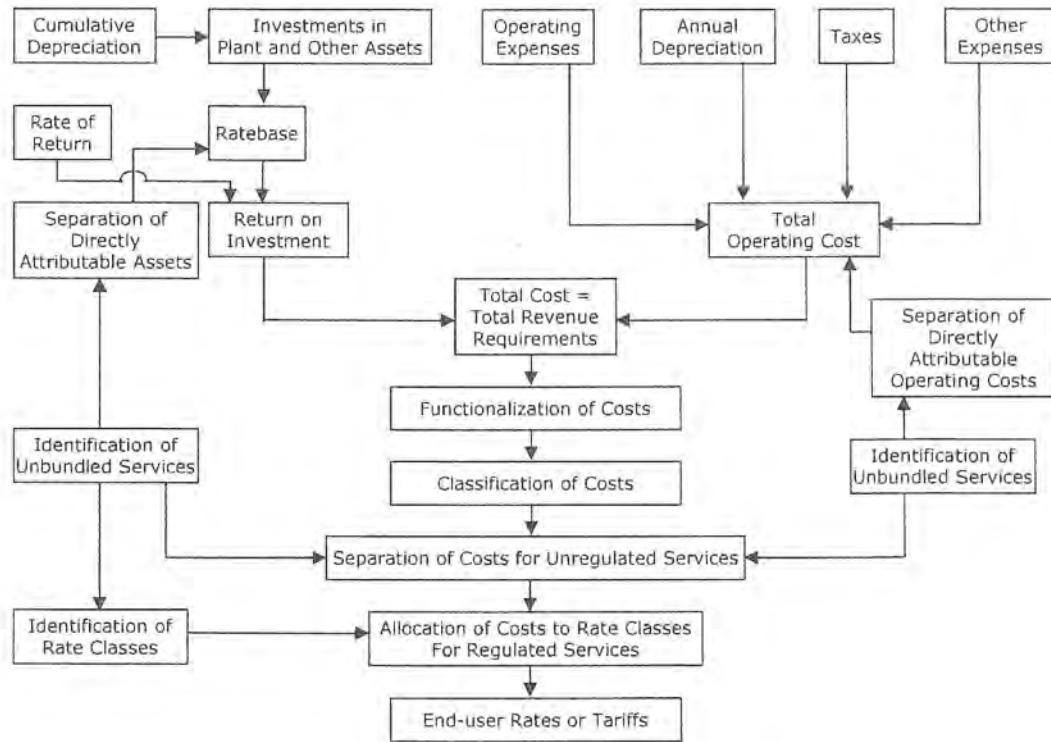


Fig.ES-2. Overview of rate design under unbundling.  
Source: Author's Construct.

The reason for this is that no unique combination of options has all the desirable properties to satisfy most of the regulatory objectives. For example, some options may be economically efficient but inhibit competition. Also, the public interest compulsions and preferences of each PUC may be different, and the desirable set of options for one PUC may be an inferior choice for another. The study proposes a strategic framework that can help the state regulator evaluate alternative cost separation and end-use rate design options compatible with actual conditions and the regulator's policy preferences.

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## **FOREWORD**

Gas unbundling has become a major area of interest for state public utility commissions (PUCs). Of particular concern are the methods available for cost separation and rate design. This report provides a comparative evaluation of these methods, based on longstanding regulatory objectives. It is hoped that this report will assist PUCs in their ongoing efforts to restructure the retail gas market.

Sincerely,

Raymond W. Lawton  
Director, NRRI  
April 2000

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Errors that may remain are, of course, the responsibility of the authors.



## CHAPTER 1

### INTRODUCTION

This report provides a comprehensive study of the issues related to the cost allocation and rate design of unbundled gas services, and presents policy options for state regulators.

#### Background

Over the last two decades, the gas industry has been moving toward a increasingly competitive regime, characterized by greater unbundling of gas services and expanded customer choice.<sup>1</sup> Starting with the deregulation of wellhead gas in the late seventies, the industry has moved through unbundling of the gas commodity and transportation services of the interstate pipeline, to unbundled gas services at the retail level offered by the local distribution company (LDC).

LDCs started offering unbundled transportation and gas commodity services to large customers in the mid-eighties. Over the years, large customer retail unbundling has proliferated. Beginning in the mid-nineties, pilot programs to unbundle gas services for small customers were adopted in a few state jurisdictions. The unbundling process has generally exhibited the following patterns: (1) services are unbundled first at the upstream segment of the gas

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<sup>1</sup> Whether or not the gas industry is actually transformed into a truly competitive regime depends critically on the interaction of state regulatory policies and industry players.

delivery system followed by unbundling at the downstream segments, and (2) large customers are offered unbundled services first followed by similar offerings for smaller customers. At the time of writing this report, twenty-one states and the District of Columbia have introduced either small customer pilot programs or broader customer choice programs. Utilities in eleven states have provided or are in the process of providing all of their customers with the ability to purchase their gas from a nonutility supplier.<sup>2</sup> Table 1.1 shows the current status of residential pilot programs and unbundling initiatives.

### Overview of Issues

The emergence of retail unbundling warrants a policy response from state regulators. The introduction of retail unbundling and customer choice by themselves do not guarantee efficiency benefits.

Regulators face the twin tasks of facilitating a competitive market for gas services that are believed to be competitive, and adjudicating fair and reasonable customer rates for the remaining services. To perform these tasks, regulators will be confronted with decisions about which services to unbundle, how to separate the costs of unbundled services, which services to deregulate, and how to establish rates for regulated services.<sup>3</sup>

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<sup>2</sup> Broader customer choice has been introduced in California, Georgia, Iowa, New York, Ohio, and Pennsylvania. Utilities in Maine, Massachusetts, Montana, New Mexico, and Oklahoma are in the process of introducing broader customer choice. See American Gas Association, *Providing New Services to Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives: Issue Brief 1999-05*.

<sup>3</sup> Most states that have unbundled gas services have chosen not to significantly adjust revenue requirements or rates. However, as more services (other than gas commodity) get unbundled or when the next rate cycle begins, changes to revenue requirements and rates are likely.

*COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES*

Table 1.1: Residential Pilot Programs and Unbundling Initiatives

State	Company	Potential # of Homes	Potential Demand (Bcf)	In-service Date	Pending or Completed Government Action*
Arizona					Commission Docket
California	Pacific Gas & Electric	3,454,000	190.9	8/91	CPUC rulings issued,  State law delays further residential choice until 2000
	San Diego Gas & Electric	68,000	3.6	8/91	
	Southern California Gas	455,000	24.0	In-Service	
Colorado					State law passed; allows utilities to voluntarily file customer choice programs
Connecticut					PUC hearings held; draft study
Delaware	Conectiv Power Delivery	14,500	1.4	11/99	
Dist. of Columbia	Washington Gas	130,000	17.3	1/99	
Georgia	Statewide	1,538,000	127.7	11/98	State law passed
Illinois	Central Illinois Light Co.	10,000	1.5	10/96	ICC hearing
	Nicor Gas	250,000	18.3	1999	
	Peoples Gas Light & Coke	20,000	7.0	11/97	
Indiana	N. Indiana Public Svce.	150,000	18.3	05/98	URC study completed
Iowa	Statewide	770,000	87.8	2/99	IUB rulemaking
	MidAmerican Energy	875	.1	11/95- 10/96	
Kansas					Legislation introduced; NOI
Kentucky	Columbia Gas of Kentucky	124,000	11.9		Proposed legislation
Maine	Northern Utilities				State law; PUC inquiry
Maryland	Baltimore Gas & Electric	525,000	52.5	11/97	PSC recommendations issued
	Columbia Gas	29,000	2.9	11/96	
	Washington Gas	100,000	10.0	11/96	



*COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES*

State	Company	Potential # of Homes	Potential Demand (Bcf)	In-service Date	Pending or Completed Government Action*
Massachusetts	Bay State Gas	83,000	8.0	11/96	Unbundling collaborative workshops
	Boston Gas	479,000	46.0	11/97-2000	
Michigan	Battle Creek Gas	1,000	.1	04/97	PSC hearings held; legislation pending
	Consumers Energy	300,000	42.8	04/98	
	Michigan Consolidated Gas	1,078,000	162.0	04/97	
	SEMCO Energy	23,500	3.8	04/99	
Minnesota					PUC working groups; PUC inquiry closed
Montana	Great Falls Gas	22,600	2.4	09/99	State law, PSC proceeding
	Montana Power	120,000	13.0	Winter 1999	
Nebraska	KN Energy	100,000	22.0	6/98	Localities regulate utilities
New Jersey	Statewide	2,196,000	192.0	12/99	State law
New Mexico	Public Ser. of New Mexico	361,000	28.5	12/97	
New York	Statewide	4,048,000	404.8	In-Service	PSC regulations issued
Ohio	Cincinnati Gas & Electric	360,000	30.0	10/97	State law passed
	Columbia Gas of Ohio	1,150,000	143.8	04/97	
	Dayton Power & Light	25,000	3.1	Pending	
	East Ohio Gas	1,034,000	129.3	04/98	
Oklahoma	Oklahoma Natural Gas	670,000	59.0	05/98	Proposed rulemaking
Oregon					issued statement of PUC objectives
Pennsylvania	Statewide	2,453,000	262.5	7/2000	State law
South Dakota	Mid American Energy	54,000	5.4	1995	
	N.W. Public Svc	33,000	3.5	1995	

#### COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

State	Company	Potential # of Homes	Potential Demand (Bcf)	In-service Date	Pending or Completed Government Action*
Virginia	Columbia Gas of Virginia	26,000	2.5	12/97	State law
	Washington Gas	58,000	5.6	07/98	
West Virginia	Statewide	362,432	36.0	1986	State law
Wisconsin	Wisconsin Gas	23,532	24.0	11/96	PSC report
Wyoming	KN Energy	10,000	.9	06/06	PSC study completed
	Questar Gas	19,000	1.9	1999	
TOTAL		22,728,439	2,219.8		

Source: American Gas Association, *Providing New Services to Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives: Issue Brief 1999-05*, November 30, 1999 and *Gas Utility Report*, December 31, 1999.

### Identifying Services To Be Unbundled

Choosing a service to be unbundled entails two major issues: whether it is (1) *operationally feasible* and (2) *economically beneficial* to offer the service separately.

For a service to be unbundled, it must be operationally feasible to offer it independently of other services. This means that there are no physical or engineering constraints (such as system safety) that would preclude a service from being unbundled. Further, it must be economic to offer the service separately. In other words, the cost savings from providing the service separately must offset the increase in transaction costs and foregone economies of scope of previously bundled services.

## Separating Costs of Unbundled Services

One of the most thorny issues state regulators and LDCs will face is how to separate costs of different unbundled services. The separation has to be accomplished through the use of one or more cost allocation mechanisms. Generally speaking, the separations process can be divided into two broad categories: (1) separation of investments and (2) separation of operating and other expenditures.

Costs of investments or values of assets used to provide an unbundled, deregulated service will have to be allocated to the service. The cost or value of the asset have to be determined and subtracted from the regulated asset base of the LDC. Such a determination involves choosing among competing methodologies (historical vs. replacement cost, alternative methods for depreciation rates and economic lives, and so forth) to calculate value or cost. For an asset that is used to provide multiple services, one needs to choose a method (fully distributed, incremental, stand-alone) to allocate the cost or the value of the asset to a particular service.

Likewise, the operating costs, previously aggregated for different services, have to be separated and allocated to each unbundled service. While some costs can be directly attributed to specific services, many of the costs are common or joint among services. As is true for investments, one needs to choose a method (fully distributed, incremental or stand-alone) to allocate common or joint costs to a particular service.

The allocation of investments and operating costs are subject to another degree of difficulty if an unbundled service is to be deregulated. For regulated services, it may be possible to treat certain common costs using some



accounting contrivance, such as using a separate account for chosen categories of common costs, and imposing a common charge on all users that use the related services. For a deregulated service that shares costs in common with a regulated service, such an option is not viable. In such a case, the choice of cost allocation methodologies and the treatment of data become very critical.

### *Deregulating An Unbundled Service*

The decision to deregulate a service is predicated on a judgment on whether the service is currently or potentially competitive. This requires an examination of the characteristics of the service (economies of scale, economies of scope with other services, sunk costs, etc.) and the characteristics of the relevant market (market share, barriers to entry, etc.). Services that are judged to be clearly and currently competitive (such as gas commodity) can be immediately deregulated and opened to market competition.

Among the remaining services, some may have a natural monopoly character (such as local distribution) while others may be potentially, but not currently, competitive (such as gas peaking service). Services with a natural monopoly character will continue to be regulated. A potentially competitive service may continue to be regulated until workable competition develops, at which time it may be deregulated.

### *Designing Rates for Unbundled Regulated Services*

Monopoly services will continue to be regulated to meet traditional regulatory objectives (e.g., economic efficiency, reliability of service, equity among parties and social goals). The regulator has the choice of using either

traditional (cost-plus) or performance-based rate-making mechanisms, or some combination thereof, to accomplish these objectives. For potentially competitive services, the rate-making policies need to be crafted and implemented to facilitate ultimate development of full competition, besides accomplishing traditional regulatory objectives.

The rate design of unbundled gas services, with associated regulatory ramifications and policy options, confronts the regulator with difficult and complex challenges. One of the challenges is to balance conflicting regulatory objectives and interests. For example, there may be a conflict between providing cost-minimizing incentives for a currently regulated, but potentially competitive, service and facilitating competition for the service. Although the balancing of conflicting objectives and interests is hardly new to regulators, the current transition toward gas industry restructuring and unbundling introduces perhaps an order magnitude increase in those difficulties.

### Objectives and Organization of the Study

This study attempts a comprehensive examination of issues related to the pricing and rate design of unbundled gas services. To this end, it discusses the identification of services to be unbundled, examines allocation of costs among services, and evaluates alternative rate design options. This study is intended to assist state regulators in evaluating rate unbundling schemes.

Chapter 2 of this report provides an overview of the rate unbundling process. First, the rate design process for traditionally bundled services is summarized. Next, issues introduced by unbundling are discussed and necessary revisions to the traditional rate design process are examined. Finally, the rate bundling process is summarized. Chapter 3 provides a discussion on



the identification of unbundled services. Chapter 4 provides an in-depth examination of allocation and separation of costs for unbundled services. Chapter 5 provides an examination of end-user rate design concepts and schemes. Chapter 6 provides an evaluation of cost allocation and rate design schemes. Chapter 7 summarizes the findings of this study, draws conclusions based on the findings, and offers policy recommendations for state regulators.

## CHAPTER 2

### AN OVERVIEW OF THE RATE UNBUNDLING PROCESS

The mechanics of rate design for unbundled services (also referred to as rate unbundling) are fundamentally and conceptually similar to those for the traditionally bundled services. However, the rate unbundling process may require additional cost allocation and cost separations analyses to account for the unbundling of previously bundled services. To develop a basic framework for rate unbundling, it may be helpful to review the traditional rate design process, examine implications introduced by unbundling, and introduce the needed revisions or adjustments for an unbundled rate design process.

#### Traditional Rate Design Process: Review of Basics

The traditional rate design process is shown in Figure 2.1. The process consists of the following steps.

- Determination of total costs and revenue requirements
- Functionalization of costs
- Classification of costs
- Identification of rate classes
- Design of end-user rates

## COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

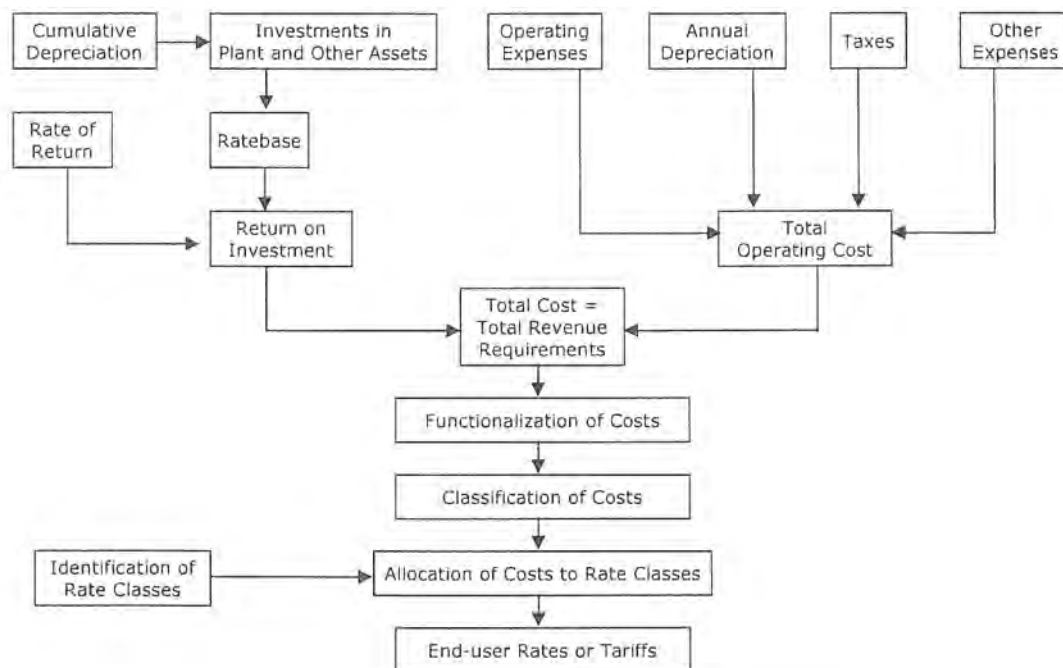


Fig. 2.1. Overview of the traditional rate design process.  
Source: Author's Construct.

*Total revenue requirements* are the total of all costs incurred by the utility in providing its services, and is authorized to recover from its customers. For purposes of determining revenue requirements, the costs are grouped into capital, operations and maintenance, and administrative, and taxes. The revenue requirements, or the total cost of service, is the sum of the return on undepreciated capital investment and all other expenses.<sup>1</sup>

<sup>1</sup> The standard equations for revenue requirements are:

$$RR = (RB) * r + E + D + T + O \quad \text{and} \quad RB = (PV - CD)$$

where RR = revenue requirements; r = allowed rate of return; RB = rate base; E = operating expenses; D = annual depreciation; T = taxes; O = other expenses; PV = plant value (investment in plant); CD = cumulative depreciation.

A utility is required to maintain detailed accounting records of its costs. The major accounting categories include plant, operating expenditures and taxes. Each major accounting category has a number of subaccounts. The gas plant category, for example, may include land and land rights, structures and improvements, boiler plant equipment, field compressor station structures. For purposes of rate design, costs from different accounting categories are grouped into different operating functions, such as production, transmission and distribution. This process is known as *functionalization* of costs.

The costs of each functional category are then classified by their consumption or cost causation characteristics. The *classification* criteria include demand (capacity), energy (commodity), customer and revenues. Demand-related costs, such as the capital cost of reserving capacity on an interstate pipeline, generally correspond to maximum system demand or maximum system capacity (in thousand cubic feet or Mcf). The energy related costs, such as gas procurement costs, correspond to the total consumption volume over a specific period of time (in Mcf). Customer-related costs, such as costs of metering and billing, correspond to services dedicated to customers. Revenue-related costs, such as gross receipts taxes and certain administrative overhead costs, correspond to total sales over a specific period of time (in dollars).

Customers are divided into *rate classes* for purposes of allocating costs of service and designing rates. A rate class is defined by characteristics that are common to all members of a class. Factors that have been used to define a rate class include: (1) size, (2) customer type, (3) type of usage, (4) firmness or interruptibility of service, (5) load factor, and (6) access to alternatives.<sup>2</sup> These

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<sup>2</sup> United Nations, *Gas Distribution Rate Design Manual* (New York: United Nations, 1995).



defining factors or criteria are not mutually exclusive and may have various degrees of overlap.

Size refers to the total volume of use over a time period or rate cycle. The size factor, for example, distinguishes the large commercial customer from the small commercial customer.

Customer type refers to types of buildings and other physical facilities for which gas service is used, as well as some demographic characteristics. The broad customer types include residential, commercial, industrial, electric utilities, and government. Residential customers may be further subdivided by demographic characteristics, for example, into general residential customers, senior citizens and low income customers.

Type of usage refers to various end-uses of gas that include space heating, lighting, air conditioning, electricity generation and industrial processes. For example, residential customers may be divided into space heating and non-space heating customers.

Firmness or interruptibility of a service is a well-known criterion to define a rate class. Because firm customers require a full commitment of service up to their peak demand, the utility must acquire and pay for firm capacity. On the other hand, interruptible customers do not require such a commitment, and therefore cost much less to serve.

Load factor is an index of a customer's consumption pattern and is defined as the ratio of average consumption to peak consumption. Low load factor customers, such as residential and small commercial customers, tend to have a spiked consumption pattern, characterized by high peak consumption relative to their average consumption. High load factor customers, on the other hand, tend to have a flatter consumption pattern, with their peak consumption closer to their average consumption. Load factor is an important determinant of cost allocation. It generally costs more to deliver a unit of energy to a low load factor customer

than to a high load factor customer. The reason is that the low load factor customer imposes a relatively high capacity cost on the system and this cost needs to be recovered from fewer units of energy.

Access to alternatives refers to the fact that some customers may have alternative fuel capability or access to nonutility providers for their gas services.

A rate class is generally defined by a combination of two or more of the above criteria. For example, a rate class may be defined as "firm capacity, industrial" or FCI. Another rate class may be defined as "space heating, residential" or SHR.

Once costs have been classified by cost causation criteria (e.g., demand, energy), and rate classes have been defined, the costs are *allocated* to each rate class. Certain costs can be allocated by direct assignment. For example, the cost of installing a meter on a customer's premises can be assigned directly to the customer. For costs that are not directly assignable, costs are allocated on the basis of the contribution of each rate class to each cost causation category.

For example, the cost of procuring gas is classified as a commodity cost. To determine the contribution of the FCI rate class to the commodity cost, one can compute the ratio of the volume of gas consumed by the FCI class to the total system consumption. This ratio is then multiplied by the total cost of gas procurement to find the allocation of the commodity cost to the FCI class. This method of allocating costs is known as the fully distributed cost (FDC) method. Alternative cost allocation methods can also be used to allocate the commodity cost. Similar allocation of costs can be done for demand, customer, and revenue-related costs.

Certain types of costs are particularly difficult to allocate. They are common costs and joint costs. Common costs are those which are incurred in common while providing multiple services, and generally involve the use of a



common facility. Common costs are characterized by a congestibility or capacity constraint feature. For example, a gas main is used to serve several classes of customers, and the amount of service that can be provided is constrained by size. Therefore, its operating and maintenance costs constitute common costs.

When provision of one service leads to the automatic provision of another as a by-product, the underlying cost is a joint cost. For example, when a utility serves its system peak demand, it also serves demands below peak.

Allocation of common and joint costs is difficult and often contentious. The most well-known method for allocating common and joint costs is the FDC. The FDC method assigns this cost on the basis of relative demand of each rate class. Using the noncoincident peak (NCP) method, for example, the capacity cost allocated to the FCI class would be the ratio of the FCI peak and the system peak multiplied by the capacity cost. The coincident peak (CP) method uses the ratio of FCI demand on the day of the system peak to allocate the same cost. Table 2.1 shows an example of a cost of service analysis with functionalization, classification, and allocation of costs.

The last step in the rate design process is the *design of end-user rates* or tariffs. The generic rate is a combination of a fixed charge per accounting period (e.g., month) and a volumetric charge per unit of service (e.g., Mcf). The fixed charge corresponds to the fixed costs allocated to the rate class and generally reflects capacity costs. The volumetric charge corresponds to the variable costs allocated to the rate class and generally reflects energy or commodity costs. Both the fixed charge and the volumetric charge may also incorporate customer and revenue-related costs. However, either the fixed charge or the volumetric charge may incorporate costs that are not truly reflective of the corresponding fixed and variable costs allocated to a rate class. For example, prior to the issuance of Order 636 by the Federal Energy Regulatory Commission (FERC), interstate pipelines charged customers according the modified fixed-variable

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 2.1: Cost of Service Analysis

Function	Classification with Allocation Methods				
	Demand	Commodity	Customer	Specific	Revenue
Production & Gas Supply					
1. Gas Supply	CP	Mcf or Therms			
2. Storage	CP	Seasonal Mcf or Th			
3. Liquefied Nat Gas	CP	Seasonal Mcf or Th			
4. Propane	CP	Seasonal Mcf or Th			
Transmission					
5. Compressor Stations	CP	Mcf or Th		Spec Assign	
6. Mains	CP	Mcf or Th		Spec Assign	
7. Regulatory Stations	CP	Mcf or Th	Spec Assign		
Distribution					
8. Compressor Stations	NCP				
9. Mains	NCP		No. of Cust.	Spec Assign	
10. M&R Stations	NCP		No. of Cust.	Spec Assign	
11. Services	NCP		No. of Cust.		
12. Meter & Install			Wgt. Cust		
13. House Reg & Install			Wgt. Cust		
14. Imd M&R Stations				Spec Assign	
15. Cust. Install				Spec Assign	
Other					
16. Customer Accts			Wgt. Cust		
17. Sales Expense			Wgt. Cust		
Revenue					
18. Revenue from Sales					Revenue
19. Revenue Taxes					Revenue

Source: American Gas Association, *Gas Rate Fundamentals* (Arlington, Virginia: AGA, 1987), 142.

<u>Key</u>	CP: Coincident Peak	Spec Assign:	Special Assignment
	Th: Therms	No. of Cust:	Number of Customers
	NCP: Noncoincident Peak	Wgt. Cust:	Weighted Number of Customers



(MFV) tariff, in which the variable part of the tariff incorporated certain components of the fixed cost (rate of return and taxes). In theory, the rate design can vary anywhere between the extremes of a pure fixed charge (with no volumetric charge) and a pure volumetric charge (with no fixed charge), as long as the tariff for a rate class recovers costs allocated to that rate class.<sup>3</sup>

In most PUC jurisdictions, the fixed charge includes part of the demand costs and customer costs, and the variable charge includes the remainder of the demand and customer costs, plus commodity costs in full.

Besides tariffs with defined components, LDCs often offer special tariffs that depart from fully distributed costs. Such tariffs may be designed to meet social objectives such as low income assistance, local employment and energy conservation. For example, increasing block rates may be offered to low-income customers, although actual costs may decline with the volume of consumption. Further, industrial customers may be offered a flexible volumetric rate for interruptible service that varies between a rate floor (set at short-run incremental cost ) and a rate ceiling (set at FDC). Such a tariff generally results in a lower bill for the relevant customers and presumably promotes local employment by preventing such customers from relocating to a different service jurisdiction.

Although end-user rates are designed to recover the costs (i.e., revenue requirements) allocated to a rate class, the revenues actually recovered may deviate from projected allocations. The resulting deficit or surplus may be subjected to a truing up process and adjusted in the rates for the next rate period.

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<sup>3</sup> The merits and demerits of different tariff designs are discussed in Chapter 6.

### Changes to the Rate Design Process Introduced by Unbundling

As mentioned above, the basic mechanics of rate design under unbundling are similar to those for a traditional rate design process. The major change introduced by unbundling is the incorporation of additional cost allocation and cost separations that correspond to the unbundling of services. Throughout the rate design process, it may be necessary to reallocate and separate costs of unbundled services from the previously bundled ones.

Two basic approaches may be used with respect to adjusting the rate design process to account for unbundling of gas services. The more comprehensive approach, or the top-down approach, calls for repeating a traditional cost of service analysis with adjustments to steps that are affected by unbundling. The alternative approach, or the bottom-up approach, starts the adjustments at the tariff design level and moves up as necessary and appropriate.

Figure 2.2 provides an overview of the rate unbundling process using the top-down approach. The bottom-up approach can be understood as one that starts the process at the bottom box of Figure 2.2 and may terminate at any of the boxes preceding it. To date, most of the state commissions have used the bottom-up or *ad hoc* approach, which is simpler to implement and more appropriate for pilot programs. As state commissions move toward full choice programs, or when they reach the next rate cycle, the use of the top-down approach is more likely.<sup>4</sup> The following sections explain the different steps of the rate unbundling process using the top-down approach.

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<sup>4</sup> See, for example, the Georgia program; Atlanta Gas Light (AGL) filed for adjustments to revenue requirements, customer cost allocations, allocation of costs between AGL and its affiliate, and end-use tariffs.

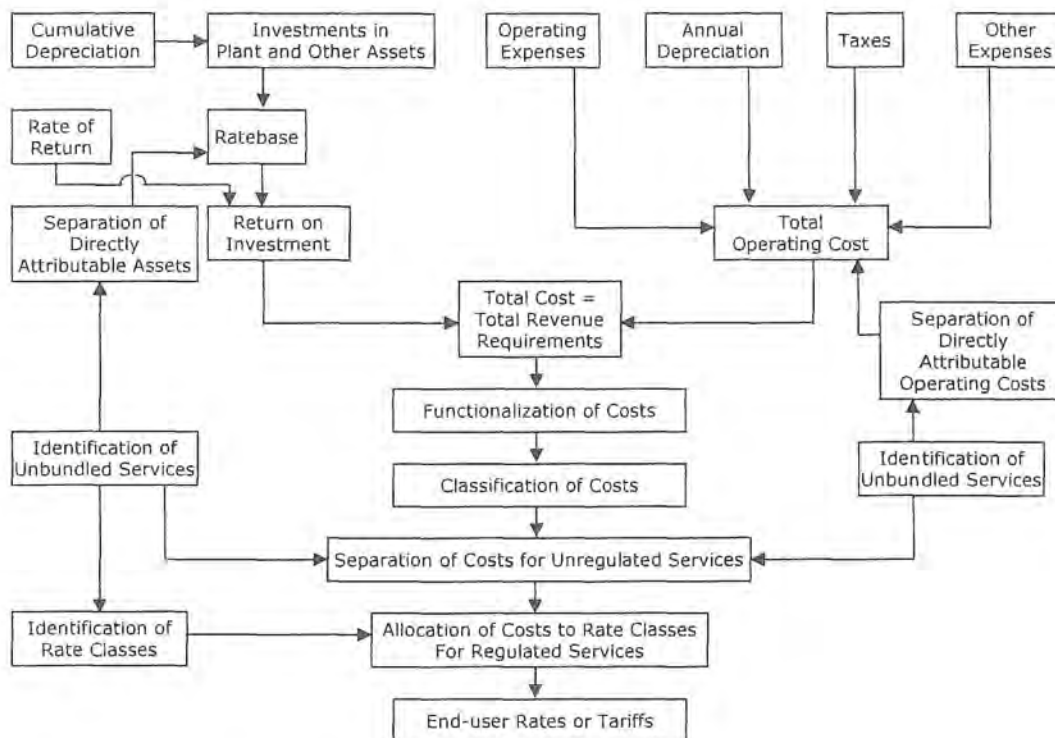


Fig. 2.2. Overview of rate design under unbundling.  
Source: Author's Construct.

## Identification of Services to be Unbundled

An important step in the rate unbundling process is the identification of services to be unbundled. Until recently, rate unbundling has meant the unbundling of gas commodity and gas transportation services. As of the writing



of this report, unbundling of a wider scale with a greater differentiation of services has been introduced by a few jurisdictions.<sup>5</sup>

### Determination of Total Costs and Revenue Requirements

As a certain service is unbundled, the gas utility either stops providing the service, or provides the service at a reduced volume. Therefore, there is a corresponding reduction in the total cost of service, and the total revenue requirements of the utility. If an asset is no longer used in providing a service, the corresponding capital costs can be removed from the rate base. If certain operations of the utility are discontinued or reduced, there needs to be a corresponding reduction in the operating cost component of the revenue requirements.

Some of the above cost separations may be straightforward. For example, if the utility sells a upstream storage facility because it is no longer needed to provide commodity gas, the corresponding capital costs are excluded from the utility's rate base,<sup>6</sup> and related operating costs are excluded from the utility's operating costs. Other cost separations may be more complex. For example, if the utility holds upstream capacity rights on an interstate pipeline on an unexpired contract, and there is a reduction in the use of the capacity because marketers choose to purchase capacity from another party, the treatment of this "stranded capacity" in the utility's revenue requirements poses difficult policy and

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<sup>5</sup> *Gas Utility Report*, December 31, 1999.

<sup>6</sup> A related issue would be whether the asset should be valued at market price or original cost for purposes of cost separations. If original cost valuation is chosen, the treatment of the difference between original cost and market price may be an issue.

methodological questions. Such questions can only be addressed by a combination of regulatory judgment and careful cost allocation analysis.

One component of the revenue requirements that is likely to be significantly affected by the unbundling process is the rate of return. As some of the unbundled services are competitively provided, one expects an increase in the rate of return for the corresponding investments to reflect an increase in risk and the cost of capital. Also, there might be a reduction in the market risk of "backbone" monopoly services, as competition may stimulate increased consumption of gas services that use such services. The result may be a reduction in the cost of capital and rate of return for certain monopoly services. The overall rate-of-return for the utility would depend on the net effect of unbundling on the rates of return of individual services.

### Functionalization of Costs

Generally, the functionalization of costs under an unbundling regime would be similar to that in a traditional rate design process. However, it might be possible to subdivide functional categories to facilitate separation of costs for unbundled services. For example, the functional category, interstate transmission capacity, may be divided into interstate capacity-marketers and interstate capacity-utility. Also, new functional categories may have to be introduced to reflect new operations that the local utility undertakes to deliver unbundled services. One such possible function might be standby storage to help the utility meet its obligation to serve or supplier of last resort requirements.

### Identification of Rate Classes

Under unbundling, traditional rate classes would undergo three different kinds of modifications: (1) attrition, (2) subdivision and (3) regrouping.

*Attrition* would happen to those customer classes that experience a decline in the number of customers and volume of service received. For example, the number of customers receiving firm gas commodity service would decline as some of these customers opt to receive this service from alternative providers.

*Subdivision* of a rate class may be necessary when the customer class in question rearranges itself by size and by consumption characteristics because of unbundling. For example, the traditional rate class of small distribution customers would be subdivided into utility customers and choice customers.

Also, it may be possible to subdivide a traditional rate class by such usage characteristics as delivery pressure and seasonal consumption. Finally, traditional rate classes may need to be *regrouped* under unbundling. For example, traditional large customers of distribution services, such as industrial customers may be regrouped into the same group as the new large aggregators, particularly if they have comparable load factors. Each of the reclassifications of rate classes under unbundling may have significant cost allocation and rate design consequences. A major reason for defining new rate classes for unbundling is to allocate the fixed costs associated with competitively offered services between customers taking the service from the utility and those that are not.



### Allocation of Costs

Allocation of costs to redefined rate classes can proceed as in a traditional cost allocation process. However, part of the cost allocation process will be used to separate costs for those services that are no longer provided by the utility, for example, gas procurement. Consequently, such costs will be excluded from the utility's total costs of service and total revenue requirements. The remaining services will continue to be subject to rate regulation. An issue arises with regard to fixed costs, particularly how they should be allocated and whether they become stranded costs.

### Design of End-User Rates

The end-user rate design for an unbundled service may vary, based on which of the following categories it may fall under.

- Services that are currently and clearly competitive and are provided only by nonutility providers
- Services that are currently and clearly competitive, and are provided by both the utility and the nonutility providers
- Services that are potentially competitive and are provided by only the utility
- Services that are potentially competitive and are provided by both the utility and nonutility providers
- Services that are monopolistic and are provided by only the utility

Clearly, competitive services that are provided only by nonutility providers require no further examination. Such services will be deregulated and opened to market pricing.

Individual PUCs may allow some competitive services to be provided by both the utility and nonutility providers. The reasons may include concerns about reliability, insufficient development of the market for alternative providers, and a policy preference for letting the local utility compete with other providers. For such services, the regulatory policy options may vary between traditional cost plus rate-making to complete deregulation of rates. Regulators may opt for cost plus rate-making if they have reasons to believe that the market is insufficiently developed for the services in question, that the utility enjoys market power or incumbency advantages, and that total deregulation of prices may lead to an unregulated monopolistic pricing of such services. At the other extreme, if regulators believe that the market for such services is fully developed and that the local utility has no market power or incumbency advantages, then such services are likely to be completely deregulated. Other options may include price caps for core customers, price floors for noncore customers, and tying either the price cap or the price floor to a market index based on the unregulated prices charged by nonutility providers. All of the above options, except total deregulation, are likely to be temporary for a transition period until such time when the market becomes fully developed and the regulators have sufficient confidence to deregulate the prices of the services.

Potentially competitive services that are provided only by the utility will continue to be rate-regulated until an adequate number of alternative providers enters the market. As discussed later, such services will be regulated in the same manner as regulated monopoly services. One concern that will guide regulators in designing rates for such services is the minimization of entry barriers for nonutility providers and the encouragement of competition.



#### *COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES*

Potentially competitive services that are provided by both the utility and nonutility providers will also be rate-regulated in a manner similar to competitive services. In regulating such services, regulators will probably take into account any market power and incumbency advantages of the local utility. Regulators may lean toward designing cost separations and rates that offset some of the incumbency advantages of the local utility.

Finally, regulated monopoly services will continue to be rate regulated. Regulators have the option of choosing either traditional cost-plus regulation or some form of performance-based regulation to regulate such services.

## CHAPTER 3

### IDENTIFICATION OF SERVICES TO BE UNBUNDLED

#### Introduction

Traditionally, the LDC provided a package of bundled services consisting of two primary services, gas commodity and gas transportation, plus a host of ancillary and customer services. The ancillary services included storage, peaking, load balancing and related services. The customer services included meter reading, billing, customer service centers, customer premises services, and related services. The LDC acquired the resources for providing these services and packaged them as a single unbundled service to the ultimate customers.

Over the last decade and a half, gas commodity and gas transportation were offered as separate, unbundled services to large customers. The ancillary and customer services still remained bundled with the primary services, gas commodity and transportation. Unbundling of a wider scale with varying degrees of differentiation of services have been introduced in some states that are experimenting with unbundling pilot programs. In these pilot programs, primary services are unbundled further into ancillary and customer services and offered to a selected group of small customers. Some LDCs and their state commissions are now contemplating expanding the pilot programs into full-scale customer choice programs. Such programs will include both a full unbundling of services and a full offering of such services to all customers.

One of the critical issues surrounding unbundling of gas services is the level of differentiation to be achieved in unbundling a gas service. To address this issue, certain technical and economic considerations apply.

#### Technical Considerations for Unbundling a Gas Service

For a service to be provided separately, it must be technically and operationally feasible to do so. Operational feasibility means that the service in question does not have safety and reliability implications through inter-dependencies to other operations and services of the utility system. In other words, the service in question should be capable of being provided independently of one or more of the other services. Further, providing the service separately should not impact the integrity, reliability and safety of the gas delivery system. Therefore, the utility may need to retain complete control over certain systems to maintain these system performance criteria, which may be jeopardized by allowing separate provision of the related services. Finally, there might be some services that could be provided separately but over which the LDC must retain overall control. For such services, either the alternative provider must operate through a reliable coordination mechanism with the LDC, or the LDC alone should be allowed to provide such services.

#### Economic Considerations for Unbundling a Gas Service

There are two possible economic benefits of unbundling a gas service. *The first benefit arises from letting each customer choose a menu of services,*



according to her needs.<sup>1</sup> Not every gas customer needs every service included in the bundled package currently provided by the LDC. By letting the customer choose those services that she needs, the LDC and other market providers can produce the optimal quantity of the desired services (e.g., risk management services), and efficiency losses related to production of unneeded services are minimized. *The second benefit arises from the fact that some of the unbundled services can be provided competitively.* The competitive provision of such services are expected to achieve efficiencies that were absent in traditional cost-plus regulation.<sup>2</sup>

Unbundling of gas services can introduce new costs. These costs consist of (1) an increase in transaction costs, and (2) lost economies of scope. A customer, for example, may incur search costs in learning about marketers who never before served that customer or any customer of the local utility. In addition, a customer purchasing unbundled gas services from different providers may prevent cost savings from one entity providing all of the services.

A related issue, is the level of demand for an unbundled service. The volume demanded for an unbundled service may be so small that the increased transaction costs and lost economies of scope of unbundled service largely exceed any anticipated efficiency gains. *In other words, the actual or anticipated demand may be below the "critical mass" to justify unbundling a service.*<sup>3</sup> This is one reason why almost all the unbundling and customer choice programs

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<sup>1</sup> The menu of services may include price-risk management options.

<sup>2</sup> Competition induces two different kinds of efficiency: "allocative efficiency" that causes resources to be allocated to their best uses, and "X-efficiency" that minimizes wasteful use of resources.

<sup>3</sup> Jack Zekoll, New York Public Service Commission, private communication, 1999.

#### COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

introduced so far have a minimum number of customers or minimum volume requirement for unbundling the gas commodity service. The same requirements would also apply for unbundling other services. Table 3.1 summarizes the characteristics of an unbundled service in terms of costs and benefits.

To be economically justifiable, the efficiency benefits of unbundling must be able to more than offset the increased transactions costs and lost economies of scope. Meeting this criterion, in turn, hinges critically on whether the deregulation of certain unbundled services results in true competition. Otherwise, one could have a scenario in which unbundling and deregulation would increase costs in three ways: increased transactions costs, lost economies of scope, and the efficiency and consumer-welfare costs of *unregulated monopolistic markets*. It is hoped that with careful shepherding of the gas market from a regulated regime to a mostly deregulated one by state commissions and the FERC, this scenario will not occur.

Table 3.1: Criteria for Unbundling a Gas Service

Characteristic	Correlation
Transactions costs	—
Economies of scope with other services	—
Actual or anticipated demand	+
Competitiveness	+
Regulatory costs	—

Source: Author's construct.

Key: — Indicates costs of unbundling increase with increase in magnitude of this characteristic  
+ Indicates benefits of unbundling increase with increase in magnitude of this characteristic



A related question is whether a competitive market exists, or will develop, for a deregulated, unbundled service. The economics literature characterizes the competitiveness of a market by two broad categories of tests. The market tests include an examination of market concentration indices, barriers to entry and the cost of exit. The product tests include an examination of economies of scale and the presence of close substitutes.<sup>4</sup>

The market tests obviously can be applied only to an already existing market. For example, the U.S. Department of Justice investigates whether changes in market concentration, introduced by a merger or an acquisition, would result in the development of monopolistic conditions in an already existing competitive market. Barriers to entry, and costs of entry and exit are other market indices that can be used to judge the competitiveness of a service. Baumol and others have proposed that a market with free entry and costless exit is "contestable" and exhibits the same efficiency characteristics as a competitive market, regardless of whether it has a high market concentration or not.<sup>5</sup>

For markets that do not already exist, the product tests can be applied to assess the competitiveness of a potential market. For example, if a service exhibits economies of scale, it is well-known that it satisfies the so-called natural monopoly condition. Deregulating such a service would result in an unregulated

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<sup>4</sup> For reviews of the economics literature on competitiveness of markets, see John Horning et al., *Evaluating Competitiveness of Markets: A Guide For Regulators* (Columbus, OH: The National Regulatory Research Institute, 1988) and David Chessler, *Determining When Competition is "Workable": A Handbook for State Commissions Making Assessments Required by the Telecommunications Act of 1996* (Columbus, OH: The National Regulatory Research Institute, 1996).

<sup>5</sup> William J. Baumol, John C. Panzar, and Robert D. Willig, "Contestable Markets and the Theory of Industrial Structure," (New York: Harcourt Brace Jovanovich, 1988). For an opposing view, see William G. Shepherd, "Contestability vs. Competition," *American Economic Review*, 74, 4 (September 1984).

monopoly market. Most economists would argue that such a service ought to be regulated. One example of such a service is local gas distribution. Table 3.2 summarizes some of the characteristics that are relevant in evaluating the competitiveness of an unbundled gas service.<sup>6</sup>

### **Applying the Economic Criterion to Identify an Unbundled Gas Service**

The analysis needed to apply the economic criterion that the economic efficiency benefits of unbundling and deregulation exceed the sum of increased transaction costs and lost economies of scope, is beyond the scope of the current study, and has not been attempted. Such an analysis would require access to company-specific data. In fact, such an analysis can reasonably be done only by an LDC. This report does not propose that such an analysis should necessarily be required before making decisions about unbundling a service. However, the economic criterion is suggested as an analytical standard that be used by state commissions to examine the choice of services to be unbundled. The criterion also can probably be used to monitor the success of unbundling programs.

Although it may be difficult to apply the above economic criterion, to candidate unbundled services, as well as to any aggregate package of services, it may be possible, for example, to estimate the cost of each unbundled service individually (the stand-alone cost), and also to estimate the cost of their joint provision. The difference, if any, can provide an indication of the lost economies of scope to the LDC. Further, one can estimate the transaction costs of bundled

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<sup>6</sup> The characteristics are based on the authors' judgment of factors affecting the competitiveness of services. These factors are in line with economic theory.

Table 3.2: Some Examples of Competitiveness of Unbundled Services

Characteristics	Correlation with Competitiveness	Examples
Numerous existing buyers and sellers	+	Commodity gas
Few existing buyers and sellers	-	Most services except commodity gas
High economies of scale	-	Local distribution
Low economies of scale	+	Commodity gas, meter reading, billing, peaking
High entry costs	-	Local distribution, interstate capacity
Low entry costs	+	Meter reading, billing
High sunk costs	-	Local distribution, most services that include building of facilities
Low sunk costs	+	Most services that involve reselling or using existing facilities
Brand loyalty	-	All services

Source: Author's construct based on a qualitative evaluation.

services and the sum of transactions costs of individual unbundled services. The difference would be an indicator of the increase in transactions costs due to unbundling. Furthermore, one can estimate the cost savings due to reduction of certain services in response to customer choice. However, this estimation, unlike the previous estimations, can only be done *ex post*. The service-use data



from pilot customer choice programs can help develop this estimation. Finally, one needs to estimate the efficiency gains, because of competition, from a deregulating an unbundled service. This estimation, like the previous one, can also be done only ex post. The data on estimated savings for a service, from customer choice pilot programs, can be used to develop this estimate.

### Deregulation of Unbundled Services

Services which are clearly and currently competitive (based on one or more of the service characteristics or market tests) can immediately be unbundled and deregulated. Services that are clearly monopolies, and likely to remain monopolies in the foreseeable future, will continue to be regulated. There may be a class of services for which a definitive judgment cannot be made about competitiveness (or lack thereof). Such services need to be regulated until such time when a definitive determination of competitiveness can be made. The proper regulatory dispensation with regard to these services is to continue their provision under regulated rates, allow alternative providers to offer these services, establish criteria by which the competitiveness of such services are to be judged, and monitor the potential emergence of a competitive market for these services. Once such a service meets the regulatory criteria for competitiveness, it can be deregulated and opened to full market competition.

### Candidate Services to be Unbundled

The candidate services to be unbundled can be divided into two categories: (1) upstream (before the city gate) and (2) downstream (behind the city gate).

## Upstream Services

Traditionally, the LDC owned, or had access to, wellhead gas, interstate capacity, storage, and a host of ancillary services required to deliver the bundled gas service to the end-use customer. Many of these services, which will not be needed as the gas commodity service is unbundled from the LDC's local distribution service, can be unbundled and competitively provided by an alternative provider. Some of these services are competitive (e.g. gas procurement) and others have monopoly characteristics (e.g., interstate transportation). However, *the LDC is not the monopoly provider of the upstream monopolistic services*, which are regulated by the FERC<sup>7</sup>. Therefore, both the competitive and the monopolistic upstream services can be unbundled and deregulated from the LDC's service jurisdiction. The upstream services that could be unbundled include:<sup>8</sup>

- ▶ gas procurement
- ▶ pipeline transportation – firm and interruptible
- ▶ interstate storage
- ▶ nominations and balancing on interstate pipeline
- ▶ peaking on the interstate pipeline

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<sup>7</sup> The upstream regulated services also experience a certain degree of competition because of the presence of alternative providers and close substitutes. For example, interstate transportation faces competition from secondary transportation markets.

<sup>8</sup> Although the unbundling of upstream services as well as downstream services (see the following section) may be technically feasible, it may not be economically feasible. Further, many of these services may be repackaged or bundled together by marketers, aggregators, and other entities.

## Downstream Services

The LDC generally owns and operates the facilities that are used to provide the downstream, or behind-the-city gate services. Under regulation, the LDC traditionally has been the monopoly provider of these services. Except for local transportation, the downstream services do not have any inherent monopolistic characteristics. However, a fully or workably competitive market may not exist for most of these services, but such markets may develop in the future. Most of these potentially competitive services would have to be regulated until a workably competitive market develops. Until then, the LDC could be allowed to provide these services under regulated tariffs while alternative providers are also allowed to provide the same services at unregulated prices. Some of these services may have system safety and reliability implications. For such services, either the LDC would need to retain control of the relevant operations or a good coordination mechanism would need to be developed and implemented, to ensure system safety and reliability. The downstream services that could be unbundled include:

- on-system balancing
- on-system storage
- on-system peaking
- local distribution
- metering
- billing
- customer turn-ons and turn-offs



Local distribution is the only downstream service that is clearly monopolistic. The remaining services may be competitive to various degrees and have markets that may vary between fully developed to nonexistent. The decision regarding deregulating any of these services will be contingent upon an empirical determination of a workably competitive market. Also, among these services, balancing, peaking, and customer turn-ons and turn-offs may have safety and reliability implications, which must be considered in deciding the appropriate level of control and coordination to be exercised by the LDC.

## CHAPTER 4

### ALLOCATION AND SEPARATION OF COSTS FOR UNBUNDLED SERVICES

In general, allocation of costs refers to an apportionment of costs among operations and activities of a business firm. Cost allocation is an important element in every business enterprise, and has a range of applications that include: (1) accounting for costs of inputs, (2) pricing of products and services, and (3) distribution of cost responsibility among affiliated business units.

The first two of the above applications of cost allocation have been, and will continue to be, an essential part of regulatory rate-making. The third application is likely to become increasingly relevant in the emerging market regime of unbundled and deregulated utility services, particularly if a regulated utility shares assets, facilities and operations with an unregulated business affiliate.

#### Cost Allocation: Basic Concepts and Applications

As discussed in Chapter 2, cost allocation is one of the steps in regulatory rate design, preceded by functionalization (by operations) and classification (by production and consumption) and followed by the design of end-user tariffs. In turn, the cost allocation process itself has three major steps: (1) the categorization of costs by the presence and the type of sharing among costs, (2) the categorization of costs by their variability and (3) the choice of a cost allocation technique and its application.

## Categorization by the Presence of Shared Costs

### Directly Assignable or Attributable Costs

Many of the costs of a utility is directly traceable to a service category. For example, the costs of a customer hookup and setup of facilities on a customer's premises are clearly traceable to a specific service. The allocation of costs to directly traceable services is relatively straightforward. Unfortunately, many of the costs of a utility do not belong to this category; they are either common costs or joint costs.

### Common and Joint Costs

Common costs refer to those costs that are shared because the underlying operations share a common facility, and the provision of one service constrains the provision of another. Joint costs, on the other hand, involve operations in which provision of one service leads to provision of another service as a byproduct. As a result, the provision of one service does not constrain the production of the other service, and the two services are produced in a fixed proportion. So, the distinguishing feature of a common cost is congestibility, and the distinguishing feature of a joint cost is joint or proportionate variation.

A well-known example of a common cost is the total cost of storing furniture and clothing in a warehouse. Given the capacity constraint of total warehouse space, any increase in the volume of furniture stored will diminish the space available for storing clothing. Also, the storage of either furniture or clothing does not lead to the automatic storage of the other commodity.



A well-known example of a joint cost is the cost of producing wool and mutton from sheep. If mutton is produced, wool is produced as a byproduct and the production of one does not constrain the production of the other. Also, the two are produced in a fixed proportion.

In the gas utility context, an administrative overhead cost is an example of a common cost. An administrative overhead cost, such as the total cost of billing different classes of customers, shares common facilities (e.g., computers) and operations (e.g. printouts of bills). However, if the billing-related activities increase for one group of customers, they must necessarily decrease for other groups of customers, for a given set up of facilities. This cost, therefore, satisfies the congestibility condition of common costs.

A corresponding example of a joint cost is the cost of serving customers during the peak and off-peak periods. Even though new capacity may be built to meet the coincident peaks of all customers, its use occurs across all periods.

It is easy to see that increasing the capacity to serve customers during the peak does not constrain the capacity available to serve off-peak demands. Consequently, if more capacity is built to serve peak demands, proportionately more capacity becomes available to serve off-peak demands.

### **Categorization by Variability of Output**

Costs can also be categorized by their variability in response to levels of output. Costs that do not vary when the output is varied are known as fixed costs. Costs that vary when the output is varied are known as variable costs. Well known examples of fixed costs are capital costs (including any applicable interest charges) of constructing pipeline facilities, contracts for firm capacity, fixed operating and maintenance costs, and property taxes. Well known

examples of variable costs are fuel costs, variable operating and maintenance costs, and sales taxes.

There is a general correspondence between fixed costs and demand ( or capacity) costs, and between variable costs and commodity (or energy) costs. Most fixed costs are generally traceable to demands placed on the system by customers and most variable costs are generally traceable to volume of consumption of the gas commodity by customers.

### Combining Categories

Using the above two categorizations (by the presence of sharing and by variability), one can arrive at six possible combinations of cost categories. Each combined category of cost presents a different degree of difficulty for the allocation of costs. Directly assignable costs, whether they are fixed or variable, are the easiest to allocate. Fixed costs are generally more difficult to allocate than variable costs. This is true because the level of consumption, which provides a convenient index to allocate variable costs, cannot be used to allocate fixed costs. Fixed common and joint costs are arguably the most difficult, and contentious, to allocate. The degree of difficulty in allocating a cost also depends on the choice of a cost allocation technique.

### Choice of A Cost Allocation Technique

A cost allocation technique is derived from a cost allocation principle or approach. There are three general approaches to cost allocation. Under the fully distributed cost (FDC) approach, also known as the fully allocated cost (FAC) approach, costs are allocated according to some measure of consumption



or benefit accruing to an individual or a group of customers. According to the marginal cost (MC) approach, the costs of the last unit of service are allocated to the relevant service category or customer. The stand alone cost (SAC) approach, which has been proposed as a standard to test for inter-service or inter-customer cross subsidies, is the total cost of a providing a service, when the service is provided exclusive of other services.

The cost allocation approach, in turn, is premised on chosen economic or accounting principles. In fact, the economic and the accounting approaches do not just differ on how costs are to be allocated, but also on what constitutes cost.

*Definition of Cost: Cost Allocation Implications*

In the accounting discipline, cost is viewed as the price actually paid to obtain a product or service, as and when it happens, that is the original cost. For example, the actual total amount of money paid to complete the construction of a pipeline, or alternatively, the price of purchasing one, is the accounting cost of the pipeline. This measure of original cost is what would be used as the amount (adjusted by some periodic depreciation factor over time) to be allocated to the various services or customer classes, or both. Neither the cost basis nor the depreciation factor depends on the changes in any measure of economic value over time. The cost basis would only change when another sale transaction occurs and, then, the new sale price would become the cost basis.

The economic definition of cost, on the other hand, is premised on the contemporaneous value of a commodity or service mediated by the market process between a buyer and seller. For example, the economic cost of a reserve of stored gas is not its original purchase price, but the price that the gas would command in the current market. The difference between the accounting

and the economic definitions of cost appears most clearly in the definition of two well-known concepts. The first is profit.

In accounting parlance, profit is understood as the excess of accounting revenues over accounting costs. As such, a return earned on a firm's investments constitutes its profit. But the economic definition of profit includes only earnings that are over and above the normal return on investment. In other words, a normal return earned on investment is still part of the economic cost, and only earnings in excess of this economic cost constitute economic profit. The second cost concept that distinguishes the economic formulation from the accounting formulation is the notion of opportunity cost. Opportunity cost is defined as the cost or value of the best alternative to the use of a resource or facility for producing a good or service. For example, the opportunity cost of a manager's labor is not his current salary, but the value of his best alternative earning opportunity.

The two definitions of cost have important cost allocation implications. The accounting definition relies entirely on the supply-side cost of inputs to provide a service. The economic definition on the other hand, which is based on the market value of services, must take into account demand-side considerations. For example, the consumption of a service depends both on its price and the price elasticity of customers. In allocating costs according to the economic approach, price elasticity of demand needs to be taken into account.<sup>1</sup>

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<sup>1</sup> The most well-known method that uses price elasticity of demand in cost allocations is Ramsey pricing. According to this method, costs are allocated and services are priced in proportion to the inverse price elasticity of each service class.



### Cost Causation: The Central Principle of Cost Allocation

Cost causation is the central principle for all cost allocation. This principle means that a cost is allocated on the basis of factors that cause the cost to be incurred. For example, an LDC has to invest in building distribution capacity to meet customer peak demand. There is a causal relationship between customer peak demand and investments in capacity. The investments in capacity correspond to the peak demand and, therefore, causes the investment expenditures to be incurred. It follows that the investment expenditures would be allocated on the basis of some measure of peak responsibility of different customer groups or service categories. As another example, an LDC may contract for a certain volume of gas to be transported over an interstate pipeline. The contract may specify a fixed reservation charge for capacity (for maximum take) as well as a charge per unit volume transported. There is a causal relationship between the fixed capacity charge and the LDC's peak load, and the volumetric charge and the LDC's total gas delivery. The corresponding costs may be allocated according to some measure of peak and volume responsibilities of different customer groups or service categories.

### Accounting Principles of Cost Allocation

There are several accounting principles of cost allocation, namely, traceability, variability and beneficiality.

*Traceability* is an attribute of costs that permits the resources represented by the costs to be identified in their entirety with units (some form of usage characteristics) of the service or product being provided. Not all costs may be

traceable to a unit. Cost that are not traceable, as well as those are, may vary in some fashion according to the variation of the volume of a service provided. Such costs have the attribute of *variability*. Another principle often used to allocate costs is *beneficiality*. If a service could not be provided without incurring a certain cost, the customer being served is responsible for the cost.

To illustrate the differences between the above accounting attributes, the example of costs associated with pipeline transportation services can be considered. A pipeline transportation contract generally has two components: a fixed capacity reservation charge and a volumetric charge. Both the volumetric charge and the capacity charge meet the traceability and beneficiality criteria. Costs associated with the fixed charge are traceable to demands placed on the pipeline system, and those associated with the volumetric charge are traceable to volume of gas transported. Also, if these costs were not incurred, the related pipeline services could not be provided to any customer, and therefore, meet the beneficiality criterion.

By contrast, the variability criterion is not satisfied by the capacity reservation charge, although it is satisfied by the volumetric charge. As long as the peak load of a service class remains below the system peak, the variation of load of this class does not change the cost of the corresponding service, namely the capacity reservation charge. On the other hand, the higher the volume consumed, the higher the volumetric charge.<sup>2</sup>

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<sup>2</sup> Most of the preceding and subsequent discussion of cost allocation principles and methods use customer, service or rate classes as targets of cost allocation. However, the principles and methods can be used with equal validity when no ultimate or end-use consumers are directly involved. For example, if the utility sells an asset to an affiliate, the pricing of the asset involves a cost allocation decision. Although, in this case the affiliate does not "consume" any services, the value of the asset could be determined using FDC or MC principles. In fact, a major part of cost allocation for unbundled services involves separating costs of assets no longer used or services no longer provided by the utility.



## The Fully Distributed Cost Method

The fully distributed cost (FDC) method, *based on embedded costs*, has been the method of choice in regulation. As discussed, the approach is based on the accounting definition of cost, and on the accounting principles of traceability, variability and beneficiality. The FDC method uses several techniques, each tied to the classification of the service, to allocate costs.

### Allocation of Embedded Demand or Capacity Costs

The basic methods of allocating demand costs are summarized below. There are other methods of allocating demand costs, which are variations of the basic methods.

The *coincident peak* (CP) method allocates costs a service class in proportion to its share of system peak. For example, if the system peak is  $T$  Mcf, and the firm industrial service class has a peak of  $x$  Mcf on the day of the system peak, the share of demand costs for this service class is  $x/T$ .

According to the *noncoincident peak* (NCP) method, the peaks of individual service classes are added to arrive at the composite peak (that may not coincide with the system peak). For a system consisting three service classes, with peaks of  $x$ ,  $y$  and  $z$  respectively, the costs allocated would be,  $x/(x+y+z)$ ,  $y/(x+y+z)$  and  $z/(x+y+z)$ , respectively.

The *average and excess* (A & E) method has a two-part allocation factor. The first part is the average consumption of a service class as a percent of the sum of the average consumption of all classes, multiplied by the system load factor (i.e., average system consumption divided by system peak). The second

part is the ratio of the excess demand of each service class and the system excess demand, multiplied by the complement of the system load factor (one minus the system load factor). The service class excess demand is the difference between the peak demand and the average consumption for the class. The system excess demand is the sum of all service class excess demands. For example, if the system consists of two service classes with peaks of  $p_1$  and  $p_2$  and average consumption of  $a_1$  and  $a_2$ , and the system peak demand is  $p$ , then the excess demands for the two classes are  $p_1 - a_1$  and  $p_2 - a_2$ , respectively. The system excess demand is  $(p_1 - a_1) + (p_2 - a_2)$ . The system load factor is  $(a_1 + a_2)/p$ , and its complement is  $1 - (a_1 + a_2)/p$ . Therefore, the allocator of capacity costs for the first service class is  $[(a_1 + a_2)/p] [a_1/(a_1 + a_2)] + [1 - (a_1 + a_2)/p] [(p_1 - a_1) / [(p_1 - a_1) + (p_2 - a_2)]]$ .

Each of the above three methods of allocating capacity costs can be applied to a chosen period, that may vary between a month and a year.

#### Allocation of Embedded Commodity or Energy Costs

Energy costs are generally allocated on the basis of the share of total energy consumed by a service class. Such costs may be differentiated by time to recognize the difference in costs between on-peak and off-peak hours.

#### Allocation of Embedded Customer Costs

Customer costs are generally allocated on the basis of some index of the volume of customer costs. Examples of allocators include the number of customers, the number of billing inquiries and the number of customer hookups.

### Economic Principles of Cost Allocation

As previously discussed, the economic approach to cost allocation has two fundamental differences with the accounting approach. First, the definition of cost is based on the contemporaneous market price or value, or the opportunity cost. Second, the cost to be allocated to a service or asset is based on the marginal cost or value of that service or asset. The first criterion requires the inclusion of demand-side effects in any cost allocation exercise. Both criteria make the historical or embedded cost immaterial to the cost allocation process.

#### The Marginal Cost Method

The marginal cost method calculates the cost of each unit increment of service. In contrast to the FDC method, the MC method is indifferent to the total cost of providing a service. The relevant cost, at any level of service, is the cost of the last unit of service. For example, if the system capacity has to be increased to hook up a new customer, the MC method would assign the incremental cost of the added capacity to all customers. In contrast, the FDC method would allocate a portion of the total capacity cost (sum of the cost of existing and new capacity) according to some measure of its share of the system capacity, such as the coincident or noncoincident peak. As for the FDC method, the use of the MC method to allocate costs depends on the classification of costs.



### Allocation of Marginal Capacity Costs

In the short run, capacity costs do not vary and short run marginal costs for capacity are essentially zero. Over the long run, however, capacity needs to be added to serve increases in demand. Allocation of marginal capacity costs involves two steps: calculation of marginal costs, and allocation of the costs.

By economic definition, marginal capacity costs correspond to optimal additions of capacity. Therefore, calculation of capacity costs involves optimizing the system for a given combination of existing and projected demand, and calculating the cost of additional capacity needed for the optimized system.

In theory, the cost of each additional block of capacity would be allocated to the customer whose demand would be met by the incremental capacity. In practice, however, such atomistic differentiation of capacity additions is not feasible, and capacity addition decisions are based on total capacity needs of the whole system, which consist of multiple classes of customers. Therefore, the cost allocation would be based on some measure of cost responsibility for the marginal capacity additions. Under MC pricing, customers are priced based on their total usage of the service.

### Allocation of Marginal Energy Costs

The consumption of gas varies not only by customer class and service category but also by the hour. Also, the cost of acquiring, storing and delivering gas may also vary by the hour. Therefore, the allocation of marginal energy costs of gas should take into account the time variation of gas consumption. In theory, one could track the consumption of gas by each customer at each hour



of the day and each day of the year and allocate the related costs to that customer. If we assume that each block of gas and its delivery operations cost the same at a given hour, the marginal cost to be allocated to each customer would be proportional to its share of total gas consumed during that hour. In practice, the consumption volumes of customers within a customer class may have to be averaged. Similarly, the hourly consumption data may have to be averaged across days during the work week and also days during the weekend. The final allocations would be on the basis of averaged consumption and cost data.

#### *Allocation of Marginal Customer Costs*

There are two kinds of customer costs: (1) costs that are directly traceable to a customer, such as the cost of a service drop to a customer's premises, and (2) common and joint costs, such as the cost of office space, equipment, software and personnel for customer billing, customer complaints and service calls. The first type of costs can be directly assigned to a specific customer, with MC measured in terms of current market value and FDC measured in terms of original cost. For the second type of costs, there are again two components: (1) costs that related to expansion of facilities and capabilities, and (2) costs that depend on the number of customers (or weighted number of customers), and the type and volume of customer transactions. The first type of costs is analogous to capacity costs and can be allocated using similar methods. The marginal cost is simply the cost of adding facilities and expanding capabilities. For example, if facilities need to be added to serve expanded volume of service calls, the related incremental cost is the marginal cost. This cost can be allocated in proportion to the contribution of each customer class to the system peak.

#### *COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES*

The second type of costs is analogous to energy costs and can be allocated using methods similar to those used to allocate energy costs. For example, the costs of service calls can be differentiated by the hour and each customer class can be allocated its proportionate share of these costs.

#### *Avoided Costs*

In the context of separations of costs of unbundled services, the relevant cost is the avoided cost. It is the cost that LDC does not have to incur because it is no longer providing a service (e.g., the gas commodity service if the LDC exits the merchant function) or reduces the level of a certain service (e.g. the gas commodity service if LDC continues to provide the service but at a reduced level because other providers also offer the service).

As in the case of marginal costs, avoided costs can also be divided into the short run and the long run. While avoided energy and customer costs occur both in the short run and the long run, avoided capacity costs are generally zero in the short run and occur mostly over the long run. As the LDC can avoid additions of capacity to its system because it does not provide certain services or provides them at reduced volume, it avoids related costs. One exception to this rule for time dependence of avoided capacity costs would occur if the LDC were to sell some of its assets that were used to provide a service. In this case, the LDC does not pay the carrying charges (interest, property taxes, etc.) on the related investments and, therefore, avoids short-term capacity costs.

### The Stand-Alone Cost Method

Stand-alone cost, as the phrase indicates, refers to the cost of a service if the service were provided alone, exclusive of other services. When two or more services share costs jointly or in common, the removal of all services but one from the mix would still entail the service incurring these joint and common costs.<sup>3</sup> In other words, the stand alone cost of each of the services would include the entire common and joint costs of these services. The stand alone cost of a service is generally higher than the cost allocated to this service by any other cost allocation method.<sup>4</sup> An example of a stand-alone cost is the use of separate systems of mains to each customer class. The capacity of the main to serve peak-day load is related to the volume of the pipe (area multiplied by length), while the cost is related to the pipe's circumference times its length.

The stand-alone cost is not generally used as a cost allocation method in actual regulatory or business applications. However, it serves as a theoretical benchmark specifying an upper limit on the cost to be allocated to a given service.

### Cost Allocation and Unbundling

The introduction of unbundling challenges LDCs and regulators with both a larger array of cost allocation issues and a sharper delineation of underlying

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<sup>3</sup> The stand-alone cost is the sum of directly attributable costs of a service, and the common and joint costs the service shares with others.

<sup>4</sup> On exception involves the situation where there are diseconomies of scope.



technical and policy issues. As more and more services get unbundled, LDCs will be required to analyze the underlying asset values and operating expenditures, and PUCs will be expected to evaluate the methodological correctness and policy implications of LDC submissions. Under unbundling, the cost allocation process would span three separate steps: (1) separations of costs for unbundled services that utility would no longer provide or provide at a reduced level, (2) allocation of costs among rate classes for regulated services, and (3) the design of end-use tariffs. Step 2, namely, the allocation of costs among rate classes for regulated services, has been reviewed in the foregoing section and will not be discussed further. The following sections discuss step 1, namely the separations of costs for unbundled services. Step 3, namely design of end-use tariffs is discussed in Chapter 5. Among the above three steps, separations of costs of unbundled services are a relatively new regulatory challenge in the gas utility sector;<sup>5</sup> allocation of costs among rate classes and end-use tariff design is a relatively well-developed practice under traditional regulation.

### Use of Cost Allocation in Cost Separations

The same principles, methods and techniques used to allocate costs to traditional bundled services can be used to separate the values of assets and costs of services. For example, a peak responsibility method, such as the NCP (noncoincident peak), used to allocate the costs of distribution capacity to

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<sup>5</sup> The separation of costs between inter-jurisdictional regulated services, and between regulated and unregulated services, is a relatively well-developed practice in the telecommunications sector. For a comprehensive overview, see William Pollard, *Cost-of-Service for Intrastate Jurisdictional Services* (Columbus, OH: National Regulatory Research Institute, April 1985).

regulated service classes, can also be used to separate the costs for marketers (or alternatively, "choice" customers) that purchase the distribution service. Also, because some, or many, of the unbundled services will be provided in an unregulated market, *market-value may become an important determinant in cost separations and pricing of unbundled services.*

Under unbundling, it may be useful to classify the LDC's costs into (1) upstream (i.e., before the city gate) and (2) downstream (i.e., behind the city gate) costs. This classification is particularly convenient in examining separation of costs, as most of the upstream costs are incurred in supplying the gas commodity service, a service most likely to be unbundled and provided by alternative suppliers. Also, many of the upstream services are rate-regulated by the FERC. For these services, the separation of upstream costs can be based directly on FERC-determined tariffs. The downstream costs, on the other hand, are incurred to provide local distribution service and customer services.<sup>6</sup> Local distribution service will continue be provided by the LDC and regulated while some of the customer services may be unbundled, deregulated and provided by alternative suppliers.

### Separation of Upstream Costs

As mentioned, upstream costs are incurred to provide the gas commodity service. The services that comprise the gas commodity service include gas purchasing and aggregation, interstate pipeline capacity, production and market

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<sup>6</sup> The state PUC does not have to make policy decisions regarding those upstream costs that can be based on FERC-determined tariffs. The treatment of downstream costs, on the other hand, is open to the policy choices to be made by the PUC.

area storage, parking, peaking, balancing, price risk management and title transfer. Each of the above may have up to three cost components:

- (1) financing costs or asset values if the LDC owns the underlying physical asset
- (2) contract service costs or contract values if the LDC receives the service through a contract and
- (3) operating expenditures if the LDC operates any facilities to provide a service.

### *Separation of Financing Costs or Asset Values*

An LDC may own an asset, such as a storage facility, a part of an interstate pipeline or a peaking facility. Under traditional regulation, the appropriate rate base (original cost minus cumulative depreciation) would be multiplied by the allowed rate of return to find the cost basis or revenue requirement for the facility. If a single asset were used to provide multiple services or customer groups, the appropriate FDC method (e.g., CP, NCP, A&E) for allocating capacity-related costs would be used.

Under unbundling, several possible dispensations of the asset would have to be considered before an appropriate cost allocation method can be chosen. They are:

1. The asset would be divested in its entirety because the LDC would no longer be providing the services that use the asset.
2. Part of the asset would be divested because the LDC would reduce either the volume or the number of services that use the asset.
3. The asset would be retained in its entirety because the LDC would continue to provide the services that use the asset.



### *Full Divestiture*

In the first case, the asset could be costed at either at its market value (to be determined by competitive bidding, bilateral or negotiated sale, or some other market mechanism) or its book value. If the market value is chosen as the proper cost basis, the LDC could either make a profit (if the market value exceeds the book value) or incur a stranded cost (if the market value is below the book value).

The market value option has the merit that it is consistent with economic efficiency. The demerit is that if the market value is smaller than the undepreciated book value, then the utility could face stranded costs, and regulators would have to address the proper dispensation of stranded costs. Depending on the magnitude of the costs and its impact on rates, stranded costs may or may not be a significant regulatory issue.

The book value option, for all practical purposes, is the equivalent of the market value option, in combination with stranded cost recovery. Therefore, it has all the merits and demerits of allowing regulatory recovery of uneconomic assets.

A particular case for the separation of upstream assets, in which the utility sells its assets to an affiliate, merits special attention. In this case, use of the book value option would be the most straightforward and the least controversial option. The market value option, on the other hand, provides the utility an incentive to undervalue the asset and then ask for regulatory recovery of the resulting stranded cost. By doing so, the utility minimizes the cost to the affiliate of acquiring an asset, and then passing on the residual cost (i.e., the difference between the sale price and the book value of the asset) to its monopoly customers. One way to prevent this possibility of abuse is to deny any stranded

cost recovery if the utility sells an asset to one of its affiliates. Another is to value the asset at the higher of either the book value or the market value. Either of these options eliminates the possibility of the utility manipulating the value of the asset to its or its affiliate's advantage and to the detriment of the utility's customers and the affiliate's competitors. Critics of the higher-of-book-or-market-value method contend that it is economically inefficient and does not necessarily protect customers.<sup>7</sup>

### *Partial Divestiture*

The second case can be addressed in two ways: (1) direct valuation of the partial asset or (2) valuation of the full asset and allocation of the value to the partial asset. The first option can be exercised if the partial asset is operationally and functionally separable from the full asset and can be independently put on the market. However, for a lot of utility assets, this may not be feasible and the second option would have to be exercised. From the above discussion, the second case requires a two-stage cost allocation process: the valuation of the full asset and the separation of the partial asset from the utility's rate base. Take the case of a storage facility. Under the two-stage approach, after calculating the total cost of the facility, these costs are then allocated between (say) the regulated utility and a nonregulated subsidiary.

The valuation options would be the same as for full divestiture. A market value would be established for the entire asset and a value would be assigned to the partial asset by using an appropriate cost allocation method. One problem with the market value option is that if the whole asset is not being divested, it

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<sup>7</sup> Kenneth W. Costello, "A Pricing Rule for Affiliate Transactions: Room for Consensus," *Electricity Journal* (December 1998), 59-66..



may be difficult or impossible to establish its market value. The alternative is to use the book value as the basis for allocating and separating costs for partial assets.

The allocation of costs between partial assets could be based on one of the FDC, MC or SAC methods. The following discussion assumes that  $FDC > MC$  and  $SAC > FDC$ . While these relationships arguably hold in most situations, there are exceptions. For example, with diseconomies of scope, SAC may be lower than FDC.

If the FDC method is used, one can use either direct assignment if the partial asset or any of its part is directly assignable, or one of the peak responsibility methods if the partial asset shares common or joint operations with the remainder of the asset. The latter would be true if the utility sells part-ownership of the asset to an affiliate. As a concrete example, the LDC could sell part-ownership of an upstream storage facility to an affiliate and jointly operate the facility with the affiliate. This would entail two cost separations problems. The first would be to determine the sale price and the second is the separation of costs of operation. Obviously, a regulatory commission would not approve any sale price negotiated between the utility and the affiliate; doing so would provide the utility the incentive to price the partial asset below either the normal market price or the FDC-based value of the asset. If the commission were to approve a sales value of the asset based on FDC, it could use one of the peak-responsibility methods for allocating capacity costs to apportion the value. For example, it could use the estimated percentage share of the utility's original system peak to be served by the utility as the allocation factor for the utility's part

of the asset. The separation of costs for joint operations is discussed in the next section.

Alternatively, the commission could approve an MC-based method to separate the value of the partial asset co-owned by the affiliate. The appropriate cost measure in this case would be the marginal capacity cost. Depending on the relative share of high load factor or low load factor customers between the utility and the affiliate, the marginal capacity cost could be lower or higher than the FDC-based capacity cost for the partial asset. If the regulatory commission allows the MC-based method to separate the value of the asset, the utility would have an incentive to let the affiliate acquire the relatively high load factor customers.

Finally, the value of the divested partial asset could be based on SAC. For an asset that is functionally inseparable, the SAC would be measured by creating a hypothetical asset that could provide the same services as the partial asset. Given the common or the joint nature of the costs shared between the partial and the full asset, it is likely that the stand alone cost of the divested partial asset would be larger than any cost estimate based on either FDC or MC.

Each of the methods, namely FDC, MC and SAC have merits and demerits. The FDC method has the advantage of being the traditional practice, and less difficult to measure than either MC or SAC. A disadvantage is that cost allocation according to the FDC method is inconsistent with economic efficiency, in the sense that it sends incorrect price signals to the consumer. In the particular case under discussion, the regulated services will be priced below their marginal costs, and may cause an over-consumption of these services by both marketers and end-use customers.

The use of the MC method for separation of costs of partially divested assets has the advantage that it is generally consistent with economic efficiency.



Also, use of this method minimizes the possibility of stranded costs. However, use of this method could impose a barrier to entry on firms competing with a utility or its affiliates. For example, the utility's competitors would encounter set up and initial capital costs that are equivalent to a stand-alone facility that the utility or its affiliates would not face. As mentioned, choice of an MC-based method would allow the utility to game the process to minimize the cost assigned to the divested partial asset, by allowing or assisting the affiliate to acquire a relative higher share of high load factor customers. The MC-based measure, however, can be used as a floor below which the asset could not be valued, to prevent the possibility of cross subsidization of the utility's affiliates with revenues earned by the utility from its regulated customers.

The chief merit of an SAC-based estimate of the value of the divested partial asset is that it would be comparable to what an unregulated competitor of the utility or its affiliates face to purchase or construct a functionally equivalent facility. Choice of this method would favor utility competitors even more than any estimate based on FDC methods. However, there are several disadvantages to the use of a SAC-based measure. First, estimating the SAC of a partial facility may be as difficult, if not more difficult than an MC-based method. Second, utility competitors may be able to purchase or lease the related capacity services at a cost less than the SAC from the utility or others. Costing the partial asset at SAC would offer an unduly high competitive advantage to the competitors and may encourage entry by inefficient providers. An SAC-based measure, however, can serve as a ceiling above which the partial asset would not be valued, to prevent unregulated customers from subsidizing the regulated customers and the utility competitors from earning above-normal profits, and discourage the entry of inefficient competitors.

### *No Divestiture*

The third case essentially represents a continuation of the traditional regulated service scenario. In this case, the utility's competitors and affiliates would either lease the facility or purchase the services provided by the asset, and resell or rebundle them with other services for the end-use customers. The relevant cost allocation issue is the pricing of the lease or the services. This issue is discussed in chapter 5. It should be noted here that regardless of the method chosen, the price chosen for the lease or the service should be nondiscriminatory between the utility's affiliates and alternative providers.

### *The Rate of Return*

There is another issue that needs to be addressed if any of the upstream assets are to be retained, either fully or partially, by the LDC to provide services. It is the reevaluation of the rate-of-return. The ultimate service provided by upstream assets is mostly gas commodity, which is expected to face competition. As the gas commodity service makes the transition from a regulated monopoly service to an unregulated competitive service, the market risk on the associated investments is expected to rise. As such, the investors may demand a higher return on their investments. This translates into a higher rate-of-return on investment in the upstream assets that the LDC may choose to retain. Consequently, this particular component of the total or composite rate-of-return may go up, and thereby may raise the overall rate-of-return. However, there may be other services, particularly downstream regulated services, whose market risk may decrease, warranting a downward adjustment on the rate-of-return on the investment in related assets. This effect may cause an overall



decrease in the composite rate-of-return. The overall impact on the rate-of-return will be determined by which of the effects is dominant.

*Separation of Contract Service Costs or Contract Values*

The LDC may have contracts for services with various upstream service providers including interstate pipelines, storage service companies and marketers. The LDC may choose to abandon these contracts as it either reduces the volume or the number of the services provided by the contracts. The LDC may buy out or resell the unused portion of the contract term or contracted services. The proper dispensation as well as valuation of these contracts is an issue that increasingly confronts LDCs and regulators.

There are two different options for an LDC to reassign upstream service contracts to alternative providers.

1. Mandatory assignment to alternative providers prorated by market share of customers.
2. Release of contracts to the secondary market. Alternative providers are allowed to purchase their own contracts from either the LDC, from the interstate pipeline or from the market.

If the first option is chosen, the cost of the contract, at the FERC-tariffed price, is allocated to alternative providers according to their market share of customers and there is no contested cost allocation issue. If the second option is chosen, the LDC can resell their contracts either at FERC-tariffed price or below, because of the rate-cap currently operational under FERC Order 636. If the LDC is not able to resell all of their unneeded contracts or some of the contracts are resold below FERC-tariffed prices, the LDC may be faced with

stranded costs. One option to mitigate stranded costs for the LDC would be to rebundle the capacity with other gas services and sell them in the "gray" market, which is not regulated by the FERC. To the extent an LDC is faced with stranded costs, a PUC may allow its recovery if the purchase of the related capacity contracts are deemed prudent. This may offset some of the expected savings from unbundling and deregulating some of the gas services.

The choice between mandatory assignment and market-based allocation of upstream capacity costs confronts the regulator with a difficult choice. The mandatory assignment option may foreclose potential savings to customers that could be achieved if gas marketers are allowed to purchase their own capacity from the market at prices below the FERC tariff. At the same time, this option avoids the problem of stranded costs.

On the other hand, the market-based allocation would presumably capture potential savings of using competitive or semi-competitive markets for capacity. Yet, this option could result in stranded costs to the LDC. To the extent these stranded costs could not be mitigated through market-based options such as resale in the gray market, regulatory recovery of these costs would offset the potential savings from markets for capacity. The net of costs and savings that would result from the two competing options is ultimately an empirical question.

From a purely economic efficiency point view, the preferred option would be to allow the market-based allocation of upstream capacity costs and encourage the LDC to mitigate stranded costs through resale of capacity in the gray market by providing appropriate incentives, such as allowing the LDC to retain a share of the potential profits. Any remaining stranded costs could be recovered from customers. An additional incentive could be provided to the LDC to minimize stranded costs by allowing only partial recovery of stranded costs.



Separation of Upstream Operating Expenditures

There are two kinds of expenditures to be considered. First, the LDC purchases upstream services from interstate pipelines and marketers to serve its customers. Second, the LDC owns and operates upstream facilities to serve its customers.

For the first type of services, there is essentially no need to use a cost separations process. The LDC resells these services to alternative providers and charges them the purchase prices, which are based on FERC-determined tariffs. The purchase costs of these services are part of the LDC's revenue requirements. The sales revenue from providing these services are a credit to the revenue requirements. To the extent both the purchase and sale prices are based on FERC-determined tariffs, there is no net change in revenue requirements of the utility due to upstream operating expenditures.

For the second type of services, the state regulatory commission currently has jurisdiction over their rates as long as these facilities are being operated to serve the state's jurisdictional customers. In this case, the allocation of costs would be similar to those for downstream services discussed in subsequent sections. However, if the utility chooses to sell these services to customers outside of the state's jurisdiction, it is possible that FERC will assert and gain jurisdiction over the rates charged for the services. In that case, the allocation of costs is identical to the first type of costs.<sup>8</sup>

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<sup>8</sup> In the unlikely event that the state commission asserts and gains jurisdiction over these services, the allocation of costs would be similar to those for downstream services, this issue will be discussed in detail in a subsequent section.



## Separation of Downstream Costs

A number of the LDC's downstream services are potential candidates for unbundling and eventual deregulation. They include such services as metering and billing. The separation of costs of these services can be subject to analysis similar to that done for upstream costs. The separation of costs for purposes of unbundling can be divided into two categories: (1) separation of costs for downstream assets and (2) separation of costs for downstream operations.

### Separation of Costs for Downstream Assets

The analysis of options for separating costs for downstream assets are essentially the same as that for upstream assets, and therefore, will not be repeated here. The options are briefly summarized below.

Fully divested assets could be costed at either market value or book value. Use of the market value option could result in either stranded costs or profits. If stranded costs were to occur, the state commission would have to make a choice of whether to allow full, partial or no recovery of these assets.

Partially divested assets could either be directly costed, or be subject to a two-step process in cost separations: valuation of the full asset and allocation of cost to the partial asset. The direct costing option would be feasible if it is functionally separable from the fully assets. For most assets, the partial asset is not separable and cannot be costed directly. Alternatively, the full asset could be valued at book or market value and the value of the partial asset could be based on FDC, MC or SAC. Use of FDC or SAC in estimating the cost of the partial asset would offer competitive advantages to the utility's competitors, provided

the utility is not allowed to fully recover the resulting stranded costs. Use of MC-based methods would offer competitive advantages to the utility or its affiliates. An estimate based on SAC and MC can act as a ceiling and a floor, respectively, for the cost of the partial asset.

### Separation of Costs for Downstream Operations

For the separation of downstream operating costs, three possible cases need to be considered: (1) the utility discontinues providing certain services, (2) the utility provides certain services at a reduced volume, and (3) the utility continues to provide a service at the same level. An example, such as metering service, to illustrate the above three possibilities might be helpful. In the first case, the utility would discontinue providing metering service and sell its existing meters to an unregulated metering company. In the second case, the utility continues to provide the metering service but its sales volumes decrease because alternative providers also provide metering service. The third case is a continuation of the current scenario in which a market for metering service has not yet developed. The third case does not obviously need any cost separations and will not be further discussed.

#### *Utility Discontinues Providing A Certain Service*

In this case, the separation of costs is fairly straightforward. No cost separations need to be done for operating costs because the utility neither incurs related costs nor earns related revenues. Therefore, there is no net effect on the revenue requirements that the utility needs to earn. There may be minor adjustments to costs and revenues due to the transaction costs involved in discontinuing a service. Examples of these costs include increased customer



#### *COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES*

costs due to increase in customer queries and requests, related to switching to an alternative provider, and costs involved in coordinating the transition with alternative providers. These additional costs can be treated as items separate from the costs related to the provision of the discontinued service. But for the most part, nothing needs to be done in the current rate period to separate costs, change revenue requirements or adjust rates for the discontinued service. In the next rate period, the costs of these services would be excluded from revenue requirements.

#### *Utility Continues to Provide A Certain Service At A Reduced Volume*

The separation of costs in this case is not as straightforward as the previous two cases. There are several possible methods to separate downstream operating costs. Besides the methods already discussed, namely FDC, MC and SAC, there are two other possible methods. These latter methods do not require any cost-of-service analysis. They are: no cost separations with adjustment to rates to maintain revenue requirements, and no cost separations with no adjustment to rates. All of the above methods are examined in subsequent parts of this section.

#### *No Cost Separations: Rates Adjusted to Maintain Revenue Requirements*

In this case, the utility does not incur short run variable costs associated with the reduced volume of service. The utility also does not earn the revenues associated with the reduced volume of service. Therefore, as for the preceding case, a regulatory commission may choose not to require any cost separations. Unlike the preceding case, however, there is a possibility of revenue shortfall because the utility is not able to recover the capacity costs and some of the fixed operating and maintenance costs associated with the reduced volume of

services. These costs will continue to be incurred even if the corresponding volume of services are no longer provided. Therefore, the utility would probably propose some mechanism for recovery of the revenue shortfall, or stranded cost.

There are several possible mechanisms to achieve the cost recovery. The utility could (1) adjust the rates to remaining customers of the "choice" service, (2) adjust the rates of all services, (3) adjust the rates of remaining services, and (4) adjust the rates to only the backbone monopoly services, such as the distribution service, to make the rate increase nonbypassable. Options 1 through 4 allocate a progressively decreasing share of stranded costs to the remaining customers. One can hypothesize that the above order of options also represent the degree of commission acceptability. Given the fact that almost all customer choice programs include a rate freeze on services that the customer is allowed to choose a provider, options 1 and 2 are likely to be unacceptable to a commission. Option 1 is likely to be even less acceptable than option 2 because it imposes the entire stranded cost of the given service on the remaining customers, while option 2 spreads it out among all customers of all services. Also, option 1 may be practically untenable: as the rate is increased on a service that is available from alternative providers, more and more customers are likely to switch. This may require further increases of rates to remaining customers to offset the remaining customers and lead to a "death spiral." The same effect, perhaps of a weaker magnitude, may follow from implementing options 2 and 3 as some of the services chosen for rate adjustments may also be available from alternative providers. Therefore, option 4 may not only be the most acceptable among options to a regulatory commission, it may also be the only feasible one among rate adjustment options.



*No Cost Separations: No Adjustment to Rates*

Of course, there are other options that do not require rate adjustments. As noted previously, most customer choice programs are predicated on a rate freeze or rate reduction. So, if there are no adjustments to be made to rates to meet potential revenue shortfalls to be faced by the utility, other mechanisms can be explored to compensate the utility. One possibility that has a good rationale is to allow the utility to profit from its off system transactions and keep part or all of such profits to offset its losses resulting from the reduction of volume of certain unbundled services. For example, the utility commission may want to consider allowing the utility to keep part of its profits from capacity release or "gray market" transactions.<sup>9</sup> Besides compensating the utility for its potential revenue losses, such a mechanism also provides an incentive to the utility manage its upstream capacity efficiently, and release any excess or unneeded capacity to those who value it more highly than the utility.

The previous two methods are based on no adjustments to the revenue requirements, and would be most practical for a short transition period following the unbundling of a service. The costs of service, however, should be ultimately separated for the unbundled services that the utility no longer provides, or provides at reduced volumes, most likely at the first rate hearing following the unbundling and partial or full deregulation of a service. To separate these costs, several methods are available, each of which are discussed below.

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<sup>9</sup> "Gray market transactions" are resales of bundled interstate capacity and other services in the secondary capacity market.

### *Separation of Costs Based on FDC*

The operating costs of unbundled services from the utility's revenue requirement could be based on FDC. The variable component of these costs can be separated on the basis of relative share of volume of sales between switched and remaining customers. The fixed and overhead costs, such as fixed operating and maintenance costs could be separated according to one of the peak responsibility methods.

This method is unlikely to be favored by the utility as it removes a relatively large magnitude of costs from the utility's revenue requirements. For the same reason, this method of separating costs is likely to be favored by the utility's - or its affiliate's, competitors. From an economic efficiency perspective, this is not a sound method because it distorts price signals and may encourage entry by inefficient competitors. On the other hand, it does encourage competition and arguably offsets some of the incumbency advantages of the utility.

### *Separation of Costs Based on Short-Run Avoided Costs*

The operating costs of unbundled services could be based on short-run avoided costs. The variable component of these costs for switched customers can be separated by using the difference between the total cost for serving all customers and the cost of serving customers that choose to remain with the utility. The fixed operating costs of switched customers could be separated by using the difference between the demand cost of all customers and the demand cost of customers that choose to remain with the utility.

This method is likely to be favored by the utility as it removes a relatively small magnitude of costs from its revenue requirements. For the same reason, this method is likely to be opposed by the utility's competitors. From an



economic efficiency perspective, it is a superior method as it correctly conveys price signals based on avoided costs. However, one can argue that use of this method reinforces incumbency advantages of the utility and may discourage competition.

#### *Separation of Costs Based on Long-Run Avoided Costs*

The operating costs of unbundled services could be based on long-run avoided costs. The methods to separate these costs are similar to those for short run avoided costs, except that long-run avoided costs includes costs associated with avoided future additions of capacity, and future operations. The long-run avoided costs can be found by performing a simulation of costs for a planning horizon with all customers and with a reduced number of customers and finding the difference. In the two simulations, optimal additions of capacity and optimal management of operations would have to be assumed.

This method has the same merits and demerits of the short-run avoided cost method. Further, it captures forward-looking costs of providing a service and is arguably superior to the preceding method. Whether or not this method would be acceptable to the utility or its competitors would depend on the magnitude of costs involved in the cost separations process and is ultimately an empirical question.

#### *Separation of Costs Based on A Market-based Index*

Finally, downstream operating costs could be separated using a market-based index. The avoided cost is the market price of the unbundled service times the avoided volume of service. If the prices offered by alternative providers are available to the utility or the commission, the volume-weighted average price for all providers can be used as an index of the market price. One



problem with implementing this method is that either the price offered or the volume of sales of each provider, or both, may not be available to the utility or to the commission.

This method has sound economic efficiency properties in the sense that the cost separations are based on the market value of the underlying services. If the market for the services can be assumed to be workably competitive, use of this method would convey correct price signals to the utility's customers and provide them with a rational standard to judge whether to remain with the utility or switch. Use of this method, however, may disadvantage the utility's competitors because it tends to equalize the unit avoided cost of the utility and the cost of a competitor for providing the service. Given the fact that the utility has well-recognized incumbency advantages, use of this method may discourage competition.

### Examination of Some General Issues With Regard to Cost Separations

Throughout the above discussion, there appeared a number of general regulatory policy issues that have common bearing in all the different approaches and methods for cost allocations and cost separations. These issues are examined in the following sections.

#### Economic Efficiency vs. Competition

In the context of unbundling, policy choices that tend to be economically efficient sometimes inhibit competition for a number of reasons. Economic efficiency requires that goods and services are produced at quantities and prices that maximize the social surplus. It is well recognized that the above criterion

applies only to a perfectly competitive market that is rarely realizable in practice, and that the goal of regulation is to strive for the second best. Given the above fact and the fact that the utility has incumbency advantages that allow it to impede competitors and appropriate a part of the consumer surplus, policies that meet the economic efficiency standard under a regulatory regime may harm competition, and therefore work against economic efficiency. In the previous discussions, for example, we observed that cost separations based on marginal or avoided costs are economically more efficient than those based on fully distributed costs; and yet use of marginal cost to separate costs may offer competitive advantages to the utility, or its affiliates.

One can characterize this conflict between the two strands of economic efficiency as a conflict between static, and short run, economic efficiency and dynamic, and long run, economic efficiency.<sup>10</sup> There appears to a good argument for tilting the scales in favor of a utility's competitors, at least in the beginning and transition periods of deregulating a market to "get the market up and running." If one accepts the above premise, that long-run economic efficiency is to be preferred over short-run efficiency, the level and form of leverage to be given to a utility's competitors to offset the utility's incumbency advantages becomes another challenging issue. No regulator would want to tilt the scales in favor of the utility's competitors so much that an inordinately large number of inefficient providers enter the market, and the prices offered to consumers are significantly higher than the economically efficient level, either in the short run or the long run.

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<sup>10</sup> For a discussion of static and dynamic efficiencies, see Kenneth Rose, *An Economic and Legal Perspective on Electric Utility Transition Costs* (Columbus, OH: National Regulatory Research Institute, July 1996), 30-38.

This is particularly true for those states in which customers already enjoy relatively low rates for gas services.

The regulatory challenge is to find the right balance between short-term and long-term economic efficiency and frame policies that produce the optimal pace and level of competition.

### Recovery of Stranded Costs

The issue of stranded cost has appeared in much of the previous discussions on cost allocations and cost separations. The stranded cost issue is involved in all instances in which the utility faces the potential problem of being unable to recover its embedded costs because of either a reduction of its revenue requirements caused by the use of a cost separations mechanism or because the market value of an asset is lower than its undepreciated book value.

An important regulatory challenge before a regulatory commission is whether, how and how much of, the stranded cost is to be allowed to be recovered from regulated rates. A commission may decide not to allow any regulatory recovery of stranded costs on the argument that the utility is entitled to an opportunity to recover its prudently incurred costs but not to a guarantee of such recovery.<sup>11</sup> The fact that the regulated gas utility has been operating under monopoly franchise agreement indicates that the utility has been allowed ample opportunities to recover all its costs.

On the other hand, it can be argued that restructuring of the regulated market and the unbundling and deregulation of services are events precipitated by the process of regulation, events that were beyond the control of the utility

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<sup>11</sup> Ibid., 39-72.



and events that jeopardized the ability and opportunities of the utility to recover its costs.

If a regulatory commission agrees to the recovery of stranded costs by a utility, an important issue is whether these costs are to be recovered from all customers or just the customers who have opted to leave the LDC. If the first option is chosen, the stranded cost can be uniformly distributed among all customers by imposing a surcharge on all customers. If the second option is chosen, the LDC could impose an exit fee on customers that leave the system. The exit fee could be designed to recover the LDC's stranded costs. The exit fee, however, can be at such a high level that the departing customer is either indifferent between staying and leaving the system or finds it more advantageous to a stay in the system. Such an exit fee defeats the intended goal of facilitating competition and creating a more efficient market place through unbundling and deregulating some gas services.

Between the two stranded cost recovery options, imposing an exit fee on departing customers has a better regulatory rationale. One can argue that the capacity in question was contracted to serve all customers based on prudently developed forecasts of demand. Therefore, if a customer chooses to leave the system, she should be responsible to pay for her share of the contracted capacity, which is precisely the capacity that would become stranded. It makes very little sense to reallocate these costs to remaining customers, in effect making them pay more than their share of the capacity.

The exit fee option could be combined with options to minimize stranded costs. As discussed, the LDC could be provided incentives to mitigate stranded costs by allowing profit-sharing on resales of capacity or by allowing partial recovery of stranded costs. If stranded costs have been minimized by using the above options, the resulting exit fees imposed on departing customers would

also be minimized such that a customer would not feel constrained to stay on the system.

### Unbundling and Cross Subsidization

Any policy deliberation involving cost allocation and rate design invariably entails the issues of cross subsidies and price discrimination. Both of these issues are also likely to confront regulators engaged in crafting rate-making policies for unbundled gas services.

*Cross subsidization is generally understood as an allocation of costs in such a manner that one customer, one service category, one segment of an industry or one market, bears more than, while another bears less than, its "true" share of costs.<sup>12</sup> Price discrimination is generally understood as the charging of different prices to different customers for a product when it costs the same to provide each customer with the product.* Although the concepts of cross subsidization and price discrimination are closely related, they are also independent. Cross subsidization refers to sharing of the *total cost burden* for a service among parties. Price discrimination refers to *the per unit price* charged to different customers. Although many instances of cross subsidization may translate into price discrimination and vice versa, the two practices are not always, and not necessarily, related. An example of *cross subsidization with price discrimination* is a utility company's charging of a price to a customer group

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<sup>12</sup> For example, there can be cross subsidization among the customers of a regulated utility, and between the regulated and unregulated businesses of a parent company.



below its marginal cost.<sup>13</sup> An example of *cross subsidization without price discrimination* is a utility company's purchasing of one of its inputs from an affiliated company at above-market prices. In this case, *all the customers of the utility are subsidizing the affiliate*, and *there is no related price discrimination among the customer groups*. Finally, an example of *price discrimination without cross subsidization* is a utility company's charging different prices to different customer groups for the same service such that the price charged to each customer group is above its marginal cost.

Subsequent sections contain elaborations of the concepts of cross subsidization and price discrimination from the perspectives of different disciplines and a review of the relevant economics literature. These are followed by some general observations, and an examination of opportunities and remedies for cross subsidization and undue price discrimination, in the context of unbundled gas services.

### *Cross Subsidization: An Examination of the Concept*

A universally acceptable definition of cross subsidization does not exist. However, an examination of real-world examples of cross subsidization and review of relevant literature may be helpful in elucidating the concept.

In common parlance, subsidization refers to an "unearned benefit" conferred to a person or party. Forms of subsidization range from those inspired by social equity concerns (e.g., low income assistance programs) and

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<sup>13</sup> Marginal cost is a standard that neoclassical economics uses to test for the presence of cross subsidies. This and other tests of cross subsidization and price discrimination are examined in detail in subsequent sections of this chapter.

protectionist policies (e.g., subsidies to farmers) to business practices that allow disproportionate share of costs to be borne by different divisions of a company.

Cross subsidization is a term used to denote one form of subsidization; it is internal to an institution or firm. Therefore, cross subsidization may also be called internal subsidization. Heald<sup>14</sup> lists the following possibilities for cross subsidization.

- Between outputs which are bundled together in a vertically integrated industry structure.
- Between outputs which are bundled together in a horizontally integrated structure.
- Between a monopolist and its affiliated supplier of inputs
- Between different consumers of a single product
- Resources committed by the firm to activities unrelated to its business to meet government requirements
- Between the regulated and unregulated sectors of an enterprise

Central to the concept of cross subsidization is the notion of the cost burden accruing to the production of a commodity or service and how the burden is shared. The perceived cost burden, in turn, depends on how the relevant cost is defined. From the discussions in previous chapters, it is known that the relevant cost differs from the accounting and economic perspectives. Once the relevant cost is defined, one needs to define the appropriate sharing rule for the cost, which can be used to test the presence of inappropriate sharing of costs.

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<sup>14</sup> David Heald, *Cost Allocations and Cross Subsidies*, European Commission, 28-30.



*Cross Subsidization: The Accounting Approach and the Equity Standard*

According to the accounting approach, the relevant cost is the average accounting cost. The appropriate sharing rule is the FDC costing methodology. Using these standards, one can say a cross subsidy exists if the average accounting cost of a product is shared among parties in a manner that deviates from that which would be derived from a valid FDC cost of service analysis. In the gas utility context, cross subsidies are costs (i.e., average costs) that are attributable to (according to the FDC costing methodology), but not borne by, a service category. Such a service category is the recipient of cross subsidies. Alternatively, cross subsidies are costs that are borne by, but not attributable to, a service category. Such a service category is the source of cross subsidies.

For example, the capacity costs of a distribution network, according to the FDC methodology, should be allocated to a service category in proportion to its share of peak capacity (determined by the CP or NCP method, or their variations). Any departure from this allocation, from an accounting perspective, would constitute a cross subsidy.

The accounting approach to cross subsidization also comports well with the notion of distributional equity. If a service class receives a benefit, the common sense notion of equity would require that the class be charged a price that is commensurate with the benefit, regardless of what the marginal cost of serving the class is. This argument is exactly what would follow from a fully distributed cost perspective, based on the beneficiality criterion.

*Cross Subsidization: The Economic Approach  
and the Efficiency Standard*

As alluded to earlier, the economic approach to cost allocation rejects the formulation based on average accounting costs and the FDC costing methodology. According to this approach, the relevant costs are economic costs, and the sharing rule is governed by marginal costs. The costs to be allocated to a service are the economic, and marginal, costs of providing that service. Using this principle, it is clear that any service that is charged a cost less than its marginal cost is the recipient of a cross subsidy. It follows that a service that is charged a cost equal to or greater than its marginal cost is not the recipient of a cross subsidy.

It is not as straightforward to establish a test by which one can judge whether a service is a source of cross subsidy. One can, however, hypothesize an upper limit on the cost that can be charged to a service such that any higher charge would clearly constitute a cross subsidy. One such limit, proposed by Faulhaber,<sup>15</sup> is the stand-alone cost, or the cost to provide a service exclusive of all other services. According to Faulhaber, if a service is charged higher than its stand alone cost, it is a source of cross subsidy.

The above discussion is based entirely on costs, which are presumed to be known with certainty, and their allocation. The discussion does not take into account demand conditions, or uncertainties of either costs or demand. To examine the phenomenon of cross subsidization under various conditions of costs, demand and uncertainty, it may be helpful to review the economics literature and trace the evolution of economic thought on cross subsidization.

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<sup>15</sup> Gerald R. Faulhaber, "Cross Subsidization: Pricing in Public Enterprises," *American Economic Review*, Vol. 65 (1975), 966-77.



*Review of Economic Literature on Cross Subsidies*

Cross Subsidization as Predation: The earliest reference to cross subsidies appears in Edwards,<sup>16</sup> who considered cross subsidization as a form of predatory pricing. A firm, engaging in this form of cross subsidization, would price its products below the competitive price in one market and raise its price in another market where it has a competitive advantage. According to Areeda and Turner, one such form of predatory pricing would be for a firm to price its product below the marginal cost.<sup>17</sup> In view of the fact that marginal cost is generally difficult to estimate, Areeda and Turner proposed that average variable cost would be a good index to test for predatory pricing. Most economists, however, dismiss predatory pricing intermarket cross-subsidization as untenable.<sup>18</sup>

Overcapitalization for Intermarket Cross Subsidization: The next well-known reference to cross subsidies was made by Averch and Johnson, who contended that a regulated firm earning an above-market return on its capital (i.e. the famous "overcapitalization" or "A-J" bias of a regulated firm) has "an incentive to expand into other regulated markets, even if it operates at a (long-run loss) in these markets."<sup>19</sup> While the A-J model is well-known for its

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<sup>16</sup> Corwin Edwards, *Maintaining Competition* (New York, NY: McGraw Hill, 1949).

<sup>17</sup> Phillip P. Areeda and Donald F. Turner, "Predatory Pricing and Related Practices Under Section 2 of the Sherman Act," *Harvard Law Review*, Vol. 88 (1975), 697-733.

<sup>18</sup> Robert C. Brooks, "Injury to Competition Under the Robinson-Patman Act," *University of Pennsylvania Law Review* (1961), 797.

<sup>19</sup> Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, vol. 52 (5) (1962), 1052-1069.

overcapitalization hypothesis, it is less known for its intermarket cross subsidization hypothesis.

Bailey analyzed a two-market model to examine the A-J proposition and concluded that a regulated firm does not have an incentive to enter a second regulated market.<sup>20</sup> The same conclusion was reached by Brock<sup>21</sup>, who used a rigorous model of a regulated firm that explicitly accounts for fixed and common costs.

*The Faulhaber Tests for Cross Subsidization:* Kahn<sup>22</sup> and Posner<sup>23</sup> used the experience in regulated industries, rather than formal theoretical models, to indirectly introduce the notions of stand alone costs and incremental costs as tests for cross subsidization.

Faulhaber was the first to develop rigorous tests of cross subsidization. Faulhaber's model consists of a cooperative game between an efficient multi-product firm facing a zero economic profit constraint and its consumers.<sup>24</sup> He concluded that a firm is not the recipient of a cross subsidy if the revenue from producing a subset of services is greater than or equal to the change in total cost

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<sup>20</sup> Elizabeth E. Bailey, *Economic Theory of Regulatory Constraint* (Lexington, MA: Lexington Books, 1973).

<sup>21</sup> William A. Brock, "Pricing, Predation and Entry Barriers in Regulated Industries," in *Breaking Up Bell: Essays on Industrial Organization and Regulation*, edited by David S. Evans (city, state: North-Holland, 1983), 91-229.

<sup>22</sup> Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* (New York, NY: John Wiley and Sons, 1970).

<sup>23</sup> Richard A. Posner, "Taxation by Regulation," *Bell Journal of Economics and Management Science*, Vol. 2 (1) (1971), 22-50.

<sup>24</sup> Faulhaber, "Cross Subsidization: Pricing in Public Enterprises."

by not producing the subset of services. This constitutes the marginal cost test for cross subsidies. Faulhaber also concludes that a firm is not the source of a cross subsidy if the revenue from a subset of services is less than or equal to the cost of producing that subset of services independent of other services. This constitutes the stand-alone cost test for cross subsidies. The two tests introduced by Faulhaber, the incremental cost test and the stand-alone cost test, have become the standard in examining the economics of cross subsidization.

*A Consumer-Focus Test for Cross Subsidization:* Other economists have extended Faulhaber's work by relaxing his assumptions and coming up with more stringent tests of cross subsidization. Sharkey and Telser introduce a "consumer focus" in contrast to Faulhaber's "product focus" in defining criteria to test for cross subsidization.<sup>25</sup> They define "consumer subsidy-free prices" as those for which no coalition of consumers could provide services to themselves at a lower price. This is the so called "burden test." This test is more stringent than the Faulhaber test.

*Later Developments:* Other economists have extended the analysis further to include the effect of service quantities, demand functions and complementarity of services on cross subsidies.<sup>26</sup>

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<sup>25</sup> William W. Sharkey and Lester A. Telsen, "Supportable Cost Functions for the Multiproduct Firm," *Journal of Economic Theory*, Vol 18 (1978), 23-37.

<sup>26</sup> Karen Palmer, "Using An Upper Bound Stand-Alone Cost in Tests of Cross Subsidy," *Economics Letters*, Vol. 35 (4) (1991), 457-460.



*The Difficulty of Applying Economic Tests of Cross Subsidization:* While some of the economic tests, particularly the Faulhaber test, may be easy to follow as theoretical constructs, and the underlying test parameters (e.g., incremental costs and stand-alone costs) may be easy to define, they are difficult to apply in practical situations. For example, the two central assumptions of the Faulhaber model, efficient production and zero economic profit constraint, may not generally hold for a regulated firm. The traditional cost-plus, rate-of-return regulated utility may not choose the least cost or the most efficient input mix or production technologies. The zero economic profit constraint may not be satisfied under traditional regulation if the regulatory lag is long. The constraint is less likely to be satisfied under incentive or price cap regulation, whose very purpose is to allow an efficient firm to earn economic profits.

Cross elasticity of demand among various services also complicate the application of the Faulhaber tests. If services are substitutes, the incremental cost test becomes a necessary, but not a sufficient, condition for cross subsidization. On the other hand, if services are complements, the incremental cost test becomes a sufficient, but not necessary, condition for cross subsidization.<sup>27</sup>

The second of the Faulhaber tests, the stand-alone cost test, is even more difficult to apply, particularly in the presence of common and joint costs. The stand-alone cost is rarely estimated and has not been used as a test of cross subsidization. However, it may be possible to estimate an upper limit on the

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<sup>27</sup> Ibid.

stand alone cost. Such an estimate is unlikely to be very useful given the fact that in most practical situations no service is likely to be allocated a cost above this limit.

*Practical Alternatives to Economic Tests for Cross Subsidization:* The Faulhaber tests, however, can be applied if certain conditions are met even if both of its major assumptions (i.e. efficient production and zero economic profit) are not completely satisfied. For example, the incremental cost can be taken as a lower bound that precludes a *single service* from being the recipient of a cross subsidy, even if the zero economic profit constraint is not met. For example, if the local distribution service of a gas utility is subject to a price cap plan, the zero economic profit constraint may not be satisfied, but the efficient production condition is likely to be satisfied. Under these circumstances, if any customer class is charged a price below its incremental cost, one can safely conclude that the customer class is the recipient of a cross subsidy.

Alternatively, the fully distributed cost can serve as a lower limit on the stand-alone cost. Therefore, in most practical situations, allocations of cost between the incremental cost and the fully distributed cost can be taken as a reasonable indicator for the absence of cross subsidies. This range, commonly used, can act as a “safe harbor” for the prevention of cross subsidies.



## CHAPTER 5

### PRICING AND DESIGN OF TARIFFS FOR END-USE SERVICES

The services that continue to be regulated will be subject to rate-making by PUCs. Such services will be provided under approved tariffs. As mentioned in Chapter 1, the generic local distribution company (LDC) tariff is a combination of a fixed charge per accounting period (e.g., month) and a volumetric charge per unit of service (e.g., Mcf).<sup>1</sup> The Federal Energy Regulatory Commission (FERC) and state public utility commissions have generally differed on how the costs of service are to be distributed between the fixed and variable parts of the two-part tariff. FERC-approved interstate pipeline service tariffs generally consist of a demand charge that reflects capacity costs and a volumetric charge that reflects costs of throughput.<sup>2</sup> The PUC-approved local distribution company (LDC) tariffs, on the other hand, commonly have a monthly charge that reflects customer costs and a volumetric charge that reflects all upstream costs (gas commodity, interstate capacity, storage, etc.) and the cost of local transportation. In other

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<sup>1</sup> In theory, one can design N-part tariffs such that each part incorporates one or more consumption factors.

<sup>2</sup> Prior to issuing Order 636, FERC used the MFV (the modified fixed variable) method in which the volumetric or commodity component of the interstate pipeline transportation tariff contained parts of the fixed capacity costs, such as the rate of return on investments and taxes. Under Order 636, FERC adopted the SFV (the straight fixed variable) method that incorporates fixed costs exclusively into the demand component of the tariff.

words, both capacity and energy costs are incorporated in the volumetric charge in the typical LDC tariff.<sup>3</sup>

With the generic rate as the template, there are a multitude of ways in which the tariff can be designed to reflect costs or values of the demand for capacity and the volume of use. The two most extreme forms are a flat fixed rate tariff and a pure volumetric tariff. There are numerous forms of tariff that fall in between these extreme forms. A tariff generally incorporates consumption factors in combination with chosen accounting, economic and public interest objectives. The consumption factors may include time-of-use, share of the system peak, price elasticity of demand and level of reliability (i.e. firmness or interruptibility) demanded. The chosen regulatory objectives may include accounting cost responsibility, economic efficiency or low income assistance.

### End-Use Tariffs Under Unbundling

Presumably, there are some changes to conventional tariff designs that need to be considered under an unbundled and partially deregulated regime. Most of the changes are engendered by the following conditions.

- Some of the previously monopolistic services will be provided by unregulated providers.

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<sup>3</sup> Depending on the objectives of the firm and the type of market, a two-part rate structure can be designed to distribute the fixed and variable costs in various ways between the fixed and variable part of the rate. For example, if the demand for access to phone service is fixed and if the usage is price sensitive, the optimal tariff would consist of a usage fee that equals the marginal cost of usage, and an access fee that is sufficiently high for the firm to break even. See Kenneth E. Train, *Optimal Regulation*, pp 196, MIT Press, Cambridge, Massachusetts, 1991.

- Some of the unbundled services will be provided by both the utility and unregulated providers.
- Some of the utility's services may continue to be price regulated although they are provided by alternative unregulated providers.
- The utility will provide regulated monopoly services (e.g., local transportation) to a new class of customers, namely marketers and aggregators of small customers.

The above conditions may merit a reexamination of traditional regulatory objectives, and identification of changes, warranted by the new realities, to those objectives.

### Traditional Regulatory Objectives

The rationales for regulating public utilities were that they were natural monopolies and that they were enterprises "affected with the public interest." The natural monopoly argument contends that for a good or service with economies of scale, it is most efficacious for a single firm to serve the market. Such a firm, if unregulated, however, could restrict output and raise prices to inefficient levels to reap monopoly benefits. The public interest argument proposes that externalities and the possibilities of undue price discrimination and "cut-throat" competition also require public utilities to be operated as regulated monopolies. Based on the above rationales, public utility commissions have generally pursued the following goals:<sup>4</sup>

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<sup>4</sup> Adapted from Charles F. Phillips, Jr., *The Regulation of Public Utilities*, Public Utilities Reports, Arlington, Virginia, 1993.



- Ensure just and reasonable rates.
- Prevent excessive (monopoly) profits.
- Prevent unreasonable (inequitable) price discrimination among customers and places.
- Assure adequate earnings to the regulated utility.
- Assure service to the maximum number of customers.
- Promote economic development and employment in a geographical area.

### Evolution of Regulatory Objectives

Over the years, public utility regulation has increasingly adopted other objectives pursuant to its mandate of upholding the public interest.<sup>5</sup> These objectives include assistance to low income customers, promotion of energy conservation and energy efficiency, and management efficiency. The expansion of regulatory objectives has led to subsidization of rates to promote social goals, incentive-based rates to promote energy conservation and energy efficiency, and performance-based rate schemes to promote management efficiency.

In some sectors of the utility industry, particularly telecommunications and the interstate gas market, certain services were unbundled and deregulated. For such services, public utility regulators faced the issues of competitive entry, discriminatory access and pricing, and affiliate transactions. The traditional

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<sup>5</sup> For a comprehensive discourse on the evolution of regulatory objectives, see Sridarshan Koundinya, "Electricity Pricing Policy: A Neo-Institutional, Developmental and Cross-National Policy Design Map," Ph.D. Dissertation, The Ohio State University, 1998.

objectives of regulation were supplanted with other objectives that centered on the facilitation of market forces for deregulated services .

### Regulatory Objectives Under Unbundling of Retail Gas Services

The current state of the retail gas market mirrors the situation sketched above. Besides continuing the traditional mandate for ensuring just and reasonable rates, nondiscriminatory prices, and supporting social goals, state regulators are increasingly faced with the issues of:

- Facilitating competitive entry
- Preventing cross subsidization of costs among the regulated and unregulated sectors of the industry.
- Developing codes of conduct for different players of the industry.
- Protecting consumers from potential abuses and risks associated with the transition to a restructured industry.

In the context of rate design, state regulators are confronted with choosing pricing policies for both regulated and unregulated services that generally advance the above goals.

### Examination of Pricing Schemes and Tariffs for Unbundled Services

The following sections examine end-use tariff designs for each service type under defined regulatory and market conditions. For purposes of this examination, different end-use tariff designs are classified into nine broad categories as follows:

- One part tariffs
- Two part tariffs
- Block tariffs
- Price caps
- Other incentive rates
- Interruptible rates
- Value of service pricing
- Time-of-use rates
- Seasonal rates

It should be noted that the above are not parallel categories in the sense that they do not represent variations of the same pricing principle or concept. Two part tariffs, for example, distribute the price of service between its components (fixed and variable). Block tariffs, on the other hand, distribute the price among blocks of consumption. While each of the above tariff designs comprise a *price structure*, price caps represent a scheme to manage the *price level*, by establishing a formula to adjust the price from one rate period to another. Finally, seasonal rates and time of use rates attempt to incorporate the *time dependence of consumption*. Because the various tariff designs and pricing schemes are not parallel categories, they are not mutually exclusive and may be combined in various ways. For example, one can have a price cap with a two part tariff such that each part of the tariff is subject to a periodic adjustment.

### One Part Tariffs

Under the one-part tariff, the customer is charged a single price per unit of consumption. The price needs to be set at a level that recovers all variable costs



and makes a sufficient contribution to fixed costs such that the utility recovers all its costs including a rate of return on its investments. The appeal of the one-part tariff is its simplicity. However, the one part tariff is inconsistent with the fundamental cost-of-service principle that the price of a service should reflect its cost. In gas utility service, the cost of service is not linearly proportional to units of consumption. There is a set up or initial fixed cost resulting from the capital costs of building capacity. Further, there are fixed carrying charges (interest, taxes, etc.) on the related investments and fixed overhead costs related to the operation and maintenance of underlying facilities. These fixed costs are incurred regardless of units of consumption. By pricing successive units at a constant price, the distinction between the costs of capacity and the costs of output is not captured in the one-part tariff. The one-part tariff is not generally used in utility rate-making.

It may be instructive to observe that pricing of goods and services in most unregulated markets is akin to the one-part tariff. In such markets, there is a per unit price for an item purchased. The price generally includes the marginal cost of producing the unit and a contribution to the fixed overhead cost.<sup>6</sup> However, there are products in the unregulated market for which a reservation or access fee is charged in addition to the usage price. Markets for such products are generally observed to have one or more of the following characteristics. They are markets (1) for services rather than goods, (2) for input, intermediate or wholesale goods, (3) for firm delivery of goods under contract, and (4) in which customers separately value access to the good or service. The most relevant

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<sup>6</sup> To the extent the market is imperfectly competitive (e.g., monopolistic competition) and the firm is able to separate customers by price elasticity or volume of consumption, the firm may also engage in price discrimination by offering discounts to certain groups of customers and for quantity consumed.

example in the gas utility context is the firm gas supply contract that requires a certain minimum take or a reservation fee.

To capture the nonlinear relationship between costs and the amount of services, some form of a multi-part tariff can be considered. Two most commonly used multi-part tariffs are the two-part tariff and the block rate.

### Two Part Tariffs

A two-part tariff consists of a fixed component and usage component. In designing a two-part tariff, the basic issue is how to allocate the costs of the service between the two components. Based on the traditional fully distributed cost (FDC) method, the most straightforward way of allocating these costs is to assign all fixed costs, including the fixed component of common costs, to the fixed part of the tariff and to allocate the variable component to the variable part. This is the method currently followed by FERC in the SFV pricing rule used for interstate transportation services. An alternative is to assign a part of fixed costs to the volumetric or usage component of the tariff. The latter was used by the FERC under the MFV rate in which a part of the fixed costs, namely, the rate of return and taxes, were allocated to the usage component. The latter method is also used by most PUCs for pricing an LDC's services. The typical LDC tariff for residential customers has a monthly charge that incorporates fixed customer costs and some of the other fixed costs, and the gas usage component that incorporates all other costs, including costs of gas commodity and upstream capacity and storage, and local distribution.<sup>7</sup>

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<sup>7</sup> The usage charge is the sum of two components: the base rate that represents the local distribution costs and the purchased gas adjustment (PGA) component that represents costs of gas commodity and upstream capacity and storage.

As mentioned above, a reservation charge akin to the fixed charge is incorporated into a two-part tariff in some unregulated markets. In such markets, a firm may design two part tariffs such that low (high) demand users are charged a low (high) reservation fee and a high (low) usage fee to (1) maximize consumption, (2) penalize breach of contract and (3) prevent entry of competitors. Such a two-part tariff can be designed to maximize economic welfare.<sup>8</sup>

Unlike two-part tariffs in regulated markets, two-part price schedules in unregulated markets have no correspondence to input cost structures. Such two-part price schedules are based more on the price elasticities and volumes of usage of the consumer. One could argue that allowing a regulated utility to design a self-selecting two-part tariff (i.e., to offer a menu of different combinations of fixed and variable charges to customers), subject to the revenue constraint, would be economically efficient. Such a tariff, however, would be in conflict with traditional cost of service principles (for example, the low volume user has a low load factor and a high contribution to capacity cost). It would also meet with opposition from the small-consumer advocate because the tariff for the small customer would have a relatively high usage charge compared to that of the large customer.

### Block Rates

Block rates, or nonlinear tariffs, is commonly used by firms to maximize sales. The two common forms of block rates are the declining block rate and the

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<sup>8</sup> Robert Graniere, The National Regulatory Research Institute, personal communication, 1999.



inverted block rate. In the declining block rate, each succeeding block is charged a progressively lower rate and in the increasing block rate, the opposite holds true.

The basic rationale for the declining block is that under increasing returns to scale, successive blocks of production have a decreasing cost schedule. Also, under a downward sloping linear demand schedule, higher blocks of consumption have a higher price elasticity. As a result, a declining block tariff allows a firm to maximize the producer's surplus by charging a progressively smaller price for successive blocks of output. The most common form of declining block tariffs is quantity discounts offered to the large customers of a utility. To the extent that a declining block tariff allows a utility sell larger volumes of service relative to a uniform schedule, it allows a greater recovery of fixed costs, maximizes utilization of capacity and reduces the revenue burden of the smaller customers. Therefore, a properly designed declining block tariff has a welfare-enhancing effect.

Inverted block tariffs have very little cost-of-service or economic welfare justification.<sup>9</sup> Inverted block rates were introduced primarily to provide a social subsidy to economically disadvantaged customers and are rarely used in utility pricing.

### Price Caps

Regulators, particularly in the telecommunications sector, have been using the form of pricing known as price caps for a number years. Price caps have

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<sup>9</sup> An exception to this occurs when marginal cost increases with additional production.

rarely been used in gas regulation in the U.S.<sup>10</sup> The basic price cap consists of a price ceiling for a single utility service, or a basket of utility services, that is based on the previous year's price cap, rather than the utility's actual cost. The price cap formula has three basic components: last year's price cap, an adjustment index for inflation and an adjustment index for productivity. The inflation index accounts for changes to the utility's cost of inputs based on an industry or economy index. The productivity index accounts for changes in industry-wide productivity as well as other factors. It is generally a negative index and adjusts the price cap downward. The utility is allowed to charge any price equal to or less than the cap. If the utility's cost is less than the cap, the utility earns profits that it is allowed to keep. The regulator may review the price cap periodically and adjust the cap and its parameters based on the conditions of the firm and the market.

The basic rationale for the price cap is that it induces efficient behavior by the firm. As the cap is based on factors that are exogenous to the utility, with the utility rewarded for reducing its input costs below the cap, the utility has an strong incentive to choose a cost minimizing input mix, invest in cost-effective innovations, and adjust optimally to changes in cost.<sup>11</sup> There are, however, problems associated with implementing a price cap. The estimation of price cap parameters (such as the inflation and productivity indices) is often difficult and contentious. Further, if the utility makes windfall profits or suffer large losses, that most likely would trigger a rate review; the regulator is likely to adjust the cap to limit the profits to levels that are consistent with an "acceptable" range of

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<sup>10</sup> Price caps have been used for both gas and electric utilities in the U.K.

<sup>11</sup> Kenneth E. Train, *Optimal Regulation* (Cambridge, MA: The MIT Press, 1994), 318.

rates of return. This reduces the effectiveness of the price cap to that of a traditional cost-plus rate-making arrangement. The possibility of a utility's profits being constrained reduces the incentive of the utility to minimize costs. Furthermore, a price cap may induce strategic behavior by the utility. For example, to preempt the possibility of a price cap reduction, a utility may choose to incur additional costs right before a rate review. After an evaluation of its strengths and weaknesses, price caps represent a promising rate-making mechanism that warrants strong consideration for setting rates for monopoly gas services.<sup>12</sup>

### Interruptible Tariffs

Gas utility companies generally offer interruptible tariffs to customers that do not require firm service. These tariffs have lower rates than those for firm rates. In exchange for receiving a lower rate, the interruptible customer agrees to be curtailed during times of shortage and high demand. The interruptible rate generally does not include a capacity charge, and covers only the marginal cost of serving the interruptible customer.<sup>13</sup> Interruptible tariffs are generally beneficial to the gas utility's firm customers because they allow utilization of capacity during times, such as the summer, when the utility has a lot of idle capacity. An important issue is whether the interruptible customer should be required to make a contribution to the capacity cost and other fixed costs of the

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<sup>12</sup> Under fully competitive conditions, price caps are unnecessary. Under quasi-competitive conditions, price caps may impede the development of competition. For more discussion on these issues, see subsequent sections.

<sup>13</sup> An interruptible customer may also be interrupted when the marginal cost of serving the customer exceeds the interruptible rate.



utility. One common argument often made is that interruptible customers are rarely interrupted, particularly under conditions of excess capacity. Under these circumstances, the interruptible customer is essentially receiving a firm service while paying much less than other firm customers; this constitutes a case of price discrimination. However, the interruptible customer generally has alternatives to the gas delivery service and increasing the rate may cause the customer to leave the system, with adverse effects on the system load factor and the utility's revenues.

### **Value of Service Pricing**

Under value-of-service pricing, the price of a product is not based on its cost of production, but on the willingness of the customer to purchase the product at the specified price. In a perfectly competitive market, the marginal value of the product and the marginal cost tend to converge and is equal to the market price. For a regulated utility, however, the marginal value of a service is likely to be different from its marginal cost. Given the fact that marginal-cost-based prices for regulated utility service may lead to a revenue deficiency and FDC-based prices (although it collects the required revenues) have no economic rationale, mechanisms that incorporate value-of-service considerations to achieve the optimal combination of price and output under the revenue constraint have been proposed.

The most well-known mechanism that incorporates value-of-service factors or customer price elasticities is the Ramsey Pricing Rule. Under Ramsey pricing, the deviation of the price of a service from its marginal cost is inversely proportional to the price elasticity of the service. It follows that customers with high price elasticities would be charged lower prices relative to customers with

high price elasticities. Because the prices differ from marginal cost, necessitated by the revenue constraint, there is a loss of social surplus and the outcome is not the "first best." However, Ramsey pricing seeks to achieve the "second best" prices that meet the revenue requirement while minimizing the loss of social surplus.

One of the problems with Ramsey pricing is that it has undesirable distributional equity consequences. Customers with lower incomes generally also have low price elasticities because they do not have access to alternatives to utility services. Therefore, under Ramsey pricing such customers would be charged a higher price relative to their marginal costs. Although Ramsey prices are optimal under the revenue constraint, they may consequently have unacceptable social equity consequences. Perhaps for this reason, Ramsey prices have not been used by gas utilities.

## CHAPTER 6

### EVALUATION OF ALTERNATIVE RATE DESIGN OPTIONS

#### Criteria for Evaluation

The state regulator's choice of a rate design option<sup>1</sup> for unbundled gas services would depend on regulatory objectives. While the public interest compulsions and attendant regulatory objectives may vary somewhat among state public utility commissions (PUCs), one can list the most important ones that are likely to dominate rate-making policies of most PUCs. As discussed in foregoing chapters, the regulatory objectives would include traditional ones that comported well with the regulated monopoly world and the more contemporaneous ones that are emerging in response to a mixed regulatory-competitive regime. The traditional regulatory objectives include: economic efficiency, equity among stakeholders, revenue sufficiency and ease of implementation. The emerging regulatory objectives include facilitation of competition for deregulated services and consumer protection.

In choosing a rate design option, the state regulator can perform a comparative evaluation of alternative options, with selected regulatory objectives as the evaluation criteria. Each state PUC may attach a different "public interest"

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<sup>1</sup> Unless otherwise specified, the term "rate design" refers to the combination of cost allocation, cost separation, and tariff design schemes.



or welfare weight to each criteria. The final choice of an option would depend on the relative weights assigned to each criteria. Each of the criteria is briefly examined in the following section.

### **Economic Efficiency**

The text book economic definition of efficiency refers to a combination of price and output that maximizes total social surplus or welfare. In common regulatory parlance, economic efficiency refers to providing incentives to the regulated firm to plan and manage their operations in a least cost manner.<sup>2</sup> In the pre-unbundling world, regulators used a number of tools, which range from oversight and scrutiny to performance incentives, to encourage efficiency. Under the emerging mixed regulated-competitive regime, the promotion of economic efficiency may involve choosing a mix of options - or among them, that account for the incentive properties of both purely regulatory performance benchmarks and the presence of competitive or quasi-competitive market conditions.

### **Equity**

Equity, a more controversial and elusive concept, has its root in the notion that each party to an arrangement has certain rights and entitlements. Such rights and entitlements are predicated, among other things, on "fair" or "just" sharing of costs and benefits that accrue from the arrangement. In regulatory

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<sup>2</sup> The setting of revenue requirements or rate levels with accompanying oversight was intended to promote efficient production. The allocation of costs among customer classes and pricing of services was intended to promote efficient consumption.

parlance, equity has meant the protection of such rights for each group that has a stake in regulatory outcomes. Closely related to the notion of equity is the notion of symmetry. For example, if the utility exercises price discrimination among customer groups, one or more customer group may claim that it has been treated inequitably – i.e., the symmetry principle has been violated. On the other hand, the utility or other customer groups may be able to argue that differentiated prices alone do not constitute price discrimination, and therefore, do not constitute inequitable treatment, if there are cost differentials involved in serving different customer groups. Price discrimination itself can be welfare enhancing. For example, it can be shown that pricing of a product to a customer group according to the inverse elasticity rule maximizes economic welfare under the revenue constraint. Another situation that may engender claims of inequitable treatment is, if based on a marginal cost allocation methodology, a customer group is charged less than its accounting cost of service, while another group is charged more. The regulatory deliberations in such a situation would involve arguments on the economic and public interest rationales of the marginal cost versus embedded cost-based methodologies. Finally, a utility may make a claim of inequity if the distribution of benefits of an incentive program is asymmetric – the utility is severely penalized for unusually poor performance but not allowed to make high profits for exceptionally good performance.

### Competition

The major goal of unbundling utility services has been to introduce and promote competition for those services that are believed to be competitive. In the gas utility sector, some of these competitive services already have an adequately developed market or are anticipated to develop a market. One such

service is the gas commodity. There are other competitive services for which we do not yet have a developed market and for which a market may not develop rapidly. Billing and metering are such services. To facilitate competition for competitive or potentially competitive services, state regulators need to address issues such as access, barriers to entry, sharing of information between the utility and marketers, codes of conduct, brand name and incumbency advantages of the utility, and cost allocation and tariff design. In particular, choice of cost allocation and tariff design options affects relative advantages of the utility or its affiliates, and their competitors. For example, a service may be unbundled and opened to competition, while the utility is still allowed or required to offer the service. If the related costs are separated from the utility's revenue requirements on a marginal cost basis, marketers face initial set up costs that the utility does not. This may translate into a relatively high entry cost for the marketer and may therefore discourage competition.<sup>3</sup> As another example, if the utility sells a service to an affiliate at marginal cost that is lower than the market price, this confers a competitive advantage to the affiliate over unaffiliated marketers. In both of the above examples, marginal cost-based cost allocation can be supported on economic efficiency grounds, yet such an allocation would have an adverse impact on competition. One can argue that in the above cases, there is a possible conflict between short term static efficiency and long term dynamic efficiency.

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<sup>3</sup> By assumption, a competitive service is likely to have low economies of scale and low entry costs. However, allocation of only marginal costs and guaranteed recovery of embedded costs would disadvantage the utility's competitors.



## Consumer Protection

One of the rationales for traditional monopoly regulation was to protect the customer from inefficiencies of a unregulated "natural monopoly." However, when some of the previously monopolistic services developed competitive characteristics, there was a movement to unbundle and deregulate these services. The argument has been that the customer would gain from the benefits of competition. However, the transition from regulation to competition also may take away certain protections traditionally available to the customer, such as guaranteed service at an acceptable quality, the lowest rates achievable through the regulatory process and certain publicly sanctioned social subsidies. The transition imposes certain risks on the customer, such as the possibility that prices of deregulated services may actually increase because of weak competition offsetting the economies of scale, scope or network, or lower transactions costs under the regulated monopoly regime, or because the utility or parties other than customers are able to appropriate the efficiency gains from competition. Loss of some of the protections of traditional regulation as well as some of the consumer risks of competition may have to be accepted as indispensable to the process transition to competition; regulatory policy may be able to preserve some of the traditional protections and minimize some of the risks. For example, politically driven social subsidies may be retained by imposing a non-bypassable surcharge on a backbone monopoly service, such as local distribution. As another example, regulators may choose an FDC-based method, as opposed to an MC-based method, to separate capacity costs for assets and facilities that are not used by the utility to provide an unbundled service. The reason for this is that this choice favors competitors and offsets

some of the incumbency advantages of the utility. Customers may benefit if this regulatory choice promotes competition and results in lower prices for services.

### Revenue Sufficiency

Revenue sufficiency has been one of the accepted objectives of traditional regulation. The regulatory compact has implied that the utility, under a monopoly franchise arrangement, would be allowed the opportunity to earn sufficient revenues to meet its costs. One of the reasons marginal cost (MC) based rate-making, as opposed to fully-distributed-costs (FDC) based rate-making, was not generally adopted was that it would fail to recover the total revenue requirements of the utility. Also, any revenue shortfall or surplus was to be compensated for in a truing up process.

Any time a utility service was opened to competition in the past, the likelihood of the utility earning insufficient revenues became a significant regulatory issue. Most recently, the "stranded cost" issue, arising from the unbundling and deregulation of the electric power generation sector, dominated the policy debate on electric utility regulation. In choosing options for cost allocation and end-user rates for gas services that will continue to be regulated, a state public utility commission will probably consider the impact on revenue sufficiency. If other things are equal, an option that offers a better assurance for revenue sufficiency is likely to be preferred over one that does not.

### Ease of Implementation

Some cost allocation and pricing options that may appear to be methodologically sound may be hard to implement. It may be difficult or onerous

to compile the relevant data, perform the needed measurements or do the underlying analysis.

Another important issue related to the ease of implementation is the related administrative costs. The administrative cost of regulation includes the direct costs of holding regulatory proceedings to the state PUC as well as the indirect costs incurred by the utility and other participants in the proceedings. Most of the above costs would ultimately be borne by the ratepayer; their magnitudes depend on the frequency of regulatory proceedings, and the underlying information processing and evidentiary requirements. In choosing a rate design option, the state PUC should be mindful of the trade off between the expected benefits of the option and the offsetting regulatory costs.

### Comparison of Options

Tables 6-1 through 6-12 provide summary comparisons of different cost allocation and tariff design options. For each option, the tables contain the effects on economic efficiency, equity, competition, consumer protection, revenue sufficiency and ease of implementation. Certain general observations that follow from the tables are discussed in the subsequent sections.

#### **It Is Easier to Separate Upstream Costs than Downstream Costs**

As observed in earlier chapters, separation of costs for upstream assets and operations are easier to separate than downstream costs: the first costs are generally dictated by FERC-determined tariffs while the second costs depend on the regulatory policy choices of the state PUC. FERC-determined tariffs determine both the rate level (i.e., revenue requirements) and the rate structure



Table 6-1: Separation of Costs for Upstream Assets – Full Divestiture						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Book Value	Inconsistent with economic efficiency	Alternative providers may consider it inequitable	Disadvantages alternative providers	May harm consumers through anti-competitive effects	Recovers revenue requirements	No significant implementation issue. May be contested by alternative providers and customer groups
Market Value	Consistent with economic efficiency	Utility may consider it inequitable if it faces stranded costs	No disadvantage to competitors	Consumer at risk if asset is undervalued and stranded cost recovery is allowed	May not recover revenue requirements. May cause stranded costs	Market value may be difficult to estimate if the asset is sold to an affiliate or not sold
Higher of Book or Market Value*	Inconsistent with economic efficiency	Utility affiliates may consider it inequitable because of asymmetry	Favors competitors of utility and its affiliates	Consumer is protected against the risks of asset valuation	Recovers revenue requirements	Market value may be difficult and contentious to estimate
* May be used if the utility sells an asset to an affiliate.						

Table 6-2: Separation of Costs for Upstream Assets – Partial Divestiture*						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC Methods for Capacity Costs	Inconsistent with economic efficiency	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	High informational and regulatory costs
Marginal Cost Methods for Capacity Costs	Consistent with economic efficiency	Competitors and consumers consider it inequitable	Favors utility	Anti-competitive effects may harm consumers	Minimizes revenue deficiency	Difficult to measure
Stand Alone Cost	A value between stand-alone cost and marginal cost meets the no-cross-subsidy test	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure
Pro-Rated Market Value	Consistent with economic efficiency	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure
The asset is co-owned by the utility and its affiliate.						

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-3: Separation of Costs of Contracts for Upstream Services

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Mandatory Assignment	Inconsistent with economic efficiency	Alternative providers may consider it inequitable	Disadvantages competitors	Anti-competitive effects may harm consumers	Recovers revenue requirements	No significant implementation issues
Marketers Purchase Upstream Services	Consistent with economic efficiency	Utility may consider it inequitable	Helps competitors	Pro-competitive effects may help consumers	May cause stranded costs	No significant implementation issues

Table 6-4: Separation of Upstream Operating Expenditures

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC Methods	Inconsistent with economic efficiency	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause revenue deficiency	High informational costs
Avoided costs	Consistent with economic efficiency	No significant equity issue	Favors utility	Effect on consumers is neutral	Minimizes revenue deficiency	Low informational costs. Can be based on FERC tariffs



*COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES*

Table 6-5: Separation of Costs for Downstream Assets – Full Divestiture						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Book Value	Inconsistent with economic efficiency	Alternative providers may consider it inequitable	Disadvantages alternative providers	May harm customers through anti-competitive effects	Recovers revenue requirements	No significant implementation issue. May be contested by alternative providers and customer groups
Market Value	Consistent with economic efficiency	Utility may consider it inequitable if it faces stranded costs	No disadvantage to competitors	Consumer at risk if asset is undervalued and stranded cost recovery is allowed	May not recover revenue requirements. May cause stranded costs	Market value may be difficult to estimate if the asset is sold to an affiliate or not sold
Higher of Book or Market Value*	Inconsistent with economic efficiency	Utility affiliates may consider it inequitable because of asymmetry	Favors competitors of utility and its affiliates	Consumer is protected against the risks of asset valuation	Recovers revenue requirements	Market value may be difficult and contentious to estimate
May be used if the utility sells an asset to an affiliate.						

# COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-6: Separation of Costs for Downstream Assets – Partial Divestiture*						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC Methods for Capacity Costs	Inconsistent with economic efficiency	Utility may consider inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	High informational and regulatory costs
Marginal Cost Methods for Capacity Costs	Consistent with economic efficiency	Competitors and consumers consider it inequitable	Favors utility	Anti-competitive effects may harm consumers	Minimizes revenue deficiency	Difficult to measure
Stand Alone Cost	A value between stand-alone cost and marginal cost meets the no-cross-subsidy test	Utility may consider inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure
Pro-Rated Market Value	Consistent with economic efficiency	Utility may consider inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure
The asset is co-owned by the utility and its affiliate.						

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-7: Separation of Costs for Downstream Operations						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
No Cost Separations: Adjust Rates to Maintain RR	Inconsistent with economic efficiency	Inequitable for customers who remain with utility	Favors utility	Harms customers through increased rates and also anti-competitive effects	Recovers RR	High informational costs
No Cost Separations: No adjustment to rates	Consistent with economic efficiency	Utility may consider it inequitable	Disadvantages utility	Customers are protected from increased rates and anti-competitive effects	May cause revenue deficiency	Almost zero informational costs
FDC Methods	Inconsistent with economic efficiency	Utility may consider it inequitable	Disadvantages utility	May help customers with pro-competitive effects	May cause revenue deficiency	High informational costs

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-7 – *continued*

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Short-Run Avoided Costs	Consistent with economic efficiency	Competitors may consider it inequitable	Favors utility	May harm customers through anti-competitive effects	Minimizes revenue deficiency	Applicable in excess capacity situation. Avoided costs are hard to measure
Long-run Avoided Costs	Consistent with economic efficiency	Equity implications unclear or neutral	Effect on competition depends on estimated costs of capacity additions	Helps current customers with credit for avoided capacity additions	Depends on magnitude of avoided capacity costs	Applicable in capacity shortage situation. Avoided costs are hard to measure
Market-Indexed Price Times Avoided Volume of Service	Consistent with economic efficiency	Equity implications unclear or neutral	May disadvantage competitors	May harm customers through anti-competitive effects	Revenue implications on the index and magnitude of avoided volume of service	Market index may be hard to measure. Not suitable if the market is not workably competitive



Table 6-8: End-Use Tariffs for Services Exclusively Provided by the Utility

Option	Economic Efficiency	Equity	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Traditional Rate Designs	Generally inconsistent with economic efficiency	Generally considered equitable	Not a significant issue	Recovers revenue requirements	High informational costs
Price Caps	Provides good cost minimization incentives. Allocates cost better than targeted PBR	Allows utility to price discriminate among customers	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Price cap parameters may be hard to measure and controversial
Value of Service Pricing	Generally promotes welfare maximization	Lets the utility appropriate consumer surplus. Allows utility to price discriminate	One group of customers may be disadvantaged relative to another	Utility is able to recover revenue requirements	May be politically unacceptable to certain customers

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-8 -- *continued*

Option	Economic Efficiency	Equity	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Interruptible Rates	Consistent with economic efficiency	May be considered inequitable if there is no capacity cost component	To protect captive or firm customers, price floor should be set at variable cost	Helps meet revenue requirements	No significant implementation issue
Time-of-Use Rates	Consistent with economic efficiency	Low load factor customers may consider it inequitable	Low load factor customers may be charged relatively high rates	Generally designed with revenue reconciliation	High metering and informational costs
Seasonal Rates	Provides correct price signals about seasonal fluctuations of demand and supply	Customers with relatively high demands during seasonal peak periods may consider it inequitable	No clear consumer protection implications	Generally designed with revenue reconciliation	No significant implementation issue. Currently practiced in the form of gas-cost recovery (GCR) charges



Table 6-9: End-Use Tariffs for Services Provided by the Utility and Others  
Case 1: Utility Is the Dominant Provider

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Traditional Rate Designs	Generally inconsistent with economic efficiency	Generally considered equitable	May promote competition as utility prices are likely to be higher than others	Utility customers may face higher prices than other customers	Recovers revenues	High informational costs
Price Caps	Provides good cost minimization incentives.	Allows utility to price discriminate among customers	Utility may have an incentive to undercut competitors by minimizing prices for competitive services	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Price cap parameters may be hard to measure and controversial
Price Tied To Market Index	Provides good cost minimization incentives	Allows utility to price discriminate among customers	Utility may have an incentive to undercut competitors by minimizing prices for competitive services	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Generally allows revenue adjustment on a forward-looking basis

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-9 – *continued*

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Value of Service Pricing	Generally promotes welfare maximization	Lets the utility appropriate consumer surplus	Utility may be able to price discriminate to deter competition	Anti-competitive effects may harm customers	Utility is able to recover RR	May be politically unacceptable to certain customer groups
Interruptible Rates	Consistent with economic efficiency	May be considered inequitable if there is no capacity cost component	No clear competitive implications	To protect captive or firm customers, price floor should be set at variable cost	Helps meet revenue requirements	No significant implementation issue
Time-of-Use Rates	Consistent with economic efficiency	May be considered inequitable by low load factor customers	Utility may be able to price discriminate to deter competition	Low load factor customers may be charged relatively high rates	Generally designed with revenue reconciliation	High metering and informational costs
Seasonal Rates	Provides correct price signals about seasonal fluctuations of demand and supply	Customers with relatively high demands during seasonal peak periods may consider it inequitable	No clear competitive implications	No clear consumer protection implications	Generally designed with revenue reconciliation	No significant implementation issue. Currently practiced in the form of GCR

# COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-10: End-Use Tariffs for Services Provided by the Utility and Others Case 2: Utility Is Not the Dominant Provider						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Traditional Rate Designs	Generally inconsistent with economic efficiency	Generally considered equitable	May promote competition as utility prices are likely to be higher than others	Utility customers may face higher prices than other customers	Recovers revenues	High informational costs
Price Caps	Provides good cost minimization incentives. Allocates cost better than targeted PBR	Allows utility to price discriminate among customers	Competitive implications are neutral	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Price cap parameters may be hard to measure and controversial
Price Tied To Market Index	Provides good cost minimization incentives	Allows utility to price discriminate among customers	Competitive implications are neutral	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Market index parameters may be hard to measure and controversial

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-10 – continued

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Value of Service Pricing	Generally promotes welfare maximization	Lets the utility appropriate consumer surplus	Competitive implications neutral	Consumer protection implications unclear	Utility may be able to recover revenues	May be politically unacceptable for certain customer groups
Interruptible Rates	Consistent with economic efficiency	May be considered inequitable if there is no capacity cost component	Competitive implications neutral	No clear consumer protection implications	Helps meet revenue requirements	No significant implementation issue
Time-of-Use Rates	Consistent with economic efficiency	May be considered inequitable by low load factor customers	Competitive implications neutral	No clear consumer protection implications	Generally designed with revenue reconciliation	High metering and informational costs
Seasonal Rates	Provides correct price signals about seasonal fluctuations of demand and supply	Customers with relatively high demands during seasonal peak periods may consider it inequitable	Competitive implications neutral	No clear consumer protection implications	Generally designed with revenue reconciliation	No significant implementation issue. Currently practiced in the form of GCR



# COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

Table 6-11: Pricing of Assets Sold/Purchased by Utility to/from Its Affiliate						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Book Value of Assets Sold By Utility	Inconsistent with economic efficiency	Generally considered equitable	Favors the affiliate if book value is lower than market	May harm consumers through anti-competitive effects	Recovers RR	No significant implementation issue
Market Value of Assets Sold By Utility	Consistent with economic efficiency	No significant equity implication	Competitive implications are neutral	Protects consumers from anti-competitive outcomes	May cause stranded costs or prohibits recovery	Market value estimation may be difficult and contentious
Market Value of Assets Purchased By Utility	Consistent with economic efficiency	No significant equity implication	Competitive implications are neutral	Protects consumers from anti-competitive outcomes	No revenue recovery implications	Market value estimation may be difficult and contentious
Higher of Book/Market of Assets By Utility	Inconsistent with economic efficiency	May be considered inequitable by utility and its affiliate	Disadvantages utility and its affiliate. May help competition	Customers are protected from risks of asset valuation	May cause stranded costs	Market value estimation may be difficult and contentious

Table 6-12  
Pricing of Services Sold/Purchased by Utility to/from Its Affiliate

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC-Based Price for Services Sold by Utility	Inconsistent with economic efficiency	Generally considered equitable	Favors affiliate if FDC-based price is lower than market	May harm consumers through anti-competitive effects	Recovers RR	No significant implementation issue
Market Prices For Services Sold By Utility	Consistent with economic efficiency	No significant equity implications	Competitive implications neutral	Protects consumers from anti-competitive outcomes	May cause revenue deficiency and excess	Market price estimation may be hard or contentious
Market Prices For Services Purchased By Utility	Consistent with economic efficiency	No significant equity implications	No significant equity implications	Protects consumers from anti-competitive outcomes	May cause revenue deficiency and excess	Market price estimation may be hard or contentious
Higher of FDC/Market in Sale and Lower of FDC/Market in Purchase	Inconsistent with economic efficiency	Utility and its affiliate may consider it inequitable	Disadvantages utility and its affiliate	Protects consumers from price risk	May cause revenue deficiency and excess	Market price estimation may be hard or contentious



(i.e., tariff design). Also, the costs of some of the upstream services to be unbundled (such as pipeline capacity) may already be separated based on a FERC-determined cost allocation scheme. Therefore, the state PUC has neither the obligation nor the difficulty of separating these costs for purposes of unbundling these services. This is particularly true for upstream *operations*. For separating the costs of upstream *assets*, however, the PUC may have to address the choice of a cost allocation method or scheme. For example, if the state PUC is trying to separate the cost of an upstream storage facility that the utility chooses to divest, the PUC needs to decide whether the facility would be valued at undepreciated book value, market value or the higher/lower of the book or the market value.

#### **Cost Separations Are More Difficult If the Utility Continues to Provide an Unbundled Service**

If the utility no longer provides an unbundled service (such as commodity gas), it may be relatively easy to separate the costs of such service from the utility's revenue requirements. There may still be some common and joint costs that the unbundled service shares with a regulated monopoly service. For example, commodity gas service may share labor and administrative costs with the local distribution service. The cost separations would become significantly more difficult if the unbundled service (such as commodity gas) was provided by the utility as well as alternative providers. There are methodological and technical difficulties in separating common and joint costs of a service. Issues of competitive impacts, inter-market and interclass cross subsidies, and the sharing of benefits may however exacerbate such difficulties if a service is provided by both a regulated monopolist and an unregulated provider.

### **Effect of Rate Design Options Depend on the Degree of Market Dominance of the Utility**

One of the reasons an unbundled service would continue to be provided by the utility is that there is either an insufficient number of non-utility providers, or an insufficient volume of service produced by non-utility providers to supply the demand. In either case, the utility needs to continue to provide the service until such time as a sufficient supply market for the service develops. During the transition period, the state regulator would probably want to implement policies that expedite the development of a market. Likewise, once a market develops, the regulator would probably want to implement policies that foster and sustain competition in the market.

The above examination points to the critical role of the local utility company's market dominance in informing the policy choices of the regulator. Policies that were predicated on the regulated monopoly arrangement can no longer serve the new regulatory objective of expediting, fostering and sustaining a competitive market for certain unbundled gas services. The thrust of the regulatory policy must be to reduce the market dominance of the incumbent utility during the transition period, and to restrain market dominance of the utility or of any of its competitors once a market develops. This means that regulatory policies, including rate design policies, should address market dominance as a critical decision variable. For example, the same rate design option would have different effects on the behavior of the utility and alternative providers, and on the rates charged to ultimate customers, depending on whether any of the providers has market dominance. It follows that rate design options have to be evaluated on chosen regulatory objectives under two different scenarios: one in



which the utility has market dominance and the other in which it does not (see Tables 6-9 and 6-10).

### **Conflicts Among Regulatory Objectives Are Exacerbated by Unbundling**

While traditional regulation spawned conflicts among regulatory objectives, especially equity and economic efficiency, unbundling and deregulation of certain services tend to enlarge the scope of such conflicts and introduce new conflicts. Perhaps the most paradoxical one is the conflict between economic efficiency (within the regulatory framework) and competitiveness. For example, cost allocations based on marginal costs are believed to be economically efficient. Yet, cost separations for utility services based on marginal costs would put the incumbent utility at an advantage relative to its competitors. Further, providing the utility with an incentive intended to minimize costs and rates (such as in a PBR scheme) may have the perverse effect of allowing the utility to undercut potential competitors and deter entry, or drive out existing competitors. Finally, the economic efficiency criterion would support allowing the utility and its affiliate to conduct transactions that exploit underlying economies of scope (such as selling a service to its affiliate at a price that is lower than the price charged to others because it costs less to serve the affiliate). Yet such a discriminatory practice would deter entry by potential competitors or drive out existing competitors.

The above discussion underscores the conflict between short-term economic efficiency and long-term dynamic efficiency. There may be good arguments on both sides on whether short-term economic efficiency or competitiveness ought to be promoted in a mixed regulatory-competitive regime.

The argument cannot be settled conclusively by appeals to economic theory alone. The ultimate regulatory choice might be determined by a combination of a priori policy preferences and empirical evidence (that would emerge in the future).

### No Rate Design Option Meets All the Regulatory Objectives

As is evident from Tables 6-1 through 6-12, no single combination of cost allocation and tariff design options has all the desirable properties to meet the most important regulatory objectives, although some may meet more regulatory objectives than others. The reason is that there are inherent conflicts among regulatory objectives. Therefore, and as in the past, the regulator is forced to make educated trade offs among regulatory objectives.

### A Strategic Framework for Evaluating Rate Design Options

It may be helpful to view the choice of rate design options in terms of regulatory strategies for unbundling. Table 6-13 lists possible regulatory strategies and attendant choice of rate design options. *Strategy I* represents a *gradualist approach* in which none of the unbundled services is totally deregulated, and the utility continues to be a provider of these services, along with alternative providers. Also, the PUC does not take an activist role to expedite the development of a competitive market; instead, it limits itself to providing consumer protections. The PUC anticipates that a market will develop with time through the working of market forces. *Strategy II* represents a *market facilitation* approach, which is similar to the gradualist approach, with the additional feature that the PUC plays an activist role in expediting the

Table 6-13: Regulatory Strategies for Unbundling	
<b>Strategy I:</b>	<b>Gradualist</b> (utility and others provide unbundled services; cost separations are based either on FDC or MC; tariffs for utility services are based on traditional or PBR methods)
<b>Strategy II:</b>	<b>Market facilitation</b> (utility and others provide unbundled services; cost separations are based on FDC or SAC; tariffs for utility services are based on traditional methods)
<b>Strategy III:</b>	<b>Radical deregulation</b> (utility does not provide deregulated unbundled services; choice of cost separation and tariff design options do not have any noticeable effect on competition)

development of a competitive market. In this strategy, the PUC chooses rate design and other (e.g, codes of conduct) policies that restrain and reduce the incumbency advantages of the utility. Strategy III represents a *radical deregulation approach* in which every service that is viewed as workably competitive is totally deregulated with the utility not required or allowed to provide the service.

Each regulatory strategy has its merits and demerits. Strategy I is predicated on caution, the belief that the benefits of full unbundling and deregulation are uncertain and an unduly activist posture toward developing a market may be harmful to the customers. This strategy has the demerit that it may prolong the transition to the development of a market, thereby depriving



customers of the resulting benefits. Strategy II puts more faith on the feasibility and merits of competition, and attempts to facilitate its development. Given the fact that deregulation in several industries, including the wholesale gas industry, has produced significant benefits for consumers, and that the regulatory strategy employed by the relevant federal regulatory agency, including FERC, has been similar to strategy II, this strategy has a strong rationale. The only demerit is that the precedents cited above do not resemble the conditions of retail gas unbundling, and the expected benefits are arguably expected to be small relative to other instances of deregulation. Therefore, an unduly activist regulatory posture may not produce the desired competition and benefits, and may impose regulatory and other costs on society. Strategy III also relies strongly on the merits of competition. In addition, by eliminating the utility from the market for competitive services, it avoids the task of addressing its incumbency advantages. Also, the regulatory burden and cost related to allocation and separation of costs are significantly reduced. Therefore, provided a service is truly competitive, strategy III may be superior to strategy II. However, the determination of the true competitiveness of a service becomes the critical issue in pursuing this strategy. This problem, combined with the fact that the benefits of competition may be arguably small, makes this a relatively risky regulatory strategy.

As discussed with regard to the choice of rate design options, the choice of a regulatory strategy would ultimately depend on the preferences of each state commission; these preferences in turn depend on the unique realities and public interest compulsions obtaining in each state. However, the delineation of rate design options and their properties, the composition of rate design options into a framework of regulatory strategies, with hope, will help the state regulator better evaluate regulatory policy options.



## CHAPTER 7

### CONCLUSIONS AND RECOMMENDATIONS

#### General Observations

This report attempts to delineate the relative merits of various rate design options for unbundled gas services. To accomplish this goal, the report examines and evaluates alternative options for allocating costs and designing tariffs against the yardstick of a set of chosen regulatory objectives. The regulatory objectives used as evaluation criteria include those inherited from the regulated monopoly era, such as economic efficiency and equity, and others spawned by the emerging hybrid regime of regulation and competition, such as facilitation of competition and consumer protection.

This report focuses on various cost allocation and tariff design options generally practiced by regulators or proposed by regulatory analysts. Each option has its origins in the accounting or economic disciplines and has its rationale in one or more of the following notions: cost causation, beneficiality, revenue sufficiency and welfare maximization. Also, each option is derived from one or more of the principal methodologies of cost allocation – fully distributed costs, marginal costs, stand alone costs and market value. The cost allocation and separation schemes that were examined include book and market valuation of assets, peak-based methods for capacity costs, short- and long-run marginal costs and market-based methods for operating expenditures. The tariff design options examined include traditional tariffs, performance-based rates (PBRs),

interruptible, time-of-use and seasonal. rates. It should be reiterated that the cost allocation schemes and tariff designs are not mutually exclusive as there may be a significant degree of overlap among them. For example, one can use a fully distributed cost-based allocator to prorate the market value of an asset among its various uses.

### Conclusions

This study finds that no single cost allocation or rate design option has all the desirable properties to meet the most important regulatory objectives, although some may better meet more regulatory objectives than others. One of the reasons no single option can perfectly satisfy all of the important regulatory objectives is because of the inherent conflicts among regulatory objectives. Arguably the most critical and somewhat paradoxical conflict is the one between short-run economic efficiency and competitiveness in a situation where the utility is the dominant provider of an unbundled service. Providing the utility with an incentive to minimize rates may allow it to undercut potential competitors and deter entry. One can argue that encouraging entry of potential competitors promotes long-term dynamic efficiency and that the public interest may be better served by such a policy even though it may entail the sacrifice of short-term economic efficiency. Another, and somewhat related, example would be to let the utility and its affiliate conduct a transaction that exploits the underlying economies of scope (such as selling a service to the affiliate at a price that is lower than charged to others because it costs less to serve the affiliate). Although it would be economically efficient to allow this discriminatory practice, it would deter entry by the affiliate's potential competitors and may even drive out the current competitors. There may be good arguments on both sides of

whether economic efficiency or competitiveness ought to be promoted in a mixed regulatory-competitive regime. Ultimately, the state regulatory commissions will make a choice among conflicting regulatory objectives on the basis of their preferences.

### Recommendations

Given the finding that no combination of cost allocation schemes and tariff designs is likely to meet all of the most important regulatory objectives, the study does not recommend any specific option. Also, the public interest compulsions and preferences of each state public utility commission may be different, and the desirable set of options for one PUC may be an inferior choice for another PUC. Finally, given the differing characteristics of each LDC even within the jurisdiction of a PUC, the same set of options may not be suitable for different LDCs.

This study identifies three possible regulatory strategies with regard to rate design options (see Table 6-13). The gradualist strategy is designed to move into a competitive regime at a relatively slow pace to allow for adjustments to traditional regulatory objectives and customer interests. The market facilitation strategy would facilitate market forces more aggressively and would attempt to achieve competitive conditions at a relatively rapid pace. The radical deregulation strategy would immediately unbundle and deregulate services that are deemed competitive.

The choice of the regulatory strategy would depend on the conditions prevailing in each state in addition to regulatory preferences. For example, a state in which gas utility service rates are relatively low may opt for the gradualist strategy. On the other hand, a state with relatively high gas utility service rates may opt for either the market facilitation or the radical deregulation strategy.

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 4**

**ATTACHMENT D**

**SHAPLEY CALCULATION**



## COOPERATIVE GAMES: the SHAPLEY VALUE

The description of a cooperative game is still in terms of a **characteristic function** which specifies for every group of players the total payoff that the members of  $S$  can obtain by signing an agreement among themselves; this payoff is available for distribution among the members of the group.

DEFINITION. A **coalitional game with transferable payoff** (or characteristic function game) is a pair  $\langle N, v \rangle$  where  $N = \{1, \dots, n\}$  is the set of players and for every subset  $S$  of  $N$  (called a **coalition**)  $v(S) \in \mathbb{R}$  is the total payoff that is available for division among the members of  $S$  (called the **worth** of  $S$ ). We assume that the larger the coalition the higher the payoff (this property is called superadditivity):

$$\text{for all disjoint } S, T \subseteq N, \quad v(S \cup T) \geq v(S) + v(T)$$

As before, an agreement is a list  $(x_1, x_2, \dots, x_n)$  where  $x_i$  is the proposed payoff to individual  $i$ . Shapley proposed some conditions (or axioms) that a solution should satisfy and proved that there is a unique solution that meets those conditions. The solution, known as the **Shapley value**, has a nice interpretation in terms of **expected marginal contribution**. It is calculated by considering all the possible orders of arrival of the players into a room and giving each player his marginal contribution. The following examples illustrate this.

**EXAMPLE 1.** Suppose that there are two players and  $v(\{1\}) = 10$ ,  $v(\{2\}) = 12$  and  $v(\{1,2\}) = 23$ . There are two possible orders of arrival: (1) first 1 then 2, and (2) first 2 then 1.

If 1 comes first and then 2, 1's contribution is  $v(\{1\}) = 10$ ; when 2 arrives the surplus increases from 10 to  $v(\{1,2\}) = 23$  and therefore 2's marginal contribution is  $v(\{1,2\}) - v(\{1\}) = 23 - 10 = 13$ .

If 2 comes first and then 1, 2's contribution is  $v(\{2\}) = 12$ ; when 1 arrives the surplus increases from 12 to  $v(\{1,2\}) = 23$  and therefore 1's marginal contribution is  $v(\{1,2\}) - v(\{2\}) = 23 - 12 = 11$ .

Thus we have the following table:

Probability	Order of arrival	1's marginal contribution	2's marginal contribution
$\frac{1}{2}$	first 1 then 2	10	13
$\frac{1}{2}$	first 2 then 1	11	12

Thus 1's expected marginal contribution is:  $\frac{1}{2} 10 + \frac{1}{2} 11 = 10.5$  and 2's expected marginal contribution is  $\frac{1}{2} 13 + \frac{1}{2} 12 = 12.5$ . This is the Shapley value:  $x_1 = 10.5$  and  $x_2 = 12.5$ .

**EXAMPLE 2.** Suppose that there are three players now and  $v(\{1\}) = 100$ ,  $v(\{2\}) = 125$ ,  $v(\{3\}) = 50$ ,  $v(\{1,2\}) = 270$ ,  $v(\{1,3\}) = 375$ ,  $v(\{2,3\}) = 350$  and  $v(\{1,2,3\}) = 500$ . Then we have the following table:



$$v(\{1\}) = 100, v(\{2\}) = 125, v(\{3\}) = 50, v(\{1,2\}) = 270, v(\{1,3\}) = 375, v(\{2,3\}) = 350 \text{ and } v(\{1,2,3\}) = 500$$

Probability	Order of arrival	1's marginal contribution	2's marginal contribution	3's marginal contribution
$\frac{1}{6}$	first 1 then 2 then 3: 123	$v(\{1\}) = 100$	$v(\{1,2\}) - v(\{1\}) = 270 - 100 = 170$	$v(\{1,2,3\}) - v(\{1,2\}) = 500 - 270 = 230$
$\frac{1}{6}$	first 1 then 3 then 2: 132	$v(\{1\}) = 100$	$v(\{1,2,3\}) - v(\{1,3\}) = 500 - 375 = 125$	$v(\{1,3\}) - v(\{1\}) = 375 - 100 = 275$
$\frac{1}{6}$	first 2 then 1 then 3: 213	$v(\{1,2\}) - v(\{2\}) = 270 - 125 = 145$	$v(\{2\}) = 125$	$v(\{1,2,3\}) - v(\{1,2\}) = 500 - 270 = 230$
$\frac{1}{6}$	first 2 then 3 then 1: 231	$v(\{1,2,3\}) - v(\{2,3\}) = 500 - 350 = 150$	$v(\{2\}) = 125$	$v(\{2,3\}) - v(\{2\}) = 350 - 125 = 225$
$\frac{1}{6}$	first 3 then 1 then 2: 312	$v(\{1,3\}) - v(\{3\}) = 375 - 50 = 325$	$v(\{1,2,3\}) - v(\{1,3\}) = 500 - 375 = 125$	$v(\{3\}) = 50$
$\frac{1}{6}$	first 3 then 2 then 1: 321	$v(\{1,2,3\}) - v(\{2,3\}) = 500 - 350 = 150$	$v(\{2,3\}) - v(\{3\}) = 350 - 50 = 300$	$v(\{3\}) = 50$

Thus 1's expected marginal contribution is:  $\frac{1}{6}(100 + 100 + 145 + 150 + 325 + 150) = \frac{970}{6}$

2's expected marginal contribution is  $\frac{1}{6}170 + \frac{1}{6}125 + \frac{1}{6}125 + \frac{1}{6}125 + \frac{1}{6}125 + \frac{1}{6}300 = \frac{970}{6}$

3's expected marginal contribution is  $\frac{1}{6}230 + \frac{1}{6}275 + \frac{1}{6}230 + \frac{1}{6}225 + \frac{1}{6}50 + \frac{1}{6}50 = \frac{1060}{6}$

The sum, of course, is  $\frac{3000}{6} = 500 = v(\{1,2,3\})$

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 4**

**ATTACHMENT E**

**SHAPLEY VALUE PAPERS**

## ATTACHMENT E: SHAPLEY VALUE PAPERS

- Acuña, Luceny Guzmán, et al. "Cooperation Model in the Electricity Energy Market Using Bi-Level Optimization and Shapley Value." *Operations Research Perspectives*, Elsevier, 17 July 2018, [www.sciencedirect.com/science/article/pii/S221471601830037X](http://www.sciencedirect.com/science/article/pii/S221471601830037X).
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**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 5**

**ELECTRIC GENERATION LOCAL TRANSMISSION RATE**

**DESIGN ANALYTICS**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 5  
ELECTRIC GENERATION LOCAL TRANSMISSION RATE DESIGN ANALYTICS  
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1 **PACIFIC GAS AND ELECTRIC COMPANY**  
2 **CHAPTER 5**  
3 **ELECTRIC GENERATION LOCAL TRANSMISSION RATE DESIGN**  
4 **ANALYTICS**

5 **A. Introduction**

6 This chapter presents Pacific Gas and Electric Company's (PG&E) analytics  
7 on a different electric generation (EG) local transmission (G-EG LT) rate design  
8 than the current design, during the 2023 Gas Transmission and Storage (GT&S)  
9 Cost Allocation and Rate Design proceeding period of 2023-2026. This section  
10 describes PG&E's analytical methods, results, and conclusions on how a new  
11 G-EG LT rate design could impact net EG gas throughput compared to the  
12 status quo rate design.

13 The 2019 GT&S Rate case Decision (D.) 19-09-025, Conclusion of Law  
14 (COL) 124<sup>1</sup> requires PG&E to participate in workshops to evaluate proposals to  
15 revise the G-EG LT rate design for reasonableness. In compliance with the  
16 Decision, PG&E held a workshop on December 10, 2019. This chapter adds to  
17 this effort by analyzing how a new G-EG LT rate design could impact net EG gas  
18 throughput.

19 The G-EG LT rate design analyzed in this chapter has a high fixed  
20 reservation charge and a low volumetric rate. The current G-EG LT rate design  
21 is mostly a volumetric rate. The G-EG LT rate design analytical results show  
22 conflicting indications whether a high fixed reservation charge and low  
23 volumetric rate benefits all EG customers gas throughput on the PG&E system.

24 The chapter contains two sets of analyses: historical data and production  
25 cost simulations.<sup>2</sup> The historical data analysis shows inconclusive results that  
26 this rate design leads to improved EG throughput for all EG customers or  
27 throughput increases correlate to other electric market drivers. Simulating EG  
28 gas throughput using a production cost model shows a net increase in total EG

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1 D.19-09-025, p. 319, COL 124, "Requiring PG&E to participate in workshops to  
evaluate proposals to revise the Electric Generation Local Transmission rate design is  
reasonable."

2 Production cost simulations provide estimates of consumption of all fuels used for  
power generation on an economic basis.



gas throughput. EG customers on Local Transmission (LT) increases while throughput comes with a decline in backbone (BB) throughput and electric imports into the PG&E Service Territory. Renewable generation does not change. This production cost simulation analysis relies on two key assumptions. The first assumption is that transportation rate designs other than the PG&E G-EG LT rate do not change during the 2023-2026 period. This assumption reflects the competitive nature of the California Independent System Operator (CAISO) electric marketplace. The second assumption is that the conceptual rate design includes a sunk reservation cost, without making any assumptions regarding how the reservation cost would affect generators' behavior or how the electric generators recover this sunk cost. These assumptions are beyond PG&E's insight but fundamental in their impact on the analytical conclusions from the simulations.

## **1. Purpose and Scope of the Chapter**

This chapter presents the analysis of the G-EG LT rate design with a high reservation charge and a low volumetric rate. PG&E analyzes whether this rate design impacts EG gas throughput. Currently, customers on the G-EG LT tariff pay a virtually 100 percent volumetric rate.<sup>3</sup> The rate design would lower the volumetric rate portion and add a reservation charge. Both rate components aim to recover the revenue requirement applied to EG customers on the LT system. The rate design aligns to the workshop held on December 10, 2019.<sup>4</sup>

## **2. Summary of Analysis**

The chapter describes the analysis and results to determine how this rate design concept may benefit EG customers. The analysis looks at how EG gas throughput changes for BB and LT EG customers.

The analytics performed by PG&E show some positive model results, however inconclusive. Conflicting results consist of a decline in EG BB

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<sup>3</sup> The G-EG tariff includes a tiered Customer Access Charge that amounts to approximately 0.4 percent of the total end-user revenue requirement allocated to EG-LT customers Gas Schedule G-EG, <[https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_SCHS\\_G-EG.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHS_G-EG.pdf)> (as of Sept. 9, 2021).

<sup>4</sup> Electric Generation Rate Design Workshop Ordered in D.19-09-025, p. 319, COL 124.

1 customers throughput while EG LT customers throughput increases. Also,  
2 the inability for PG&E to validate the assumptions causes concerns about  
3 how this rate design would work in the real world.

4 In late 2019, PG&E and many customers on the G-EG LT tariff  
5 negotiated a new rate implemented on a contractual basis through  
6 December 31, 2022. The rate consists of a monthly reservation charge and  
7 a low end-user volumetric transportation rate. This analysis examined  
8 actual throughput increase for the EG LT customers from October 2019  
9 through June 2021. These customers' throughput increased during this  
10 time. However, throughput also increased for other EG customers. These  
11 include other EG LT customers who did not take this negotiated rate and BB  
12 connected EG (EG BB) customers. Additionally, changes in EG throughput  
13 show good correlation to changes in other throughput drivers, such as  
14 hydroelectric conditions and electric load. These factors lead to  
15 inconclusive results of the impact of the rate design concept. Whether the  
16 other factors were sufficient to overwhelm the potential impact of the  
17 negotiated rate design cannot be easily parsed.

18 Under production cost simulations, the new rate design shows that  
19 EG LT and total EG customer throughput does increase. The analysis also  
20 finds that EG BB customers throughput declines with a decline of electric  
21 imports into Northern California. Given questions regarding the  
22 assumptions' validity and some decline in EG BB throughput as further  
23 elaborated below PG&E views the results on this rate design as  
24 inconclusive.

#### 25 **a. Summary Table of Conclusions**

26 The G-EG LT rate design analytics results show conflicting support.  
27 The analytics employed two methods: historical data analysis and  
28 production cost simulation. The historical data analysis shows  
29 conflicting indications that the EG LT negotiated rate led to positive  
30 throughput changes. Table 5-1 shows that the EG LT throughput on the  
31 renegotiated rate increased 7 percent prior and after the rate change.  
32 During this same period, G-EG BB (G-EG BB) total throughput increase  
33 more at 25 percent. However, in general given that power plants on EG  
34 BB pay a significantly reduced transportation rate by virtue of not having

an LT component in their rates, they are typically facing a different gas rate-related impact in competing to supply power than EG plants on the LT system. These results show inconclusive evidence that throughput increased for the EG LT customers because of the negotiated rate.

**TABLE 5-1  
HISTORICAL ANALYSIS GAS THROUGHPUT SUMMARY STATISTICS  
THOUSAND DECATHERMS PER DAY (MDTH/D)**

Line No.	Throughput Groups	Before Renegotiated Rate Throughput (MDth/d)	After Renegotiated Rate Throughput (MDth/d)	Percent Change
		Jan-2018 through Sep-2019	Oct-2019 through Jun-2021	
1	G-EG LT on the renegotiated rate	190	204	7%
2	G-EG LT on the current rate	79	82	4%
3	G-EG LT Total	270	286	6%
4	G-EG BB Total	305	380	25%

With the inconclusive results from the historical data analysis, PG&E used a production cost model to simulate conditions with and without the G-EG LT rate design concept. The production cost simulation analysis suggests that gas throughput could increase, supporting the new rate design concept but within the limitations of the model assumptions as stated above. However, the increase in EG LT throughput comes at some expense of EG BB throughput and electric imports into Northern California. Table 5-2 shows that with a lower volumetric rate compare to the current 100 percent volumetric rate, gas throughput increases.

**TABLE 5-2  
PRODUCTION COST SIMULATION  
GAS THROUGHPUT COMPARISON (MDTH/D)  
2023-2026 AVERAGE**

Line No.	Case	Total	Backbone	Local Transmission
1	100 percent volumetric rate	333	274	59
2	Low volumetric rate	365	254	111
3	Volumetric change	32	-19	52

## b. Organization of the Remainder of This Chapter

The analytics for the G-EG LT rate design concept has three sections as follows:

- Historical analysis: This section describes the historical data analysis to determine how EG gas throughput changed from the G-EG LT negotiated rate. This analysis reviews EG gas throughput relative to changes in CAISO electric load and hydroelectric generation.
- Production cost modeling: This section describes the results from the production cost modeling simulating EG gas throughput with and without the rate design concept.
- Rate design analytical conclusion: This section concludes with the impact of the rate design concept on throughput while noting the limitations of the models to answer questions beyond its capabilities and purpose.

## B. Background

Since October 2019, PG&E and G-EG LT customers could negotiate the rate design structure of the at-risk component of the G-EG LT tariff.<sup>5</sup> Rates under this tariff schedule may be negotiated and implemented in a contract. According to the tariff, negotiated rates for G-EG service shall not be less than PG&E's short-run marginal cost of providing the service.

Prior to October 2019, many G-EG LT customers engaged with PG&E for a negotiated tariff rate. As negotiated, the rate consisted of a lower volumetric rate and a monthly reservation charge. However, the negotiated rate was not a discount but an alternative rate design that would fully collect the allocated cost of service under the adopted throughput across the EG-LT customer class. PG&E viewed the negotiated rate structure as an opportunity to stabilize the revenue collection under a significant fixed charge from a customer class with variable gas usage. The hypothesis for PG&E's participation was that a lower volumetric rate could make EG plants more competitive in the CAISO

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<sup>5</sup> Gas Schedule G-EG, <[https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_SCHEDS\\_G-EG.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHEDS_G-EG.pdf)> (as of Sept. 9, 2021).

marketplace by enabling them to bid in a lower marginal cost rather than a higher marginal cost that reflects the current high volumetric G-EG LT tariff.

## **1. Historical Analysis**

Because PG&E and the G-EG LT customers have experienced a negotiated rate similar to the rate design concept, this analysis investigates if throughput increased or stabilized. If this analysis shows net throughput benefits, this rate design may be preferred.

### **a. Modeling Methodology**

The negotiated rate consisted of a monthly fixed charge that recovers about 90 percent of the annual revenue requirement assigned to the G-EG LT tariff. This led to a lower volumetric end-user transportation rate. Customers representing about 70 percent of the EG LT volumes agreed to the negotiated rate. The other 30 percent of EG LT volumes continued to be served on the all volumetric G-EG-LT tariff.

This historical analysis studied how gas throughput changed from January 2018 through June 2021 with the renegotiated rate coming into effect in October 2019. The analysis calculates summary statistics and analyzes correlation between primary electric market drivers. These drivers are hydroelectric generation (hydro) and electric load (demand) for the CAISO marketplace. The summary statistics consist of average and percent change of EG gas throughput over time. Also, correlation analysis measured the degree of linear association between EG gas throughput, hydro, and electric load. These metrics show how EG gas throughput reacts to the negotiated rate and the strength of throughput changes to changes in the electric market.

The historical data analysis broke out EG throughput into four categories. The throughput categories examined are:

- 1) G-EG LT on the renegotiated rate;
- 2) G-EG LT on the current rate;
- 3) G-EG LT Total; and
- 4) G-EG BB Total.

1                   These categories will separate how customers on the renegotiated  
2 rate compare to all other EG customers.

3                   **b. Model Input Assumptions**

4                   The historical analysis segments the data in to two segments. The  
5 first segmentation is January 2018 through September 2019. During  
6 this period, all G-EG LT customers were under the all volumetric tariff  
7 rate. This analysis assumes that G-EG LT gas throughput was only  
8 impacted by the negotiated rate.

9                   **c. Analytical Results**

10                  The historical analysis provides inconclusive evidence that the  
11 negotiated rate increases throughput. Table 5-3 shows the summary  
12 statistics. For the G-EG LT customers with the negotiated rate,  
13 throughput increases 7 percent. This shows some support that the  
14 G-EG LT rate design concept increases throughput. However, EG BB  
15 (G-EG BB) customer gas throughput increases 25 percent. For  
16 customers on the current G-EG LT rate, throughput increases 4 percent.  
17 Additionally, power imports into the PG&E Service Territory decline  
18 while renewable generation did not change. Though the EG LT  
19 customers on the negotiate rate design had almost twice the increase in  
20 throughput compared to those remaining on the standard tariff design,  
21 the differential is not significant enough to be conclusive. Therefore, the  
22 historic analysis is directionally supportive but insufficient to provide a  
23 clear judgment on the impacts of the G-EG LT negotiated rate design  
24 concept.



**TABLE 5-3**  
**HISTORICAL ANALYSIS GAS THROUGHPUT SUMMARY STATISTICS**

Line No.	Throughput Groups	Before Renegotiated Rate Throughput (MDth/d)	After Renegotiated Rate Throughput (MDth/d)	Percent Change
		Jan-2018 through Sep-2019	Oct-2019 through Jun-2021	
1	G-EG LT on the renegotiated rate	190	204	7%
2	G-EG LT on the current rate	79	82	4%
3	G-EG LT Total	270	286	6%
4	G-EG BB Total	305	380	25%

To further examine the historical data, this analysis looked at correlations between the same four EG gas throughput categories and electric load and hydroelectric generation. The choice of these two electric market drivers can show whether throughput changes differently than all other EG customers. The strength of correlation does not predict gas throughput, it only measures the degree of linear association.

The analysis in Table 5-4 shows consistent linear correlation for gas throughput and electric load or hydroelectric generation. The lack of standout correlation results between the throughput groups indicate inconclusive results for the G-EG L rate design concept. For example, the correlation for customers on the negotiated rates shows similar results at 50 percent compared to the BB EG customers at 46 percent. The throughput correlation to hydro conditions show similar correlation for all throughput groups. The extent of correlation separation ranges from negative 6 percent to -39 percent. Consequently, these correlation results show inconclusive conclusions on how the negotiate rate design impacted throughput.

**TABLE 5-4**  
**CORRELATION ANALYSIS GAS THROUGHPUT**  
**(JAN-2018 THROUGH JUN-2021)**

Line No.	Throughput Group	CAISO Electric Load	CAISO Hydro Generation
1	G-EG LT on the renegotiated rate	50%	-26%
2	G-EG-LT on the current rate	66%	-6%
3	G-EG LT Total	59%	-21%
4	G-EG BB Total	46%	-39%

With the inconclusive supportive nature of the historical data analysis to make a decision regarding the rate design concept, PG&E used production cost modeling to isolate EG gas throughput and the G-EG LT rate design concept. This helps to examine a single change to understand if the rate design concept impacts gas throughput.

## **2. Production Cost Modeling**

### **a. Modeling Methodology**

The simulation of EG gas throughput uses the PLEXOS<sup>6</sup> production cost modeling tool. This application provides estimates of consumption of all fuels used for power generation within the Western Electricity Coordinating Council (WECC) on an economic basis. As described more fully in Chapter 2A, PLEXOS models competition of EG power plants in the WECC under the assumptions employed.

### **b. Model Input Assumptions**

Since Northern California is part of a much larger electricity market, PG&E used PLEXOS to model the entire WECC area. Many assumptions are needed as input data. Chapter 2A provides a full detail of these assumptions. In short, the key assumptions impacting the PLEXOS model includes natural gas burnertip prices that include pipeline transportation rates, electric load, existing and new generation resources, and hydro conditions. PLEXOS also incorporates transmission capacities between load regions and operating

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<sup>6</sup> PLEXOS is software licensed by Energy Exemplar Ltd.

1 characteristics of power plant, factors that can play a role in determining  
2 economic dispatch.

3 Two production cost modeling cases were prepared. The first case,  
4 named Base case, uses the same assumptions in Chapter 2A. Some of  
5 the key assumptions include natural gas commodity and transportation  
6 rates, generation resources and additions, and hydroelectric generation.  
7 The second case changes the G-EG LT all volumetric end-use  
8 transportation rate to a lower volumetric rate and a monthly fixed  
9 charge. This case is named G-EG LT rate design. The rate design  
10 incorporated for this simulation recovered as a fixed charge 50 percent  
11 of the Base case allocation of LT revenue requirement for market  
12 sensitive power plants served from PG&E's LT system, with the  
13 remaining revenue requirement recovered through the volumetric rate  
14 component.<sup>7</sup> Compared to the Base case, no other assumptions were  
15 modified. This allows for easy comparison between these analyses  
16 since only one change in assumptions was made.

17 The G-EG LT rate design sensitivity contains these important  
18 assumptions. The first one assumes that the monthly fixed charge is a  
19 sunk cost and plants only bid in their marginal cost.<sup>8</sup> The sunk cost  
20 assumption recognizes that a power plant owner decided to incur this  
21 cost and that it is not recovered in the wholesale marketplace.<sup>9</sup> Also,  
22 the analysis does not determine whether or if the fixed charge is  
23 recovered in the marketplace beyond the CAISO market-clearing  
24 dispatch price. Last, all other gas burnertip prices bid into CAISO do not  
25 change compared to the Base case. Specifically, the marginal  
26 competition in the CAISO marketplace typically comes from EG plants  
27 throughout California. This means that the assumption in the analysis is  
28 that EG transportation rates in the San Diego Gas and Electric and

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7 The Base case and G-EG LT rate design scenario rates were provided by the Chapter 6, Cost Allocation and Rate Design witness. Chapter 6 discusses the reasonableness of the G-EG LT rate design structure used for this analysis.

8 Plants bidding into CAISO cannot bid lower than their marginal cost.

9 Other revenue sources could be received from, for example, resource adequacy payments and ancillary services.

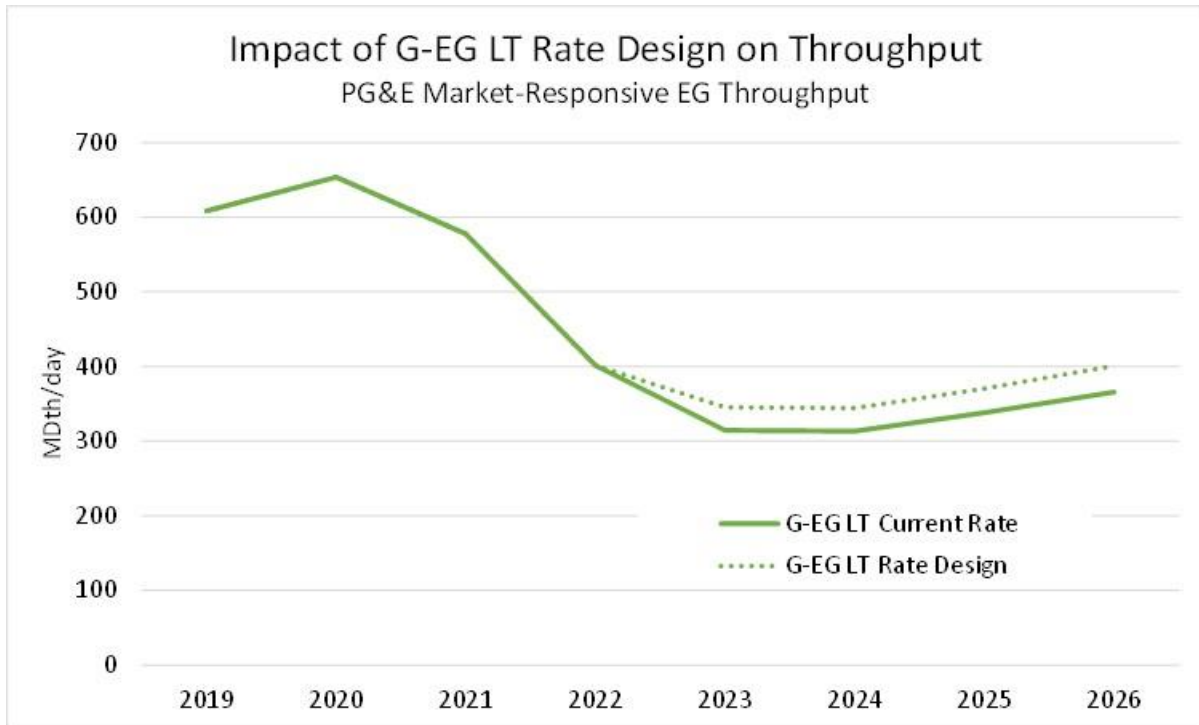
1 Southern California Gas Company (SoCalGas) service areas do not  
2 change.

3 **c. Analytical Results**

4 To understand how the G-EG LT rate design concept could impact  
5 gas throughput, two simulations were performed as described above.  
6 The first simulation, named the Base case, shows the EG gas  
7 throughput forecast given in Chapter 2, EG Demand and Throughput.  
8 The second simulation, a sensitivity named G-EG Rate Design  
9 (Sensitivity), reflects the throughput impact in changing the tariff from an  
10 all volumetric rate to a rate design with a reservation charge and smaller  
11 volumetric rate. The comparison of PG&E's EG customers throughput  
12 in the Base case and the Sensitivity simulations show a net increase.  
13 Figure 5-1 plots both the Base case and Sensitivity throughput through  
14 the rate case period.

15 In the Base case for this rate case period for years 2023 and 2024,  
16 EG gas throughput decreases as renewable generation increases, and  
17 Northern California EG burnertip prices become less competitive.  
18 Consequently, throughput declines. For years 2025 and 2026, the  
19 retirement of Diablo Canyon drives higher EG gas throughput.  
20 Therefore, Northern California EG gas plants increase gas throughput  
21 for power generation to meet electric load.

**FIGURE 5-1  
ELECTRIC GENERATION GAS THROUGHPUT  
BASE CASE AND G-EG LT RATE DESIGN CONCEPT**

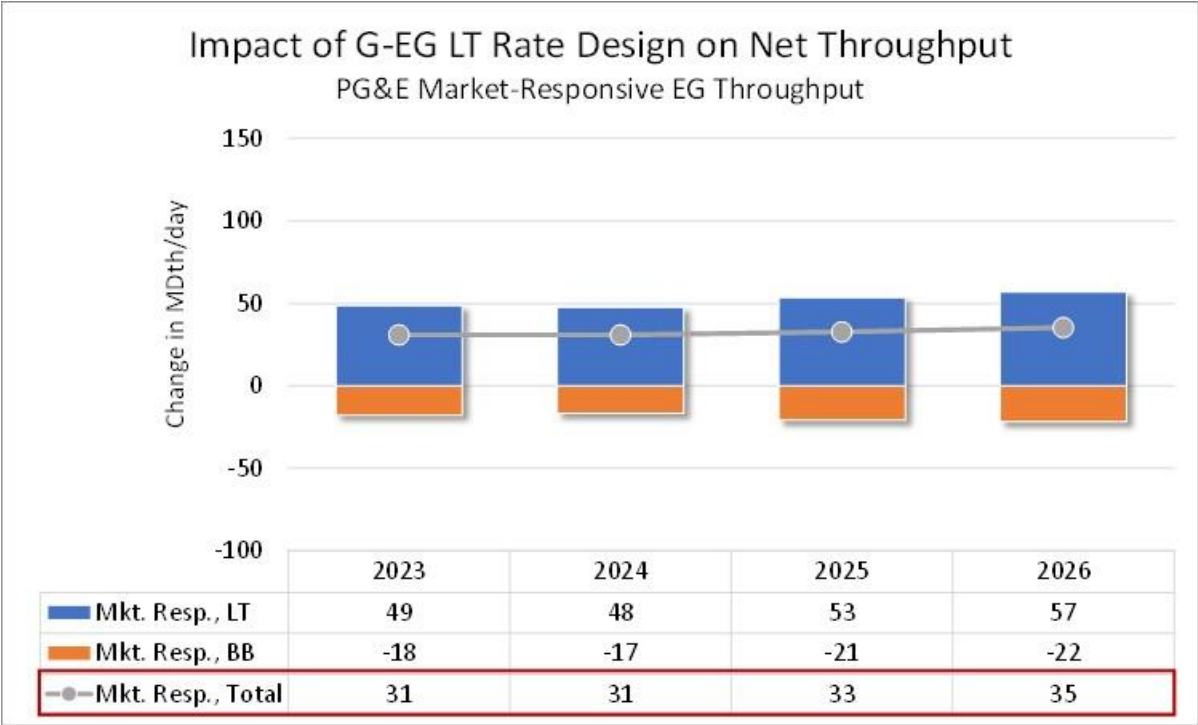


The Sensitivity case shows similar trends as the Base case. However, the trend is slightly elevated. The Sensitivity case EG gas throughput increase comes from a lower effective volumetric burnertip price for EG plants connected to the PG&E LT system. All other assumptions in the Base case hold in the Sensitivity case. Consequently, the only change in these two cases is the G-EG LT rate design. This shows that the only variable impacting the higher throughput for EG LT customers is the rate design.

The results of these two cases are shown in Figure 5-2. The net increase in total EG throughput ranges from 31 MDth/d to 35 MDth/d. The increase in LT throughput is offset by approximately 30 percent to 40 percent decline in BB throughput. The lower burnertip gas prices from the G-EG LT rate design yields a higher LT throughput of about 80 percent to 95 percent. Yet, less efficient and/or higher operational cost BB connected EG plants lose market share. The decline compared to the Base case is 6 percent to 8 percent. The analysis shows that the

1 increase in LT throughput coincides with a lower BB generator  
2 throughput.

**FIGURE 5-2**  
**ELECTRIC GENERATION NET GAS THROUGHPUT**  
**BASE CASE AND G-EG LT RATE DESIGN CONCEPT**



3 The production cost modeling shows how isolating the impact of the  
4 G-EG LT rate design concept could impact EG throughput. This  
5 analysis shows that a fixed reservation charge and lower volumetric rate  
6 increases net EG throughput. However, this analysis contains two key  
7 assumptions as described above. The monthly fixed charge has already  
8 been incurred and not recoverable. This analysis does not address  
9 recovery of this cost by generators. Other value streams may be  
10 available to generators other than CAISO marketplace, but PG&E does  
11 not have insight into them. Also, SoCalGas EG pipeline transportation  
12 rates do not change in this analysis. Weakening these assumptions  
13 could cast doubt on the magnitude of the net EG throughput increase.

14 **C. Conclusion**

15 The G-EG LT rate design analytics results point towards a potential increase  
16 in the net EG gas throughput assuming a redesign in the G-EG LT rate as



1 analyzed in this chapter. But the analysis does not provide conclusive results to  
2 support the rate design concept. One factor is the inability of PG&E to validate  
3 the underlying assumptions used in the PLEXOS analysis. The historical data  
4 analysis shows modest but inconclusive evidence compared to power plants  
5 served on LT that did not sign the negotiated contracts. Given other potential  
6 drivers of EG throughput differences among the various plants served from LT,  
7 this perspective is inconclusive.

8 Production cost simulations show a net increase in EG gas throughput and  
9 potential improved stability in recovering costs through the fixed charge,  
10 consistent with principles in Chapter 6, Cost Allocation and Rate Design.  
11 However, the increase in LT throughput coincides with a lower level of BB  
12 generator throughput and lower electric imports into Northern California.  
13 Renewable generation does not change. Last two key assumptions underlie the  
14 PLEXOS model results: (1) SoCalGas transportation rates do not change from  
15 base case and (2) sunk cost (fixed charge) recovery is available for the EG LT  
16 plants from other sources than bidding into CAISO. As PG&E does not have  
17 insight into the validity of these assumptions, from an analytical point of view its  
18 analysis is supportive but inconclusive.

19 This analysis informs the proposal to keep the EG LT rate design explained  
20 in Chapter 6, Section E, page 6-11. Given the importance of this topic to the  
21 Commission and parties as evidenced by the Workshop ordered in the 2019  
22 GT&S Rate case Decision, PG&E is sharing this analysis.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 6**  
**COST ALLOCATION AND RATE DESIGN**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 6  
COST ALLOCATION AND RATE DESIGN

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 6**  
**COST ALLOCATION AND RATE DESIGN**

**A. Introduction**

**1. Purpose and Scope of the Chapter**

This chapter presents the gas rates and gas rate impacts for Pacific Gas and Electric Company's (PG&E) 2023 Gas Transmission and Storage (GT&S) Cost Allocation and Rate Design (CARD) Case. As a result of the final decision in the California Public Utilities Commission's (CPUC or the Commission) Rate Case Plan for Energy Utilities, this is the first PG&E GT&S case since 1996 where GT&S revenue requirements and certain capacity forecasts, described below, are adopted in the General Rate Case (GRC) Phase 1 Track I (GRC I) rather than in the GT&S rate case.<sup>1</sup> This chapter presents impacts of PG&E's CARD proposals in CARD, including unbundled backbone transmission rates and illustrative class-average end-use rates.<sup>2</sup> PG&E proposes to implement the throughput and billings forecasts, backbone load factor, and CARD methodologies adopted in PG&E's 2023 CARD proceeding concurrent with the GT&S revenue requirements and capacity forecasts adopted in PG&E's 2023 GRC I proceeding, Application (A.) 21-06-021, which PG&E filed on June 30, 2021.<sup>3</sup>

The unbundled rates presented in this chapter incorporate the following components: the backbone and storage rate design proposals; storage capacity forecasts proposed in PG&E's 2023 GRC I;<sup>4</sup> and backbone capacity forecasts and backbone load factor (Chapter 3 – Backbone Rate

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<sup>1</sup> Decision (D.) 20-02-002, pp. 78-79, Ordering Paragraph (OP) 4.

<sup>2</sup> End-use customers are customers obtaining delivery of natural gas from PG&E's gas transmission or distribution lines within PG&E's service territory.

<sup>3</sup> PG&E presented this proposal for simultaneous implementation of the 2023 GRC and CARD at the Rate Case Plan Workshop #2 (Topic 5) on October 7, 2020. No party objected.

<sup>4</sup> A.21-06-021, Exhibit (PG&E-3), p. 7-52, line 13 to p. 7-53, line 14, Sections D.4 and D.5.

Inputs). The end-user rates presented incorporate the following rate proposals made in this chapter:

1. Local Transmission (LT), including the cost allocation proposal described in Chapter 4;
2. The CARD proposal associated with inventory management as described below in Section F.2;
3. The recovery of depreciation and decommissioning costs associated with the Pleasant Creek storage facility and the return of previously collected depreciation and decommissioning costs associated with the Los Medanos storage facility as described below in Section F.4; and
4. The Customer Access Charge (CAC) rate proposal described in Section G below.

This chapter also presents the average monthly residential usage for an individually-metered customer, segmented between California Alternate Rates for Energy (CARE) and non-CARE customers,<sup>5</sup> and the average monthly non-CARE small commercial usage, based on the throughput and customer (billings) forecasts (Chapter 2B –Non-Generation Demand and Throughput Forecast), that are used to present average non-CARE residential and small commercial bill impacts.<sup>6</sup>

A variety of customers pay the rates described in this chapter, as illustrated below in Figure 6-1. PG&E's bundled core customers pay backbone transmission and storage costs in their procurement rates. Gas Energy Service Providers (ESP), noncore customers, and shippers delivering on- and off-system pay unbundled backbone transmission rates and charges separately to PG&E. Core and most noncore end-use transportation rates include LT charges.<sup>7</sup> All core and noncore end-use

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<sup>5</sup> The proposed throughput and billings forecast does not forecast the CARE vs non-CARE segmentation as that is updated each year when preparing the Public Purpose Program (PPP) Surcharge Tier 2 Advice Letter (AL). To provide illustrative residential bill impacts, PG&E applies recent historic relationship between average CARE and non-CARE usage to segment the total individually metered average usage.

<sup>6</sup> Average monthly usage for other classes is not included, as the range of usage is so large as to make the average usage irrelevant as a point of information, compared to the average rate change for the class.

<sup>7</sup> Except for end-use customers qualifying for backbone level transportation service under G-NT, G-EG, or G-NGV4 as further described in Section C below.

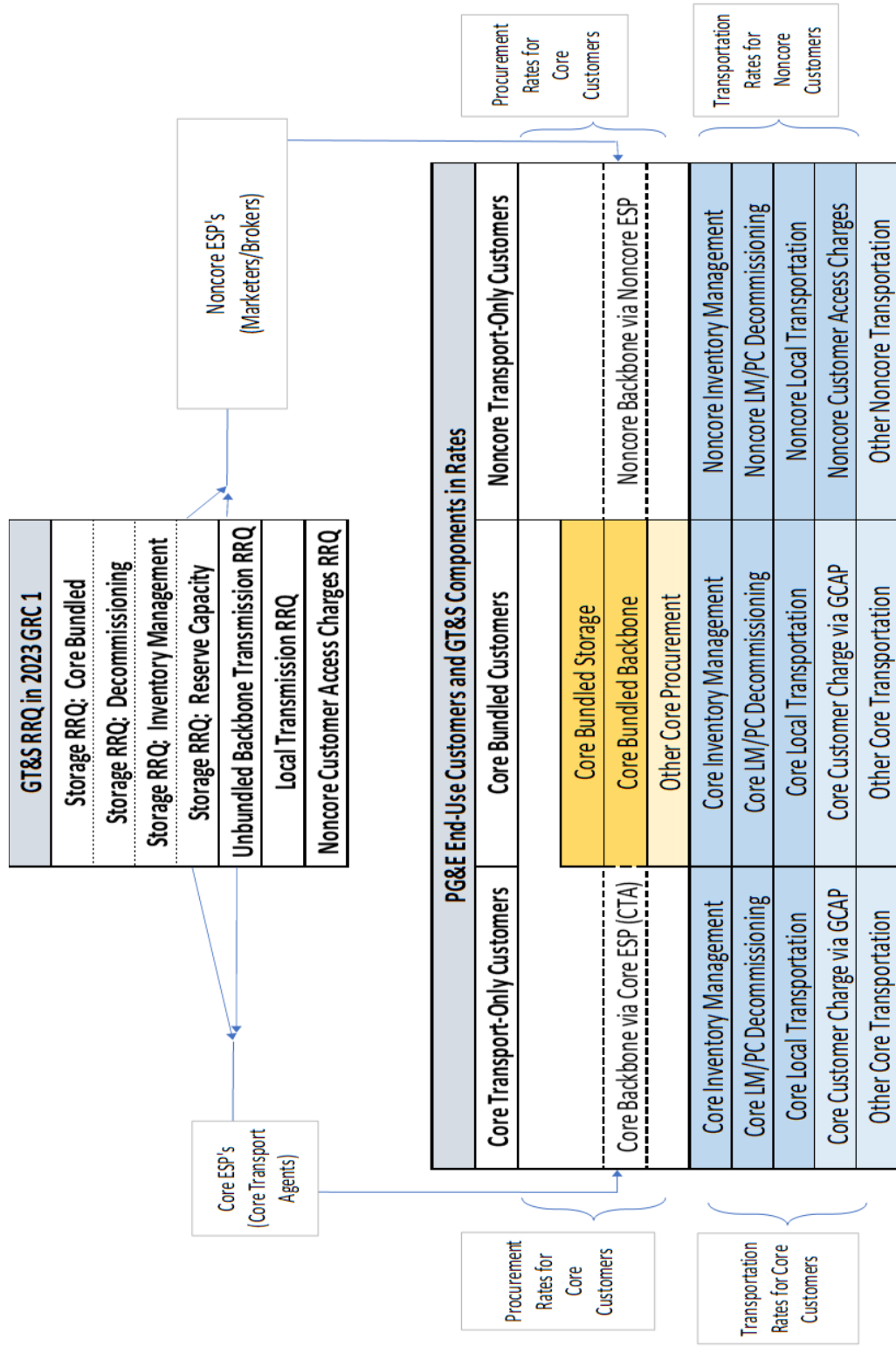


1 transportation rates include Los Medanos and Pleasant Creek depreciation  
2 and decommissioning costs. On a monthly basis, noncore end users pay  
3 transmission-level CAC.<sup>8</sup> Since the implementation of the Natural Gas  
4 Storage Strategy (NGSS) in April 2020, end-use transportation customers  
5 have also paid for Los Medanos and Pleasant Creek depreciation and  
6 decommissioning costs. As proposed in PG&E's 2023 GRC 1, PG&E will  
7 retain Los Medanos in operation and return to customers the revenues  
8 PG&E has received since the 2019 GT&S Rate Case adopted the NGSS.  
9 However, the depreciation and decommissioning recovery in end-use rates  
10 for Pleasant Creek will continue through 2023 and for 2023 through 2026,  
11 respectively, as originally authorized. Finally, as proposed in this chapter,  
12 Inventory Management would be collected in end-use transportation rates  
13 with differentiation by customer class instead of being recovered on an  
14 effective equal cents per therm basis in unbundled backbone transmission  
15 rates.

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<sup>8</sup> G-NT-Distribution customers also pay the CAC's determined in the CARD but with an adjustment to their volumetric transportation rates to true-up on a zero-sum basis their allocation of customer function costs from PG&E's Gas Cost Allocation Proceedings (GCAP) and GRC Phase 1.

**FIGURE 6-1**  
**RECOVERY OF GT&S REVENUE REQUIREMENTS IN RATES BY SERVICE AND CLASS**



1 This CARD application does not set end-user rate components such as  
2 distribution, core gas procurement rate components (other than setting the  
3 core allocation for backbone transmission and storage),<sup>9</sup> gas PPP  
4 surcharges or the Customer Class Charge (CCC) components. These rate  
5 components continue to be set in GRCs, GCAP, Annual True-Ups of  
6 Balancing Accounts, and other regulatory proceedings. However, this  
7 application determines the rate treatment of:

- 8 • Inventory management costs as noted above and proposed in  
9 Section F.2.;
- 10 • As described in more detail in Section F.4. below, end-user rate  
11 components for recovery of Pleasant Creek and return of Los Medanos  
12 NGSS depreciation and decommissioning amounts;<sup>10</sup> and
- 13 • Any late implementation shortfall amortization should it be necessary.

## 14 **2. Summary of Proposals**

15 This chapter provides the calculated proposed 2023-2026 rates for LT,  
16 backbone transmission and storage. In this chapter, PG&E proposes to  
17 change the cost allocation and recovery method in rates for costs  
18 associated with inventory management (described in more detail in  
19 Section F.2.).

20 Additionally, this chapter:

- 21 • Provides the calculated proposed 2023-2026 rates for LT based on the  
22 cost allocation methodology described in Chapter 4 and the currently  
23 adopted rate design methodology;
- 24 • Provides the calculated proposed 2023-2026 rates for backbone  
25 transmission, and storage services, in accordance with currently  
26 adopted CARD methodologies, as modified by the backbone rate  
27 differential and load factor proposed in Chapter 3 and the proposed  
28 treatment of inventory management services described in Section F.2.;
- 29 • Continues the long-standing rate design methodology of scaling the  
30 tiered monthly CACs applicable to noncore customers to recover the

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<sup>9</sup> Actual core storage and backbone rate components are determined in PG&E's monthly pricing AL.

<sup>10</sup> In its GRC 1, PG&E has proposed to retain its Los Medanos Storage Facility, A.21-06-021, Exhibit (PG&E-3), p. 7-50, line 11 to p. 752, line 12, Section D.3.

2023-2026 CAC revenue requirement proposed in PG&E's 2023 GRC I, based on the proposed billings forecasts (Chapters 2A and 2B);

- provides illustrative end-user rate impacts, by customer class, of the resulting proposed rates, as compared to present rates;<sup>11</sup> and,
- provides, for purpose of the Bill Insert, illustrative end-user rates by customer class, as compared to present rates which reflect presently adopted revenue requirements.

**a. Summary Tables of Present and Proposed Rates**

Attachment A provides PG&E's present and proposed:

- Core and Noncore GT&S Revenue Responsibility Table
- Illustrative End-Use Class Average Rates
- Illustrative End-Use Noncore and Wholesale Class Average Rates with Procurement Proxy
- Average Rate Detail by End-Use Customer Class
- Illustrative Backbone Transmission Rates by Path at Full Contract Usage
- Schedule G-XF Rates
- Storage Rates
- LT Rates for Core and Noncore Customers
- Customer Access Charge Rates
- Self-Balancing Credit Rates
- Average Monthly Bill Impacts for Residential and Small Commercial Customer Classes

**b. Organization of the Remainder of This Chapter**

The remainder of this chapter is organized as follows:

- Section B – Backbone Transmission
- Section C – Backbone Level End-Use Service
- Section D – Local Transmission Rate Design
- Section E – Fixed Charge Rate Design of Local Transmission Rates for Electric Generation

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<sup>11</sup> Present rates are based on PG&E's June 1, 2021 rate change filing per AL 4440-G as modified by the revenue requirement and capacity proposals in PG&E's 2023 GRC, A.21-06-021.

- Section F – Storage Cost Allocation and Rate Design
- Section G – Transmission-Level CACs
- Section H – Illustrative Rate Tables with Present and Proposed Rates
- Section I – Residential and Small Commercial Average Monthly Bill Impacts
- Section J – Alternate Illustrative Rate Tables with Present and Proposed Rates for Bill Insert Presentation
- Section K – Alternate Illustrative Residential and Small Commercial Average Monthly Bill Impacts for Bill Insert Presentation
- Section L – Timing of Decision and Implementation
- Section M – Conclusion

## **B. Backbone Transmission**

### **1. Summary**

As described in Chapter 3, Backbone Rate Inputs, PG&E proposes to set a rate differential between the Baja Path and Redwood Path rates paid by core customers and a rate differential between the Baja Path and Redwood Path rates paid by noncore customers (also referred to as shippers) equal to 50 percent of the natural rate differential that would result from the traditional backbone cost allocation.

Proposed backbone transmission rates use a system-wide load factor proposed in Chapter 3, Backbone Rate Inputs, which excludes the incremental Line 401 service under Schedule G-XF contracts. Rates for G-XF contracts will continue to be based on the methodology adopted in D.94-02-042.<sup>12</sup>

### **2. Backbone Transmission Cost Allocation and Rate Design**

The Gas Accord rate structure<sup>13</sup> for backbone transmission rates is unbundled from end-user gas transportation rates and provides firm and as-available on-system and off-system service along various backbone service paths. PG&E proposes to continue to segment total backbone

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<sup>12</sup> D.94-02-042, OP 2, 1994 Cal. PUC LEXIS 82, \*111-112.

<sup>13</sup> D.97-08-055, Section 5; 1997 Cal. PUC LEXIS 763, \*29.

transmission revenue requirements between vintage Redwood (Line 400), expansion Redwood (Line 401), Baja (Line 300), and Common backbone costs. Common backbone costs, including the portion of the storage function revenue requirement allocated to Reserve Capacity, will continue to be allocated to each path based on a *pro rata* share of the firm design capacities of each path. PG&E then allocates the resulting revenue requirements, segmented between core and noncore, by path, based on firm design capacities.

The cost allocation process excludes costs and capacities associated with Sacramento Municipal Utility District's (SMUD) equity interests in Lines 300 and 401. SMUD's equity ownership by line by year is provided in the table below.

**TABLE 6-1  
SMUD EQUITY BACKBONE TRANSMISSION OWNERSHIP**

Line No.		2023	2024	2025	2026
1	SMUD Equity – Line 300 (MDth/d)	38.162	38.162	38.162	38.162
2	SMUD Equity – Line 401 (MDth/d)	48.175	48.175	45.370	43.896

The G-XF revenue requirement will continue to be based on G-XF customers' firm contract quantities (85.8 MDth/d).

As discussed in detail in Chapter 3, Backbone Rate Inputs, PG&E proposes to design backbone path rates, excluding Line 401 contracts under Schedule G-XF, using annual system average load factors.

In D.19-09-025 the CPUC adopted Joint Stipulation 06 (JS-06), "Backbone Path Rate Differential."<sup>14</sup> JS-06 retained the fixed differential rate design for the Redwood and Baja backbone transmission paths adopted in Gas Accord V Settlement,<sup>15</sup> adopting a phased-in rate differential of \$0.10 per Dth beginning in 2019 to \$0.18 per Dth in 2022.<sup>16</sup>

<sup>14</sup> D.19-09-025, p. 334, OP 83.

<sup>15</sup> D.11-04-031, Appendix A, p. 12.

<sup>16</sup> A.17-11-009, Exhibit JS-06, p. 5, Section V.A.



1 Adopted Firm Backbone Transmission rates by year are shown in the table  
2 below.

**TABLE 6-2**  
**ADOPTED FIRM BACKBONE TRANSPORTATION RATES**  
**ANNUAL RATES (AFT) – MFV RATE DESIGN**  
**(\$/DTH@ FULL CONTRACT)**

Line No.	Year	Core Baja	Core Redwood	Differential	Noncore Baja	Noncore Redwood	Differential
1	2019	0.5538	0.4538	0.1000	0.5905	0.4905	0.1000
2	2020	0.7442	0.6092	0.1350	0.7961	0.6611	0.1350
3	2021	N/A	0.6875	N/A	0.8994	0.7294	0.1700
4	2022	N/A	0.7180	N/A	0.9318	0.7518	0.1800

3 As discussed in detail in Chapter 3, PG&E proposes a modified  
4 Baja-Redwood rate differential based on 50 percent of the natural rate  
5 differential calculated using the traditional backbone cost allocation. This  
6 methodology results in a rate differential between the Baja and Redwood  
7 Paths for each year of the rate case as shown in Table 6-3 below.

**TABLE 6-3**  
**PROPOSED BACKBONE RATE DIFFERENTIAL**

Line No.	Year	Proposed Rate Differential (\$/Dth)
1	2023	\$0.137
2	2024	\$0.161
3	2025	\$0.164
4	2026	\$0.176

8 PG&E's proposed core rates continue to reflect the cost of  
9 611.9 MDth/d<sup>17</sup> of vintage Line 400 capacity. Although PG&E's Core Gas  
10 Supply (CGS) Department is proposing in the case to contract for additional  
11 seasonal Redwood capacity,<sup>18</sup> this additional capacity is not part of the  
12 vintage Line 400 capacity and is subject to non-vintage Redwood rates.  
13 Only the original 611.9 MDth/d receives the benefit of vintage costing.

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<sup>17</sup> The 611.9 MDth/d vintage Line 400 capacity consists of 605.1 MDth/d for PG&E's CGS Department and 6.8 MDth/d for PG&E's wholesale customers.

<sup>18</sup> See Ch. 7 of this testimony for CGS' proposals.

1 The Silverado/Mission Path rates are based on a partial allocation of  
2 revenue requirements associated with the noncore Redwood and noncore  
3 Baja paths, and include common costs. The rates for the Silverado and  
4 Mission Paths apply to all shippers, whether core or noncore.

5 G-XF rates are designed to collect incremental Line 401 costs. This is a  
6 closed rate schedule and services are not available to new customers.

7 Firm backbone transportation is available under Modified Fixed-Variable  
8 (MFV) and Straight Fixed-Variable (SFV) rate design options. Both rate  
9 designs incorporate a two-part (reservation and usage) rate structure.  
10 Seasonal two-part MFV and SFV rate options and volumetric as-available  
11 rates are based on 120 percent of the corresponding annual firm rate.

12 Core backbone transmission costs are unbundled from core  
13 transportation rates. Core backbone transmission costs are recovered from  
14 core procurement customers through PG&E's monthly core procurement  
15 rates, from core transport-only customers via their Core Transport Agents  
16 (CTA) responsibility for core backbone transmission capacity costs, and  
17 from gas ESPs through PG&E's backbone transmission rates.

### 18 **C. Backbone Level End-Use Service**

19 Customers qualifying for backbone-level end-use service<sup>19</sup> are exempt from  
20 paying the LT rate component in their end-use tariff. However, these customers  
21 continue to be responsible for all other rate components in their end-use tariffs,  
22 including the CAC and the CCC.<sup>20</sup> To the extent current or future components  
23 of the CCC become separate rate components or tariffs in the future,  
24 backbone-level end-use customers will continue to be responsible for these  
25 costs, where applicable, including gas PPP charges (G-PPPS rider tariff),  
26 Greenhouse Gas Emission Allowance Recovery, CPUC fees, franchise fees,  
27 class-averaged distribution rates<sup>21</sup> and G-SUR (Customer-Procured Gas

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<sup>19</sup> Backbone level end-use service rates were adopted in D.04-012-050, and the rules and eligibility requirements were slightly modified in D.07-09-045. The qualification requirements are defined in PG&E's tariffs (see Rule 1 – "Backbone Level End-Use Customer").

<sup>20</sup> D.03-12-061, pp. 367-368.

<sup>21</sup> Class average distribution rate components are not applicable to Industrial Backbone or transmission level G-NGV 4 customers.

Franchise Fee Surcharge). In addition, a backbone-level end-use service customer would be responsible for Inventory Management recovered in end-use transportation rates under PG&E's proposal in this chapter.

Rates for customers qualifying for backbone-level end-use service under Schedules G-EG, G-NT, and G-NGV4 are presented in Attachment A, Table 6-3, Illustrative End-Use Class Average Rates.

#### **D. Local Transmission Rate Design**

As described in Chapter 4, PG&E proposes to change the existing LT cost allocation, based on a cold year, peak month methodology,<sup>22</sup> to a method based on Abnormal Peak Day. In this chapter PG&E proposes to continue to adjust the LT CARD to account for forecast LT rate discounts<sup>23</sup> and to continue the single average LT rate design for all core classes and a single average LT rate for all noncore and wholesale customer classes. Rates are calculated by dividing the annual costs allocated to each class by the adopted throughput forecast by year.

LT rates will continue to be non-bypassable for all customers not qualifying for backbone-level end-user service.

#### **E. Fixed Charge Rate Design of Local Transmission Rates for Electric Generation**

As presented in Chapter 5, PG&E has analyzed the impact that incorporating a fixed charge for partial recovery of the LT function would have on G-EG throughput. From solely a rate design perspective, such a rate design is

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<sup>22</sup> The Commission adopted this cost allocation methodology in the Long Run Marginal Cost Proceeding, D.92-12-058, pp. 23, 30 and 31.

<sup>23</sup> G-NT and G-EG allow for Negotiable Rates under the specified Negotiated Rate Guidelines on each tariff. See: [https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_SCHEDS\\_G-EG.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHEDS_G-EG.pdf) and [https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_SCHEDS\\_G-NT.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHEDS_G-NT.pdf) (as of Sept. 23, 2021).

Long-standing cost allocation practice is to discount-adjust allocations for discounted contracts and G-10 discounts to spread those discounts across all customers using a function in proportion to their allocation of that function's revenue requirement. Ch. 6 incorporates an adjustment to the Local Transmission allocation proposed in Ch. 4 to account for the confidential discounted contracts and G-10 discounts in effect at the time PG&E prepared its application. PG&E based the estimated contractual discounts on monthly historical usage data for the period from March 2018 through February 2021. See the workpapers supporting this chapter for the aggregate impact of those revenue and volume adjustments.

justifiable given the nature of PG&E's LT function cost of service and the long-standing Backbone Transmission rate design which incorporates a substantial fixed charge recovery. However, given the inconclusive results of the analysis and the inability for PG&E to validate certain key assumptions to the analysis as identified in Chapter 5, PG&E is not proposing to make this a standard rate design applicable to all market-participating generators not qualifying for backbone-level end-use transportation service. Instead, PG&E will continue to design LT Rates for Electric Generation (EG) as described above in Section D.

## **F. Storage Cost Allocation and Rate Design**

### **1. Summary**

PG&E does not propose changes to core service rate design. The storage cost of service, including PG&E's share of Gill Ranch, will be allocated to the storage services (core firm, inventory management and reserve capacity) based on the *pro rata* share of current annual injection, inventory and withdrawal cycling capacity assigned to each service for the 2023-2026 rate case period.<sup>24</sup> PG&E does, however, propose to change the method used to recover storage costs associated with Inventory Management as described below in Section 2.

#### **a. Core Firm Storage Service**

Core gas storage costs are unbundled from core transportation rates. Core gas storage costs are recovered from core procurement customers through PG&E's monthly core procurement rates and from gas CTAs through PG&E's gas storage rates. Core transport-only customers pay for a portion of core firm storage through their CTAs. CTA responsibility for Core Storage costs has been diminishing annually on April 1 via the step-down process. The step-down was to have been completed during this rate case period on April 1, 2025 at which time, CTAs would no longer be responsible for taking any portion of the Core

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<sup>24</sup> Storage capacities are as proposed in A.21-06-021, Exhibit (PG&E-3), p. 7-52, line 13 to p. 7-53, line 14, Sections D.4 and D.5. Please refer to the workpapers to this chapter for the calculations of storage capacities into storage units (the basis for cost allocation).

1 Storage capacities proposed by PG&E's CGS.<sup>25</sup> However, in Chapter 7  
2 of this application, PG&E proposes to expedite the CTA step-down such  
3 that beginning the first April after the final decision in this case is  
4 implemented, CTAs will procure 100 percent of their allocated Core Firm  
5 Storage from Independent Service Providers and the entirety of PG&E's  
6 Core Firm Storage volume will then be allocated to bundled core.<sup>26</sup>

7 Gas Procurement Groups, including PG&E's CGS, pay a single  
8 monthly storage capacity charge under PG&E's gas rate  
9 Schedules G-CFS – Core Firm Storage. Core wholesale customers  
10 have a one-time option to subscribe to core storage capacity prior to the  
11 beginning of each storage season.

12 **b. Parking and Lending Services**

13 Parking and lending services (Schedules G-PARK and G-LEND) are  
14 negotiated under a cost-based maximum charge. PG&E proposes to  
15 continue the existing tariffed maximum charge for G-PARK and G-LEND  
16 services at the rates adopted for 2022 in the 2019 GT&S Rate Case.  
17 PG&E proposes to continue to return revenues generated under these  
18 schedules to end-use customers under the mechanism described in  
19 D.19-09-025,<sup>27</sup> that is, to continue to allocate these revenues between  
20 core and noncore customers based on their proportional share of the  
21 total storage revenue requirements. Revenues allocated to core  
22 customers would be returned to core customers through the Core Cost  
23 Subaccount of the Core Fixed Cost Account (CFCA) and revenues  
24 allocated to noncore customers would be returned to noncore customers  
25 through the Noncore Subaccount of the Noncore Customer Class  
26 Charge Account.<sup>28</sup>

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<sup>25</sup> D.16-06-056, pp. 484-485, OP 40.

<sup>26</sup> Ch. 7, Section C.

<sup>27</sup> D.19-09-025, pp. 290-292, Section 14.5.4 reflective of PG&E's 2019 GTS testimony, Exhibit PG&E-1, Chapter 11, Section B.3.a and Exhibit PG&E-2, Ch. 17B, p. 17B-8.

<sup>28</sup> PG&E proposes a similar rate and revenue treatment for Negotiated Firm Storage (G-NFS) and Maximum Rate Negotiated As-Available Storage (G-NAS) services.

1           **c. Reserve Capacity Service**

2           Storage costs allocated to Reserve Capacity are included in all  
3           backbone transmission rates as continued from the adoption of the  
4           NGSS.

5           **2. Inventory Management Service**

6           **a. Summary**

7           PG&E proposes to move the recovery of Inventory Management  
8           from its unbundled backbone transmission rates to its end-use  
9           transportation rates where it can differentiate cost recovery by customer  
10          class in a manner reflective of cost causation and utilization of the  
11          service.

12          **b. Background**

13          Inventory Management Service (Inventory Management) was  
14          established in the PG&E's NGSS adopted in the 2019 GT&S Rate  
15          Case.<sup>29</sup> Inventory Management uses a portion of PG&E's storage  
16          capacity to maintain safe and reliable pressure and gas service on an  
17          hourly and daily basis. This service is necessary as gas flows into  
18          PG&E's gas transmission system at the Oregon and Arizona borders  
19          generally on a steady basis, hour to hour and day to day. The  
20          consumption of gas at the burner tip is generally not steady. It  
21          fluctuates significantly, mostly related to weather but also to availability  
22          of renewable generation and whether it is a weekday or  
23          weekend/holiday, impacting demand for not only natural gas but for  
24          electricity generated by natural gas. The cost recovery of Inventory  
25          Management as adopted in the NGSS and 2019 GT&S Rate Case is as  
26          a common cost in PG&E's unbundled backbone transmission rates  
27          recovered on an effective equal cents per therm basis across customers  
28          using PG&E's backbone transmission system.

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<sup>29</sup> D.19-09-025, p. 321, OP 8.



1           **c. Discussion**

2           The NGSS was a major first step to reflect the changing dynamic of  
3           PG&E's storage capacity post-Aliso Canyon<sup>30</sup> and in an environment of  
4           ever-expanding reliance on renewable sources of EG. The predecessor  
5           function to Inventory Management and its parallel Reserve Capacity was  
6           Load Balancing. In 2019, prior to implementation of the 2019 GT&S  
7           Rate Case, the Load Balancing revenue requirement was \$18 million  
8           per year,<sup>31</sup> reflecting approximately 18 percent of the total storage  
9           revenue requirement. In January 2020, post implementation of the 2019  
10          GT&S Rate Case but prior to NGSS taking effect, Load Balancing's  
11          revenue requirement was \$33 million, reflecting approximately  
12          19 percent of the total storage revenue requirement. In April 2020 with  
13          implementation of NGSS, Inventory Management was \$159 million,  
14          reflecting 87 percent of the adopted Storage revenue requirement.  
15          Therefore, on both a cost of service and share of cost of service basis,  
16          the Inventory Management service has enhanced importance for  
17          ratemaking.

18           **d. Gas Planning OIR Workshops (Summer 2020)**

19          During Summer 2020, the CPUC Energy Division held workshops  
20          as part of the Gas Planning OIR,<sup>32</sup> in which the topic of cost causation  
21          and recovery of storage system costs used to support the gas  
22          transportation system was the focus of presentations and discussion.  
23          One example was the proposal of a Renewables Balancing Tariff.<sup>33</sup> As

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30 "Not long after PG&E began to study its options regarding Los Medanos and Pleasant Creek, Southern California Gas Company reported a major leak at its largest and most central natural gas storage facility, Aliso Canyon, near the community of Porter Ranch. ...The leak continued unabated until February 11, 2016." (A.17-11-009, Exh. PG&E-1, p. 11-4, lines 15-21).

31 Based on the adopted revenue requirement for 2018 from PG&E's 2015 GT&S Rate Case.

32 *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning*, Rulemaking 20-01-007 (Jan. 16, 2020).

33 Southern California Gas Company (SoCalGas) workshop held December 10, 2020 and SoCalGas' (U 904 G) Proposal for a Conceptual Renewable Balancing Services Tariff filed January 8, 2021.

1 an outcome of those presentations and discussions, and in preparation  
2 for PG&E's 2023 GT&S CARD application, PG&E undertook new  
3 analysis as to whether an additional step or steps in recovery by  
4 customer class of this increased use of the storage system was  
5 warranted on a cost causation basis.

6 **e. Analysis**

7 **Step 1: Analyze the hourly and daily gas flow into PG&E's system**  
8 **versus gas demand by three major segments of end-use**  
9 **transportation customers:**

- 10 • Core;  
11 • Industrial+Cogeneration+Noncore Natural Gas Vehicle  
12 (NGV)+Wholesale; and  
13 • Market-Responsive EG.

14 The analysis by PG&E's Gas System Operations (GSO)  
15 organization looked at both use of daily balancing of usage versus flow  
16 into the PG&E system and hourly usage compared to daily flow by  
17 these three major segments. This segmentation was based on the  
18 readily available information to GSO, which was available in the  
19 above-mentioned segmentations. Table 6-4 below summarizes the  
20 results based on the analytical period of January 1,  
21 2016-December 31, 2020.

**TABLE 6-4  
USAGE VERSUS INFLOW BY SEGMENT**

Line No.	Customer Class	Status-quo	Inter-day	Intra-day	Allocation based on Weighting of Inter vs Intra-day Results	
					Secondary Method 50% - 50%	Proposed Method 37% - 63%
		(a)	(b)	(c)		(d)
1	Core	32.3%	27.3%	62.8%	45.0%	50.0%
2	Ind	34.8%	27.4%	3.9%	15.7%	12.4%
3	EG	23.1%	45.3%	33.2%	39.3%	37.6%
4	Off-system	9.9%	0.0%	0.0%	0.0%	0.0%
5	Total	100.0%	100.0%	100.0%	100.0%	100.0%

(a) The status quo allocation is based on the percent of customer class throughput for 1/1/2016 – 12/31/2020.

(b) Inter day imbalances are based on the absolute value of the average customer class daily imbalance for 1/1/2016 – 12/31/2020.

(c) Intra day (hourly imbalance) based on the absolute value of the average of the hourly differences of average daily demand to the actual hourly demand for the customer class from 1/1/2016 – 12/31/2020.

(d) Inter day to Intra day weighting is based on the ratio of customer class imbalance volumes (1/1/2016 – 12/31/2020).

Off-system customers of PG&E's backbone transmission system currently pay for this service in their unbundled backbone rates despite not being end-use customers and not contributing to the imbalances across the hours of the day or days of the month. Recovering these costs in end-use transportation rates would also better align that recovery with cost causation in this aspect of ratemaking.

The rate results when the proposed allocations to these three segments of PG&E end-use customers are applied to the proposed 2023 revenue requirement for the Inventory Management service and divided by the proposed average 2023-2026 throughput are shown below. The table also shows the systemwide equal cents per therm result that would be effectively collected if Inventory Management remained in unbundled backbone transmission rates as a common cost given proposed average throughput forecast for 2023-2026.

**TABLE 6-5**  
**STEP 1: GSO ANALYSIS (\$/T): COMPOSITION OF DAILY BALANCING + HOURLY**  
**FLUCTUATION WITHIN THE DAY**

Line No.	Core	NONCORE			Total ECPT*
		Industrial + COG+NGV4 + Whsl	EG (Market-Responsive)	Whsl	
1	\$0.0179	\$0.0046	\$0.0275		\$0.0146

**Step 2: Adjust the above analysis to reflect the individual end-user customer classes as billed by PG&E.**

PG&E proposes to first segment the “Industrial + Cogen + NGV4 + Whsl” groups into their specific customer classes as reflected in the tariffs (G-NT, G-EG, G-NGV, and G-WSL). As a proxy of volatility in usage for this segmentation, given the information used by GSO for Step 1 analysis is not available at the end-use customer class basis, PG&E analyzed five calendar years (2016-2020) of daily usage data by the three segments illustrated above, by season, and calculated the seasonal standard deviation in usage. PG&E then totaled the standard deviation across the seasons and year for industrial distribution and industrial transmission/backbone and NGV4 versus cogeneration and wholesale and calculated the resulting industrial distribution vs industrial transmission/backbone/NGV4 inventory management rates. These rates are presented below:

**TABLE 6-6**  
**STEP 2: INVENTORY MANAGEMENT RATE COMPONENT, IND-D AND IND-T/BB/NGV4**

Excluding COG + WHSL		
Line No.	IND-D	IND-T/BB + NGV4
1	\$0.0052	\$0.0050

**Step 3: Address the core Large Commercial and Core NGV classes.**

These classes are far more similar in their profiles of usage to the Industrial Distribution customer class than they are to the Residential and Small Commercial customer classes that dominate the Core

1 segment in the Step 1 analysis by GSO. The table below illustrates this  
 2 based on currently adopted throughput and customer forecasts by class.

**TABLE 6-7**  
**COMPARISON OF CORE NGV AND LARGE COMMERCIAL BASED ON ADOPTED**  
**2019 GT&S FORECASTS**

Line No.	Customer Segment	Customer Class	Average Monthly Usage per Customer (therms)	% of Usage in Summer	% of Usage in Winter
1	Core	Residential (incl. Master Metered)	35	35.5%	64.5%
2	Core	Small Commercial	281	44.2%	55.8%
3	Core	Core NGV	16,661	58.4%	41.6%
4	Core	Large Commercial	36,647	57.0%	43.0%
5	Noncore	Industrial Distribution	43,131	54.6%	45.4%
6	Noncore	Industrial Transmission	488,349	62.0%	38.0%

3 The Core NGV and Large Commercial classes closely mimic the  
 4 Industrial Distribution class in terms of winter usage, which indicates  
 5 temperature sensitivity and resulting hourly and day to day volatility.  
 6 Therefore, PG&E proposes that the Inventory Management rate  
 7 component applied to core NGV and Large Commercial be set at the  
 8 level proposed for Industrial Distribution.

**TABLE 6-8**  
**STEP 3: SET LARGE COMMERCIAL AND CORE NGV EQUAL TO INDUSTRIAL DISTRIBUTION**

	LC + Core NGV	
Line No.	IND-D	
1	\$0.0052	\$0.0052

9 The prior table also illustrates the reasonableness of the analysis  
 10 described above using standard deviation as a proxy allocator to  
 11 differentiate between Industrial Distribution and Industrial  
 12 Transmission/Backbone/Noncore NGV with the percent of Transmission  
 13 volumes consumed during winter, i.e., temperature sensitivity being  
 14 lower than for Industrial Distribution.

**Step 4: Adjust the Core rate from Step 1 to remove the impact of the Core NGV and Large Commercial customer classes.**

Given the above result of using the Industrial Distribution rate for Inventory Management for Core NGV and Large Commercial classes, the Core rate as determined by the Step 1 analysis for the entire Core set of classes must be adjusted to remove the impact of the Core NGV and Large Commercial customer classes lower cost causation for Inventory Management compared to the bulk of Core. That result is shown below and is, as one would expect, slightly higher than the GSO analysis for all of Core given the percentage of total Core usage consumed by the Core NGV and Large Commercial customer classes:

**TABLE 6-9  
STEP 4: INVENTORY MANAGEMENT RATE COMPONENT FOR RESIDENTIAL AND SMALL COMMERCIAL**

Line No.	Res + Small Comm
1	\$0.0184

**Step 5: Wholesale**

Wholesale customers, as notionally “noncore customers”, were included in the GSO analysis with the Industrial dominated segment. However, their usage patterns are not similar to industrial, which is virtually non-temperature sensitive and dominated by the industrial transmission class, or even the mildly temperature sensitive industrial distribution class. Wholesale customers serve almost solely end-use customers classified as core. Therefore, PG&E proposes that wholesale customers pay the Inventory Management rate associated with PG&E’s total Core group:



**TABLE 6-10  
STEP 5: WHOLESALE**

<b>Wholesale</b>
<b>\$0.0179</b>

**Step 6: Segment G-EG group between Backbone-Service Level Customers and those not qualifying for Backbone-Service Level.**

The last remaining end-use customer class aggregation per the GSO analysis is the G-EG group with segmentation between Backbone-Service Level Customers and those not qualifying for Backbone-Service Level, which includes cogeneration customers primarily served from LT.<sup>34</sup>

Calculating the Inventory Management component for the two segments of PG&E's G-EG tariff would result in the rates below.

**TABLE 6-11  
STEP 6: EG-D/T AND EG-BB**

Line No.	EG-D/T	EG-BB
1	\$0.0229	\$0.0169

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<sup>34</sup> As most cogeneration volumes were associated with Service Agreement IDs with usage billed under another schedule, PG&E used the portion of cogeneration customers that were pure cogeneration to determine standard deviation and then scaled that result to match the total cogeneration class size. That result was then aggregated with the EG-D/T class standard deviation to develop the cost allocator.

**TABLE 6-12**  
**SUMMARY OF PROPOSAL AND IMPACTS COMPARED TO ADOPTED 2022 AND STATUS QUO**  
**METHOD APPLIED TO 2023**

Line No.	Description	Res + Sml Comm	LC + Core NGV	IND-D	IND-T/BB + NGV4	EG-T	EG-BB	Whsl	Off-System
1	A) Current (2022) rates, Equal Cents Per Therm	\$0.0165	\$0.0165	\$0.0165	\$0.0165	\$0.0165	\$0.0165	\$0.0165	\$0.0165
2	B) Status Quo (2023) rates, Equal Cents Per Therm	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146
3	C) Implementation Rates under this proposal (2023)	\$0.0184	\$0.0184	\$0.0052	\$0.0052	\$0.0050	\$0.0229	\$0.0169	\$0.0179
4	D) Percent Change, Current (2022) v. this proposal	11.4%	11.4%	-68.4%	-68.4%	-69.4%	38.9%	2.6%	8.4%
5	E) Percent Change, Current (2022) vs Status Quo (2023)	26.1%	26.1%	-64.2%	-64.2%	-65.4%	57.3%	16.2%	22.7%

### 3. Self-Balancing Credit

Customers or Balancing Agents who elect the self-balancing option can opt out of PG&E's Monthly Balancing Program, consistent with requirements stated in PG&E's gas rate Schedule G-BAL. Customers choosing to self-balance receive a self-balancing credit.

As a result of the changes in storage services provided under the NGSS,<sup>35</sup> a slight modification continues to be necessary in the calculation of the self-balancing credit. The new inventory management service provides two functions, intra-day balancing between variable demand and ratable supply, and monthly balancing. As previously done in the 2019 GT&S Rate Case, to calculate the self-balancing credit, it was necessary to separate the costs associated with monthly balancing from the costs associated with intra-day balancing.<sup>36</sup> PG&E separated the costs using a factor based on historic monthly balancing storage units. Once the monthly balancing costs were determined, PG&E used the methodology previously used in the 2015 GT&S rate case, that is, to apply a historic "Percentage of Load Balancing Costs in Credit" factor of 80 percent of the total storage balancing assets to arrive at the credit amount. Please refer to the workpapers to this chapter for detailed calculations.

<sup>35</sup> A discussion of PG&E's NGSS can be found in D.19-09-025, pp. 20-84, Section 5.

<sup>36</sup> This separation of costs is for rate making purposes only and does not reflect operational necessities or priority service putting monthly balancing equal to or above Inventory Management. Inventory Management is the priority service to be dispatched at PG&E's sole discretion.

#### 4. Los Medanos and Pleasant Creek Storage Fields Depreciation and Decommissioning Costs

In its 2023 GRC Phase 1, PG&E proposed to retain operation of its Los Medanos storage field.<sup>37</sup> Since the implementation of PG&E's NGSS, adopted in its 2019 GT&S Rate Case, end-use customers have been paying for the depreciation and expected decommissioning costs for Los Medanos in addition to those costs for Pleasant Creek.<sup>38</sup> As detailed in PG&E's 2023 GRC I testimony, this change to retaining Los Medanos storage field in operation will result in a return to customers in 2023 of the revenue requirement paid by customers in rates through 2022 and the elimination of any further collection in end-user rates of depreciation and decommissioning costs in 2023 for Los Medanos.<sup>39</sup>

PG&E proposes that the approximately \$51.9 million in excess depreciation revenues as calculated in PG&E GRC 1<sup>40</sup> and \$51.9 million in decommissioning revenues,<sup>41</sup> previously collected in end-use rates for the Los Medanos storage field, be returned in end-use rates in 2023. PG&E proposes to return these revenues using the allocation methodology found by the Commission in D.19-09-025 to be "just and reasonable."<sup>42</sup> That is, approximately 68 percent of the costs collected are allocated to core and returned in rates based on a core distribution allocation basis,<sup>43</sup> and 16 percent of the costs collected are allocated to noncore and returned in rates on an equal cents per therm basis. The remaining 16 percent of the costs collected are treated similar to load balancing costs, that is, allocated

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<sup>37</sup> A.21-06-021, Exhibit (PG&E-3), p. 7-50, line 11 to p. 7-52, line 12, Section D.3.

<sup>38</sup> D.19-09-025, p. 321, OP 3 and Appendix H, adopts the rates, inclusive of the recovery of Los Medanos and Pleasant Creek Depreciation and Decommissioning costs in end-use rates.

<sup>39</sup> A.21-06-021, Exhibit (PG&E-10), p. 11-28, line 16 to p. 11-30, line 11, Section C.10.b.

<sup>40</sup> A.21-06-021, Exhibit (PG&E-10), WP 11-384, line 60.

<sup>41</sup> A.21-06-021, Exhibit (PG&E-10), p. 11-36, lines 17-26, Section E.8.a.

<sup>42</sup> D.19-09-025. Allocation percentages are found on page 268. Commission findings are found on page 271.

<sup>43</sup> The allocation across core classes of the CFCA – Distribution transportation subaccount is similar to the allocation of storage costs in gas procurement rates and, therefore, is the more appropriate account than the Core CCC subaccount.

to both core and noncore customers and returned in rates based on an equal cents per therm basis, as they would have been historically in backbone transmission rates.<sup>44</sup>

The approximately \$4.3 million in depreciation costs<sup>45</sup> for the Pleasant Creek storage field will be collected from customers in end-use rates in 2023 based on the methodology described above. The \$3.0 million per year in decommissioning costs<sup>46</sup> for the Pleasant Creek storage field will continue to be collected from customers in end-use rates in 2023-2026 based on the methodology described above.

## **5. Timing of Change to Storage Services: Impact on Rate Calculations**

Due to the CTA Core Storage Step Down ordered in D.16-06-056,<sup>47</sup> core storage rates will change on January 1 of each year with the change in the adopted GRC revenue requirement, and then on April 1 of each year with the incorporation of the step down core capacities. Rather than changing backbone and bundled core end user rates twice per year as the change in core storage rates would require, in its 2019 GT&S, PG&E proposed to blend the storage revenue requirements collected in backbone transmission and bundled core end user rates to create average annual rates.<sup>48</sup> In this 2023 CARD, PG&E proposes to continue to blend the resulting storage revenue requirements in backbone transmission and bundled core end user rates to create annual average backbone transmission and bundled core end user rates. Should the Commission adopt PG&E's Chapter 7 proposal to accelerate the step-down period to end as of the first April after the final decision in this case is implemented, this averaging would only be necessary for the first year of implementation. However, if the proposal is not adopted, PG&E proposes to continue to change core storage rates recovered in PG&E's gas procurement rates

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<sup>44</sup> Costs allocated to core customers on an equal cents per therm bases are recovered in the Core Cost Subaccount of the CFCA.

<sup>45</sup> A.21-06-021, Exhibit (PG&E-10), WP 11-383.

<sup>46</sup> A.21-06-021, Exhibit (PG&E-10), p. 11-37, lines 1-13, Section E.8.b.

<sup>47</sup> D.16-06-056, pp. 484-485, OP 40.

<sup>48</sup> D.19-09-025, p. 321, OP 3, adopts the rates which incorporate the averaging of storage revenue requirements in backbone transmission and bundled core end user rates.

beginning April 1 of each year until the expiration of the CTA Core Storage Step Down in 2025.<sup>49</sup>

## **G. Transmission-Level CACs**

### **1. Summary**

For 2023-2026, PG&E proposes to continue to scale the currently-adopted CACs, multiplied by the forecast of customers by tier, such that the resulting revenues match the CAC revenue requirement proposed in PG&E's 2023 GRC I, A.21-06-021.

### **2. Future Transmission Level CAC Ratesetting**

In D.20-01-002, "Decision Modifying the Commission's Rate Case Plan for Energy Utilities," the Commission ordered PG&E to "incorporate its requests for test year 2023 revenue requirements related to its GT&S systems into its test year 2023 GRC application."<sup>50</sup> To be able to determine CACs on a more consistent basis across the core commercial, industrial distribution, industrial transmission and EG customer classes, in its 2019 GT&S, PG&E proposed that the CAC rate design be determined in PG&E's GCAP. The Commission, in D.19-09-025, noted that "[n]o party opposes PG&E's CAC methodology or rates."<sup>51</sup> Accordingly, in this GT&S CARD application, PG&E updates the billing determinants to calculate the CAC charges under the current structure consistent with the throughput and customer billings forecasts in Chapters 2A and 2B. In its 2024 GCAP, PG&E currently plans to submit a proposal for all commercial/noncore customer charges and rate design.<sup>52</sup>

## **H. Illustrative Rate Tables with Present and Proposed Rates**

In the following tables, PG&E presents the illustrative proposed January 2023 end-user rate changes inclusive of NGSS depreciation and

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<sup>49</sup> Actual storage rates included in bundled procurement costs for core customers change monthly to reflect acceptances and declines of core storage capacity until the end of the CTA step-down process on April 1, 2025 (or on the first April after a final decision in this case is implemented should the Commission approve PG&E's proposal in Ch. 7).

<sup>50</sup> D.20-01-002, pp. 78-79, OP 4.

<sup>51</sup> D.19-09-025, p. 280, Section 14.3.

<sup>52</sup> PG&E is anticipating filing its 2024 GCAP in the first quarter 2023, or 90 days after both GRC I and GT&S CARD decisions have been released, whichever occurs later.

- 1 decommissioning costs discussed previously in Section 4 and inventory
- 2 management costs discussed previously in Section 2.



**TABLE 6-13**  
**ILLUSTRATIVE END-USE CLASS AVERAGE RATES (\$/DTH)<sup>(4), (5)</sup>**

Line No.		Illustrative June 1 Rates with 2022 GT&S Components	2023 Illustrative Rates with Proposed GRC 1 RRQ (1)	\$ Change GRC 1 v. June 1 with 2022 GT&S Components	% Change GRC 1 v. June 1 with 2022 GT&S Components	Proposed 2023 GT&S (Year 2023 GT&S Components & 2023 Illustrative GRC 1)	\$ Change from GRC 1 (5)	% Change from GRC 1
		A	B	C	D	E	F	G
<b>Core Retail Bundled Service (2)</b>								
1	Residential Non-CARE	19.186	22.671	3.484	18.2%	22.303	-0.368	-1.6%
2	Residential CARE	15.059	17.761	2.702	17.9%	17.474	-0.287	-1.6%
3	Small Commercial Non-CARE	13.819	16.348	2.530	18.3%	16.002	-0.346	-2.1%
4	Small Commercial CARE	10.777	12.716	1.938	18.0%	12.446	-0.269	-2.1%
5	Large Commercial	9.805	11.692	1.888	19.3%	11.379	-0.313	-2.7%
6	Uncompressed Core NGV	9.361	11.484	2.123	22.7%	11.175	-0.309	-2.7%
7	Compressed Core NGV	25.737	26.196	0.459	1.8%	25.888	-0.309	-1.2%
<b>Core Retail Transport Only (3)</b>								
8	Residential Non-CARE	15.327	18.788	3.461	22.6%	18.578	-0.211	-1.1%
9	Residential CARE	11.200	13.879	2.679	23.9%	13.749	-0.130	-0.9%
10	Small Commercial Non-CARE	10.139	12.679	2.540	25.1%	12.468	-0.211	-1.7%
11	Small Commercial CARE	7.098	9.010	1.912	26.9%	8.912	-0.098	-1.1%
12	Large Commercial	6.518	8.420	1.902	29.2%	8.196	-0.224	-2.7%
13	Uncompressed Core NGV	6.342	8.257	1.915	30.2%	8.033	-0.224	-2.7%
14	Compressed Core NGV	22.718	22.970	0.252	1.1%	22.746	-0.224	-1.0%
<b>Noncore Retail Transportation Only (3)</b>								
15	Industrial – Distribution	5.493	6.736	1.243	22.6%	7.125	0.389	5.8%
16	Industrial – Transmission	2.804	3.487	0.683	24.3%	3.875	0.389	11.1%
17	Industrial – Backbone	1.566	1.523	-0.043	-2.7%	1.522	-0.002	-0.1%
18	Uncompressed Noncore NGV – Distribution	5.027	6.401	1.374	27.3%	6.790	0.389	6.1%
19	Uncompressed Noncore NGV – Transmissi	2.599	3.260	0.661	25.4%	3.649	0.389	11.9%
20	Electric Generation – Distribution/Transmiss	2.103	2.662	0.558	26.5%	3.084	0.423	15.9%
21	Electric Generation – Backbone	0.958	0.810	-0.148	-15.5%	0.826	0.017	2.1%
<b>Wholesale Transportation Only (3)</b>								
22	Alpine Natural Gas	1.366	1.918	0.552	40.4%	2.326	0.408	21.3%
23	Coalinga	1.353	1.923	0.570	42.2%	2.334	0.411	21.4%
24	Island Energy	1.393	2.045	0.652	46.8%	2.455	0.410	20.1%
25	Palo Alto	1.356	1.882	0.526	38.8%	2.294	0.412	21.9%
26	West Coast Gas - Castle	4.426	5.735	1.310	29.6%	6.150	0.414	7.2%
27	West Coast Gas - Mather D	6.751	8.397	1.646	24.4%	8.809	0.412	4.9%
28	West Coast Gas - Mather T	1.496	1.937	0.440	29.4%	2.348	0.412	21.3%

\* CARE customers receive a 20 % discount on transportation and procurement and are exempt from CARE and CSI Solar Water Heater rate components.

**Notes:**

- 2023 rates are based on PG&E's June 1, 2021 rate change filing per Advice Letter 4440-G as modified by the revenue requirement and capacity proposals in PG&E's 2023 General Rate Case, A. 21-06-021.
- PG&E's bundled gas service is available to core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding are included in end-use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, shrinkage, transportation on Canadian and Interstate pipelines, core brokerage, and franchise fees and uncollectibles expense. The illustrative annual average rates for these elements are based on the illustrative revenue requirements shown on PG&E's Preliminary Statement Part C2. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burner tip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.
- PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.
- Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.
- Dollar difference are due to rounding.

- To isolate the effects of the cost allocation, rate design and throughput
- proposals addressed in this application while presenting PG&E's total proposed

1 GT&S rates and charges for the 2023-2026 rate case period, illustrative present  
2 rates include the full revenue requirements proposed in each of the four years of  
3 PG&E's 2023 GRC I, including GT&S functions. The GT&S rate components in  
4 the illustrative present rates for each year are calculated using currently adopted  
5 CARD methodologies and throughput. All other rate components in illustrative  
6 present and proposed rates are kept constant at the current June 1, 2021  
7 implemented levels. These components held constant include, PPP Surcharge  
8 Rates, procurement rate components other than backbone and storage, and  
9 end-user transportation rates other than LT. Illustrative Proposed 2023 rates  
10 include the backbone, LT, transmission-level customer access, and storage  
11 CARD proposals made in this application. The purpose of this presentation is to  
12 provide the Commission and parties an equivalent and comprehensive showing  
13 of GT&S ratemaking proposals as has existed under the Gas Accords and  
14 GT&S Rate Cases since the decision adopting Gas Accord I in 1997 and  
15 implemented on March 1, 1998.

16 Table 6-14 illustrates the burner-tip impacts on noncore customers of  
17 PG&E's proposed 2023 GT&S CARD Rate Case by including a procurement  
18 rate proxy. Noncore customers arrange for procurement of gas either acting as  
19 their own agent or via the third-party providers. Therefore, PG&E does not have  
20 precise information as to what its noncore customers pay for procurement  
21 services. A reasonable approximation of what they pay for procurement  
22 service—for illustrative purposes only—is based on the rate that PG&E's core  
23 NGV customers pay.<sup>53</sup> Of PG&E's core customer classes for which it provides  
24 bundled service, core NGV customers have cost characteristics most similar to  
25 noncore customers. The procurement proxy for 2023 is adjusted to reflect the  
26 impact of PG&E's proposed 2023 backbone transmission volumetric rates.

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**53** For illustrative purposes, the proxy procurement rate includes PG&E's 2021 Weighted Average Cost of Gas and associated shrinkage, Canadian transmission capacity, interstate transmission capacity, and PG&E's backbone transmission capacity paid by PG&E's core NGV customers but not the other elements such as core brokerage fee or core storage.

**TABLE 6-14**  
**ILLUSTRATIVE END-USE NONCORE AND WHOLESALE CLASS AVERAGE RATES WITH**  
**PROCUREMENT PROXY (\$/DTH)<sup>(3), (4)</sup>**

Line No.	Illustrative June 1 Rates with 2022 GT&S Components	2023 Illustrative Rates with Proposed GRC 1 RRQ (1)	\$ Change GRC 1 v. June 1 with 2022 GT&S Components	% Change GRC 1 v. June 1 with 2022 GT&S Components	Proposed 2023 GT&S (Year 2023 GT&S Components & 2023 Illustrative GRC 1)	\$ Change from GRC 1 (5)	% Change from GRC 1
	A	B	C	D	E	F	G
<b>Noncore Retail with Procurement Proxy (2)</b>							
1 Industrial – Distribution	8.481	9.922	1.441	17.0%	10.206	0.284	2.9%
2 Industrial – Transmission	5.792	6.673	0.881	15.2%	6.956	0.283	4.2%
3 Industrial – Backbone	4.554	4.710	0.156	3.4%	4.603	(0.107)	-2.3%
4 Uncompressed Noncore NGV – Distribution	8.015	9.587	1.572	19.6%	9.871	0.284	3.0%
5 Uncompressed Noncore NGV – Transmission	5.587	6.447	0.859	15.4%	6.730	0.283	4.4%
6 Electric Generation – Distribution/Transmission	5.091	5.848	0.757	14.9%	6.165	0.317	5.4%
7 Electric Generation – Backbone	3.946	3.996	0.050	1.3%	3.907	(0.089)	-2.2%
<b>Wholesale with Procurement Proxy (2)</b>							
8 Alpine Natural Gas	4.354	5.104	0.751	17.2%	5.407	0.303	5.9%
9 Coalinga	4.340	5.109	0.769	17.7%	5.415	0.306	6.0%
10 Island Energy	4.381	5.231	0.850	19.4%	5.536	0.305	5.8%
11 Palo Alto	4.344	5.068	0.724	16.7%	5.375	0.306	6.0%
12 West Coast Gas - Castle	7.413	8.922	1.508	20.3%	9.230	0.309	3.5%
13 West Coast Gas - Mather D	9.738	11.583	1.845	18.9%	11.890	0.306	2.6%
14 West Coast Gas - Mather T	4.484	5.123	0.639	14.2%	5.429	0.306	6.0%

**Notes:**

- 1) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate which includes costs for gas commodity, gas transmission (i.e., Canadian, interstate and intrastate backbone) and shrinkage but excludes bundled storage.
- 2) 2023 gas transportation rates are based on PG&E's June 1, 2021 rate change filing per Advice Letter 4440-G as modified by the revenue requirement and capacity proposals in PG&E's 2023 General Rate Case, A. 21-06-021.
- 3) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.
- 4) Dollar difference are due to rounding.

**I. Residential and Small Commercial Average Monthly Bill Impacts<sup>54</sup>**

If the Commission adopts PG&E's 2023 GT&S CARD Application forecasts and rate design proposals, gas rates and bills will decrease effective January 1, 2023, relative to the illustrative 2023 GRC 1 bills. A typical CARE residential customer using 26 therms per month would see an average monthly gas bill decrease, relative to the illustrative 2023 GRC 1 bill, of \$0.75 (or 1.6 percent), from \$46.18 to \$45.43 on January 1, 2023 due solely to the proposals made in the CARD. A Non-CARE residential customer using 31 therms per month would see an average monthly gas bill decrease, relative to the illustrative 2023 GRC 1 bill, of \$1.14 (or 1.6 percent), from \$70.28 to \$69.14 on January 1, 2023 due solely to the proposals made in the CARD. A typical Non-CARE small business

<sup>54</sup> The forecast monthly average individually-metered residential customer usage for the 2023-2026 test period of the 2023 GT&S CARD is 31 therms for Non-CARE customers and 26 therms for CARE customers. The forecast average 2023-2026 monthly usage for small commercial customers is 272 therms.

customer using 272 therms per month would see an average monthly gas bill decrease of \$9.41 (or 2.1 percent), from \$444.67 to \$435.26, on January 1, 2023 due solely to the proposals made in the CARD. Individual customers' bills will differ.

**J. Alternate Illustrative Rate Table with Present and Proposed Rates for Bill Insert Presentation**

In this section PG&E provides, in Table 6-15, an alternate presentation of present and proposed rates in compliance with the Commission's requirements regarding bill inserts. For present rates, PG&E used unadjusted June 1, 2021 rates, the rates currently in effect at the time of filing. For proposed rates, PG&E applied the throughput and billings forecasts, CARD proposals in this CARD application to the revenue requirements underlying the June 1, 2021 rates, that is, the 2021 GT&S function revenue requirements adopted in D.19-09-025. This presentation provides the rates that customers would pay, absent a change in revenue requirement, should the Commission adopt the proposals made in this CARD application.

**TABLE 6-15**  
**ILLUSTRATIVE END-USE AVERAGE RATES (\$/DTH)<sup>(4), (5)</sup>**

Line No.		Illustrative 2023 GT&S (Year 2023 CARD Proposals, Adopted 2021 RRQ)			% Change from Present
		June 1, 2021 Present Rates (1)		\$ Change from Present	
		A	B	C	D
	<b>Core Retail Bundled Service (2)</b>				
1	Residential Non-CARE	18.173	18.182	0.009	0.1%
2	Residential CARE *	14.248	14.255	0.007	0.1%
3	Small Commercial Non-CARE	13.114	13.131	0.017	0.1%
4	Small Commercial CARE *	10.213	10.227	0.013	0.1%
5	Large Commercial	9.352	9.370	0.017	0.2%
6	Uncompressed Core NGV	9.128	9.147	0.018	0.2%
7	Compressed Core NGV	24.615	24.633	0.019	0.1%
	<b>Core Retail Transport Only (3)</b>				
8	Residential Non-CARE	14.410	14.451	0.042	0.3%
9	Residential CARE *	10.485	10.524	0.040	0.4%
10	Small Commercial Non-CARE	9.553	9.595	0.041	0.4%
11	Small Commercial CARE *	6.652	6.691	0.038	0.6%
12	Large Commercial	6.164	6.188	0.024	0.4%
13	Uncompressed Core NGV	5.984	6.007	0.024	0.4%
14	Compressed Core NGV	21.470	21.494	0.024	0.1%
	<b>Noncore Retail Transportation Only (3)</b>				
15	Industrial – Distribution	5.204	5.304	0.099	1.9%
16	Industrial – Transmission	2.686	2.785	0.099	3.7%
17	Industrial – Backbone	1.499	1.508	0.009	0.6%
18	Uncompressed Noncore NGV – Distribution	4.870	4.969	0.099	2.0%
19	Uncompressed Noncore NGV – Transmissic	2.488	2.587	0.099	4.0%
20	Electric Generation – Distribution/Transmiss	1.991	2.119	0.128	6.4%
21	Electric Generation – Backbone	0.890	0.912	0.023	2.6%
	<b>Wholesale Transportation Only (3)</b>				
22	Alpine Natural Gas	1.242	1.356	0.114	9.2%
23	Coalinga	1.245	1.362	0.117	9.4%
24	Island Energy	1.332	1.448	0.116	8.7%
25	Palo Alto	1.216	1.333	0.117	9.6%
26	West Coast Gas - Castle	4.130	4.249	0.119	2.9%
27	West Coast Gas - Mather D	6.150	6.267	0.117	1.9%
28	West Coast Gas - Mather T	1.255	1.372	0.117	9.3%
* CARE customers receive a 20 % discount on transportation and procurement and are exempt from CARE and CSI Solar Water Heater rate components.					
<b>Notes:</b>					
1) 2021 rates are in accordance with PG&E's June 1, 2021 rate change filing per Advice Letter 4440-G.					
2) PG&E's bundled gas service is available to core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding are included in end-use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, shrinkage, transportation on Canadian and Interstate pipelines, core brokerage, and franchise fees and uncollectibles expense. The illustrative annual average rates for these elements are based on the illustrative revenue requirements shown on PG&E's Preliminary Statement Part C2. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.					
3) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.					
4) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.					
5) Dollar difference are due to rounding.					

1 **K. Alternate Residential and Small Commercial Average Monthly Bill Impacts**  
2 **for Bill Insert Presentation**

3 If the Commission adopts PG&E's 2023 GT&S CARD Application forecasts  
4 and rate design proposals, absent any change in revenue requirements, gas  
5 rates and bills would increase effective January 1, 2023. A typical CARE  
6 residential customer using 26 therms per month would see an average monthly  
7 gas bill increase, relative to the June 1, 2021 bill, of \$0.02 (or 0.1 percent),  
8 from \$37.04 to \$37.06 on January 1, 2023 due to the proposals made in the  
9 CARD. A Non-CARE residential customer using 31 therms per month would  
10 see an average monthly gas bill increase, relative to the June 1, 2021 bill, of  
11 \$0.03 (or 0.1 percent), from \$56.34 to \$56.37 on January 1, 2023 due to the  
12 proposals made in the CARD. A typical Non-CARE small business customer  
13 using 272 therms per month would see an average monthly gas bill increase  
14 of \$0.45 (or 0.1 percent), from \$356.71 to \$357.16, on January 1, 2023 due to  
15 the proposals made in the CARD. Individual customers' bills would differ.

16 **L. Timing of Decision and Implementation**

17 Rates provided in this chapter rely on receiving a final decision in this case  
18 as well as in the 2023 GRC I, with sufficient time to implement the proposals set  
19 forth in this Application. PG&E understands that it is possible a decision may  
20 not be issued within the Rate Case Plan timeframe for the 2023 GRC I and,  
21 therefore, proposes to work with the Energy Division to develop a mutually  
22 acceptable implementation plan.

23 **M. Conclusion**

24 The CPUC should adopt the proposals made in this chapter to continue the  
25 currently-adopted and long-standing CARD methods for CACs as reasonable.  
26 The CPUC should also adopt the proposed modifications to CARD methods for  
27 LT rates<sup>55</sup> and storage costs, specifically as it relates to the recovery of  
28 inventory management costs in end-use rates, as reasonable. Finally, the  
29 CPUC should adopt the calculation of backbone transmission, LT, and storage

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55 Chapter 4 proposes the Local Transmission allocation method and this chapter proposes to adjust the results of the Chapter 4 proposal for PG&E's forecast of discounted contracts similar to the current method.



- 1 rates and CACs, and the illustrative present- and proposed gas rates and
- 2 impacts presented in this chapter as reasonable.

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 6**

**ATTACHMENT A**

**PRESENT AND PROPOSED RATES**

**PACIFIC GAS AND ELECTRIC COMPANY  
2023 GAS TRANSMISSION AND STORAGE COST ALLOCATION AND RATE DESIGN CASE**

**CHAPTER 6 - ATTACHMENT A  
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6-24	Average Monthly Bill Impacts: Residential and Small Commercial Customer Classes

# 2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase Application

## Table 6-1 Guide to Gas Ratemaking by Component

Line No.	Rate Component	Cost/Rate Setting
1	Backbone Transmission	GRC sets revenue requirement; Gas Transmission and Storage Cost Allocation and Rate Design (GTS CARD) Proceedings set cost allocation and rate design.
2	Storage (Core, inventory management and reserve capacity service)	GRC sets revenue requirement; GTS CARD Proceedings set cost allocation and rate design.
3	Local Transmission	GRC sets revenue requirement; GTS CARD Proceedings set cost allocation and rate design.
4	Customer Access Charge - (Transmission-level)	GRC sets revenue requirement; GTS CARD Proceedings set cost allocation and rate design.
5	Distribution rate and distribution-level customer charges	GRC sets revenue requirement; Gas Cost Allocation Proceedings set cost allocation and rate design.
6	Customer Class Charge (CCC) - Public Purpose Program charges (California Alternative Rates for Energy (CARE), Energy Efficiency (EE) and Low Income Energy Efficiency (LIEE) programs)	CARE, EE and LIEE program costs set in separate proceedings. PPP gas surcharge set annually by Advice letter pursuant to A.B. 1002 and P.U. Code Sec 890. Gas Cost Allocation Proceedings set cost allocation.
7	Customer Class Charge (CCC) - Other Forecast Period costs and Balancing Account charges	Revenues set in various regulatory proceedings. Gas Cost Allocation Proceedings and Annual True-ups set rates.
8	Core Procurement	Core Procurement Monthly Pricing Filings. (CPIM Application)

2023 GAS TRANSMISSION AND STORAGE COST ALLOCATION AND RATE DESIGN CASE

Table 6-2

GT CARD Core and Noncore Revenue Responsibility

(\$ Thousand)

Line No.	2019 GT&S Rate Case*	Illustrative Annual GT&S Revenue Requirements by Class and Service Under Adopted Methods from 2019 GT&S Rate Case And Incorporating Proposed Change by UCC Over Present Rates at Time of CARD Application					2023 Gas Transmission & Storage Cost Allocation and Rate Design				
		2023	2024	2025	2026		2023	2024	2025	2026	
Core Revenue Requirements											
1	Illustrative Backbone Transmission Base - Fixed Reservation (1)	156,723	156,618	184,711	193,440	206,605	110,430	128,197	133,587	144,761	
2	Illustrative Backbone Transmission Base - Volumetric (1)	64,009	61,501	72,535	75,963	81,134	58,144	66,776	73,776	78,198	
3	Subtotal Backbone Transmission Base - Illustrative (1)	220,732	218,119	257,247	269,403	287,739	168,574	196,973	207,363	222,959	
4	Backbone Transmission Adders	-	-	-	-	-	-	-	-	-	
5	Subtotal Backbone Transmission - Illustrative (1)	220,732	218,119	257,247	269,403	287,739	168,574	196,973	207,363	222,959	
6	Local Transmission Base	650,937	1,062,569	1,110,969	1,178,771	1,250,547	971,262	1,016,242	1,078,282	1,144,262	
7	Local Transmission Adder	-	-	-	-	-	-	-	-	-	
8	Subtotal Local Transmission	650,937	1,062,569	1,110,969	1,178,771	1,250,547	971,262	1,016,242	1,078,282	1,144,262	
9	Storage	24,377	18,257	28,220	29,112	32,184	23,862	38,338	40,077	44,293	
10	Customer Access Charge	-	-	-	-	-	-	-	-	-	
11	Total Core GT&S	\$896,046	\$1,280,946	\$1,396,435	\$1,477,286	\$1,570,470	\$1,163,698	\$1,252,553	\$1,325,721	\$1,411,513	
12	NGSS Enduser Depreciation/Decommissioning	27,618	-867,737	\$6,616	\$7,202	\$7,701	-867,737	\$6,616	\$7,202	\$7,701	
13	Enduser Inventory Management	-	\$0	\$0	\$0	\$0	\$37,460	\$57,971	\$59,063	\$65,298	
14	Total Core	\$923,864	\$1,231,209	\$1,403,052	\$1,484,488	\$1,578,172	\$1,133,421	\$1,317,141	\$1,391,986	\$1,484,512	
15	Core Share of Revenue Requirement	58.5%	61.9%	62.0%	62.0%	62.0%	57.0%	58.2%	58.2%	58.3%	
Noncore / Unbundled Revenue Requirements											
16	Illustrative Backbone Trans. Base w/o G-XF Contracts (1)	336,547	288,656	338,297	355,395	380,345	257,307	271,141	287,682	301,589	
17	Backbone Transmission Adders	-	-	-	-	-	-	-	-	-	
18	Subtotal Backbone Transmission - Illustrative (1)	336,547	288,656	338,297	355,395	380,345	257,307	271,141	287,682	301,589	
19	G-XF Contracts	5,904	5,585	5,809	6,004	6,183	5,587	5,811	6,298	6,647	
20	G-XF Contract Adders	-	-	-	-	-	-	-	-	-	
21	G-XF Contracts Subtotal	5,904	5,585	5,809	6,004	6,183	5,587	5,811	6,298	6,647	
22	Subtotal Backbone Transmission - Illustrative (1)	342,450	294,241	344,106	361,398	386,528	262,894	276,952	293,981	308,237	
23	Local Transmission Base	301,851	484,823	508,176	539,344	572,827	576,131	602,903	639,833	679,113	
24	Local Transmission Adder	-	-	-	-	-	-	-	-	-	
25	Subtotal Local Transmission	301,851	484,823	508,176	539,344	572,827	576,131	602,903	639,833	679,113	
26	Storage	-	-	-	-	-	-	-	-	-	
27	Customer Access Charge	2,331	3,323	4,089	4,976	5,849	3,323	4,089	4,976	5,849	
28	Total Noncore / Unbundled	\$646,632	\$782,387	\$856,371	\$905,718	\$965,204	\$842,347	\$883,944	\$938,790	\$993,198	
29	NGSS Enduser Depreciation/Decommissioning	9,695	-\$23,779	\$2,323	\$2,528	\$2,704	-\$23,779	\$2,323	\$2,528	\$2,703	
30	Enduser Inventory Management	-	-	-	-	-	37,459	57,970	59,062	65,297	
31	Total Noncore/Unbundled	\$656,327	\$758,608	\$858,693	\$908,246	\$967,907	\$856,028	\$944,236	\$1,000,380	\$1,061,198	
32	Noncore Share of Revenue Requirement	41.5%	38.1%	38.0%	38.0%	38.0%	43.0%	41.8%	41.8%	41.7%	
Total											
33	Illustrative Backbone Transmission Base w/o G-XF Contracts (1)	557,279	506,775	595,543	624,798	668,084	425,881	468,114	495,046	524,548	
34	Backbone Transmission Adders	-	-	-	-	-	-	-	-	-	
35	Subtotal Backbone Trans. w/o G-XF Contracts - Illustrative (1)	557,279	506,775	595,543	624,798	668,084	425,881	468,114	495,046	524,548	
36	G-XF Contracts	5,904	5,585	5,809	6,004	6,183	5,587	5,811	6,298	6,647	
37	G-XF Contract Adders	-	-	-	-	-	-	-	-	-	
38	G-XF Contracts Subtotal	5,904	5,585	5,809	6,004	6,183	5,587	5,811	6,298	6,647	
39	Subtotal Backbone Transmission - Illustrative (1)	563,182	512,360	601,352	630,801	674,267	431,468	473,925	501,344	531,195	
40	Local Transmission Base	952,788	1,547,393	1,619,145	1,718,115	1,823,374	1,547,393	1,619,145	1,718,115	1,823,374	
41	Local Transmission Adder	-	-	-	-	-	-	-	-	-	
42	Subtotal Local Transmission	952,788	1,547,393	1,619,145	1,718,115	1,823,374	1,547,393	1,619,145	1,718,115	1,823,374	
43	Storage	24,377	18,257	28,220	29,112	32,184	23,862	38,338	40,077	44,293	
44	Customer Access Charge	2,331	3,323	4,089	4,976	5,849	3,323	4,089	4,976	5,849	
45	Total GT&S	\$1,542,678	\$2,081,333	\$2,262,806	\$2,383,005	\$2,535,674	\$2,006,045	\$2,136,497	\$2,284,512	\$2,404,711	
46	NGSS Enduser Depreciation/Decommissioning	37,313	-\$1,515	8,939	9,730	10,405	-\$1,515	8,939	9,730	10,405	
47	Enduser Inventory Management	-	-	-	-	-	74,919	115,941	118,125	130,595	
48	Total Gas Transmission and Storage System	\$1,579,991	\$1,989,817	\$2,261,745	\$2,392,734	\$2,546,079	\$1,989,449	\$2,261,377	\$2,392,366	\$2,546,711	
49	Total Revenue Requirement Share	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	

Backbone Transmission revenues are illustrative because the calculation assumes for simplicity that the core backbone capacity assignments are utilized at 100%, which is not precisely the case.

\* Adopted 2019 GT&S for 2022 excludes 2011-2015 Capital Audit RRQ while

2023-2026 includes the impact of A. 21-06-021.

2023 GAS TRANSMISSION AND STORAGE COST ALLOCATION AND RATE DESIGN CASE

Table 6-2

GT CARD Core and Noncore Revenue Responsibility  
(\$ Thousand)

Line No.		Change from GRC 1			% Change from GRC 1			
		2023	2024	2025	2023	2024	2025	
Core Revenue Requirements								
1	Illustrative Backbone Transmission Base - Fixed Reservation (1)	48,188	56,515	59,853	61,844	29.5%	30.9%	29.9%
2	Illustrative Backbone Transmission Base - Volumetric (1)	3,358	3,759	2,187	2,936	5.5%	5.2%	2.9%
3	Subtotal Backbone Transmission Base - Illustrative (1)	49,545	60,274	62,040	64,780	22.7%	23.4%	22.5%
4	Backbone Transmission Adders	-	-	-	-	-	-	-
5	Subtotal Backbone Transmission - Illustrative (1)	49,545	60,274	62,040	64,780	22.7%	23.4%	22.5%
6	Local Transmission Base	91,307	94,727	100,490	106,286	8.6%	8.5%	8.5%
7	Local Transmission Adder	-	-	-	-	-	-	-
8	Subtotal Local Transmission	91,307	94,727	100,490	106,286	8.6%	8.5%	8.5%
9	Storage	(5,604)	(11,119)	(10,965)	(12,109)	-30.7%	-39.4%	-37.6%
10	Customer Access Charge	-	-	-	-	-	-	-
11	Total Core GT&S	135,248	143,882	151,565	158,957	10.4%	10.3%	10.1%
12	NGSS Enduser Depreciation/Decommissioning	0	(0)	(0)	(0)	0.0%	0.0%	0.0%
13	Enduser Inventory Management	(37,460)	(57,971)	(59,063)	(65,298)	7.9%	6.1%	5.9%
14	Total Core	97,788	85,911	92,502	93,659	0.0%	0.0%	0.0%
15	Core Share of Revenue Requirement	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Noncore / Unbundled Revenue Requirements								
16	Illustrative Backbone Trans. Base w/o G-XF Contracts (1)	31,349	67,156	67,712	78,756	10.9%	19.9%	20.7%
17	Backbone Transmission Adders	-	-	-	-	-	-	-
18	Subtotal Backbone Transmission - Illustrative (1)	31,349	67,156	67,712	78,756	10.9%	19.9%	20.7%
19	G-XF Contracts	(2)	(2)	(295)	(465)	0.0%	0.0%	-7.5%
20	G-XF Contract Adders	-	-	-	-	-	-	-
21	G-XF Contracts Subtotal	(2)	(2)	(295)	(465)	0.0%	0.0%	-7.5%
22	Subtotal Backbone Transmission - Illustrative (1)	31,347	67,154	67,418	78,291	10.7%	19.5%	20.3%
23	Local Transmission Base	(91,307)	(94,727)	(100,490)	(106,286)	-18.8%	-18.6%	-18.6%
24	Local Transmission Adder	-	-	-	-	-	-	-
25	Subtotal Local Transmission	(91,307)	(94,727)	(100,490)	(106,286)	-18.8%	-18.6%	-18.6%
26	Storage	-	-	-	-	-	-	-
27	Customer Access Charge	(59,981)	(27,573)	(33,072)	(27,994)	0.0%	0.0%	0.0%
28	Total Noncore / Unbundled	(0)	0	0	0	-7.7%	-3.2%	-2.9%
29	NGSS Enduser Depreciation/Decommissioning	-	-	-	-	0.0%	0.0%	0.0%
30	Enduser Inventory Management	(37,459)	(57,970)	(59,062)	(65,297)	-12.8%	-10.0%	-9.6%
31	Total Noncore/Unbundled	(97,420)	(85,543)	(92,134)	(93,291)	0.0%	0.0%	0.0%
32	Noncore Share of Revenue Requirement	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total								
33	Illustrative Backbone Transmission Base w/o G-XF Contracts (1)	80,894	127,430	129,752	143,536	16.0%	21.4%	21.5%
34	Backbone Transmission Adders	-	-	-	-	-	-	-
35	Subtotal Backbone Trans. w/o G-XF Contracts - Illustrative (1)	80,894	127,430	129,752	143,536	16.0%	21.4%	21.5%
36	G-XF Contracts	(2)	(2)	(295)	(465)	0.0%	0.0%	-7.5%
37	G-XF Contract Adders	-	-	-	-	-	-	-
38	G-XF Contracts Subtotal	(2)	(2)	(295)	(465)	0.0%	0.0%	-7.5%
39	Subtotal Backbone Transmission - Illustrative (1)	80,892	127,427	129,457	143,072	15.8%	20.5%	21.2%
40	Local Transmission Base	-	-	-	-	0.0%	0.0%	0.0%
41	Local Transmission Adder	-	-	-	-	-	-	-
42	Subtotal Local Transmission	-	-	-	-	0.0%	0.0%	0.0%
43	Storage	(5,604)	(11,119)	(10,965)	(12,109)	-30.7%	-39.4%	-37.6%
44	Customer Access Charge	-	-	-	-	0.0%	0.0%	0.0%
45	Total GT&S	75,288	116,309	118,493	130,963	3.6%	5.2%	5.2%
46	NGSS Enduser Depreciation/Decommissioning	-	-	-	-	0.0%	0.0%	0.0%
47	Enduser Inventory Management	(74,919)	(115,941)	(118,125)	(130,595)	0.0%	0.0%	0.0%
48	Total Gas Transmission and Storage System	368	368	368	368	0.0%	0.0%	0.0%
49	Total Revenue Requirement Share	0%	0%	0%	0%	0.0%	0.0%	0.0%

Backbone Transmission revenues are illustrative because the calculation assumes for

\* Adopted 2019 GT&S for 2022 excludes 2011-2015 Capital Audit RRQ while

simplicity that the core backbone capacity assignments are utilized at 100%, which is not precisely the case.

2023-2026 includes the impact of A. 21-06-021.



2023 Gas Transmission and Storage Cost Allocation  
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Table 6-3  
Illustrative End-Use Class Average Rates (\$/dth)

Line No.	Illustrative June 1 Rates with 2022 GT&S Components	2023 Illustrative Rates with Proposed GRC 1 RRQ (1)	\$ Change GRC 1 v. June 1 Components	% Change GRC 1 v. June 1 Components	Proposed 2023 GT&S (Year 2023 GT&S Components & 2023 Illustrative GRC 1)	\$ Change from GRC 1 (5)	% Change from GRC 1
<b>Core Retail Bundled Service (2)</b>							
1	Residential Non-CARE	19.186	3.484	18.2%	22.303	-0.368	-1.6%
2	Residential CARE	15.059	2.702	17.9%	17.474	-0.287	-1.6%
3	Small Commercial Non-CARE	13.819	2.530	18.3%	16.002	-0.346	-2.1%
4	Small Commercial CARE	10.777	1.938	18.0%	12.446	-0.269	-2.1%
5	Large Commercial	9.805	1.888	19.3%	11.379	-0.313	-2.7%
6	Uncompressed Core NGV	9.361	2.123	22.7%	11.175	-0.309	-2.7%
7	Compressed Core NGV	25.737	0.459	1.8%	25.888	-0.309	-1.2%
<b>Core Retail Transport Only (3)</b>							
8	Residential Non-CARE	15.327	3.461	22.6%	18.578	-0.211	-1.1%
9	Residential CARE	11.200	2.679	23.9%	13.749	-0.130	-0.9%
10	Small Commercial Non-CARE	10.139	2.540	25.1%	12.468	-0.211	-1.7%
11	Small Commercial CARE	7.098	1.912	26.9%	8.912	-0.098	-1.1%
12	Large Commercial	6.518	1.902	29.2%	8.196	-0.224	-2.7%
13	Uncompressed Core NGV	6.342	1.915	30.2%	8.033	-0.224	-2.7%
14	Compressed Core NGV	22.718	0.252	1.1%	22.746	-0.224	-1.0%
<b>Noncore Retail Transportation Only (3)</b>							
15	Industrial – Distribution	5.493	1.243	22.6%	7.125	0.389	5.8%
16	Industrial – Transmission	2.804	0.683	24.3%	3.875	0.389	11.1%
17	Industrial – Backbone	1.566	-0.043	-2.7%	1.522	-0.002	-0.1%
18	Uncompressed Noncore NGV – Distribution	5.027	1.374	27.3%	6.790	0.389	6.1%
19	Uncompressed Noncore NGV – Transmission	2.599	0.661	25.4%	3.649	0.389	11.9%
20	Electric Generation – Distribution/Transmission	2.103	0.558	26.5%	3.084	0.423	15.9%
21	Electric Generation – Backbone	0.958	-0.148	-15.5%	0.826	0.017	2.1%
<b>Wholesale Transportation Only (3)</b>							
22	Alpine Natural Gas	1.366	0.552	40.4%	2.326	0.408	21.3%
23	Coalinga	1.353	0.570	42.2%	2.334	0.411	21.4%
24	Island Energy	1.393	0.652	46.8%	2.455	0.410	20.1%
25	Palo Alto	1.356	1.882	38.8%	2.294	0.412	21.9%
26	West Coast Gas - Castle	4.426	1.310	29.6%	6.150	0.414	7.2%
27	West Coast Gas - Mather D	6.751	1.646	24.4%	8.809	0.412	4.9%
28	West Coast Gas - Mather T	1.496	0.440	29.4%	2.348	0.412	21.3%

**Notes:**  
2023 rates are based on PG&E's June 1, 2021 rate change filing per Advice Letter 4440-G as modified by PG&E's GRC 1 Application 21-06-021.

1) PG&E's bundled gas service is available to core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding are included in end-use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, shrinkage, transportation on Canadian and intrastate pipelines, core brokerage, and franchise fees and miscellaneous expense. The intrastate backbone transmission and storage costs are included in the rates for the non-core customers. PG&E's Procurement Statement Part C2. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burner, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

2) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

3) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

4) Dollar difference are due to rounding.

5)

2023 Gas Transmission and Storage Cost Allocation  
and Rate Design Ratecase Application

Table 6-3  
Illustrative End-Use Class Average Rates (\$/dth)

Line No.	2024 Illustrative Rates with Proposed GRC 1 RRQ (1)	Proposed 2024 GT&S Components & Change from GRC 1 (1)	\$ Change from GRC 1 (1)	% Change from GRC 1	2025 Illustrative Rates with Proposed GRC 1 RRQ (1)	Proposed 2025 GT&S Components & Change from GRC 1 (1)	\$ Change from GRC 1 (1)	% Change from GRC 1	2026 Illustrative Rates with Proposed GRC 1 RRQ (1)	Proposed 2026 GT&S Components & Change from GRC 1 (1)	\$ Change from GRC 1 (1)	% Change from GRC 1
<b>Core Retail Bundled Service (2)</b>												
1	24.377	24.091	-0.286	-1.2%	25.908	25.705	-0.203	-0.8%	27.536	27.477	-0.059	-0.2%
2	19.095	18.872	-0.222	-1.2%	20.291	20.134	-0.158	-0.8%	21.564	21.519	-0.044	-0.2%
3	17.441	17.178	-0.263	-1.5%	18.409	18.231	-0.179	-1.0%	19.450	19.415	-0.034	-0.2%
4	13.559	13.354	-0.205	-1.5%	14.305	14.167	-0.138	-1.0%	15.107	15.082	-0.025	-0.2%
5	12.332	12.097	-0.235	-1.9%	12.901	12.756	-0.146	-1.1%	13.521	13.517	-0.003	0.0%
6	12.126	11.895	-0.230	-1.9%	12.702	12.561	-0.141	-1.1%	13.327	13.329	0.001	0.0%
7	27.116	26.885	-0.230	-0.8%	27.625	27.484	-0.141	-0.5%	28.190	28.192	0.001	0.0%
<b>Core Retail Transport Only (3)</b>												
8	20.289	20.167	-0.123	-0.6%	21.765	21.731	-0.034	-0.2%	23.304	23.418	0.114	0.5%
9	15.007	14.948	-0.059	-0.4%	16.149	16.160	0.012	0.1%	17.332	17.460	0.128	0.7%
10	13.592	13.469	-0.123	-0.9%	14.511	14.477	-0.034	-0.2%	15.472	15.586	0.114	0.7%
11	9.709	9.646	-0.063	-0.7%	10.407	10.413	0.007	0.1%	11.130	11.253	0.123	1.1%
12	8.923	8.780	-0.143	-1.6%	9.456	9.401	-0.055	-0.6%	10.015	10.106	0.091	0.9%
13	8.768	8.625	-0.143	-1.6%	9.309	9.254	-0.055	-0.6%	9.876	9.967	0.091	0.9%
14	23.758	23.615	-0.143	-0.6%	24.232	24.177	-0.055	-0.2%	24.739	24.830	0.091	0.4%
<b>Noncore Retail Transportation Only (3)</b>												
15	7.162	7.575	0.413	5.8%	7.609	8.049	0.439	5.8%	8.077	8.546	0.469	5.8%
16	3.686	4.097	0.411	11.2%	3.851	4.289	0.438	11.4%	4.025	4.493	0.467	11.6%
17	1.632	1.635	0.003	0.2%	1.671	1.677	0.006	0.4%	1.711	1.722	0.011	0.6%
18	6.827	7.240	0.412	6.0%	7.275	7.714	0.439	6.0%	7.742	8.211	0.469	6.1%
19	3.451	3.862	0.411	11.9%	3.605	4.043	0.438	12.2%	3.768	4.235	0.467	12.4%
20	2.814	3.270	0.456	16.2%	2.935	3.418	0.483	16.4%	3.063	3.576	0.513	16.8%
21	0.879	0.904	0.026	3.0%	0.882	0.908	0.026	2.9%	0.885	0.913	0.028	3.2%
<b>Wholesale Transportation Only (3)</b>												
22	2.078	2.516	0.438	21.1%	2.207	2.670	0.463	21.0%	2.343	2.834	0.491	21.0%
23	2.084	2.525	0.441	21.2%	2.214	2.681	0.467	21.1%	2.351	2.848	0.497	21.1%
24	2.234	2.673	0.439	19.7%	2.397	2.862	0.465	19.4%	2.566	3.061	0.496	19.3%
25	2.033	2.474	0.441	21.7%	2.153	2.619	0.466	21.6%	2.279	2.774	0.495	21.7%
26	6.194	6.637	0.443	7.2%	6.682	7.162	0.470	7.0%	7.210	7.710	0.500	6.9%
27	9.051	9.493	0.442	4.9%	9.792	10.260	0.468	4.8%	10.563	11.061	0.498	4.7%
28	2.101	2.542	0.442	21.0%	2.235	2.703	0.468	20.9%	2.375	2.873	0.498	21.0%

Notes:  
1) 2023 rates are based on PG&E's June 1, 2021 rate change filing per Advice Letter 444D-G as modified by PG&E's GRC 1 Application 21-06-021.

2) PG&E's bundled gas service is available to core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding are included in end-use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, shrinkage, transportation on Canadian and interstate pipelines, core brokerage, and franchise fees and uncollectibles expense. The illustrative annual average rates for these elements are based on the illustrative revenue requirements shown on PG&E's Preliminary Statement Part C2. Core bundled rates also include the cost of transportation and delivery of gas from the citygate to the customer's burner, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

3) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

4) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

5) Dollar difference are due to rounding.

**2023 Gas Transmission and Storage CARD Application**  
**Table 6-4**  
**Illustrative End-Use Noncore and Wholesale Class**  
**Average Rates with Procurement Proxy (\$/dth) (3) (4)**

Line No.	Illustrative June 1 Rates with 2022 GT&S Components	2023 Illustrative Rates with Proposed GRC 1 RRQ (1)	\$ Change GRC 1 v. June 1 with 2022 GT&S Components	% Change GRC 1 v. June 1 with 2022 GT&S Components	Proposed 2023 GT&S (Year 2023 GT&S Components & 2023 Illustrative GRC 1)	\$ Change from GRC 1 (5)	% Change from GRC 1
<b>Noncore Retail with Procurement Proxy (2)</b>							
1	Industrial – Distribution	8.481	9.922	17.0%	10.206	0.284	2.9%
2	Industrial – Transmission	5.792	6.673	15.2%	6.956	0.283	4.2%
3	Industrial – Backbone	4.554	4.710	3.4%	4.603	(0.107)	-2.3%
4	Uncompressed Noncore NGV – Distribution	8.015	9.587	19.6%	9.871	0.284	3.0%
5	Uncompressed Noncore NGV – Transmission	5.587	6.447	15.4%	6.730	0.283	4.4%
6	Electric Generation – Distribution/Transmission	5.091	5.848	14.9%	6.165	0.317	5.4%
7	Electric Generation – Backbone	3.946	3.996	1.3%	3.907	(0.089)	-2.2%
<b>Wholesale with Procurement Proxy (2)</b>							
8	Alpine Natural Gas	4.354	5.104	17.2%	5.407	0.303	5.9%
9	Coalinga	4.340	5.109	17.7%	5.415	0.306	6.0%
10	Island Energy	4.381	5.231	19.4%	5.536	0.305	5.8%
11	Palo Alto	4.344	5.068	16.7%	5.375	0.306	6.0%
12	West Coast Gas - Castle	7.413	8.922	20.3%	9.230	0.309	3.5%
13	West Coast Gas - Mather D	9.738	11.583	18.9%	11.890	0.306	2.6%
14	West Coast Gas - Mather T	4.484	5.123	14.2%	5.429	0.306	6.0%

**Notes:**

- 1) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate which includes costs for gas commodity, gas transmission (i.e., Canadian, interstate and intrastate backbone) and shrinkage but excludes bundled storage.
- 2) 2023 gas transportation rates are based on PG&E's June 1, 2021 rate change filing per Advice Letter 444D-G as modified by PG&E's GRC 1 Application 21-06-021.
- 3) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.
- 4) Dollar difference are due to rounding.

**2023 Gas Transmission and Storage CARD Application**  
**Table 6-4**  
**Illustrative End-Use Noncore and Wholesale Class**  
**Average Rates with Procurement Proxy (\$/dth) (3) (4)**

Line No.	2024 Illustrative Rates with Proposed GRC 1 RRQ (1)	Proposed 2024 GT&S (Year 2024 Components & 2024 Illustrative GRC 1)	\$ Change from GRC 1 (5)	% Change from GRC 1	2025 Illustrative Rates with Proposed GRC 1 RRQ (1)	Proposed 2025 GT&S (Year 2025 Components & 2025 Illustrative GRC 1)	\$ Change from GRC 1 (5)	% Change from GRC 1	2026 Illustrative Rates with Proposed GRC 1 RRQ (1)	Proposed 2026 GT&S (Year 2026 Components & 2026 Illustrative GRC 1)	\$ Change from GRC 1 (5)	% Change from GRC 1
<b>Noncore Retail with Procurement Proxy (2)</b>												
1	10.457	10.742	0.536	5.3%	10.938	11.251	0.313	2.9%	11.456	11.791	0.335	2.9%
2	6.981	7.264	0.308	4.4%	7.179	7.491	0.311	4.3%	7.405	7.738	0.333	4.5%
3	4.927	4.802	0.200	4.3%	4.999	4.879	(0.120)	-2.4%	5.091	4.968	(0.123)	-2.4%
4	10.122	10.407	0.536	5.4%	10.603	10.916	0.312	2.9%	11.121	11.456	0.335	3.0%
5	6.746	7.029	0.300	4.5%	6.933	7.245	0.311	4.5%	7.147	7.481	0.333	4.7%
6	6.109	6.437	0.272	4.4%	6.264	6.620	0.356	5.7%	6.442	6.822	0.379	5.9%
7	4.173	4.072	0.165	4.2%	4.210	4.110	(0.101)	-2.4%	4.265	4.159	(0.106)	-2.5%
<b>Wholesale with Procurement Proxy (2)</b>												
8	5.373	5.683	0.276	5.1%	5.536	5.872	0.336	6.1%	5.722	6.079	0.357	6.2%
9	5.379	5.692	0.277	5.1%	5.543	5.883	0.340	6.1%	5.731	6.093	0.362	6.3%
10	5.529	5.840	0.305	5.5%	5.726	6.064	0.339	5.9%	5.945	6.307	0.362	6.1%
11	5.328	5.642	0.267	5.0%	5.482	5.821	0.340	6.2%	5.659	6.019	0.361	6.4%
12	9.489	9.805	0.574	6.2%	10.021	10.364	0.343	3.4%	10.590	10.956	0.366	3.5%
13	12.346	12.660	0.771	6.5%	13.121	13.462	0.341	2.6%	13.943	14.307	0.364	2.6%
14	5.396	5.710	0.280	5.2%	5.564	5.905	0.341	6.1%	5.755	6.119	0.364	6.3%

**Notes:**

- 1) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate which includes costs for gas commodity, gas transmission (i.e., Canadian, interstate and intrastate backbone) and shrinkage but excludes bundled storage.
- 2) 2023 gas transportation rates are based on PG&E's June 1, 2021 rate change filing per Advice Letter 4440-G as modified by PG&E's GRC 1 Application 21-06-021.
- 3) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.
- 4) Dollar difference are due to rounding.

2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase  
Application

Table 6-5  
January 2023 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

	Core			Noncore Transportation									
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Industrial			Natural Gas Vehicle			Electric Gen	
Dist						Trans	BB	Dist	Trans	BB	D/I	BB	
End-Use Transportation:	3.7304	3.7304	3.7304	3.7304	3.7304	2.2070	2.2070	0.0000	2.2070	2.2070	2.2070	2.2070	0.0000
Local Transmission	0.0925	(0.0428)	0.0095	0.0000	0.0000	(0.0140)	0.0036	0.0000	(0.0140)	0.0000	0.0000	0.0000	0.0000
Self Generation Incentive Program	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0586	0.0086
CPUC Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 ARB Cost of Implementation Fee	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
AB32 Greenhouse Gas Compliance & Obligation Cost	(0.2953)	(0.1678)	(0.0786)	(0.0804)	(0.3128)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)
NGSS Transition Costs Recovery	1.0014	0.6532	0.3942	0.3841	1.1925	0.1905	0.1115	0.1164	0.1905	0.1030	0.0724	0.0796	(0.0606)
Balancing Accounts	0.0000	0.0000	0.0000	0.0000	0.0000	0.0304	0.0304	0.0000	0.0304	0.0304	0.0304	0.0000	0.0000
NCA - Local Transmission Cost Subaccount (10)	0.0184	0.0184	0.0052	0.0052	0.0052	0.0052	0.0050	0.0050	0.0050	0.0050	0.0229	0.0169	0.0071
Inventory Management Cost Recovery	0.0240	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0071	0.0144	0.0144	0.0144	0.0144	0.0071
GT&S Pension	12.3950	5.9969	2.5072	2.6203	16.7665	3.0143	0.1143	0.0000	3.0143	0.0000	0.0175	0.0175	0.0175
Distribution - Annual Average (b)	17.7785	11.0244	7.4041	7.4958	22.2180	6.1993	3.2379	0.8802	6.1992	3.1114	3.0664	0.8229	
Volumetric Rate - Annual Average													
CAC - Class Avg Volumetric Equivalent (c)	0.7991	0.5822	0.0411	0.0095	0.0000	0.0633	0.0098	0.0142	0.0633	0.0098	0.0177	0.0035	
Gas Public Purpose Program Surcharge	18.5776	12.4684	8.1961	8.0331	22.7458	7.1253	3.8752	1.5218	6.7903	3.6490	3.0841	0.8264	
Total Rate													
Procurement Charges for Core Bundled Customers:													
Storage	0.0907	0.0750	0.0522	0.0484	0.0484								
Backbone Capacity	0.4347	0.3654	0.2316	0.2171	0.2171								
Backbone Usage	2.1210	2.1211	0.2711	0.2711	0.2711								
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210								
Interstate Capacity and Other	0.7823	0.6805	0.4926	0.4707	0.4707								
Total Core Procurement	3.6998	3.5131	3.1284	3.1284	3.1284								
Total Core Bundled Rates	22.2774	15.9815	11.3647	11.1615	25.8742								

Procurement Charges for Core Bundled Customers:

Storage	0.0907	0.0750	0.0522	0.0484	0.0484
Backbone Capacity	0.4347	0.3654	0.2316	0.2171	0.2171
Backbone Usage	0.2711	0.2711	0.2711	0.2711	0.2711
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210
Interstate Capacity and Other	0.7823	0.6805	0.4926	0.4707	0.4707
Total Core Procurement	3.6998	3.5131	3.1686	3.1284	3.1284
Total Core Bundled Rates	22.2774	15.9815	11.3847	11.1615	25.8742

	Wholesale Transportation									
	Alpine	Coalinaa	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans	WCG	Mather	Trans
End-Use Transportation:	2.2070	2.2070	2.2070	2.2070	2.2070	2.2070	2.2070	2.2070	2.2070	2.2070
Local Transmission	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Self Generation Incentive Program	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CPUC Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 ARB Cost of Implementation Fee	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198
AB32 Greenhouse Gas Compliance & Obligation Cost	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)
NGSS Transition Costs Recovery	0.1192	0.1192	0.1192	0.1192	0.1967	0.2607	0.1192	0.1192	0.1192	0.1192
Balancing Accounts	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179
Inventory Management Cost Recovery	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144
GT&S Pension	0.0000	0.0000	0.0000	0.0000	3.6824	6.3189	0.0000	0.0000	0.0000	0.0000
Distribution - Annual Average (b)	3.0177	3.0177	3.0177	3.0177	6.7776	9.4780	3.0177	3.0177	3.0177	3.0177
Volumetric Rate - Annual Average										
CAC - Class Avg Volumetric Equivalent (c)	0.0452	0.0531	0.1739	0.0127	0.1086	0.0673	0.0673	0.0673	0.0673	0.0673
Gas Public Purpose Program Surcharge	3.0629	3.0707	3.1915	3.0304	6.8862	9.5454	3.0629	3.0629	3.0629	3.0629
END-USE RATE	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
GHG COMPLIANCE COST EXEMPTION	2.3263	2.3341	2.4549	2.2938	6.1496	8.8088	2.3263	2.3263	2.3263	2.3263
END-USE RATE EXCLUDING GHG COMPLIANCE COST										

Notes:

- a) Class average rates reflect load shape for bundled core.
- b) Distribution rates represent the annual class average.
- c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

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Table 6-6  
April 2023 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

	Core				Industrial				Noncore Transportation			
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	BB	Electric Gen
End-Use Transportation:												
Local Transmission	3.7304	3.7304	3.7304	3.7304	3.7304	2.2070	2.2070	0.0000	2.2070	2.2070	0.0000	0.0000
Self Generation Incentive Program	0.0925	(0.0428)	0.0095	0.0000	0.0000	(0.0140)	0.0036	0.0000	(0.0140)	0.0000	0.0000	0.0000
CPUC Fee	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0086
AB32 ARB Cost of Implementation Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
NGSS Transition Costs Recovery	(0.2953)	(0.1678)	(0.0786)	(0.0804)	(0.3128)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)
Balancing Accounts	1.0014	0.6532	0.3942	0.3841	1.1925	0.1905	0.1115	0.1164	0.1905	0.1030	0.0796	0.0796
NCA - Local Transmission Cost Subaccount (10)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0304	0.0304	0.0000	0.0304	0.0304	0.0304	0.0000
Inventory Management Cost Recovery	0.0184	0.0184	0.0052	0.0052	0.0052	0.0052	0.0050	0.0050	0.0050	0.0050	0.0229	0.0169
GT&S Pension	0.0240	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0071	0.0144	0.0144	0.0144	0.0071
Distribution - Annual Average (b)	12.3950	5.9969	2.5072	2.6203	16.7665	3.0143	0.1143	0.0000	3.0143	0.0000	0.0175	0.0175
Volumetric Rate - Annual Average	17.7765	11.0244	7.4041	7.4958	22.2180	6.1993	3.2379	0.8802	6.1992	3.1114	3.0664	0.8229
CAC - Class Avg Volumetric Equivalent (c)												
Gas Public Purpose Program Surcharge	0.7991	0.8617	0.7509	0.5278	0.5278	0.8626	0.6275	0.0142	0.6275	0.5278	0.0177	0.0035
<b>Total Rate</b>	<b>18.5776</b>	<b>12.4684</b>	<b>8.1961</b>	<b>8.0331</b>	<b>22.7458</b>	<b>7.1263</b>	<b>3.8752</b>	<b>1.5218</b>	<b>6.7903</b>	<b>3.6490</b>	<b>3.0841</b>	<b>0.8264</b>
Procurement Charges for Core Bundled Customers:												
Storage	0.1237	0.1023	0.0712	0.0660	0.0660							
Backbone Capacity	0.4347	0.3654	0.2316	0.2171	0.2171							
Backbone Usage	0.2711	0.2711	0.2711	0.2711	0.2711							
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210							
Interstate Capacity and Other	0.7828	0.6909	0.4931	0.4712	0.4712							
Total Core Procurement	3.7333	3.5408	3.1881	3.1465	3.1465							
<b>Total Core Bundled Rates</b>	<b>22.3109</b>	<b>16.0092</b>	<b>11.3842</b>	<b>11.1796</b>	<b>25.8923</b>							

	Wholesale Transportation						WCG		
	Alpine	Coalinaa	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	Mather Trans	WCG	
End-Use Transportation:									
Local Transmission	2.2070	2.2070	2.2070	2.2070	2.2070	2.2070	2.2070		
Self Generation Incentive Program	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
CPUC Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
AB32 ARB Cost of Implementation Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198		
NGSS Transition Costs Recovery	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)	(0.0606)		
Balancing Accounts	0.1192	0.1192	0.1192	0.1192	0.1967	0.2607	0.1192		
Inventory Management Cost Recovery	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179		
GT&S Pension	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144		
Distribution - Annual Average (b)	0.0000	0.0000	0.0000	0.0000	3.6824	6.3189	0.0000		
Volumetric Rate - Annual Average	3.0177	3.0177	3.0177	3.0177	6.7776	9.4780	3.0177		
CAC - Class Avg Volumetric Equivalent (c)									
Gas Public Purpose Program Surcharge	0.0452	0.0531	0.1739	0.0127	0.1086	0.0673	0.0673		
<b>END-USE RATE</b>	<b>3.0629</b>	<b>3.0707</b>	<b>3.1915</b>	<b>3.0304</b>	<b>6.8862</b>	<b>9.5454</b>	<b>3.0850</b>		
<b>GHG COMPLIANCE COST EXEMPTION</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>		
<b>END-USE RATE EXCLUDING GHG COMPLIANCE COST</b>	<b>2.3263</b>	<b>2.3341</b>	<b>2.4549</b>	<b>2.2938</b>	<b>6.1496</b>	<b>8.8088</b>	<b>2.3484</b>		

Notes:  
a) Class average rates reflect load shape for bundled core.  
b) Distribution rates represent the annual class average.  
c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.



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Table 6-7  
January 2024 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

	Core (a)				Noncore Transportation				Electric Gen	
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Industrial		Natural Gas Vehicle	Electric Gen	
						Dist	Trans		Dist	Trans
<b>End-Use Transportation:</b>	3.9872	3.9872	3.9872	3.9872	3.9872	2.3082	2.3082	2.3082	2.3082	2.3082
Local Transmission	0.0925	(0.0428)	0.0095	0.0000	0.0000	(0.0140)	0.0036	0.0000	0.0000	0.0000
Self Generation Incentive Program	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585
CPUC Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 ARB Cost of Implementation Fee	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
AB32 Greenhouse Gas Compliance & Obligation Cost	0.0288	0.0164	0.0077	0.0079	0.0284	0.0059	0.0059	0.0059	0.0059	0.0059
NGSS Transition Costs Recovery	1.0015	0.6532	0.3943	0.3841	1.2169	0.1905	0.1115	0.1905	0.1031	0.0797
Balancing Accounts	0.0000	0.0000	0.0000	0.0000	0.0304	0.0000	0.0304	0.0304	0.0304	0.0000
NCA - Local Transmission Cost Subaccount (10)	0.0284	0.0284	0.0081	0.0081	0.0081	0.0081	0.0078	0.0078	0.0078	0.0354
Inventory Management Cost Recovery	0.0240	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0144	0.0144	0.0071
GT&S Pension	13.3525	6.5062	2.7048	2.8243	16.9705	3.2383	0.1232	0.0000	3.2383	0.0189
Distribution - Annual Average (b)	19.3273	11.9847	7.9477	8.0478	23.0473	6.5940	3.4173	0.9495	6.5937	3.2820
Volumetric Rate - Annual Average										
CAC - Class Avg Volumetric Equivalent (c)	0.8394	0.9020	0.0411	0.0095	0.0000	0.0779	0.0120	0.0175	0.0779	0.0120
Gas Public Purpose Program Surcharge				0.5681		0.9029	0.6678	0.6678	0.5681	0.0000
<b>Total Rate</b>	<b>20.1667</b>	<b>13.4690</b>	<b>8.7801</b>	<b>8.6254</b>	<b>23.6154</b>	<b>7.5748</b>	<b>4.0970</b>	<b>1.6349</b>	<b>7.2397</b>	<b>3.8620</b>
<b>0.9045</b>										

Procurement Charges for Core Bundled Customers:

Storage	0.1908	0.1578	0.1099	0.1019	0.1019
Backbone Capacity	0.5046	0.4242	0.2688	0.2520	0.2520
Backbone Usage	0.3207	0.3207	0.3207	0.3207	0.3207
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210
Interstate Capacity and Other	0.7846	0.6828	0.4950	0.4731	0.4731
Total Core Procurement	3.9219	3.7066	3.3155	3.2687	3.2687
<b>Total Core Bundled Rates</b>	<b>24.0686</b>	<b>17.1756</b>	<b>12.0956</b>	<b>11.8941</b>	<b>26.8841</b>

Wholesale Transportation

	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
<b>End-Use Transportation:</b>	2.3082	2.3082	2.3082	2.3082	2.3082	2.3082	2.3082
Local Transmission	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Self Generation Incentive Program	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CPUC Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 ARB Cost of Implementation Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198
NGSS Transition Costs Recovery	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059
Balancing Accounts	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192
Inventory Management Cost Recovery	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276
GT&S Pension	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144
Distribution - Annual Average (b)	0.0000	0.0000	0.0000	0.0000	3.9680	6.8089	0.0000
Volumetric Rate - Annual Average	3.1952	3.1952	3.1952	3.1952	7.2408	10.1457	3.1952
CAC - Class Avg Volumetric Equivalent (c)	0.0571	0.0662	0.2145	0.0156	0.1331	0.0837	0.0837
Gas Public Purpose Program Surcharge	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
<b>END-USE RATE</b>	<b>3.2523</b>	<b>3.2614</b>	<b>3.4097</b>	<b>3.2108</b>	<b>7.3739</b>	<b>10.2294</b>	<b>3.2790</b>
<b>GHG COMPLIANCE COST EXEMPTION</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>
<b>END-USE RATE EXCLUDING GHG COMPLIANCE CC</b>	<b>2.5157</b>	<b>2.5248</b>	<b>2.6731</b>	<b>2.4742</b>	<b>6.6372</b>	<b>9.4928</b>	<b>2.5423</b>

a) Class average rates reflect load shape for bundled core.  
b) Distribution rates represent the annual class average.  
c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

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Table 6-8  
April 2024 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

End-Use Transportation:	Core (a)					Noncore Transportation				
	Industrial					Natural Gas Vehicle				
	Res	Small Comin	Large Comin	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans
Local Transmission	3.9872	3.9872	3.9872	3.9872	3.9872	2.3082	2.3082	0.0000	2.3082	2.3082
Self Generation Incentive Program	0.0925	(0.0428)	0.0095	0.0000	0.0000	(0.0140)	0.0000	0.0000	(0.0140)	0.0000
CPUC Fee	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585
AB32 ARB Cost of Implementation Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
NGSS Transition Costs Recovery	0.0288	0.0164	0.0077	0.0079	0.0284	0.0059	0.0059	0.0059	0.0059	0.0059
Balancing Accounts	1.0015	0.6532	0.3943	0.3841	1.2169	0.1905	0.1905	0.1165	0.1905	0.1031
NCA - Local Transmission Cost Subaccount (10)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0304	0.0304	0.0000	0.0304	0.0304
Inventory Management Cost Recovery	0.0284	0.0284	0.0081	0.0081	0.0081	0.0081	0.0078	0.0078	0.0078	0.0078
GT&S Pension	0.0240	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0071	0.0144	0.0144
Distribution - Annual Average (b)	13.3525	6.5062	2.7048	2.7048	16.9705	3.2383	3.2383	0.0000	3.2383	0.0000
Volumetric Rate - Annual Average	19.3273	11.9847	7.9477	8.0478	23.0473	6.5940	3.4173	0.9495	6.5937	3.2820
CAC - Class Avg Volumetric Equivalent (c)	0.8394	0.5822	0.0411	0.0095	0.0000	0.0779	0.0120	0.0175	0.0779	0.0120
Gas Public Purpose Program Surcharge		0.9020	0.7912	0.5681	0.5681	0.9029	0.6678	0.6678	0.9029	0.6681
Total Rate	20.1667	13.4690	8.7801	8.6254	23.6154	7.5748	4.0970	1.6349	7.2397	3.8620
Procurement Charges for Core Bundled Customers:										
Storage	0.1940	0.1604	0.1118	0.1036	0.1036					
Backbone Capacity	0.5046	0.4242	0.2688	0.2520	0.2520					
Backbone Usage	0.3207	0.3207	0.3207	0.3207	0.3207					
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210					
Interstate Capacity and Other	0.7846	0.6828	0.4950	0.4731	0.4731					
Total Core Procurement	3.9250	3.7092	3.3173	3.2704	3.2704					
Total Core Bundled Rates	24.0917	17.1782	12.0974	11.8958	26.8858					

Wholesale Transportation										
End-Use Transportation:	Alpine					Wholesale Transportation				
	Coalinga					Wholesale Transportation				
	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans	WCG Mather Trans	WCG Mather Trans	WCG Mather Trans
Local Transmission	2.3082	2.3082	2.3082	2.3082	2.3082	2.3082	2.3082	2.3082	2.3082	2.3082
Self Generation Incentive Program	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CPUC Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 ARB Cost of Implementation Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198
NGSS Transition Costs Recovery	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059
Balancing Accounts	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192
Inventory Management Cost Recovery	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276	0.0276
GT&S Pension	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144
Distribution - Annual Average (b)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Volumetric Rate - Annual Average	3.1952	3.1952	3.1952	3.1952	3.1952	3.1952	3.1952	3.1952	3.1952	3.1952
CAC - Class Avg Volumetric Equivalent (c)	0.0571	0.0662	0.2145	0.0156	0.1331	0.0837	0.0837	0.0837	0.0837	0.0837
Gas Public Purpose Program Surcharge		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
END-USE RATE	3.2523	3.2614	3.4097	3.2108	7.3739	10.2294	3.2790	3.2790	3.2790	3.2790
GHG COMPLIANCE COST EXEMPTION	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
END-USE RATE EXCLUDING GHG COMPLIANCE CC	2.5157	2.5248	2.6731	2.4742	6.6372	9.4928	2.5423	2.5423	2.5423	2.5423

a) Class average rates reflect load shape for bundled core.  
b) Distribution rates represent the annual class average.  
c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

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Table 6-9  
January 2025 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

	Core (a)				Noncore Transportation				Electric Gen			
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Industrial		Dist	Natural Gas Vehicle		Dist	BB
						Trans	BB		Trans	BB		
End-Use Transportation:												
Local Transmission	4.3254	4.3254	4.3254	4.3254	4.3254	2.4484	2.4484	0.0000	2.4484	2.4484	2.4484	0.0000
Self Generation Incentive Program	0.0925	(0.0428)	0.0095	0.0000	0.0000	(0.0140)	0.0036	0.0000	(0.0140)	0.0000	0.0000	0.0000
CPUC Fee	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0086	0.0086
AB32 ARB Cost of Implementation Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
NGSS Transition Costs Recovery	0.0314	0.0178	0.0084	0.0085	0.0283	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064
Balancing Accounts	1.0017	0.6532	0.3943	0.3843	1.1504	0.1906	0.1116	0.1164	0.1906	0.1030	0.0724	0.0796
NCA - Local Transmission Cost Subaccount (10)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0304	0.0304	0.0000	0.0304	0.0304	0.0304	0.0000
Inventory Management Cost Recovery	0.0289	0.0289	0.0082	0.0082	0.0082	0.0082	0.0079	0.0079	0.0079	0.0079	0.0361	0.0267
GT&S Pension	0.0240	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0071	0.0144	0.0144	0.0144	0.0071
Distribution - Annual Average (b)	14.5386	7.1371	2.9496	3.0769	17.2231	3.5170	0.1342	0.0000	3.5170	0.0000	0.0206	0.0206
Volumetric Rate - Annual Average	20.8547	12.9558	8.5316	8.6395	23.5716	7.0137	3.5893	0.9502	7.0134	3.4229	3.3912	0.9028
CAC - Class Avg Volumetric Equivalent (c)	0.8766	0.5822	0.0411	0.0095	0.0000	0.0948	0.0145	0.0214	0.0948	0.0145	0.0267	0.0048
Gas Public Purpose Program Surcharge		0.9392	0.8284	0.6053		0.9401	0.7050	0.7050	0.6053	0.6053	0.0000	0.0000
<b>Total Rate</b>	<b>21.7313</b>	<b>14.4772</b>	<b>9.4011</b>	<b>9.2544</b>	<b>24.1769</b>	<b>8.0486</b>	<b>4.2888</b>	<b>1.6765</b>	<b>7.7136</b>	<b>4.0427</b>	<b>3.4179</b>	<b>0.9076</b>

Procurement Charges for Core Bundled Customers:

Storage	0.1969	0.1628	0.1134	0.1051	0.1051							
Backbone Capacity	0.5258	0.4421	0.2801	0.2626	0.2626							
Backbone Usage	0.3440	0.3440	0.3440	0.3440	0.3440							
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210							
Interstate Capacity and Other	0.7855	0.6837	0.4959	0.4740	0.4740							
Total Core Procurement	3.9733	3.7536	3.3545	3.3067	3.3067							
<b>Total Core Bundled Rates</b>	<b>28.7046</b>	<b>18.2308</b>	<b>12.7556</b>	<b>12.5611</b>	<b>27.4836</b>							

Wholesale Transportation									
Alpine	Coalinga	Island	Energy	Palo	WCG	WCG	WCG	WCG	WCG
				Alto	Castle	Mather	Mather	Mather	Mather
						Dist	Dist	Trans	Trans
End-Use Transportation:									
Local Transmission	2.4484	2.4484	2.4484	2.4484	2.4484	2.4484	2.4484	2.4484	2.4484
Self Generation Incentive Program	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CPUC Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 ARB Cost of Implementation Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198
NGSS Transition Costs Recovery	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064
Balancing Accounts	0.1192	0.1192	0.1192	0.1192	0.1192	0.2608	0.2608	0.1192	0.1192
Inventory Management Cost Recovery	0.0282	0.0282	0.0282	0.0282	0.0282	0.0282	0.0282	0.0282	0.0282
GT&S Pension	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144
Distribution - Annual Average (b)	0.0000	0.0000	0.0000	0.0000	0.0000	7.4159	7.4159	0.0000	0.0000
Volumetric Rate - Annual Average	3.3365	3.3365	3.3365	3.3365	7.7358	10.8940	10.8940	3.3365	3.3365
CAC - Class Avg Volumetric Equivalent (c)	0.0699	0.0813	0.2624	0.0191	0.1628	0.1028	0.1028	0.1028	0.1028
Gas Public Purpose Program Surcharge		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
<b>END-USE RATE</b>	<b>3.4064</b>	<b>3.4178</b>	<b>3.5990</b>	<b>3.3557</b>	<b>7.8986</b>	<b>10.9968</b>	<b>10.9968</b>	<b>3.4393</b>	<b>3.4393</b>
<b>GHG COMPLIANCE COST EXEMPTION</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>
<b>END-USE RATE EXCLUDING GHG COMPLIANCE CC</b>	<b>2.6698</b>	<b>2.6812</b>	<b>2.8623</b>	<b>2.6191</b>	<b>7.1620</b>	<b>10.2601</b>	<b>10.2601</b>	<b>2.7027</b>	<b>2.7027</b>

a) Class average rates reflect load shape for bundled core.  
b) Distribution rates represent the annual class average.  
c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

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Table 6-10  
April 2025 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

	Core (a)				Noncore Transportation				Electric Gen			
					Industrial				Natural Gas Vehicle			
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/I	BB
End-Use Transportation:												
Local Transmission	4.3254	4.3254	4.3254	4.3254	4.3254	2.4484	2.4484	0.0000	2.4484	2.4484	2.4484	0.0000
Self Generation Incentive Program	0.0925	(0.0428)	0.0095	0.0000	0.0000	(0.0140)	0.0036	0.0000	(0.0140)	0.0000	0.0000	0.0000
CPUC Fee	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0086	0.0086
AB32 ARB Cost of Implementation Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
NGSS Transition Costs Recovery	0.0314	0.0178	0.0084	0.0085	0.0283	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064
Balancing Accounts	1.0017	0.6532	0.3943	0.3843	1.1504	0.1906	0.1116	0.1164	0.1906	0.1030	0.0724	0.0796
NCA - Local Transmission Cost Subaccount (10)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0304	0.0304	0.0000	0.0304	0.0304	0.0304	0.0000
Inventory Management Cost Recovery	0.0289	0.0289	0.0082	0.0082	0.0082	0.0082	0.0079	0.0079	0.0079	0.0079	0.0361	0.0267
GT&S Pension	0.0240	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0071	0.0144	0.0144	0.0144	0.0071
Distribution - Annual Average (b)	14.5386	7.1371	2.9496	3.0769	17.2231	3.5170	0.1342	0.0000	3.5170	0.0000	0.0206	0.0206
Volumetric Rate - Annual Average	20.8547	12.9558	8.5316	8.6395	23.5716	7.0137	3.5693	0.9502	7.0134	3.4229	3.3912	0.9028
CAC - Class Avg Volumetric Equivalent (c)	0.8766	0.5822	0.0411	0.0095	0.0000	0.0948	0.0145	0.0214	0.0948	0.0145	0.0267	0.0048
Gas Public Purpose Program Surcharge		0.9392	0.8284	0.6053	0.6053	0.9401	0.7050	0.7050	0.6053	0.6053	0.0000	0.0000
<b>Total Rate</b>	<b>21.7313</b>	<b>14.4772</b>	<b>9.4011</b>	<b>9.2544</b>	<b>24.1769</b>	<b>8.0486</b>	<b>4.2888</b>	<b>1.6765</b>	<b>7.7136</b>	<b>4.0427</b>	<b>3.4179</b>	<b>0.9076</b>

Procurement Charges for Core Bundled Customers:

Storage	0.1969	0.1628	0.1134	0.1051	0.1051							
Backbone Capacity	0.5258	0.4421	0.2801	0.2626	0.2626							
Backbone Usage	0.3440	0.3440	0.3440	0.3440	0.3440							
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210							
Interstate Capacity and Other	0.7855	0.6837	0.4959	0.4740	0.4740							
Total Core Procurement	3.9733	3.7536	3.3545	3.3067	3.3067							
<b>Total Core Bundled Rates</b>	<b>25.7046</b>	<b>18.2308</b>	<b>12.7556</b>	<b>12.5611</b>	<b>27.4836</b>							

Wholesale Transportation									
Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans	WCG		
2.4484	2.4484	2.4484	2.4484	2.4484	2.4484	2.4484	2.4484		
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198		
0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064	0.0064		
0.1192	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192	0.1192		
0.0282	0.0282	0.0282	0.0282	0.0282	0.0282	0.0282	0.0282		
0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144		
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
Volumetric Rate - Annual Average	3.3365	3.3365	3.3365	7.7358	10.8940	3.3365			
CAC - Class Avg Volumetric Equivalent (c)	0.0699	0.0813	0.2624	0.0191	0.1628	0.1028	0.1028		
Gas Public Purpose Program Surcharge		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		
<b>END-USE RATE</b>	<b>3.4064</b>	<b>3.4178</b>	<b>3.5990</b>	<b>3.3557</b>	<b>7.8986</b>	<b>10.9968</b>	<b>3.4393</b>		
<b>GHG COMPLIANCE COST EXEMPTION</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>		
<b>END-USE RATE EXCLUDING GHG COMPLIANCE CC</b>	<b>2.6698</b>	<b>2.6812</b>	<b>2.8623</b>	<b>2.6191</b>	<b>7.1620</b>	<b>10.2601</b>	<b>2.7027</b>		

a) Class average rates reflect load shape for bundled core.  
b) Distribution rates represent the annual class average.  
c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

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Table 6-11  
January 2026 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

	Core (a)				Noncore Transportation										
	Res	Small Comm	Large Comm	Uncomp. NGV	Industrial				Natural Gas Vehicle				Electric Gen		
					Dist	Trans	BB	Dist	Trans	BB	Dist	Trans	D/I	BB	
End-Use Transportation:															
Local Transmission	4.7341	4.7341	4.7341	4.7341	2.5964	2.5964	0.0000	2.5964	2.5964	0.0000	2.5964	2.5964	0.0000	0.0000	0.0000
Self Generation Incentive Program	0.0925		0.0095	0.0000	(0.0140)	0.0036	0.0000	(0.0140)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CPUC Fee	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0086	0.0086
AB32 ARB Cost of Implementation Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
NGSS Transition Costs Recovery	0.0336	0.0191	0.0089	0.0091	0.0279	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069
Balancing Accounts	1.0018	0.6533	0.3943	0.3843	1.0917	0.1906	0.1116	0.1165	0.1906	0.1031	0.0724	0.0724	0.1031	0.0797	0.0797
NCA - Local Transmission Cost Subaccount (10)	0.0000	0.0000	0.0000	0.0000	0.0304	0.0304	0.0000	0.0304	0.0304	0.0304	0.0304	0.0304	0.0304	0.0000	0.0000
Inventory Management Cost Recovery	0.0320	0.0320	0.0091	0.0091	0.0091	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0295	0.0295
GT&S Pension	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0071	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0071	0.0071
Distribution - Annual Average (b)	15.7708	7.7924	3.2040	3.3393	17.4855	3.8076	0.1456	0.0000	3.8076	0.0000	0.0223	0.0223	0.0000	0.0223	0.0223
Volumetric Rate - Annual Average	22.5009	14.0242	9.1960	9.3121	24.1845	7.4535	3.7298	0.9515	7.4532	3.5721	3.5451	3.5451	3.5721	0.9079	0.9079
CAC - Class Avg Volumetric Equivalent (c)		0.5822	0.0411	0.0095	0.0000	0.1115	0.0171	0.0251	0.1115	0.0171	0.0313	0.0313	0.0171	0.0052	0.0052
Gas Public Purpose Program Surcharge	0.9172	0.9798	0.8690	0.6459	0.6459	0.9807	0.7456	0.7456	0.6459	0.6459	0.0000	0.0000	0.6459	0.0000	0.0000
Total Rate	23.4181	15.5862	10.1061	9.9675	24.8304	8.5457	4.4925	1.7222	8.2106	4.2351	3.5763	3.5763	4.2351	0.9130	0.9130
Procurement Charges for Core Bundled Customers:															
Storage	0.2176	0.1799	0.1253	0.1161											
Backbone Capacity	0.5698	0.4790	0.3035	0.2846											
Backbone Usage	0.3647	0.3647	0.3647	0.3647											
WACOG	2.1210	2.1210	2.1210	2.1210											
Interstate Capacity and Other	0.7863	0.6845	0.4967	0.4747											
Total Core Procurement	4.0594	3.8291	3.4112	3.3612											
Total Core Bundled Rates	27.4775	19.4153	13.5173	13.3287											

Procurement Charges for Core Bundled Customers:

Storage	0.2176	0.1799	0.1253	0.1161	0.1161									
Backbone Capacity	0.5698	0.4790	0.3035	0.2846	0.2846									
Backbone Usage	0.3647	0.3647	0.3647	0.3647	0.3647									
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210									
Interstate Capacity and Other	0.7863	0.6845	0.4967	0.4747	0.4747									
Total Core Procurement	4.0594	3.8291	3.4112	3.3612	3.3612									
<b>Total Core Bundled Rates</b>	<b>27.4775</b>	<b>19.4153</b>	<b>13.5173</b>	<b>13.3287</b>	<b>28.1816</b>									

Wholesale Transportation

End-Use Transportation:	Alpine				Coalinga				Island Energy				Palo Alto				WCG			
	Alpine	Coalinga	Island Energy	WCG	Alpine	Coalinga	Island Energy	WCG	Alpine	Coalinga	Island Energy	WCG	Alpine	Coalinga	Island Energy	WCG	Alpine	Coalinga	Island Energy	WCG
Local Transmission	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964
Self Generation Incentive Program	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CPUC Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 ARB Cost of Implementation Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AB32 Greenhouse Gas Compliance & Obligation Cost	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198
NGSS Transition Costs Recovery	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069
Balancing Accounts	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193	0.1193
Inventory Management Cost Recovery	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311
GT&S Pension	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144
Distribution - Annual Average (b)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Volumetric Rate - Annual Average	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879	3.4879
CAC - Class Avg Volumetric Equivalent (c)	0.0826	0.0963	0.3100	0.0226	0.1923	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218	0.1218
Gas Public Purpose Program Surcharge	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
<b>END-USE RATE</b>	<b>3.5705</b>	<b>3.5842</b>	<b>3.7979</b>	<b>3.5105</b>	<b>8.4470</b>	<b>11.7978</b>	<b>3.6097</b>	<b>3.5105</b>	<b>8.4470</b>	<b>11.7978</b>	<b>3.6097</b>	<b>3.5105</b>	<b>8.4470</b>	<b>11.7978</b>	<b>3.6097</b>	<b>3.5105</b>	<b>8.4470</b>	<b>11.7978</b>	<b>3.6097</b>	<b>3.5105</b>
<b>GHG COMPLIANCE COST EXEMPTION</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>	<b>0.7366</b>
<b>END-USE RATE EXCLUDING GHG COMPLIANCE CC</b>	<b>2.8339</b>	<b>2.8476</b>	<b>3.0613</b>	<b>2.7739</b>	<b>7.7104</b>	<b>11.0611</b>	<b>2.8731</b>	<b>2.7739</b>	<b>7.7104</b>	<b>11.0611</b>	<b>2.8731</b>	<b>2.7739</b>	<b>7.7104</b>	<b>11.0611</b>	<b>2.8731</b>	<b>2.7739</b>	<b>7.7104</b>	<b>11.0611</b>	<b>2.8731</b>	<b>2.7739</b>

a) Class average rates reflect load shape for bundled core.  
b) Distribution rates represent the annual class average.  
c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

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Table 6-12  
April 2026 Average Rate Detail By End-Use Customer Class (a)  
(\$/dth)  
(Bundled Rates are Prior to Proposed Annual Averaging)

	Core (a)				Industrial				Noncore Transportation			
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	BB	Electric Gen
End-Use Transportation:	4.7341	4.7341	4.7341	4.7341	4.7341	2.5964	2.5964	0.0000	2.5964	2.5964	2.5964	0.0000
Local Transmission	0.0925	(0.0428)	0.0095	0.0000	0.0000	(0.0140)	(0.0140)	0.0000	(0.0140)	0.0000	0.0000	0.0000
Self Generation Incentive Program	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0585	0.0086
CPUC Fee	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171	0.0171
AB32 ARB Cost of Implementation Fee	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
AB32 Greenhouse Gas Compliance & Obligation Cost	0.0336	0.0191	0.0089	0.0091	0.0279	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069
NGSS Transition Costs Recovery	1.0018	0.6533	0.3943	0.3843	1.0917	0.1906	0.1165	0.1165	0.1906	0.1031	0.0724	0.0797
Balancing Accounts	0.0000	0.0000	0.0000	0.0000	0.0000	0.0304	0.0304	0.0000	0.0304	0.0304	0.0304	0.0000
NCA - Local Transmission Cost Subaccount (10)	0.0320	0.0320	0.0091	0.0091	0.0091	0.0091	0.0088	0.0088	0.0088	0.0088	0.0399	0.0295
Inventory Management Cost Recovery	0.0240	0.0240	0.0240	0.0240	0.0240	0.0144	0.0144	0.0071	0.0144	0.0144	0.0144	0.0071
GT&S Pension	15.7708	7.7924	3.2040	3.3393	17.4855	3.8076	0.1456	0.0000	3.8076	0.0000	0.0223	0.0223
Distribution - Annual Average (b)	22.5009	14.0242	9.1960	9.3121	24.1845	7.4535	3.7298	0.9515	7.4532	3.5721	3.5451	0.9079
Volumetric Rate - Annual Average												
CAC - Class Avg Volumetric Equivalent (c)	0.9172	0.9798	0.8690	0.6459	0.6459	0.9807	0.7456	0.7456	0.8459	0.6459	0.0000	0.0000
Gas Public Purpose Program Surcharge	23.4181	15.5862	10.1061	9.9675	24.8304	8.5457	4.4925	1.7222	8.2106	4.2351	3.5763	0.9130
Total Rate												
Procurement Charges for Core Bundled Customers:												
Storage	0.2176	0.1799	0.1253	0.1161	0.1161							
Backbone Capacity	0.5698	0.4790	0.3035	0.2846	0.2846							
Backbone Usage	0.3647	0.3647	0.3647	0.3647	0.3647							
WACOG	2.1210	2.1210	2.1210	2.1210	2.1210							
Interstate Capacity and Other	0.7863	0.6845	0.4967	0.4747	0.4747							
Total Core Procurement	4.0594	3.8291	3.4112	3.3612	3.3612							
Total Core Bundled Rates	27.4775	19.4153	13.5173	13.3287	28.1916							

Wholesale Transportation							
Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather	WCG Mather	WCG Trans
2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964	2.5964
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198	0.7198
0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069
0.1193	0.1193	0.1193	0.1193	0.1968	0.2608	0.1193	0.1193
0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311	0.0311
0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144	0.0144
0.0000	0.0000	0.0000	0.0000	4.6893	8.0465	0.0000	0.0000
3.4879	3.4879	3.4879	3.4879	8.2547	11.6760	3.4879	3.4879
CAC - Class Avg Volumetric Equivalent (c)	0.0826	0.0963	0.3100	0.0226	0.1923	0.1218	0.1218
Gas Public Purpose Program Surcharge	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
END-USE RATE	3.5705	3.5842	3.7979	3.5105	8.4470	11.7978	3.6097
GHG COMPLIANCE COST EXEMPTION	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366	0.7366
END-USE RATE EXCLUDING GHG COMPLIANCE CO	2.8339	2.8476	3.0613	2.7739	7.7104	11.0611	2.8731

a) Class average rates reflect load shape for bundled core.  
b) Distribution rates represent the annual class average.  
c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.



**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase**  
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**Table 6-13**  
**Firm Backbone Transportation**  
**Annual Rates (AFT) -- SFV Rate Design**  
**On-System Transportation Service**

	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
<b><u>Redwood Path - Core</u></b>									
Reservation Charge	21.7537	20.4110	16.6391	24.2016	19.4390	25.3793	20.4828	27.1557	22.0240
Usage Charge	0.0028	0.0026	0.0014	0.0031	0.0017	0.0033	0.0018	0.0035	0.0019
Total (b)	0.7180	0.6737	0.5485	0.7988	0.6408	0.8377	0.6752	0.8963	0.7260
<b><u>Redwood Path - Noncore</u></b>									
Reservation Charge	22.7597	20.5536	17.3197	24.4646	20.1241	25.7864	21.0941	27.7247	22.6141
Usage Charge	0.0036	0.0032	0.0011	0.0038	0.0013	0.0040	0.0013	0.0044	0.0014
Total (b)	0.7518	0.6790	0.5705	0.8082	0.6629	0.8518	0.6948	0.9158	0.7449
<b><u>Baja Path - Noncore</u></b>									
Reservation Charge	28.2087	25.6999	21.4789	29.6109	25.0117	30.9327	26.0729	32.8710	27.9571
Usage Charge	0.0044	0.0040	0.0013	0.0046	0.0016	0.0049	0.0017	0.0052	0.0018
Total (b)	0.9318	0.8490	0.7075	0.9782	0.8239	1.0218	0.8588	1.0858	0.9209
<b><u>Silverado and Mission Paths</u></b>									
Reservation Charge	17.9215	15.8339	12.2451	19.3173	14.4906	20.2056	15.1101	21.7184	16.2239
Usage Charge	0.0027	0.0023	0.0007	0.0028	0.0009	0.0030	0.0010	0.0032	0.0010
Total (b)	0.5919	0.5228	0.4033	0.6379	0.4773	0.6673	0.4977	0.7172	0.5344

**Notes:**

- Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
- The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
- Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.
- Dollar difference are due to rounding.

**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase  
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**Table 6-14  
Firm Backbone Transportation  
Annual Rates (AFT) -- MFV Rate Design  
On-System Transportation Service**

	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
<b><u>Redwood Path - Core</u></b>									
Reservation Charge	15.4990	14.7108	10.9220	17.4428	12.6772	18.2917	13.2220	19.5720	14.3287
Usage Charge	0.2084	0.1900	0.1894	0.2253	0.2240	0.2363	0.2405	0.2528	0.2549
Total	0.7180	0.6737	0.5485	0.7988	0.6408	0.8377	0.6752	0.8963	0.7260
<b><u>Redwood Path - Noncore</u></b>									
Reservation Charge	16.7183	15.2013	11.8859	18.0938	13.6895	19.0714	14.2036	20.5050	15.3016
Usage Charge	0.2022	0.1792	0.1797	0.2133	0.2128	0.2248	0.2279	0.2417	0.2419
Total	0.7518	0.6790	0.5705	0.8082	0.6629	0.8518	0.6948	0.9158	0.7449
<b><u>Baja Path - Noncore</u></b>									
Reservation Charge	20.7209	19.0074	14.7402	21.9000	17.0144	22.8776	17.5560	24.3112	18.9169
Usage Charge	0.2506	0.2241	0.2229	0.2582	0.2645	0.2697	0.2817	0.2866	0.2990
Total	0.9318	0.8490	0.7075	0.9782	0.8239	1.0218	0.8588	1.0858	0.9209
<b><u>Silverado and Mission Paths</u></b>									
Reservation Charge	12.9629	11.2023	7.9372	14.1637	9.3632	14.3214	9.6139	15.5866	10.4187
Usage Charge	0.1657	0.1546	0.1424	0.1722	0.1695	0.1964	0.1816	0.2048	0.1919
Total	0.5919	0.5228	0.4033	0.6379	0.4773	0.6673	0.4977	0.7172	0.5344

**Notes:**

- Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
- The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
- Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.
- Dollar difference are due to rounding.

**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase**  
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**Table 6-15**  
**Firm Backbone Transportation**  
**Seasonal Rates (SFT) -- SFV Rate Design**  
**On-System Transportation Service**

	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
<b><u>Redwood Path - Core</u></b>									
Reservation Charge	26.1044	24.4932	19.9670	29.0419	23.3268	30.4552	24.5793	32.5868	26.4288
Usage Charge	0.0034	0.0032	0.0017	0.0038	0.0020	0.0039	0.0021	0.0042	0.0023
Total	0.8616	0.8084	0.6581	0.9586	0.7689	1.0052	0.8102	1.0756	0.8712
			Contract)						
<b><u>Baja Path - Core</u></b>									
Reservation Charge	32.6488	30.6739	24.9546	35.2226	29.1881	36.6359	30.5498	38.7675	32.8362
Usage Charge	0.0042	0.0040	0.0021	0.0046	0.0025	0.0047	0.0026	0.0050	0.0028
Total	1.0776	1.0124	0.8225	1.1626	0.9621	1.2092	1.0070	1.2796	1.0824
			Contract)						
<b><u>Redwood Path - Noncore</u></b>									
Reservation Charge	27.3116	24.6643	20.7836	29.3575	24.1489	30.9437	25.3129	33.2697	27.1369
Usage Charge	0.0043	0.0039	0.0013	0.0046	0.0015	0.0049	0.0016	0.0052	0.0017
Total	0.9022	0.8148	0.6846	0.9698	0.7955	1.0222	0.8338	1.0990	0.8939
			Contract)						
<b><u>Baja Path - Noncore</u></b>									
Reservation Charge	33.8504	30.8399	25.7747	35.5330	30.0141	37.1192	31.2874	39.4452	33.5486
Usage Charge	0.0053	0.0048	0.0016	0.0056	0.0019	0.0058	0.0020	0.0062	0.0021
Total	1.1182	1.0188	0.8490	1.1738	0.9887	1.2262	1.0306	1.3030	1.1051
			Contract)						
<b><u>Silverado and Mission Paths</u></b>									
Reservation Charge	21.5059	19.0007	14.6941	23.1807	17.3887	24.2467	18.1321	26.0620	19.4686
Usage Charge	0.0032	0.0027	0.0009	0.0034	0.0011	0.0036	0.0011	0.0038	0.0012
Total	0.7103	0.6274	0.4840	0.7655	0.5728	0.8007	0.5973	0.8607	0.6413
			Contract)						

**Notes:**

- Firm Seasonal rates are 120 percent of Firm Annual rates.
- Rates are only the backbone transmission charge component of the transmission service. They include exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
- The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
- Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.
- Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.
- Dollar difference are due to rounding.

**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase Application**

**Table 6-16**

**Firm Backbone Transportation  
Seasonal Rates (SFT) -- MFV Rate Design  
On-System Transportation Service**

	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
<b><u>Redwood Path - Core</u></b>									
Reservation Charge	18.5988	17.6530	13.1064	20.9314	15.2126	21.9500	15.8664	23.4863	17.1944
Usage Charge	0.2501	0.2280	0.2273	0.2704	0.2688	0.2836	0.2886	0.3034	0.3059
Total	0.8616	0.8084	0.6581	0.9586	0.7689	1.0052	0.8102	1.0756	0.8712
<b><u>Bala Path - Core</u></b>									
Reservation Charge	23.2616	22.1076	16.3803	25.3860	19.0350	26.4046	19.7205	27.9410	21.3630
Usage Charge	0.3128	0.2856	0.2840	0.3279	0.3363	0.3411	0.3587	0.3610	0.3800
Total	1.0776	1.0124	0.8225	1.1626	0.9621	1.2092	1.0070	1.2796	1.0824
<b><u>Redwood Path - Noncore</u></b>									
Reservation Charge	20.0620	18.2416	14.2631	21.7126	16.4274	22.8857	17.0443	24.6060	18.3619
Usage Charge	0.2426	0.2150	0.2157	0.2559	0.2554	0.2698	0.2735	0.2901	0.2902
Total	0.9022	0.8148	0.6846	0.9698	0.7955	1.0222	0.8338	1.0990	0.8939
<b><u>Bala Path - Noncore</u></b>									
Reservation Charge	24.8651	22.8089	17.6883	26.2800	20.4172	27.4531	21.0672	29.1734	22.7003
Usage Charge	0.3007	0.2689	0.2675	0.3098	0.3174	0.3236	0.3380	0.3439	0.3588
Total	1.1182	1.0188	0.8490	1.1738	0.9887	1.2262	1.0306	1.3030	1.1051
<b><u>Silverado and Mission Paths</u></b>									
Reservation Charge	15.5555	13.4428	9.5246	16.9964	11.2358	17.1856	11.5367	18.7039	12.5025
Usage Charge	0.1989	0.1855	0.1709	0.2067	0.2034	0.2357	0.2180	0.2458	0.2303
Total	0.7103	0.6274	0.4840	0.7655	0.5728	0.8007	0.5973	0.8607	0.6413

**Notes:**

- Firm Seasonal rates are 120 percent of Firm Annual rates.
- Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
- The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
- Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Bala and Silverado.
- Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.
- Dollar difference are due to rounding.

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**Table 6-17  
As-Available Backbone Transportation  
On-System Transportation Service**

	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
<b><u>Redwood Path</u></b> Usage Charge	(\$/dth) 0.9022	0.8148	0.6846	0.9698	0.7955	1.0222	0.8338	1.0990	0.8939
<b><u>Baja Path</u></b> Usage Charge	(\$/dth) 1.1182	1.0188	0.8490	1.1738	0.9887	1.2262	1.0306	1.3030	1.1051
<b><u>Silverado Path</u></b> Usage Charge	(\$/dth) 0.7103	0.6274	0.4840	0.7655	0.5728	0.8007	0.5973	0.8607	0.6413
<b><u>Mission Path</u></b> Usage Charge	(\$/dth) 0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

**Notes:**

- a) As-Available rates are 120 percent of Firm Annual rates.
- b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
- c) Mission path service represents on-system storage to on-system transportation. Customers delivering gas to storage facilities pay the applicable backbone transmission on-system rate from Redwood, Baja or Silverado.
- d) Dollar difference are due to rounding.

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Table 6-18  
Backbone Transportation  
Annual Rates (AFT-Off)  
Off-System Deliveries

		2023			2024			2025			2026		
		Illustrative GRC 1	Proposed GTS CARD		Illustrative GRC 1	Proposed GTS CARD		Illustrative GRC 1	Proposed GTS CARD		Illustrative GRC 1	Proposed GTS CARD	
<b><u>SEV Rate Design</u></b> Redwood, Silverado and Mission Paths Off-System													
	Reservation Charge		22.7597	(\$/dth/mo)									
	Usage Charge		0.0036	(\$/dth)									
	Total		0.7518	(\$/dth @ Full Contract)									
<b><u>Baja Path Off-System</u></b> Reservation Charge													
	Usage Charge		28.2087	(\$/dth/mo)									
	Usage Charge		0.0044	(\$/dth)									
	Total		0.9318	(\$/dth @ Full Contract)									
<b><u>MFV Rate Design</u></b> Redwood, Silverado and Mission Paths Off-System													
	Reservation Charge		16.7183	(\$/dth/mo)									
	Usage Charge		0.2022	(\$/dth)									
	Total		0.7518	(\$/dth @ Full Contract)									
<b><u>Baja Path Off-System</u></b> Reservation Charge													
	Usage Charge		20.7209	(\$/dth/mo)									
	Usage Charge		0.2506	(\$/dth)									
	Total		0.9318	(\$/dth @ Full Contract)									
<b><u>As-Available Service</u></b> Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore													
	Usage Charge		0.9022	(\$/dth)									
<b><u>Mission Paths (From on-system storage) Off-System</u></b> Usage Charge													
	Usage Charge		0.0000	(\$/dth)									
<b><u>Baja Path Off-System - Noncore</u></b> Usage Charge													
	Usage Charge		1.1182	(\$/dth)									

Notes:

- a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
- b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
- c) California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.
- d) Dollar difference are due to rounding.



**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase  
Application**

**Table 6-19  
Firm Transportation  
Expansion Shippers -- Annual Rates (G-XF)  
SFV Rate Design**

	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
<b>SFV Rate Design</b>									
Reservation Charge	(\$/dth/mo)	5.7262	5.4221	5.6344	5.6400	5.8231	6.1124	5.9969	6.4513
Usage Charge	(\$/dth)	0.0002	0.0001	0.0002	0.0001	0.0002	0.0001	0.0002	0.0001
Total	(\$/dth @ Full Contract)	0.1885	0.1783	0.1854	0.1855	0.1916	0.2010	0.1974	0.2122

**Notes:**

- Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
- The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.
- G-XF charges are based on the embedded cost of Line 401 and a 95 percent load factor.
- Dollar difference are due to rounding.

**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase Application**

**Table 6-20  
Storage Service Rates**

		2023				2024				2025				2026			
		Illustrative GRC 1		Proposed GTS CARD		Illustrative GRC 1		Proposed GTS CARD		Illustrative GRC 1		Proposed GTS CARD		Illustrative GRC 1		Proposed GTS CARD	
		January	April	January	April	January	April	January	April	January	April	January	April	January	April	January	April
<b>Core Firm Storage (G-CFS)</b>																	
Reservation Charge	(\$/dth/mo)	\$0.3172	\$0.3181	\$0.3154	\$0.3017	\$0.4902	\$0.4916	\$0.4655	\$0.4733	\$0.5057	\$0.5072	\$0.4802	\$0.4802	\$0.5591	\$0.5607	\$0.5307	\$0.5307
<b>Negotiated Firm Storage (G-NFS)</b>																	
Injection	(\$/dth/d)	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236
Inventory	(\$/dth)	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541	\$3.5541
Withdrawal	(\$/dth/d)	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629
<b>Negotiated As-Available Storage (G-NAS) - Maximum Rate</b>																	
Injection	(\$/dth/d)	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236	\$5.7236
Withdrawal	(\$/dth/d)	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629	\$26.1629
<b>Market Center Services (Parking and Lending Services)</b>																	
Maximum Daily Charge	(\$/Dth/d)	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650	\$1.1650
Minimum Rate	(per transaction)	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000	\$57.0000

**Notes:**

- Rates for storage services are based on the costs of storage injection, inventory and withdrawal.
- Core Firm Storage (G-CFS) rates are a monthly reservation charge designed to recover one twelfth of the annual revenue requirement of injection, inventory and withdrawal storage.
- Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and volumetric), as negotiated between parties. The volumetric equivalent is shown above.
- Negotiated As-Available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.
- PG&E proposes negotiated rates (NFS and NAS) at the adopted 2022 maximum levels with any incidental revenue collected returned to customers via PG&E's balancing accounts.
- Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal costs of providing the service.
- The maximum charge for parking and lending is based on the annual cost of cycling one Dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season as adopted for 2018 in PG&E's 2015 Gas Transmission and Storage Rate Case.
- Gas Storage shrinkage will be applied in-kind on storage injections.
- Dollar difference are due to rounding.

**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase  
Application**

**Table 6-21  
Local Transmission Rates  
\$/dth**

Customer Groups	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
Core Retail Local Transmission	2.4300	3.9498	3.7304	4.1297	3.9872	4.3817	4.3254	4.6485	4.7341
Noncore Retail and Wholesale	1.1092	1.8131	2.2070	1.8952	2.3082	2.0109	2.4484	2.1331	2.5964

2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase  
Application

Table 6-22  
Customer Access Charge Rates  
(\$ per Month)

	2022	2023		2024		2025		2026	
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
		<b>G-EG / G-NT (\$/month)</b>							
Average Monthly Therms Over 12 Months									
Tier 1	\$28.76	\$41.05	\$44.33	\$50.52	\$54.56	\$61.48	\$66.40	\$72.26	\$78.04
Tier 2	\$85.68	\$122.28	\$132.06	\$150.48	\$162.52	\$183.15	\$197.80	\$215.24	\$232.46
Tier 3	\$159.48	\$227.59	\$245.79	\$280.08	\$302.49	\$340.87	\$368.14	\$400.61	\$432.66
Tier 4	\$209.30	\$298.68	\$322.58	\$367.58	\$396.99	\$447.36	\$483.15	\$525.75	\$567.82
Tier 5	\$303.67	\$433.36	\$468.03	\$533.33	\$575.99	\$649.08	\$701.01	\$762.82	\$823.85
Tier 6	\$2,575.91	\$3,676.03	\$3,970.12	\$4,523.96	\$4,885.89	\$5,505.84	\$5,946.32	\$6,470.69	\$6,988.37
<b>Wholesale (\$/month)</b>									
Alpine	\$150.18	\$214.03	\$214.03	\$263.40	\$263.40	\$320.57	\$320.57	\$376.75	\$376.75
Coalinga	\$664.22	\$946.63	\$946.63	\$1,164.99	\$1,164.99	\$1,417.84	\$1,417.84	\$1,666.31	\$1,666.31
Island Energy	\$450.04	\$641.39	\$641.39	\$789.34	\$789.34	\$960.66	\$960.66	\$1,129.01	\$1,129.01
Palo Alto	\$2,214.67	\$3,156.29	\$3,156.29	\$3,884.34	\$3,884.34	\$4,727.39	\$4,727.39	\$5,555.83	\$5,555.83
West Coast Gas - Castle	\$385.84	\$549.89	\$549.89	\$676.73	\$676.73	\$823.61	\$823.61	\$967.94	\$967.94
West Coast Gas - Mather	\$352.61	\$502.53	\$502.53	\$618.45	\$618.45	\$752.68	\$752.68	\$884.58	\$884.58

Notes:  
a) PG&E proposes that the 2023 General Rate Case and the subsequent Gas Cost Allocation Proceeding (GCAP) would set future Customer Access Charges.

## 2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase Application

Table 6-23

## Self Balancing Credit

	2022	2023	2024	2025	2026
		Illustrative GRC 1	Proposed GTS CARD	Illustrative GRC 1	Proposed GTS CARD
<b>Self-Balancing Credit</b>	(\$0.0368)	(\$0.0265)	(\$0.0279)	(\$0.0422)	(\$0.0467)
			(\$0.0409)	(\$0.0431)	(\$0.0486)

**Notes:**

a) PG&E proposes to recover storage balancing costs in end-use transportation rates. Customers or Balancing agents who elect self balancing on a daily basis can opt out of PG&E's monthly balancing program and receive a self-balancing credit.

**2023 Gas Transmission and Storage Cost Allocation and Rate Design Ratecase Application**

**Table 6-24  
Average Monthly Bill Impacts: Residential and Small Commercial Customer Classes**

Line No.	RESIDENTIAL CLASS	A		B		C		D		E		F		G		H		I	
		June 1, 2021 Present Rates	Illustrative 2023 GRC 1 Rates (Average)	Proposed 2023 CARD Rates (Average)	Proposed 2024 GRC 1 Rates (Average)	Proposed 2024 CARD Rates (Average)	Illustrative 2025 GRC 1 Rates (Average)	Proposed 2025 CARD Rates (Average)	Illustrative 2026 GRC 1 Rates (Average)	Proposed 2026 CARD Rates (Average)									
1	Non-CARE Residential Illustrative Bundled Rate* (\$/th)	\$1.84844	\$2.18620	\$2.15035	\$2.35292	\$2.32515	\$2.50246	\$2.48280	\$2.66154	\$2.65603									
2	State-Mandated Residential Public Purpose Program Surcharge (\$/th)	\$0.07021	\$0.08087	\$0.07991	\$0.08479	\$0.08394	\$0.08831	\$0.08766	\$0.09206	\$0.09172									
3	End-User Total Rate and Surcharge (\$/th)	\$1.91865	\$2.26707	\$2.23026	\$2.43771	\$2.40909	\$2.59077	\$2.57046	\$2.75360	\$2.74775									
4	Average Monthly Use per Residential Customer (therms)	31	31	31	31	31	31	31	31	31									
5	Present Average Non-CARE Residential Customer Monthly Bill (\$)	\$59.48	\$70.28	\$69.14	\$75.57	\$74.68	\$80.31	\$79.68	\$85.36	\$85.18									
6	Change in Average Non-CARE Residential Bill		\$10.80	(\$1.14)	\$5.29	(\$0.63)	\$4.74	(\$0.63)	\$5.05	(\$0.18)									
7	% Change in Average Annual Non-CARE Residential Bill		18.2%	-1.6%	7.5%	-1.2%	6.3%	-0.8%	6.3%	-0.2%									
8	CARE Residential Illustrative Bundled Rate* (\$/th)	\$1.47630	\$1.74652	\$1.71780	\$1.87989	\$1.85764	\$1.99952	\$1.98376	\$2.12679	\$2.12234									
9	State-Mandated Residential Public Purpose Program Surcharge (\$/th)	\$0.02959	\$0.02959	\$0.02959	\$0.02959	\$0.02959	\$0.02959	\$0.02959	\$0.02959	\$0.02959									
10	End-User Total Rate and Surcharge (\$/th)	\$1.50589	\$1.77611	\$1.74739	\$1.90948	\$1.88723	\$2.02911	\$2.01335	\$2.15638	\$2.15193									
11	Average Monthly Use per Residential Customer (therms)	26	26	26	26	26	26	26	26	26									
12	Present Average Non-CARE Residential Customer Monthly Bill (\$)	\$39.15	\$46.18	\$45.43	\$49.65	\$49.07	\$52.76	\$52.35	\$56.07	\$55.95									
13	Change in Average Non-CARE Residential Bill		\$7.03	(\$0.75)	\$3.47	(\$0.58)	\$3.11	(\$0.12)	\$3.31	(\$0.12)									
14	% Change in Average Annual Non-CARE Residential Bill		18.0%	-1.6%	7.5%	-1.2%	6.3%	-0.8%	6.3%	-0.2%									
SMALL COMMERCIAL CLASS		A		B		C		D		E		F		G		H		I	
15	Non-CARE Small Commercial Illustrative Bundled Rate* (\$/th)	\$1.30540	\$1.54769	\$1.51405	\$1.65308	\$1.62755	\$1.74637	\$1.72916	\$1.84664	\$1.84355									
16	State-Mandated Small Commercial Public Purpose Program Surcharge (\$/th)	\$0.07647	\$0.08713	\$0.08617	\$0.09105	\$0.09020	\$0.09457	\$0.09392	\$0.09832	\$0.09798									
17	End-User Total Rate and Surcharge (\$/th)	\$1.38187	\$1.63482	\$1.60022	\$1.74413	\$1.71775	\$1.84094	\$1.82308	\$1.94496	\$1.94153									
18	Average Monthly Use per Small Commercial Customer (therms)	272	272	272	272	272	272	272	272	272									
19	Present Average Non-CARE Small Commercial Customer Monthly Bill (\$)	\$375.87	\$444.67	\$435.26	\$474.40	\$467.23	\$500.74	\$495.88	\$529.03	\$528.10									
20	Change in Average Non-CARE Small Commercial Bill		\$68.80	(\$9.41)	\$29.73	(\$7.17)	\$26.34	(\$4.86)	\$28.29	(\$0.93)									
21	% Change in Average Annual Non-CARE Small Commercial Bill		18.3%	-2.1%	6.7%	-1.5%	5.6%	-1.0%	5.6%	-0.2%									

**Notes**

\* CARE customers receive a 20 % discount on transportation and procurement and are exempt from CARE and CSI Solar Water Heater rate components.

<sup>a</sup> 2023 rates are based on PG&E's June 1, 2021 rate change filing per Advice Letter 4440-G as modified by PG&E's GRC 1 Application 21-06-021.



**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 7**

**CORE GAS SUPPLY**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 7  
CORE GAS SUPPLY

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 7**  
**CORE GAS SUPPLY**

**A. Introduction**

Core Gas Supply (CGS) is responsible for procuring natural gas to serve Pacific Gas and Electric Company's (PG&E) bundled core gas customers (primarily residential and small commercial customers), as well as pipeline capacity and storage capacity for all core gas customers. Previously, CGS participated in Gas Transmission and Storage (GT&S) rate cases to request and seek approval for changes to its intrastate transportation allocations, firm storage allocation, and other matters concerning all core gas customers, both bundled and unbundled. CGS now presents its portfolio for the 2023 GT&S Cost Allocation and Rate Design (CARD) proceeding. The proposed portfolio is contingent on the adoption of the 2023 GRC Phase I Track 1 proceeding pipeline asset and storage capacities.

Pursuant to Decision (D.) 16-06-056, Conclusion of Law 276, on August 31, 2021, PG&E CGS met and conferred with Core Transport Agents (CTA).<sup>1</sup>

**1. Purpose and Scope of the Chapter**

In this testimony, CGS proposes the changes as described below. Ultimately, the proposed changes aim to ensure Core Procurement Entities (CGS and CTAs) can fulfill the 1-day-in-10-year reliability requirements<sup>2</sup> and reliably meet all Core loads throughout winter. The illustrative asset portfolio's compliance with the 1-cold-day-in-10-year Reliability Standard will be shown in Table 7-4 in the Confidential Attachment, "Confidential Storage Information."

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<sup>1</sup> CTAs in attendance were: Association of Bay Area Governments, Calpine Energy, GreenWave Energy, Just Energy, Peak Six Power and Gas, School Project for Utility Rate Reduction, Symmetry Energy, and Tiger Natural.

<sup>2</sup> D.06-07-010, pp. 36-37, Ordering Paragraph (OP) 1.

## 2. Summary of Proposals

CGS proposes the following changes:

### Pipeline and Storage Portfolio Changes

- 1) Reduce December – February (Peak) Winter Pipeline Capacity;
- 2) Increase PG&E Core Storage Inventory and Winter Withdrawal Capacity allocation;
- 3) Expedite CTA Stepdown for Holding PG&E Core Firm Storage;
- 4) Expand Storage Request for Offers (RFO) Participation;
- 5) Modify the Maximum Storage Inventory Capacity Procured via RFO; and

### Other Policy Changes

- 6) Modify November Interstate Capacity Planning Range Minimum.

## B. Pipeline and Storage Portfolio Change

CGS proposes to:

- 1) Reduce and shift peak winter pipeline capacity on PG&E's backbone system. This proposal "flattens" the transportation portfolio by (1) aligning the Redwood Seasonal contract with the peak winter months of December through February and (2) replacing the 3-month Baja peak winter contract<sup>3</sup> (i.e., December through February) with a 5-month Baja full winter contract (i.e., November through March) which renders it compatible with standard upstream pipeline and gas supply products. These proposals are contingent to the adoption of the 2023 GRC Phase 1 Track 1 pipeline asset proposals. CGS proposes to modify the intrastate pipeline allocations as follows, and as summarized in Table 7-1, Figure 7-1, Figure 7-2, and Figure 7-3:
  - **Reallocate Redwood Seasonal:** Shift the 3-month November through January, 250,000 decatherm per day (Dth/d) pipeline capacity to the 3-month December through February period. This shift better aligns with peak winter loads (December through February) as shown in Total Core's winter profile as established by the 2020 California Gas Report. This reallocation results in no net increase in winter Redwood pipeline capacity.

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<sup>3</sup> A "custom" 3-month product tends to have less availability and higher prices than a 5-month standard product.

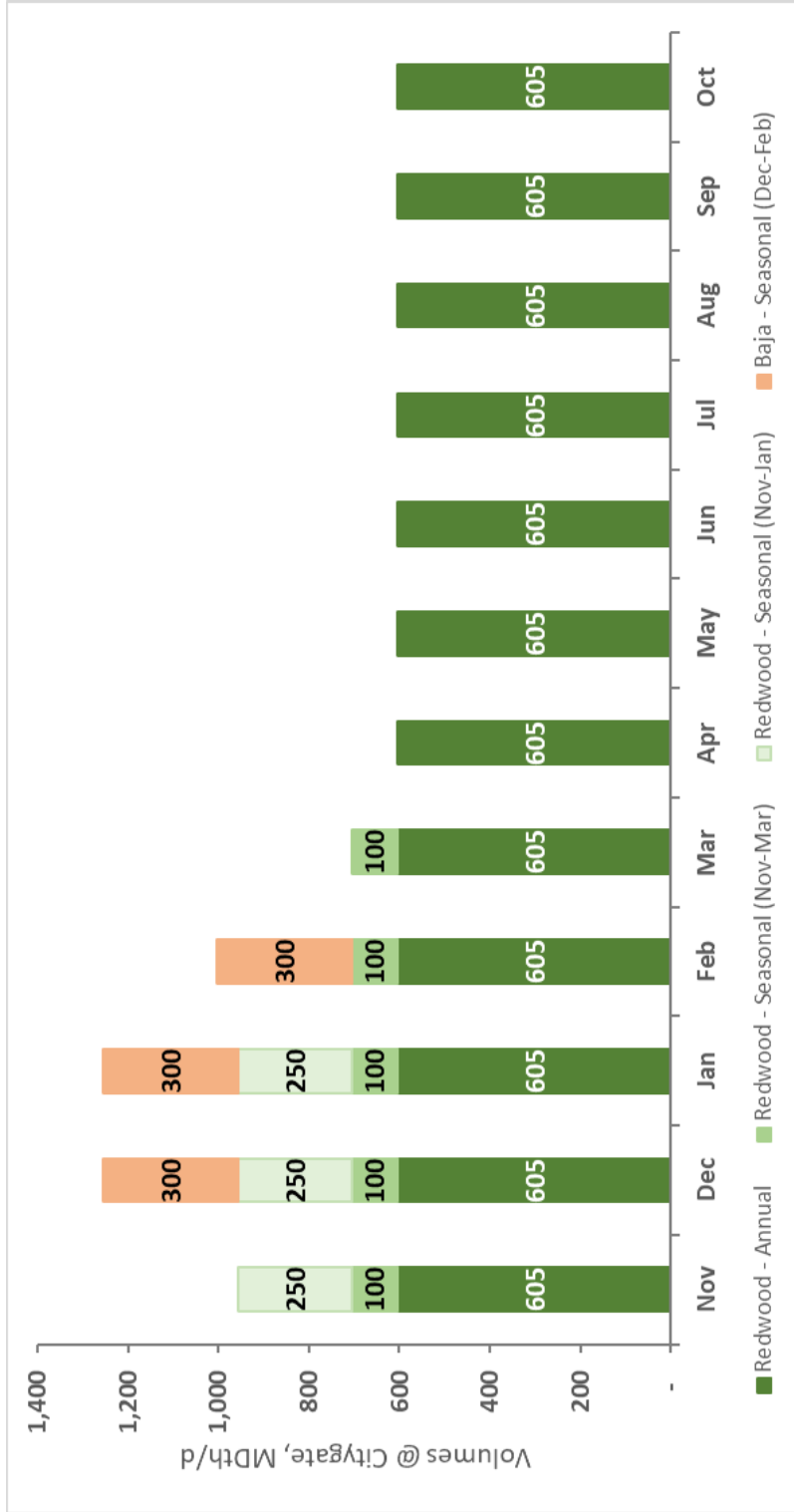
- 1       • **Replace Baja Seasonal Peak Winter with Baja Seasonal Full Winter:**  
2       Reduce by 250,000 Dth/d, Baja pipeline capacity for 3-month period of  
3       December through February and add 150,000 Dth/d of pipeline capacity  
4       for the full winter period November through March. This reallocation  
5       results in no net increase in Baja Seasonal pipeline capacity and is  
6       anticipated to increase competition between providers and availability of:  
7       a) upstream interstate pipeline transportation products, as pipeline  
8       companies prefer to offer standard five-month winter pipeline  
9       contracts rather than contracting for only the three peak winter  
10      months, and  
11      b) winter firm gas supplies, as suppliers prefer to offer standard  
12      five-month winter supply products in advance of winter rather than  
13      offering only individual winter months in the month immediately prior  
14      to the flow month.

**TABLE 7-1  
CORE INTRASTATE PIPELINE CAPACITY ALLOCATION PROPOSAL**

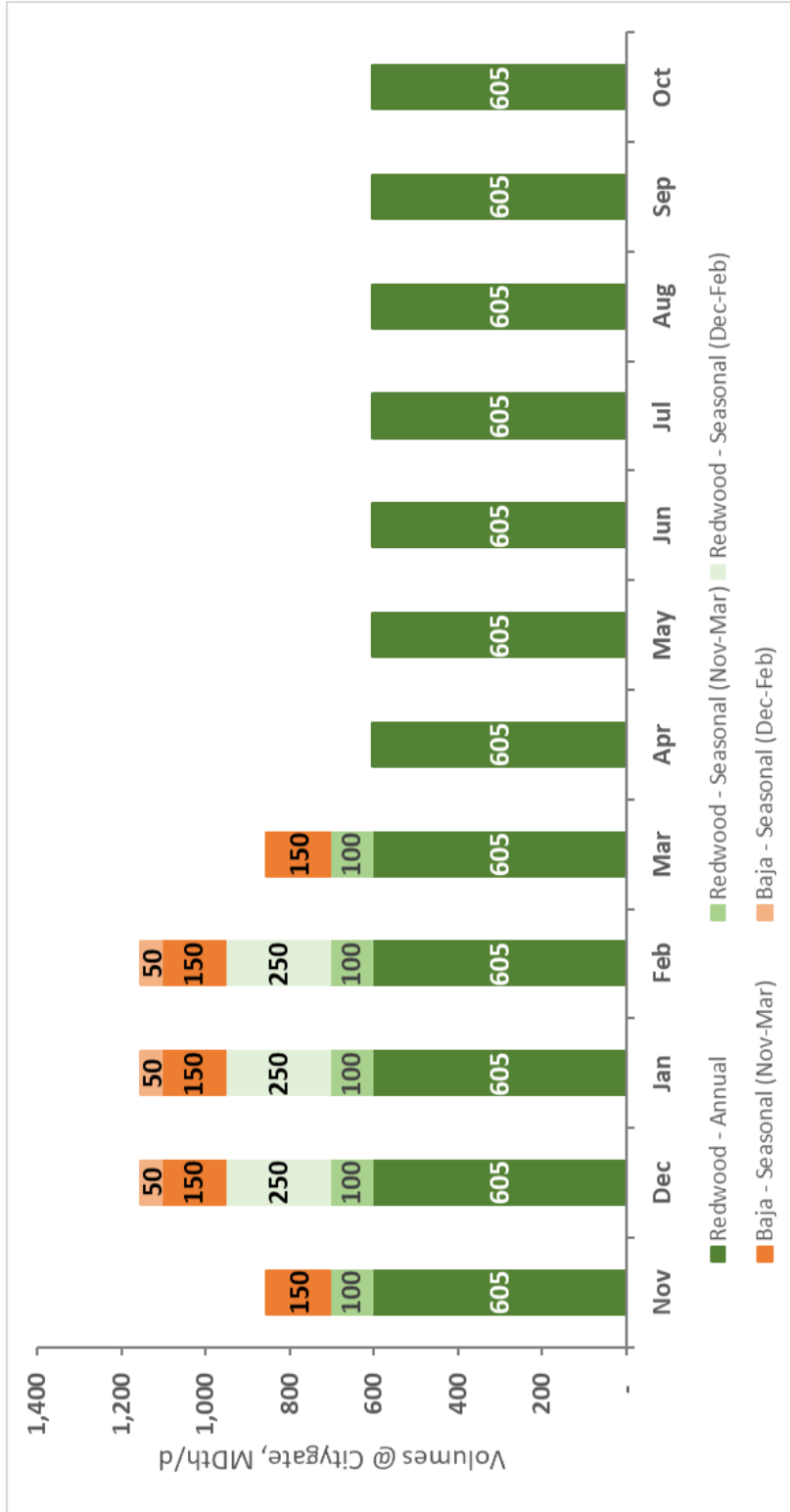
Line No.	CURRENT (MDth/d)												
	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
1	Redwood - Annual	605	605	605	605	605	605	605	605	605	605	605	605
2	Baja - Annual	-	-	-	-	-	-	-	-	-	-	-	-
3	Redwood - Seasonal (Nov-Mar)	100	100	100	100	100	-	-	-	-	-	-	-
4	Redwood - Seasonal (Nov-Jan)	250	250	250	-	-	-	-	-	-	-	-	-
5	Baja - Seasonal (Nov-Mar)	-	-	-	-	-	-	-	-	-	-	-	-
6	Baja - Seasonal (Dec-Feb)	-	300	300	300	-	-	-	-	-	-	-	-
7	<b>Total Intrastate Pipeline Capacity</b>	<b>955</b>	<b>1,255</b>	<b>1,255</b>	<b>1,005</b>	<b>705</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>9,410</b>
<b>PROPOSED (MDth/d)</b>													
8	Redwood - Annual	605	605	605	605	605	605	605	605	605	605	605	605
9	Baja - Annual	-	-	-	-	-	-	-	-	-	-	-	-
10	Redwood - Seasonal (Nov-Mar)	100	100	100	100	100	-	-	-	-	-	-	-
11	Redwood - Seasonal (Dec-Feb)	-	250	250	250	-	-	-	-	-	-	-	-
12	Baja - Seasonal (Nov-Mar)	150	150	150	150	150	-	-	-	-	-	-	-
13	Baja - Seasonal (Dec-Feb)	-	50	50	50	-	-	-	-	-	-	-	-
14	<b>Total Intrastate Pipeline Capacity</b>	<b>855</b>	<b>1,155</b>	<b>1,155</b>	<b>1,155</b>	<b>855</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>605</b>	<b>9,410</b>
<b>CHANGE (MDth/d)</b>													
15	Redwood - Annual	-	-	-	-	-	-	-	-	-	-	-	-
16	Baja - Annual	-	-	-	-	-	-	-	-	-	-	-	-
17	Redwood - Seasonal (Nov-Mar)	-	-	-	-	-	-	-	-	-	-	-	-
18	Redwood - Seasonal (Dec-Feb)	(250)	-	-	250	-	-	-	-	-	-	-	-
19	Baja - Seasonal (Nov-Mar)	150	150	150	150	150	-	-	-	-	-	-	750
20	Baja - Seasonal (Dec-Feb)	-	(250)	(250)	(250)	-	-	-	-	-	-	-	(750)
21	<b>Total Intrastate Pipeline Capacity</b>	<b>(100)</b>	<b>(100)</b>	<b>(100)</b>	<b>150</b>	<b>150</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>



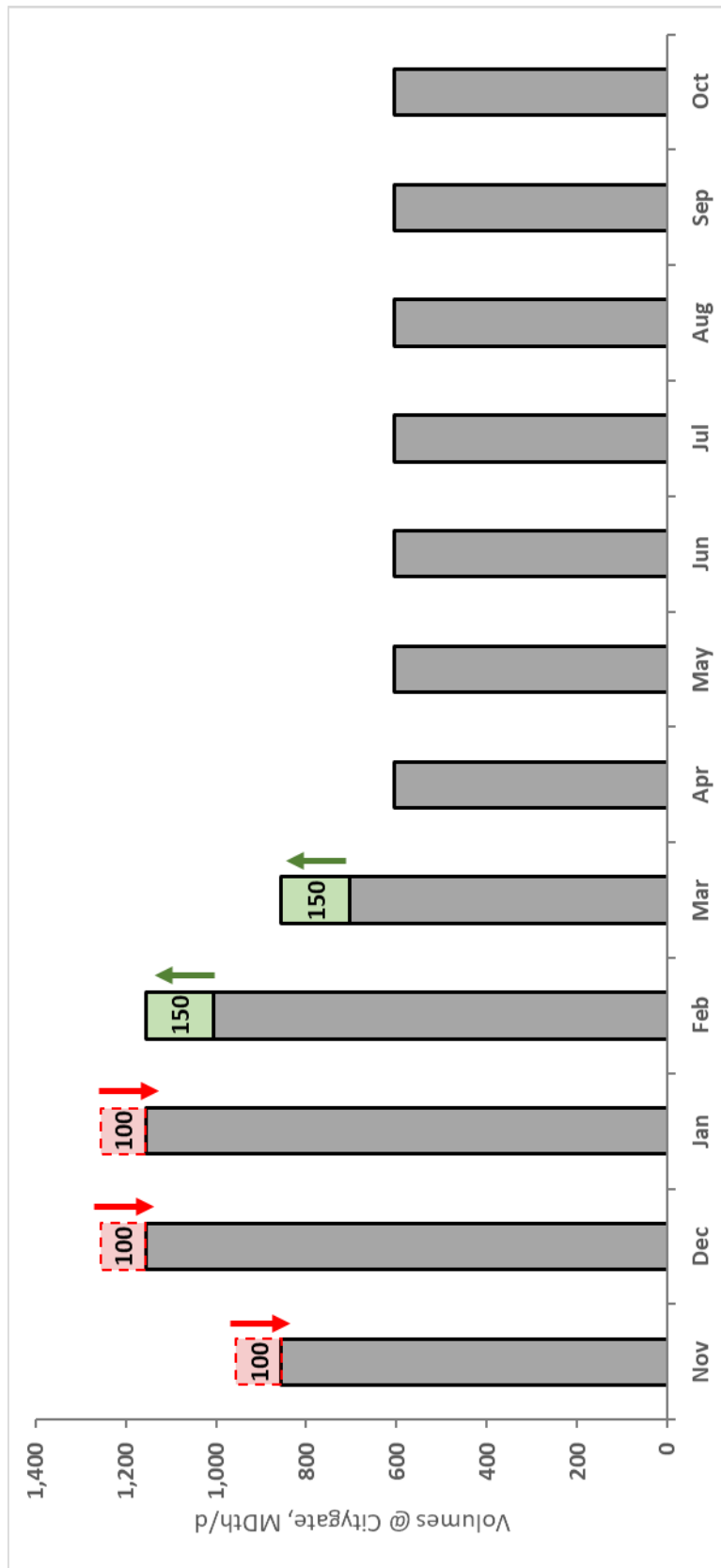
**FIGURE 7-1**  
**CURRENT CORE INTRASTATE PIPELINE CAPACITY ALLOCATION**



**FIGURE 7-2**  
**PROPOSED CORE INTRASTATE PIPELINE CAPACITY ALLOCATION**



**FIGURE 7-3**  
**OVERALL PROPOSED CHANGES TO THE**  
**CURRENT CORE INTRASTATE PIPELINE CAPACITY ALLOCATION**



- 1 2) Increase the allocation of PG&E Core Storage winter maximum withdrawal  
2 by 107,000 Dth/d and inventory by 1,760,000 decatherm (Dth) as shown in  
3 Table 7-2. This proposal is contingent on the adoption of the 2023 GRC  
4 Phase 1 Track 1 storage increase proposal.

**TABLE 7-2**  
**PG&E FIRM CORE GAS STORAGE ALLOCATION PROPOSAL**

Line No.		Current	Proposed	Change
1	Gas Inventory (MDth)	5,175	6,935	1,760
2	Maximum November Withdrawal (MDth/d)	159	213	54
3	Maximum Dec-Feb Withdrawal (MDth/d)	318	425	107
4	Maximum March Withdrawal (MDth/d)	159	213	54
5	Average Apr-Oct Injection (MDth/d)	25	34	8
6	Maximum Nov-Mar Injection (MDth/d)	0	0	0

5 **C. Expedite CTA Stepdown of PG&E Core Firm Storage Capacity**

6 Pursuant to D.16-06-056,<sup>4</sup> the procurement of PG&E Core Firm Storage  
7 services for CTAs transitions from PG&E to the CTAs during a seven-year  
8 transition period (“storage stepdown”) commencing on April 1, 2018. In 2023,  
9 CTAs would be allowed to procure 60-80 percent of their Core Firm Storage  
10 service from Independent Storage Providers (ISP).

11 CGS proposes to expedite the 7-year storage stepdown resulting in CTAs  
12 procuring 100 percent of their allocated Core Firm Storage volumes from ISPs  
13 beginning the first April after the final decision of this case is implemented. The  
14 entire PG&E Core Firm Storage volume will then be allocated to bundled core.

15 **D. Expand Storage RFO Participation**

16 In the 2019 GT&S Rate Case Final Decision (D.19-09-025), the Commission  
17 approved CGS’ proposal to procure storage from ISPs.<sup>5</sup> Furthermore,  
18 Appendix I of D.19-09-025 establishes an Approval Process for Gas Storage  
19 Contracts between PG&E and ISPs to serve Core customers. At the time of the  
20 2019 GT&S Rate case opening testimony filing in November 2017, PG&E Gas  
21 System Operations (GSO) did not indicate that they had additional storage

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<sup>4</sup> D.16-06-056, p. 486, OP 45, Part C; Gas Schedule G-CT, Sheet 8.

<sup>5</sup> D.19-09-025, p. 323, OP 19.

inventory available to offer in CGS' storage RFOs. Although it is still unknown to CGS if PG&E GSO will have additional storage to offer in future Storage RFOs, CGS proposes the ability for all California Public Utilities Commission (CPUC) jurisdictional storage facilities connected to the PG&E's system (including PG&E GSO) to participate in CGS' Storage RFOs following the process outlined in Appendix I of D.19-09-025.

In a tightening gas storage market, CGS seeks to include all gas storage entities that can reliably serve Core customers. Such ability would expand CGS' access to additional storage and foster competition amongst storage providers in the Storage RFO process. Having additional Storage RFO participants potentially reduces cost for customers.

#### **E. Modify the Maximum Storage Inventory Capacity Procured via RFO**

CGS proposes to modify the storage inventory capacity range procured via RFO as described in Appendix I from a fixed range of 10,000,000 Dth to 14,000,000 Dth to a range with a formulaic maximum.

CGS is proposing to increase the maximum storage inventory capacity to provide flexibility in procuring storage contracts. Currently, the fixed storage inventory maximum capacity of 14,000,000 Dth constrains storage product choices to higher withdrawal-to-inventory ratios which are storage products that tend to have higher contract prices. CGS proposes the use of the current withdrawal requirement<sup>6</sup> and a 0.061 withdrawal-to-inventory ratio<sup>7</sup> when determining the maximum inventory capacity. CGS proposes a maximum inventory capacity formula as follows:

$$\frac{\text{storage withdrawal requirement}}{0.061 \text{ withdrawal ratio}} \times 2 = \text{Max Inventory}$$

---

<sup>6</sup> The withdrawal requirement will change proportionally with the 1-cold-day-in-10-year Reliability Standard.

<sup>7</sup> 0.061 is the calculation of the Fixed Equivalent Withdrawal, PG&E Gas Schedule G-CFS, Sheet 2.

1 Please see Confidential Attachment Table 7-5 and Figure 7-5 for an  
2 illustrative example of how the maximum storage capacity formula is applied.  
3 CGS proposes to retain the 10,000,000 Dth storage inventory capacity  
4 minimum.

5 D.19-09-025, Appendix I, establishes a process for the CPUC to review and  
6 approve storage contracts that are "...reasonably priced, will benefit core  
7 customers, and is necessary to meet the Reliably Standard." CGS will continue  
8 to use this existing storage contract approval process to request CPUC approval  
9 of its contracts resulting from the storage RFO.

10 **F. Reduce November Interstate Capacity Planning Range Minimum From**  
11 **100 percent to 80 percent of Average Annual Demand**

12 D.19-09-025 approved reducing the March interstate capacity planning  
13 range minimum. November is also considered a shoulder, or non-peak  
14 month<sup>8</sup>—similar to March—with a wide-ranging daily customer demand.  
15 Reducing the November minimum allows for a possible reduction in interstate  
16 pipeline capacity holdings without compromising meeting demand in a nonpeak  
17 winter month. Furthermore, the widened range between the minimum and  
18 maximum interstate capacity holdings for November provides additional  
19 contracting flexibility. Such flexibility accommodates changes in customer  
20 demand, interstate pipeline product offerings and market conditions. Figure 7-4  
21 and Table 7-3 summarize the proposed changes to the November interstate  
22 capacity planning range minimum using current customer demand as an  
23 illustration.

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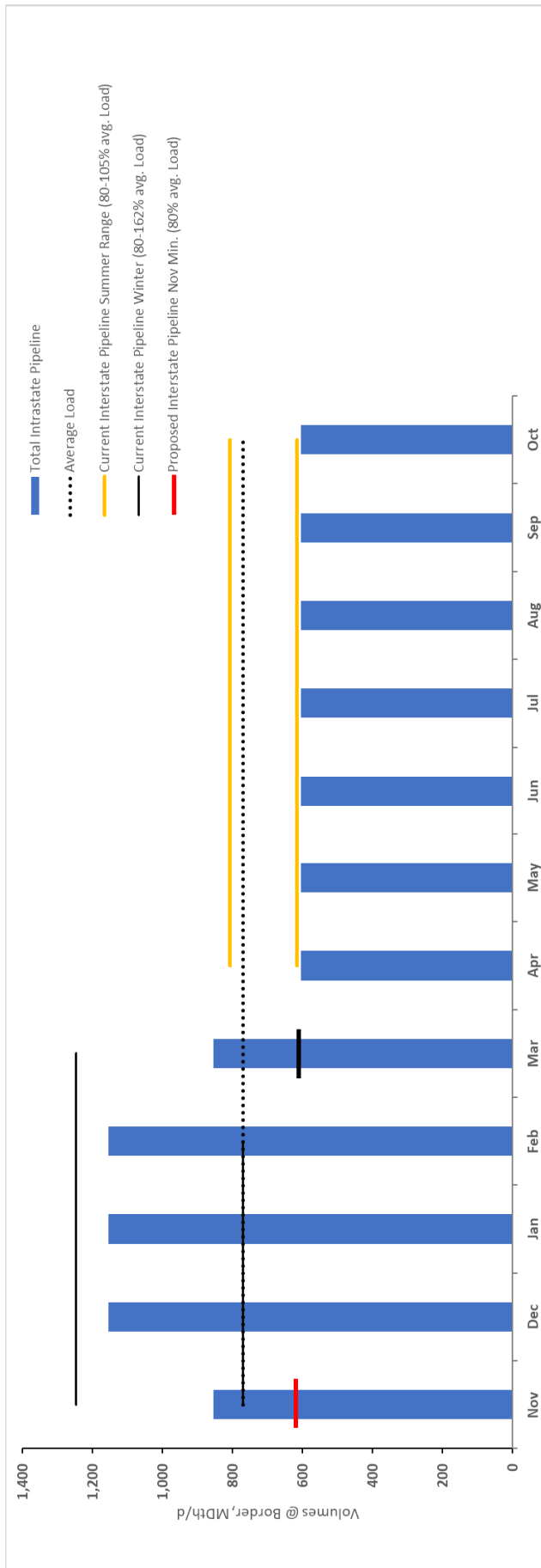
8 "Shoulder months" are the months before and after the peak winter season (i.e., November and March are shoulder months).



**TABLE 7-3**  
**INTERSTATE PIPELINE CAPACITY PLANNING RANGE PROPOSAL (ILLUSTRATIVE)**

INTERSTATE PIPELINE CAPACITY PLANNING RANGE PROPOSAL (MDth/d)												
	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Current Interstate Pipeline Summer Range Max. (105% avg. Load)						809	809	809	809	809	809	809
Current Interstate Pipeline Summer Range Min. (80% avg. Load)						616	616	616	616	616	616	616
Current Interstate Pipeline Winter Max. (162% avg. Load)	1,247	1,247	1,247	1,247	1,247							
Current Interstate Pipeline Winter Min. (80-100% avg. Load)	770	770	770	770	616							
Proposed Interstate Pipeline Nov Min. (80% avg. Load)	616											
Average Load	770	770	770	770	770	770	770	770	770	770	770	770

**FIGURE 7-4**  
**INTERSTATE PIPELINE CAPACITY PLANNING RANGE PROPOSAL (ILLUSTRATIVE)**



1 **G. Conclusion**

2 To summarize:

- 3 1) CGS' proposal to reduce December through February (Peak) Winter  
4 Pipeline Capacity is reasonable and should be adopted.
- 5 2) CGS' proposal to increase PG&E Core Storage Inventory and Winter  
6 Withdrawal is reasonable and should be adopted.
- 7 3) CGS' proposal to expedite CTA Stepdown of PG&E Core Firm Storage is  
8 reasonable and should be adopted.
- 9 4) CGS' proposal to expand Storage RFO participation is reasonable and  
10 should be adopted.
- 11 5) CGS' proposal to modify the maximum storage inventory capacity procured  
12 via RFO is reasonable and should be adopted.
- 13 6) CGS' proposal to modify the November interstate capacity planning range  
14 minimum is reasonable and should be adopted.

15 Finally, while CGS believes its proposed portfolio is reasonable based on  
16 the information available at this time, CGS reserves the right to modify its  
17 proposal via supplemental testimony once PG&E's proposed 2023 rates for  
18 pipeline and storage capacity are known.

19 In addition, if the PG&E 2023 GRC Final Decision reduces the volume of  
20 Intrastate Pipeline or PG&E Storage available to Core customers, CGS reserves  
21 the right to modify the proposal via supplemental testimony. For example, if  
22 PG&E's 2023 GRC storage expansion proposal is not approved, there will not  
23 be sufficient storage and pipeline capacity in PG&E's Core portfolio to meet the  
24 1-cold-day-in-10-year Reliability Standard. If supplemental testimony is not  
25 allowed, PG&E requests that any reduction of intrastate pipeline or PG&E  
26 storage withdrawal capacities be replaced with ISP storage withdrawal capacity.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 7**  
**ATTACHMENT A REDACTED**  
**CONFIDENTIAL STORAGE INFORMATION**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 7  
ATTACHMENT A REDACTED  
CONFIDENTIAL STORAGE INFORMATION

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 7**  
**ATTACHMENT A REDACTED**  
**CONFIDENTIAL STORAGE INFORMATION**

**A. Confidential Storage Information**

**TABLE 7-4**  
**1-COLD-DAY-IN-10-YEAR CORE RELIABILITY STANDARD CALCULATION (ILLUSTRATIVE)**

Line No.	Assets and Supply Sources (at Citygate)	Current (MDth/d)	Proposed (MDth/d)	Change (MDth/d)
1	Redwood - Annual	605	605	0
2	Baja - Annual	0	0	0
3	Redwood - Seasonal (Nov-Mar)	100	100	0
4	Redwood - Seasonal (Nov-Jan) → (Dec-Feb) <sup>(1)</sup>	250	250	0
5	Baja - Seasonal (Nov-Mar)	0	150	150
6	Baja - Seasonal (Dec-Feb)	300	50	(250)
7	<b>Subtotal Intrastate Capacity</b>	<b>1,255</b>	<b>1,155</b>	<b>(100)</b>
8	Citygate Supply	330		
9	<b>Total Capacity with Citygate Supply</b>	<b>1,585</b>		
10	PG&E Storage Withdrawal - January 15	318	425	107
11	Independent Storage Withdrawal <sup>(2)</sup>	677		
12	<b>Total Storage Withdrawal</b>	<b>995</b>		
13	<b>Total Supply</b>	<b>2,580</b>	<b>2,680</b>	<b>100</b>
14	<b>1-COLD-DAY-IN-10-YEAR CORE RELIABILITY <sup>(3)</sup></b>	<b>2,580</b>	<b>2,680</b>	<b>100</b>

<sup>(1)</sup> Current Core Pipeline Capacity is for November through January. Proposed Intrastate Pipeline Capacity is for December through February

<sup>(2)</sup> Illustrative figure as ISP withdrawal varies with the 1-Cold-Day-in-10 Reliability Standard

<sup>(3)</sup> Figures for Current and Proposed are based on California Gas Report 2016 and 2020 respectively (next issuance is 2022)



**TABLE 7-5**  
**FIRM ISP STORAGE INVENTORY AND WITHDRAWAL PROPOSAL (ILLUSTRATIVE)**

Line No.	Description	Current	Proposed	Change
1	Gas Inventory (thousands of decatherms (MDth))	10,000 - 14,000	[REDACTED]	
2	Maximum Nov-Mar Withdrawal (thousand decatherms per day (MDth/d))	677		

- (a) Based on the current Fixed Equivalent Withdrawal (FEW) capacity ratio of 0.061.
- (b) The ISP withdrawal requirement will change proportionally to the 1-cold-day-in-10-year Reliability Standard (per each issuance of the Cal Gas Report).

**FIGURE 7-5**  
**EXAMPLE CALCULATION OF THE PROPOSED ISP STORAGE INVENTORY CAPACITY FORMULA**

$$\frac{\textit{ISP withdrawal requirement}}{0.061} \times 2 \approx$$

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 8**  
**G-NGV1 AND G-NGV4 GAS TARIFF MODIFICATIONS**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 8  
G-NGV1 AND G-NGV4 GAS TARIFF MODIFICATIONS

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 8**  
**G-NGV1 AND G-NGV4 GAS TARIFF MODIFICATIONS**

**A. Introduction**

Pacific Gas and Electric Company's (PG&E) G-NGV1 (Core Natural Gas Service for Compression on Customers' Premises) and G-NGV4 (Noncore Natural Gas Service for Compression on Customers' Premises) tariffs provide service predominantly to third-party owned natural gas vehicle (NGV) stations<sup>1</sup> which compress natural gas for use as a transportation fuel by motor vehicles. These stations are connected to both PG&E's gas distribution and local transmission systems. Many of these stations are open to the public while others are for private fleet use only. This chapter describes PG&E's request to create more inclusive and modernized G-NGV1 and G-NGV4 tariffs. It does not propose changes to the rates or rate structures.

**B. Purpose and Scope of the Chapter**

The purpose of this chapter is to propose changes to PG&E gas tariffs G-NGV1 and G-NGV4, discuss the need to update the tariff language to be more inclusive, and present redline versions of proposed tariff revisions. The tariff language proposed is consistent with the original purpose of their creation more than thirty years ago in 1990,<sup>2</sup> extending the applicability to transportation vehicles instead of being limited to "motor vehicles."<sup>3</sup> Additionally, the tariff is modernized by eliminating "compressed" as a limiting factor as to the state of the vehicular gas fuel and eliminating "natural" as applied to the term "gas" in accordance with PG&E Gas Rule 14<sup>4</sup> definition of "Gas."

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<sup>1</sup> PG&E also operates 29 NGV stations to service its internal fleet with 23 open to the public.

<sup>2</sup> PG&E's NGV tariffs date to April 19, 1990.

<sup>3</sup> PUC § 5359 (a), "Motor Vehicle" means a vehicle which is self-propelled.

<sup>4</sup> Gas Rule 1, <[https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_RULES\\_1.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_1.pdf)> as of (Sept. 23, 2021).

## C. Summary of Proposals

PG&E proposes the following tariff revision changes to G-NGV1 and G-NGV4:

- Expand the applicability definition in these tariffs from “motor vehicles” to “vehicles”;
- Eliminate reference to “compression” of the gas, which excluded the process of liquifying gas by a station to create Liquefied Natural Gas (LNG),<sup>5</sup> which is often needed by larger trucks and long-haul trucking; and
- Align language to conform with Gas Rule 1’s “gas” definition.

### 1. Organization of the Remainder of This Chapter

The rest of this chapter is organized as follows:

- Section D – Background;
- Section E – Discussion;
- Section F – Proposed Tariff Changes;
- Section G –Implementation and Customer Outreach; and
- Section H –Conclusion.

## D. Background

PG&E’s G-NGV1 (core transportation) and G-NGV4 (noncore transportation) tariffs were created in the early 1990’s in response to autos and trucks, i.e., “motor vehicles” being at first converted from their manufactured state of using gasoline or diesel and then, later, designed and manufactured to use natural gas as their vehicular energy source. Tariffs exist for the specialty end-use NGV customer class<sup>6</sup> instead of applying the otherwise applicable commercial rates because:

- 1) The use of gas is good for the environment and society compared to the predominant fuels (gasoline or diesel) used by transportation vehicles in most situations even as electric vehicle options increase and

---

<sup>5</sup> In I.91-10-029/R.91-10-028, p. 3, fn., the California Public Utilities Commission (Commission) noted that “[t]he term NGV is used generically in this investigation to include alternative natural gas vehicle technologies (e.g., Liquefied Natural Gas).”

<sup>6</sup> D.90-04-021; 36 CPUC 2d 148.

2) Cost of service for NGV station customers is distinctly lower than their otherwise applicable tariff if the NGV tariffs did not exist and their applicable rates should reflect this.

The creation of these tariffs was not to pre-judge the marketplace outcome of the acceptance of NGV's as noted in the Commission's Summary in Investigation (I.) 91-10-029/Rulemaking (R.) 91-10-028:

The Commission is concerned that regulatory policies do not adversely affect the establishment and functioning of competitive markets either by mandating certain programs or by establishing prices which distort market forces with its consequent resource misallocation. Instead consumers should be the ones to make the decisions concerning vehicle fuel choice in response to competitive forces in the [Low Emission Vehicle] LEV market. To achieve that end, the Commission does not want to delay the development of the infrastructure to support a market for electric and [NGVs].<sup>7</sup>

The use of natural gas provides clear benefits in terms of reduced air pollution and Greenhouse Gas (GHG) emissions compared to using gasoline or diesel. NGVs' GHG emissions are about 20 percent lower overall than those of gasoline-powered autos and heavy-duty diesel vehicles. A new near-zero heavy-duty natural gas engine emits 90 percent cleaner than the current EPA NOx limit (0.2 g/bhp-hr).<sup>8</sup>

Therefore, the G-NGV1 and G-NGV4 end-use transportation rates were created so that the cost allocation and average rate paid by these customers would better reflect the cost of service for these customers. Had the Commission not approved creation of these end-use purposed NGV tariffs, the only core rate option for NGV stations would have been PG&E's G-NR1 "Small Commercial" rate. The economic and environmental impact would have been substantially higher rates to NGV stations than their cost of service justifies with the result potentially being a reduced growth rate of fleets choosing to move away from diesel or gasoline unless strictly required to do so. The Small Commercial class is heavily dominated by small customers with winter peaking

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<sup>7</sup> I.91-10-029/R.91-10-028, pp. 2-3.

<sup>8</sup> California Natural Gas Vehicle Coalition, NGVs Reduce Climate Emissions and Cut Air Pollution, <<https://cngvc.org/why%20nvgs/air%20climate/>> (as of Sept. 23, 2021).

load profiles<sup>9</sup> that create a class far more costly to serve for both transportation and procurement components.<sup>10</sup> These comparisons of usage profiles between NGV and general commercial/industrial classes are illustrated below in Figure 1 using information from Chapter 6, “Cost Allocation and Rate Design” based on presently adopted usage and rates. This figure demonstrates how the NGV load is relatively evenly spread between summer and winter compared to winter intensive Small Commercial and how NGV stations have a more cost effective usage level compared to the Small Commercial customer class as while customer function costs (service lines, regulators, meters increase with size, they do not increase proportionately with size).

**FIGURE 1**  
**COST OF SERVICE AND RATE COMPARISONS: NGV VS COMMERCIAL/INDUSTRIAL**

Comparison of NGV Classes with Otherwise Applicable Rates Based on Chapter 6 Information								
	Share of Annual Usage in Winter	Average Annual Therms per Customer	Illustrative Avg. Core Procurement Rate	Class Avg. Transportation Rate	Total End-User Rate	NGV Rate as % of Otherwise Applicable Rate	Adopted NGV Volumes Segmented Core vs Noncore	
Small Commercial	55.8%	3,373	\$0.356	\$0.879	\$0.076	\$1.311	70%	80.0%
Core NGV	41.6%	169,044	\$0.314	\$0.555	\$0.043	\$0.913		
Industrial Distribution	45.4%	517,575	N/A	\$0.444	\$0.077	\$0.520	94%	
Noncore NGV-D	41.6%	N/A	N/A	\$0.444	\$0.043	\$0.487		
Industrial Transmissio	38.2%	5,896,844	N/A	\$0.216	\$0.053	\$0.269	93%	20.0%
Noncore NGV-T	41.6%	1,242,442	N/A	\$0.206	\$0.043	\$0.249		

Additionally, as the customers on G-NGV1 and G-NGV4 could not participate in Energy Efficiency (EE) Programs, they should not and do not pay for the (EE)-related components in the G-PPPS Public Purpose Program

<sup>9</sup> The Gas Base Revenue Requirement functions of Backbone Transmission, Local Transmission, Core Storage, and Distribution lines are all allocated on various measures that reflect the relative peakiness of winter usage by customer class (see Chapter 6). The predominant driver of the Customer Function reflect the cost of service of meters, regulators, and service lines. While these increase with the size of the customer they increase at a rate that is less than proportional to the increase in usage. Please see Chapter 6, Table 6-5, “CAC” line across customer classes.

<sup>10</sup> Procurement rates also recover interstate pipeline, backbone transmission, and core storage components and unlike commodity costs these components are allocated across core classes base on how winter peaking their class load profiles are.



1 Surcharge rider tariff<sup>11</sup> but only the California Alternate Rates for Energy  
2 (CARE) portion that supports lower income residential customers.

### 3 **E. Discussion**

4 Thirty years ago, the general discussion of the gas vehicle potential was  
5 limited to the situation at hand, including PG&E's proposed and adopted NGV  
6 tariff applicability language at the time. While LNG was noted briefly (as in the  
7 footnote referenced above), the discussion and implementation focused on  
8 "compression" of gas for compressed natural gas (CNG) and the tariff titles even  
9 included "compression." And while the discussion across Order Instituting  
10 Rulemaking's (OIR) (I.91-10-029/R.91-10-028) used "NGV", there was in parallel  
11 a prevailing use of the term "motor vehicles" as at the time the particular focus  
12 revolved around the large emission reduction potential from our streets and  
13 highways. In the thirty years since then, the range of vehicles that can use gas  
14 as a fuel has expanded beyond the largely retrofitted cars and trucks of the time.  
15 In addition to original equipment taxis and other fleet vehicles, NGVs can now  
16 for example, potentially include construction equipment to trains and  
17 ferries/ships.

18 Additionally, instead of the fuel being "natural gas" the fuel mix is evolving to  
19 include blends of pipeline quality gas that the system originally built for  
20 100 percent natural gas can accommodate and as PG&E has referenced in its  
21 Gas Rule 1 definition.

22 Therefore, in this application, PG&E proposes to update or modernize the  
23 G-NGV1 and G-NGV4 applicability language consistent with the original intent of  
24 the tariff creation to state: "Vehicles shall include all means of transporting  
25 people or goods..." as to not prejudice specific end-use technology into the  
26 future as long as they are "transportation-related."

27 The proposed tariff language changes also eliminate "natural" from "natural  
28 gas" and aligns the tariff with the current Gas Rule 1 definition of "Gas" which  
29 includes the following language: "It shall include, but not be limited to, natural  
30 gas, renewable gas, biomethane, manufactured gas, or a mixture of any or all of  
31 the above."

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11 Gas Preliminary Statement Part B, Sheet 21, G-PPPS Rate components,  
<[https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_PRELIM\\_B.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_B.pdf)> (as of  
Sept. 23, 2021).

The purpose of the tariffs remains the same, but they need updating to apply to the various expanded transportation opportunities to displace use of diesel fuel where the marketplace finds it cost-effective and the California regulations allow.

## F. Proposed Tariff Changes

Tariff title changes include:

- The modification of G-NGV1 Core Natural Gas Service for Compression on Customers' Premises changes to Core Gas Service to Gas Fueling Stations; and
- The modification of G-NGV4 Noncore Natural Gas Service for Compression on Customers' Premises changes to Noncore Gas Service to Gas Fueling Stations.

The remainder of this section will further describe PG&E's proposal related to the gas tariffs.

### 1. Redline Version of G-NGV1 and G-NGV4 language

FIGURE 8-2  
REDLINE CHANGES OF G-NGV1

GAS SCHEDULE G-NGV1 CORE NATURAL GAS SERVICE <del>TO GAS VEHICLE FUELING STATIONS FOR COMPRESSION ON CUSTOMERS' PREMISES</del>		Sheet 1
APPLICABILITY:	<p>This rate schedule<sup>1</sup> applies <u>to the transportation of gas as defined in Rule 1, to Core End-Use customer-owned gas vehicle fueling stations on PG&amp;E's Backbone, Local Transmission and/or Distribution Systems. Vehicles shall includes all means of transporting people or goods such as but not limited to automobiles, trucks, marine vessels, trains and aircraft, to natural gas service to Core End-Use Customers on PG&amp;E's Transmission and/or Distribution Systems. Service is for uncompressed natural gas for the sole purpose of compressing it for use as a motor vehicle fuel. Compression of natural gas to the pressure required for its use as motor vehicle fuel will be performed by the Customer's equipment at the Customer's designated premises only.</u></p> <p><del>Pursuant to</del> D. 15-10-032 and D. 18-03-017, transportation rates include GHG Compliance Cost for non-covered entities. Customers who are directly billed by the <u>California</u> Air Resources Board (ARB), i.e., covered entities, are exempt from paying AB 32 GHG Compliance Costs through PG&amp;E's rates.<sup>2</sup> A "Cap-and-Trade Cost Exemption" credit for these costs will be shown as a line item on exempt customers' bills.<sup>3,4</sup></p>	
TERRITORY:	<p>Schedule G-NGV1 applies everywhere <u>within PG&amp;E's gas Service Territory</u>. <del>provides natural gas service.</del></p>	

FIGURE 8-3  
REDLINE CHANGES OF G-NGV4

GAS SCHEDULE G-NGV4		Sheet 1
NONCORE NATURAL GAS SERVICE		
TO GAS VEHICLE STATIONS FOR COMPRESSION ON CUSTOMERS' PREMISES		
APPLICABILITY:	<p>This rate schedule<sup>1</sup> applies to the transportation of gas <u>as defined in Rule 1</u>, to customer-owned <u>natural</u> gas vehicle fueling stations on PG&amp;E's Backbone, Local Transmission and/or Distribution Systems. <u>Vehicles shall include all means of transporting people or goods such as but not limited to, automobiles, trucks, marine vessels, trains and aircraft.</u> To qualify for service under this schedule, a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential Customer must have maintained an average monthly use, through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. See Rule 12 for details on core and noncore reclassification.</p> <p>Customers must procure gas supply from a supplier other than PG&amp;E.</p> <p>Per D.15-10-032 and D.18-03-017, transportation rates include GHG Compliance Cost for non-covered entities. Customers who are directly billed by the Air Resources Board (ARB), i.e., covered entities, are exempt from paying AB 32 GHG Compliance Costs through PG&amp;E's rates.<sup>2</sup> A "Cap-and-Trade Cost Exemption" credit for these costs will be shown as a line item on exempt customers' bills.<sup>3, 4</sup></p>	
TERRITORY:	Schedule G-NGV4 applies everywhere within PG&E's <u>natural</u> gas Service Territory.	

**a. Expanding Applicability from Motor Vehicle to Vehicle**

As discussed previously, PG&E is proposing parallel language for G-NGV1 and G-NGV4 that expands applicability to all vehicles capable of transporting people or goods instead of the previous language limited to "motor vehicles". PG&E believes this proposal is aligned with the intent and spirit of the Commission's use of the term "vehicles" in previous OIRs referenced above as well as California's goals to reduce emissions and improve air quality by displacing the use of fuels with higher emissions as determined by the regulating entities both state and federal.

**b. Eliminating Use of "Compression" as Only Form of Gas Fuel Created by Station in Tariff Language**

Although referenced at times in the Low Emission Vehicle (LEV) OIRs of the early 1990's, concerning LEV and NGV,<sup>12</sup> using LNG as a fuel for vehicles was only a potential form 30 years ago. This situation

<sup>12</sup> The term NGV is used generically in this investigation to include alternative NGV technologies (e.g., LNG).

1 resulted in the use of the term “compression” and overlooking liquifying  
2 natural gas which is a distinct process but with the same purpose. In  
3 the context of G-NGV1 and G-NGV4, both compressed natural gas and  
4 LNG are high density fuels for vehicles.

5 **c. Elimination of Descriptive Term “Natural” When Describing Gas**

6 PG&E’s Gas Rule 1 definition of “Gas” has evolved with the ability to  
7 include RNG and Hydrogen, and therefore the term “natural gas” is  
8 becoming obsolete but was still used in these tariffs. This tariff update  
9 as proposed, aligns with the current Gas Rule 1 definition.

10 **2. Revenue Accounting**

11 The existing regulatory mechanisms controlling recording of revenues  
12 for these two existing tariffs<sup>13</sup> will not change, with the additional revenues  
13 from the proposed expanded applicability being treated as the current  
14 revenues are and modestly improving the systemwide load profile with  
15 additional usage that PG&E believes would not be winter peaking.

16 **3. Potential New Customers**

17 PG&E has been previously approached by prospective customers for  
18 this expanded applicability of its NGV tariffed transportation service, for  
19 example the development of LNG to fuel marine vessels. However, PG&E  
20 proactively contacts potential developers and customers who might expand  
21 their service under our authorized tariffs.

22 There is a general expanded use of gas in vehicles beyond motor  
23 vehicles and via LNG and not just CNG. For example, in 2020, Carnival  
24 Cruise Line took delivery of its first LNG powered cruise ship for a future  
25 fleet of nine LNG ships.<sup>14</sup> In addition, efforts to decarbonize the rail  
26 market<sup>15</sup> include Florida East Coast Railway adopting LNG for its entire

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13 Gas Preliminary Statement Part B, Sheets 5, 10, 17, and 18,  
<[https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS\\_PRELIM\\_B.pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_B.pdf)> (as of  
Sept. 23, 2021).

14 Carnival Cruise Line, LNG Powers The Fun (Apr. 22, 2021),  
<https://www.youtube.com/watch?v=VRFB5D7bKiA> (as of Sept. 23, 2021).

15 OptiFuel Systems, OptiFuel Producing Zero Criteria Emission Freight Locomotives  
From 1,200 – 2,400 HP (Nov. 19, 2020), <<https://optifuel.com/11182020>> (as of  
Sept. 23, 2021).

line-haul locomotive fleet<sup>16</sup> and OptiFuel Systems production of zero criteria emission freight locomotives to run on renewable natural gas.<sup>17</sup>

In response to developments like these and potential new customers, PG&E uses this 2023 GT&S CARD to propose language changes in line with the intent and goals to reduce California's transportation emissions throughout the state.

#### 4. Potential Loads and Load Profile

Forecasting the annual potential load for customers who would qualify for these tariffs with PG&E's modifications would be highly speculative until the market develops based on the tariff changes being approved. PG&E's intent is being able to serve customers in the future when they come to us with an applicable request. That request requires having the appropriate tariff and tariff applicability language in place. What the opportunities are for rail, marine vessels, or long-haul trucking would be dependent on third party interest and state and federal policies. Once PG&E has these new customers on the tariffs, their usage data would be incorporated in appropriate analyses of class demands on the system.

If PG&E's proposal are approved, it would include any impact in its next California Gas Report forecast filed in the summer of 2024. The forecast would then be updated in PG&E's 2027 GT&S CARD filed in 3rd Quarter 2025.

#### 5. Emissions Benefits

Similar to the emission reduction benefits of using gas versus diesel in motor vehicles which led to the NGV tariff creation in 1990, or for back-up electric generation, as discussed in PG&E's testimony in the Emergency Summer Reliability OIR, Ph 2,<sup>18</sup> using gas instead of diesel as a fuel for propulsion for vehicles other than motor vehicles offer similar benefits to the

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<sup>16</sup> Alex Luvishis, Zero-Emission Locomotives on U.S. Railways? (Feb. 12, 2021) <<https://www.railwayage.com/news/zero-emission-locomotives-on-u-s-railways/>> (as of Sept. 23, 2021).

<sup>17</sup> OptiFuel Systems, OptiFuel Producing Zero Criteria Emission Freight Locomotives From 1,200 – 2,400 HP (Nov. 19, 2020), <<https://optifuelsystems.com/11182020>> (as of Sept. 23, 2021).

<sup>18</sup> R.20-11-003, PG&E Opening Testimony (Sept. 1, 2021), Chapter 8.

environment. According to the U.S. Department of Transportation, Federal Railroad Administration “GHG emissions from the combustion of NG are much lower than those of diesel for the same energy output. This results in less carbon dioxide and other pollutants being released into the atmosphere.”<sup>19</sup> However, as discussed above, PG&E’s current NGV tariff language is only applicable to creating CNG, not LNG. LNG-fueled trucks that displace diesel is an additional potential for PG&E’s service territory with benefits to the environment as discussed by the U.S. Department of Energy<sup>20</sup> if this proposal is approved.

#### **G. Implementation and Customer Outreach**

PG&E proposes to implement these tariff language changes, if approved in the Tier 1 advice letter that implements the other adopted changes to gas transmission and storage rates proposed in this filing.<sup>21</sup> Upon approval, PG&E will communicate the NGV tariff applicability changes to customers and developers using multiple communication avenues. For example, PG&E will contact developers and NGV customers with information on the updated tariffs. Additionally, PG&E intends to include information highlighting the approved changes on PG&E’s Small and Medium Business and Large Business websites and include information about the change in the next scheduled regular communication across its Commercial and Industrial customer classes.

#### **H. Conclusion**

In summary, updates to the G-NGV1 and G-NGV4 tariffs are appropriate and needed. Third party development of CNG or LNG stations to fuel vehicles are critical to assisting these parts of California’s transportation sector with meeting California’s GHG goals. PG&E proposes these updates to support its customers and the changing market for fuels in California.

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<sup>19</sup> U.S. Dept. of Transportation, Federal Railroad Admin., Liquid and Compressed Natural Gas as Locomotive Fuels, p. 2, <[Liquid and Compressed Natural Gas as Locomotive Fuels \(dot.gov\)](https://www.fra.dot.gov/fra/pressroom/pressroom.cfm?id=100)> (as of Sept. 23, 2021).

<sup>20</sup> Michael Laughlin and Andrew Burnham, Case Study – Natural Gas Regional Transport Trucks (Aug. 2016), <[https://afdc.energy.gov/files/u/publication/ng\\_regional\\_transport\\_trucks.pdf](https://afdc.energy.gov/files/u/publication/ng_regional_transport_trucks.pdf)> (as of Sept. 23, 2021).

<sup>21</sup> See Chapter 6, Section L, Timing of Decision and Implementation.

1 PG&E respectfully requests the Commission adopt the proposed revisions  
2 to G-NGV1 and G-NGV4 as modified in Attachments A & B to this chapter.

3 These proposals are:

- 4 1) Consistent with the spirit and intent of the above discussion referencing the  
5 LEV OIR that not just “motor vehicles” are the intended target, and
- 6 2) these proposals would not harm existing customers on G-NGV1 or G-NGV4  
7 and would possibly benefit all gas customers by adding a modest amount of  
8 relatively flat load over time.

9 The modification of *Core Natural Gas Service for Compression on*  
10 *Customers' Premises* (G-NGV1) to *Core Gas Service to Gas Fueling Stations*  
11 (G-NGV1) allows for the ability to add description of “vehicles” beyond cars and  
12 light trucks, aligns term “gas” with the Gas Rule 1 definition, and allows  
13 transportation for gas liquification end use. The modification of *Noncore Natural*  
14 *Gas Service for Compression on Customers' Premises* (G-NGV4) to *Noncore*  
15 *Gas Service to Gas Fueling Stations* (G-NGV4) allows for the ability to add  
16 description of “vehicles” beyond cars and light trucks, aligns term “gas” with the  
17 Gas Rule 1 definition, and allows transportation for gas liquification end use.



**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 8**

**ATTACHMENT A**

**CORE NATURAL GAS SERVICE FOR COMPRESSION ON  
CUSTOMERS' PREMISES (G-NGV1) REDLINE CHANGES**



**GAS SCHEDULE G-NGV1**

Sheet 1

**CORE ~~NATURAL~~ GAS SERVICE**

**TO GAS VEHICLE FUELING STATIONS ~~FOR COMPRESSION ON CUSTOMERS' PREMISES~~**

**APPLICABILITY:** This rate schedule<sup>1</sup> applies to the transportation of gas as defined in Rule 1, to Core End-Use customer-owned ~~gas vehicle fueling stations on PG&E's Backbone, Local Transmission and/or Distribution Systems. Vehicles shall include all means of transporting people or goods such as but not limited to automobiles, trucks, marine vessels, trains and aircraft. to natural gas service to Core End-Use Customers on PG&E's Transmission and/or Distribution Systems. Service is for uncompressed natural gas for the sole purpose of compressing it for use as a motor vehicle fuel. Compression of natural gas to the pressure required for its use as motor vehicle fuel will be performed by the Customer's equipment at the Customer's designated premises only.~~

Pursuant to D. 15-10-032 and D. 18-03-017, transportation rates include GHG Compliance Cost for non-covered entities. Customers who are directly billed by the California Air Resources Board (ARB), i.e., covered entities, are exempt from paying AB 32 GHG Compliance Costs through PG&E's rates.<sup>2</sup> A "Cap-and-Trade Cost Exemption" credit for these costs will be shown as a line item on exempt customers' bills.<sup>3,4</sup>

**TERRITORY:** Schedule G-NGV1 applies everywhere within PG&E's gas Service Territory. ~~provides natural gas service.~~

**RATES:** Customers on this schedule pay a Customer Charge, a Procurement Charge and a Transportation Charge, per meter, as specified below. Customers that have executed a Request for Reclassification from Noncore Service to Core Service (Form 79-983) will pay the Customer Charge and Transportation Charge shown below. Such Customers will pay the Procurement Charge specified in Schedule G-CPX for any of the first twelve (12) regular monthly billing periods that they are taking core procurement service from PG&E. After the twelfth regular monthly billing period, such Customers will pay the Procurement Charge specified on this schedule.

	<u>Per Day</u>	
Customer Charge:	\$0.44121	
	<u>Per Therm</u>	
Procurement Charge:	\$0.15999	(l)
Transportation Charge:	\$0.55433	
Total:	\$0.71432	(l)
Cap-and-Trade Cost Exemption (per therm):	\$0.07366	

The Cap-and-Trade Cost Exemption is applicable to customers who are identified by the California Air Resources Board (CARB) as being Covered Entities for their Greenhouse Gas (GHG) emissions as part of the Cap-and-Trade program. Applicable Cap-and-Trade Cost Exemptions may be provided from the date CARB identifies a customer as being a Covered Entity, or provided based upon documentation satisfactory to the Utility for the time period for which the customer was a Covered Entity, whichever is earlier.

<sup>1</sup> PG&E's gas tariffs are available online at [www.pge.com](http://www.pge.com).

<sup>2</sup> Covered entities are not exempt from paying costs associated with LUAF Gas and Gas used by Company Facilities.

(Continued)

Advice 4470-G  
Decision D. 97-10-065 and  
D. 98-07-025

Issued by  
**Robert S. Kenney**  
Vice President, Regulatory Affairs

Submitted  
Effective  
Resolution

July 26, 2021  
August 1, 2021



**GAS SCHEDULE G-NGV1**

Sheet 1

CORE ~~NATURAL~~ GAS SERVICE

TO GAS VEHICLE FUELING STATIONS ~~FOR COMPRESSION ON CUSTOMERS' PREMISES~~

- <sup>3</sup> The exemption credit will be equal to the effective non-exempt AB 32 GHG Compliance Cost Rate (\$ per therm) included in Preliminary Statement – Part B, multiplied by the customer's billed volumes (therms) for each billing period.
- <sup>4</sup> PG&E will update its billing system annually to reflect newly exempt or newly excluded customers to conform with lists of Directly Billed Customers provided annually by the ARB.

(Continued)

Advice 4470-G  
Decision D. 97-10-065 and  
D. 98-07-025

Issued by  
**Robert S. Kenney**  
Vice President, Regulatory Affairs

Submitted July 26, 2021  
Effective August 1, 2021  
Resolution



**GAS SCHEDULE G-NGV1**

Sheet 2

**CORE ~~NATURAL~~ GAS SERVICE**

**TO GAS VEHICLE FUELING STATIONS ~~FOR COMPRESSION ON CUSTOMERS' PREMISES~~**

RATES (CON'T):	<u>Public Purpose Program Surcharge:</u>	(L)
	Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.	
	The Customer's total charges are subject to adjustment for the applicable proportionate part of any taxes or governmental imposition which may be assessed on the basis of the gross revenues from such sales.	
	See Preliminary Statement, Part B for the Default Tariff Rate Components.	
	The Procurement Charge on this schedule is equivalent to the rate shown on informational Schedule G-CP—Gas Procurement Service to Core End-Use Customers.	
SERVICE AGREEMENT:	Customers must execute an <u>Agreement For Supply of Natural Gas for Compression as a Motor-Vehicle Fuel</u> (Form No. 79-755) in order to receive service under this rate schedule. <u>Gas shall be of pipeline quality as specified in Rule 21.</u>	
METERING REQUIREMENTS:	Service under this schedule must be metered by a separate gas meter.	
ALTERNATIVE PROCUREMENT OPTIONS:	Customers may procure gas supply from a party other than PG&E by taking service on this schedule in conjunction with Schedule G-CT—Core Gas Aggregation Service. Customers who procure their own gas supply will not pay the Procurement Charge component of this rate schedule and will be subject to the applicable rates specified in Schedule G-CT.	
	Customers taking service on this schedule in conjunction with Schedule G-CT, or in conjunction with noncore service, will be subject to a franchise fee surcharge under Schedule G-SUR for gas volumes purchased from parties other than PG&E and transported by PG&E.	
	Service under this schedule may also be taken in conjunction with procurement service from a party other than PG&E if: (1) the Customer is taking noncore service at the same premises, and (2) the Customer executes a <u>Natural Gas Service Agreement</u> (Form No. 79-756) with PG&E. Service will be provided in increments of one year. If there is a difference between actual deliveries and actual usage, such differences will be subject to the terms and conditions of Schedule G-BAL. Customers who procure their own gas supply will not pay the Procurement Charge component of this schedule.	
	Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.*	
	The Customer may, at its option, receive firm interstate capacity directly assigned by PG&E as provided in Rule 21.1.	
CURTAILMENT OF SERVICE:	Service under this rate schedule may be curtailed. See Rule 14 for details.	(L)

\* The rules referred to in this schedule are part of PG&E's gas tariffs. PG&E's gas tariffs are available online at [www.pge.com](http://www.pge.com). (T)

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 8**

**ATTACHMENT B**

**NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON  
CUSTOMERS' PREMISES (G-NGV4) REDLINE CHANGES**



**GAS SCHEDULE G-NGV4**

Sheet 1

**NONCORE ~~NATURAL~~ GAS SERVICE**

**TO GAS VEHICLE STATIONS ~~FOR COMPRESSION ON CUSTOMERS' PREMISES~~**

**APPLICABILITY:** This rate schedule<sup>1</sup> applies to the transportation of gas as defined in Rule 1, to customer-owned ~~natural~~ gas vehicle fueling stations on PG&E's Backbone, Local Transmission and/or Distribution Systems. Vehicles shall include all means of transporting people or goods such as but not limited to, automobiles, trucks, marine vessels, trains and aircraft. To qualify for service under this schedule, a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential Customer must have maintained an average monthly use, through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. See Rule 12 for details on core and noncore reclassification.

Customers must procure gas supply from a supplier other than PG&E.

Per D.15-10-032 and D.18-03-017, transportation rates include GHG Compliance Cost for non-covered entities. Customers who are directly billed by the Air Resources Board (ARB), i.e., covered entities, are exempt from paying AB 32 GHG Compliance Costs through PG&E's rates.<sup>2</sup> A "Cap-and-Trade Cost Exemption" credit for these costs will be shown as a line item on exempt customers' bills.<sup>3, 4</sup>

**TERRITORY:** Schedule G-NGV4 applies everywhere within PG&E's ~~natural~~ gas Service Territory.

**RATES:** The applicable Customer Access Charges and Distribution Level Transportation Rate specified below is based on the Customer's Average Monthly Usage, as defined in Rule 1. Usage through multiple noncore gas meters on a single premises will be combined to determine Average Monthly Usage.

The following charges apply to service under this schedule:

1. Customer Access Charge:

The applicable Per-Day Customer Access Charge is multiplied by the number of days in the billing period.

Average Monthly Use (Therms)	Per Day	
0 to 5,000	\$0.96099	(R)
5,001 to 10,000	\$2.86225	(R)
10,001 to 50,000	\$5.32734	(R)
50,001 to 200,000	\$6.99123	(R)
200,001 to 1,000,000	\$10.14378	(R)
1,000,001 and above	\$86.04625	(R)

<sup>1</sup> PG&E's gas tariffs are available online at [www.pge.com](http://www.pge.com).

<sup>2</sup> Covered entities are not exempt from paying costs associated with LUAF Gas and Gas used by Company Facilities.

<sup>3</sup> The exemption credit will be equal to the effective non-exempt AB 32 GHG Compliance Cost Rate (\$ per therm) included in Preliminary Statement – Part B, multiplied by the customer's billed volumes (therms) for each billing period.

<sup>4</sup> PG&E will update its billing system annually to reflect newly exempt or newly excluded customers to conform with lists of Directly Billed Customers provided annually by the ARB.

(Continued)



**GAS SCHEDULE G-NGV4**

Sheet 2

NONCORE ~~NATURAL~~ GAS SERVICE

TO GAS VEHICLE STATIONS ~~FOR COMPRESSION ON CUSTOMERS' PREMISES~~

RATES:  
(Cont'd.)

2. Transportation Charge:

A customer will pay one of the following rates for gas delivered in the current billing month.

a. Backbone Level Rate:

The Backbone Level Rate applies to Backbone Level End-Use Customers as defined in Rule 1.

Backbone Level Rate (per therm) ..... \$0.09604 (I)

b. Transmission-Level Rate:

The Transmission-Level Rate applies to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi) that do not qualify for the Backbone Level Rate.

Transmission-Level Rate (per therm)..... \$0.20500 (I)

c. Distribution-Level Rate:

The Distribution-Level Rate applies to Customers served from PG&E gas facilities that have a maximum operating pressure of sixty pounds per square inch (60 psi) or less. The Tier 5 rate is equal to the Transmission-Level Rate specified above.

Average Monthly Use (Therms)	Summer (Per Therm)	Winter (Per Therm)
Tier 1: 0 to 20,833	\$0.52909 (R)	\$0.63995 (R)
Tier 2: 20,834 to 49,999	\$0.41408 (R)	\$0.48469 (R)
Tier 3: 50,000 to 166,666	\$0.39075 (R)	\$0.45320 (R)
Tier 4: 166,667 to 249,999	\$0.37279 (R)	\$0.42894 (R)
Tier 5: 250,000 and above*	\$0.20500 (I)	\$0.20500 (I)

3. Cap-and-Trade Cost Exemption: \$0.07366 per therm

The Cap-and-Trade Cost Exemption is applicable to customers who are identified by the California Air Resources Board (CARB) as being Covered Entities for their Greenhouse Gas (GHG) emissions as part of the Cap-and-Trade program. Applicable Cap-and-Trade Cost Exemptions may be provided from the date CARB identifies a customer as being a Covered Entity, or provided based upon documentation satisfactory to the Utility for the time period for which the customer was a Covered Entity, whichever is earlier.

See Preliminary Statement Part B for Default Tariff Rate Components.

\* Tier 5 Summer and Winter rates are the same.

(Continued)





**GAS SCHEDULE G-NGV4**

Sheet 3

NONCORE ~~NATURAL~~ GAS SERVICE

TO GAS VEHICLE STATIONS ~~FOR COMPRESSION ON CUSTOMERS' PREMISES~~

SURCHARGES FEES AND TAXES:	Customer may pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details.) The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.	(L)
	<u>Public Purpose Program Surcharge:</u> Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.	(L)
SEASONS:	Summer season is from April 1 through October 31. Winter season is from November 1 through March 31.	
SERVICE AGREEMENT:	A <u>Natural Gas Service Agreement</u> (NGSA) (Form No. 79-756) is required for service under this schedule. The initial term of the NGSA will be for one (1) year. <u>Gas must be of pipeline quality as specified on Rule 21.</u>	
SHRINKAGE:	Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.	
NOMINATIONS:	Nominations are required for gas transported under this schedule. See Rule 21 for details.	
CURTAILMENT OF SERVICE:	Service under this schedule may be curtailed. See Rule 14 for details.	
BACKBONE TRANSMISSION TRANS- PORTATION SERVICE:	Transportation service on PG&E's Backbone Transmission System may be taken in conjunction with this schedule under Schedules G-AFT, G-SFT, G-AA, G-NFT, or G-NAA. A separate <u>Gas Transmission Service Agreement</u> (GTSA) (Form No. 79-866) must be executed for such service. The GTSA can be held by the Customer or by another party, such as the Customer's gas supplier.	

**PACIFIC GAS AND ELECTRIC COMPANY**  
**APPENDIX A**  
**STATEMENTS OF QUALIFICATIONS**

**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF PATRICIA C. GIDEON**

Q 1 Please state your name and business address.

A 1 My name is Patricia C. Gideon, 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 Regulatory Analyst in the Gas Rates Section of the Rates Department within the Regulatory and External Affairs organization. My functional responsibilities including preparing gas transmission and storage cost allocation and rate design analysis, testimony, and other analytical and regulatory support, as necessary, for regulatory proceedings.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science degree in Accounting and a Master's degree in Business Administration, both from Santa Clara University in Santa Clara, California. From 1989 to 2003, I worked for MCI/WorldCom in various positions in the Business Development, Account Management, and Regulatory/Tariffing departments. I joined PG&E in 2004 as a Senior Regulatory Analyst in the Generation Procurement Policy and Planning group within the Energy Revenue Requirements Department. In 2006, I moved to the Capital Accounting Department, where I was responsible for asset sales, forecasting of depreciation, and Allowance for Funds Used During Construction expenses and rate base reporting. I joined the Rates and Regulatory Analytics in the Electric Rates section in 2008, and later moved to the department's Gas Rates section in 2017. I have previously sponsored testimony on electric revenue allocation and rate design before the California Public Utilities Commission, in PG&E's 2011, 2014 and 2017 Phase II General Rate Cases. I sponsored testimony on cost allocation and rate design in PG&E's 2019 Gas Transmission and Storage Rate Case. I have also sponsored testimony before the Federal Energy Regulatory Commission (FERC) on revenue allocation and retail rate design for electric transmission-related rate components subject to FERC jurisdiction.

1 Q 4 What is the purpose of your testimony?  
2 A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas  
3 Transmission and Storage Cost Allocation and Rate Design:  
4 • Chapter 6, "Cost Allocation and Rate Design"; and  
5 • Chapter 6, Attachment A, "Present and Proposed Rates."  
6 Q 5 Does this conclude your statement of qualifications?  
7 A 5 Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF ANDREW KLINGLER**

Q 1 Please state your name and business address.

A 1 My name is Andrew Klingler, 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 Senior Manager in our Rates organization with responsibility for load forecasting and certain aspects of rates forecasting and modeling.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Arts degree in Physics from the University of California, Berkeley, and a Doctor of Philosophy degree in Mathematics from the University of California, Santa Cruz. I have worked in various quantitative, programming, analytical, and managerial roles in the energy industry for about 20 years; I have been in the utility industry for most of that time. I left Dominion Virginia Power in 2007 to join PG&E, where I have worked as a Front Office Quantitative Analyst and a Manager of Risk Analytics for about six years. I am currently a Manager of Rates and Load Forecasting and responsible for PG&E's approved sales forecasts in gas and power as well as related work in rates and forecasting. I have sponsored forecast-related testimony in the most recent General Rate Case Phase II filing as well as in the annual Energy Resource Recovery Account forecast filings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas Transmission and Storage Cost Allocation and Rate Design:

- Chapter 2B, "Non-Generation Demand and Throughput Forecast."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF PETER E. KOSZALKA**

Q 1 Please state your name and business address.

A 1 My name is Peter E. Koszalka, 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 the director of PG&E's Core Gas Supply department. I am responsible for providing natural gas supply to PG&E's bundled core gas customers. I am also responsible for contracting intra-state pipeline capacity, storage capacity and interstate pipeline capacity for all PG&E core gas customers.

Q 3 Please summarize your educational and professional background.

A 3 I earned my Bachelor of Science degree in chemical engineering from the University of California, Berkeley. I began my career at PG&E in 1983 where I worked in a variety of positions in field operations including energy management representative, account representative, and industrial power engineer. In 1993 moved to the Gas Supply Business Unit where I served as manager of market relations and manager of pricing and market research. In 1995, I earned my Master of Business Administration degree from California State University, Hayward. From 1998 to 2002, I was employed by various companies related to the energy industry, working as a product manager for direct access meter and data services and as director of operations for an internet-based home services company. I returned to PG&E in 2003 to lead PG&E's electric fuels management function, providing natural gas supply to PG&E's company-owned and contracted electric generating facilities. I began my current assignment in Core Gas Supply in early 2018. I have sponsored testimony before the California Public Utilities Commission in numerous EERRA forecast and EERRA compliance proceedings.

1 Q 4 What is the purpose of your testimony?  
2 A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas  
3 Transmission and Storage Cost Allocation and Rate Design:  
4 • Chapter 7, "Core Gas Supply"; and  
5 • Chapter 7, Attachment A, "Confidential Storage Information."  
6 Q 5 Does this conclude your statement of qualifications?  
7 A 5 Yes, it does.



**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF CARL ORR**

Q 1 Please state your name and business address.

A 1 My name is Carl Orr, and my business address is Pacific Gas and Electric Company, 6121 Bollinger Canyon Road, San Ramon, California.

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

A 2 I am a Principal Program Manager in Wholesale Marketing and Business Development, within PG&E's Gas Engineering organization. I am responsible for leading or participating in various operating, regulatory, and asset sale projects.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Science degree in Physics and Geology from the University of California at Davis. I have also completed various extension courses in Economics, Statistics, and Accounting at the University of California at Berkeley. I have been employed by PG&E since 1985. I have worked on or led every Gas Transmission and Storage (GT&S) Rate Case and Gas Accord settlement since the first Gas Accord, implemented in 1998. I was a witness in the last four GT&S Rate Cases on topics similar to my testimony in this case. I have also testified on other gas and electric matters before the California Public Utilities Commission and before the Federal Energy Regulatory Commission.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas Transmission and Storage Cost Allocation and Rate Design:

- Chapter 3, "Backbone Rate Inputs"; and
- Chapter 3, Attachment A, "Backbone Load Factor – Illustration of Adjustment for Disproportionate Usage of Backbone Paths."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF TODD PETERSON**

Q 1 Please state your name and business address.

A 1 My name is Todd Peterson, 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 Strategic Analyst, Principal in the Portfolio & Resource Forecast section of Analytics, Innovation & Strategy. Since joining PG&E in 2015, I have produced the Electric Generation gas throughput forecast for numerous proceedings before the California Public Utilities Commission (CPUC). Prior to my employment with PG&E, I have experience forecasting natural gas demand and supply at Chevron U.S.A., the Sacramento Municipal Utility District, and the California Energy Commission.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Economics from California State University, Sacramento in 1993 and a Master of Arts degree in Economics from California State University, Sacramento in 2002. I have led a variety of forecasting, policy analysis and market strategy functions at PG&E since 2015. I have sponsored testimony in PG&E's 2018 Gas Cost Allocation Proceeding before the CPUC.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas Transmission and Storage Cost Allocation and Rate Design:

- Chapter 2A, "Electric Generation Gas Demand and Throughput"; and
- Chapter 5, "Electric Generation Local Transmission Rate Design Analytics."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF STEPHEN E. SHERIDAN**

Q 1 Please state your name and business address.

A 1 My name is Stephen E. Sheridan, and my business address is Pacific Gas and Electric Company, 2320 West Yosemite Ave, Manteca, California.

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

A 2 I have served as the Manager of Liquefied Natural Gas (LNG)/Compressed Natural Gas (CNG) Engineering within PG&E's Gas Operations organization since August 2017. As part of my responsibilities I am the asset family owner for PG&E's 32 compressed natural gas fueling stations that are located throughout our service territory. Additionally, I support PG&E's internal fueling needs and provide fueling support for various 3rd party fleets. I am the asset owner for our portable LNG and CNG natural gas fleet which includes the operation and maintenance of over 200 assets that provide portable gas support to maintain customer natural gas service during pipeline operations that may otherwise cause a loss service. My current role as Manager of LNG/CNG Engineering provides the opportunity for me to support the maintenance and operation of our CNG fueling stations and portable natural gas fleet as we develop the overall strategy to reduce our asset risk while supporting our current and future customer's needs.

Q 3 Please summarize your educational and professional background.

A 3 I am a California registered professional engineer in Controls Systems Engineering receiving licensure in December of 2014. I have taken college courses from Delta College in Stockton, California as well as Chabot Community College in Hayward, California in pursuit of a degree in Business Management. I have over 25 years of experience in the natural gas vehicle and industrial gas industry with a focus in both LNG and CNG station design, construction, maintenance, and operations along with experience in providing portable gas support using LNG and/or CNG for both planned and unplanned gas outages. I joined PG&E in 2006 spending my entire career within Gas Operations with increasing responsibilities beginning as a

1 Transmission Specialist, Senior Gas Engineer, Portable Gas Engineering  
2 Supervisor eventually progressing to my current position. My focus has  
3 been on supporting both liquified and compressed natural gas uses for  
4 alternative vehicle fueling and natural gas pipeline temporary service  
5 applications. Prior to joining PG&E, I have held various roles within the  
6 industrial gas industry with a focus on the installation, maintenance and  
7 operations of natural gas vehicle fueling stations utilizing LNG and/or CNG.  
8 Examples of the transportation fleets I have supported include the University  
9 of California, Santa Cruz, Los Angeles Metro Transit, and Phoenix Area  
10 Transit. I have also supported the development and execution of LNG  
11 and/or CNG as a portable gas supply to augment utility pipeline demand for  
12 planned and unplanned pipeline service outage work to prevent loss of  
13 customers. These efforts have been with major gas investor owned utilities  
14 such as PG&E, Puget Sound Energy, and Southwest Gas Corporation. My  
15 experience also includes wintertime pipeline peak shaving activities to  
16 maintain minimum system pressures during a cold winter event in the  
17 utilities service territory.

18 Q 4 What is the purpose of your testimony?

19 A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas  
20 Transmission and Storage Cost Allocation and Rate Design:

- 21 • Chapter 8, "G-NGV1 and G-NGV4 Gas Tariff Modifications";
- 22 • Chapter 8, Attachment A, "Core Natural Gas Service for Compression  
23 on Customers' Premises (G-NGV1) Redline Changes"; and
- 24 • Chapter 8, Attachment B, "Noncore Natural Gas Service for  
25 Compression on Customers' Premises (G-NGV4) Redline Changes."

26 Q 5 Does this conclude your statement of qualifications?

27 A 5 Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF KATIA SOKOLOFF**

Q 1 Please state your name and business address.

A 1 My name is Katia Sokoloff, 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 currently Manager in the Gas Rates section of the Rates and Regulatory Analytics Department.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Accounting, from San Francisco State University, in 1992. During my initial years at PG&E, I worked in various departments including, Internal Auditing and the Controller's organization. In 1996, I joined the Rates Department as a Regulatory Analyst. In 2004, I was promoted to a Senior Regulatory Analyst position. In 2014, I was promoted to Expert Regulatory Analyst and in 2016 to Manager. During the years I have spent in Gas Rates, I have assumed increasing responsibilities in the areas of: gas revenue estimations, Public Purpose Program surcharge issues, monthly gas procurement pricing, annual gas true ups rate calculations, cost recovery and allowance return of Greenhouse Gas, and implementation of other rate changes. I served as a Witness Assistant in the Joint Utility State Mandated Social Program Cost Allocation Filing (Application (A.) 07-12-006) and the 2017 General Rate Case Filing (A.15-09-011). I served as the expert witness in the 2013 Greenhouse Gas Cost Recovery Application (A.13-09-015), the 2018 Gas Cost Allocation Proceeding (A.17-09-006), and the Gas Transmission and Storage Capital Expenditures 2011-2014 Audit (A.20-07-020).

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas Transmission and Storage Cost Allocation and Rate Design:

- Chapter 1, "Introduction and Scope"; and

- 1           • Chapter 1, Attachment A, "Rate Case Plan 2 Workshop Presentation,  
2           October 7, 2020."
- 3   Q 5   Does this conclude your statement of qualifications?
- 4   A 5   Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**STATEMENT OF QUALIFICATIONS OF ANNETTE TAYLOR**

Q 1 Please state your name and business address.

A 1 My name is Annette Taylor, 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 an Expert Data Scientist in the Cost of Service Department. My responsibilities include performing cost allocation analysis and preparing testimony for a variety of rate proceedings overseen by the California Public Utilities Commission and other regulatory agencies.

Q 3 Please summarize your educational and professional background.

A 3 I received a Master of Business Administration degree from the Keller Graduate School of Management and Bachelor of Science degree in Physics from the University of California, Davis. I served as Senior Manager of Risk Analytics and Modeling at the Charles Schwab Corporation from 2007 to 2016. In 2016, I joined PG&E as an expert data scientist consultant in the Cost of Service department under Regulatory Affairs. During my time as a consultant I worked on the marginal cost models and the 2018 Gas Cost Allocation Proceeding embedded costs study. I joined PG&E permanently in 2018 and continued to work as an expert data scientist in the Cost of Service Department. I recently was a witness in PG&E's 2020 General Rate Case Phase II and sponsored four topics, the Revenue Cycle Services Cost and the Real Economic Carrying Charge Factor under cost of service exhibit, in addition to, the Master Meter Discount and the Schedule E-CREDIT under the rate design exhibit.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following prepared testimony in PG&E's 2023 Gas Transmission and Storage Cost Allocation and Rate Design:

- Chapter 4, "Local Transmission Allocation Study";
- Chapter 4, Attachment A1, "Southern California Gas Coalition Presentation";
- Chapter 4, Attachment A2, "Calpine Presentation";



1 • Chapter 4, Attachment A3, "Independent Shippers Presentation";  
2 • Chapter 4, Attachment A4, "The Utility Reform Network Presentation";  
3 • Chapter 4, Attachment B, "Cost Allocation Principles for Pipeline  
4 Capacity Usage";  
5 • Chapter 4, Attachment C, "Cost Allocation and Rate Design for  
6 Unbundled Gas Services";  
7 • Chapter 4, Attachment D, "Shapley Calculation"; and  
8 • Chapter 4, Attachment E, "Shapley Value Papers."  
9 Q 5 Does this conclude your statement of qualifications?  
10 A 5 Yes, it does.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**APPENDIX B**  
**ACRONYMS AND ABBREVIATIONS**

**PACIFIC GAS AND ELECTRIC COMPANY  
APPENDIX B  
GLOSSARY OF ACRONYMS AND ABBREVIATIONS**

<b>Acronym</b>	<b>Definition</b>
<b>#</b>	
\$/Dth	dollars per dekatherm
\$Mil	million dollars
<b>A</b>	
A.	Application
AAEE	Additional Achievable Energy Efficiency
ABAG	Association of Bay Area Governments
AL	Advice Letter
APD	Abnormal Peak Day
<b>B</b>	
BB	backbone
BCAP	Biennial Cost Allocation Proceeding
BTU	British thermal unit
<b>C</b>	
CAC	Customer Access Charge
CAISO	California Independent System Operator
CARB	California Air Resources Board
CARD	Cost Allocation and Rate Design
CARE	California Alternate Rates for Energy
CCC	Customer Class Charge
CEC	California Energy Commission
CFCA	Core Fixed Cost Account
CFSA	Core Firm Storage Account
CGR	California Gas Report
CGS	Core Gas Supply
CI	Carbon Intensive
CNG	Compressed Natural Gas
COL	Conclusion of Law
CPUC	California Public Utilities Commission
CTA	Core Transport Agent
CWD	Cold Winter Day
CYPM	Cold Year Peak Month
<b>D</b>	
D.	Decision
DCPP	Diablo Canyon Nuclear Power Plant
DGE	Diesel Gallon Equivalent
Dth	dekatherm
<b>E</b>	
ECPT	equal cents per therm
EG	Electric Generation
EG BB	Electric Generation Backbone
EG-D/T	Electric Generation Distribution/Transmission
EGLT	Electric Generation Local Transmission
EIA	Energy Information Agency
EIRP	Electric Integrated Resource Planning
EPA	Environmental Protection Agency
ESP	Energy Service Provider
<b>F</b>	
FEW	Fixed Equivalent Withdrawal

**PACIFIC GAS AND ELECTRIC COMPANY  
APPENDIX B  
GLOSSARY OF ACRONYMS AND ABBREVIATIONS  
(CONTINUED)**

<b>G</b>	
g/bhp-hr	grams per brake horsepower hour
G-AA	As Available Transportation On-System
G-AAOFF	As-Available Transportation Off-System
G-AFT	Annual Firm Transportation On-System
G-AFTOFF	Annual Firm Transportation Off-System
GCAP	Gas Cost Allocation Proceeding
G-CT	Core Gas Aggregation Service
G-EG	Gas Transportation Service to Electric Generation
G-EG LT	Gas Electric Generation Local Transmission
GHG	greenhouse gas
G-LEND	Market Center Lending Services
G-NAA	Negotiated As-Available Transportation On-system
G-NAAOFF	Negotiated As-Available Transportation Off-System
G-NFT	Negotiated Firm Transportation On-System
G-NFTOFF	Negotiated Firm Transportation Off-System
G-NGV1	Core Natural Gas Service for Compression on Customers' Premises
G-NGV4	Noncore Natural Gas Service for Compression on Customers' Premises
G-NT	Gas Transportation Service to Noncore End-Use Customers
G-PARK	Market Center Parking Services
G-PPPS	Gas Public Purpose Program Surcharge
GRC	General Rate Case
G-SFT	Seasonal Firm Transportation On-System Only
GSO	Gas System Operations
G-SUR	Customer-Procured Gas Franchise Fee Surcharge
GT	gas turbine
GT&S	Gas Transmission and Storage
G-WSL	Gas Transportation Service to Wholesale/Resale Customers
G-XF	Pipeline Expansion Firm Intrastate Transportation Service
<b>H</b>	
HDD	heating degree days
<b>I</b>	
I.	Investigation
IEPR	Integrated Energy and Policy Report
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning
IS	Independent Shippers
ISP	Independent Storage Provider
<b>J</b>	
JS	Joint Stipulation
<b>K</b>	
kW	kilowatt
<b>L</b>	
LCFS	Low Carbon Fuel Standard
LDC	Local Distribution Company
LEV	Low Emission Vehicle
LNG	Liquefied Natural Gas
LSE	Load-Serving Entity
LT	Local Transmission
<b>M</b>	
MDM	Marginal Demand Measure

**PACIFIC GAS AND ELECTRIC COMPANY  
APPENDIX B  
GLOSSARY OF ACRONYMS AND ABBREVIATIONS  
(CONTINUED)**

MDQ	Maximum Daily Quantity
MDS	Market Data Systems
MDth/d	thousands of dekatherms per day
MDV	modified fixed variable
MM	million
MMcf/d	millions of cubic feet per day
MMT	million metric tons
MW	megawatt
<b>N</b>	
NC	noncore
NGSS	Natural Gas Storage Strategy
NGV	Natural Gas Vehicle
NMHC	non-methane hydro-carbons
NOx	nitrous oxides
NQC	net qualifying capacity
<b>O</b>	
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
<b>P</b>	
P&G	Potential and Goals
PCAF	Peak Cost Allocation Factor
PG&E	Pacific Gas and Electric Company
PM	particulate matter
PPP	Public Purpose Program
PSI	pounds per square inch
PSP	Preferred System Plan
<b>Q</b>	
QF	Qualifying Facilities
<b>R</b>	
RCP	Rate Case Plan
RFO	Request for Offer
RNG	Renewable Natural Gas
RR	revenue requirements
RSP	Reference System Plan
<b>S</b>	
SCGC	Southern California Generation Coalition
SFV	straight fixed variable
SMUD	Sacramento Municipal Utility District
Southern California Gas Company	SoCalGas
SPURR	School Project for Utility Rate Reduction
<b>T</b>	
TAC	Transmission Access Charge
TURN	The Utility Reform Network
<b>U</b>	
U.S.	United States
<b>V</b>	
<b>W</b>	
WECC	Western Electricity Coordinating Council
WP	workpaper
<b>X</b>	

**PACIFIC GAS AND ELECTRIC COMPANY  
APPENDIX B  
GLOSSARY OF ACRONYMS AND ABBREVIATIONS  
(CONTINUED)**

<b>Y</b>	
<b>Z</b>	
ZEL	Zero Emission Locomotive