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Application:	A.22-09-015
Witness:	Frank Seres
Chapter:	17

PREPARED REBUTTAL TESTIMONY OF

FRANK SERES

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

AND SAN DIEGO GAS & ELECTRIC COMPANY

(EMBEDDED COSTS)

July 28, 2023

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CHAPTER 17

PREPARED REBUTTAL TESTIMONY OF FRANK SERES

(EMBEDDED COSTS)

I. INTRODUCTION

In my prepared rebuttal testimony, I address the arguments, positions, and recommendations put forth in the intervenor testimonies provided by The Utility Reform Network (TURN), Southern California Generation Coalition (SCGC), and Long Beach Utility (Long Beach)[1]. These intervenors specifically focused on the cost allocation proposal outlined in Chapter 8 (Seres). While the intervenors' testimonies cover a wide range of technical details, their primary objective is to advocate for a smaller share of the cost allocation on behalf of their respective constituents. To support their stance, each intervenor appears to endeavor to demonstrate that the Applicants' cost allocation proposal is inconsistent with certain data, operational realities, or what they perceive as superior methodologies.

For instance, TURN criticizes the Applicants' proposal and offers corresponding recommendations that, if adopted, would result in a smaller portion of the costs being allocated to core customers compared to what the Applicants have proposed. On the other hand, SCGC and Long Beach oppose the cost escalation adjustment to storage and transmission embedded costs. Their viewpoint is that if this adjustment were to be adopted, it would lead to a higher allocation of costs to noncore customers than what the Applicants suggest.

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[1] Given the volume of the various arguments, positions, and proposals raised by intervenors, Applicants have prioritized which issues to address in rebuttal testimony. Silence on any issue should not be construed as agreement with, or non-opposition to, that issue, as Applicants reserve the right to address additional issues not specifically mentioned in this rebuttal testimony at a later opportunity, such as evidentiary hearings and briefs.

II. REBUTTAL TO INTERVENORS ON THE FOLLOWING ISSUES:

A. Embedded Cost Escalation Proposal for Transmission and Storage

1. Long Beach

Long Beach stated the following in its testimony:

> "I am expressing concern about the proposal's deviation from Commission policy, as outlined in D.20-02-045. According to this policy, the embedded cost study should be founded on actual recorded costs, avoiding the use of escalated costs."[2]

It is important to note that the Applicants' embedded cost study is grounded in actual recorded costs and does not rely on escalated costs, as implied by Long Beach.

Additionally, it should be clarified that the Applicants do not assume that all costs increase proportionally.[3] The escalation adjusted factors for O&M and Capital utilized in this study are derived from IHS/Markit Global Insight, aligning with Scott Wilder's 2024 General Rate Case (GRC) Cost Escalation testimony (Ex. SCG-36 at SRW-5) and the escalation rates included in the Post-Test Year (PTY) testimony. These inflation factors contribute to the accuracy and consistency of Applicants' approach.

2. SCGC

SCGC states in testimony that "The Commission Should Reject the Applicants' Proposal to Escalate 2021 Embedded Costs Using Percentage Escalation Factors that Would Introduce Error into the Embedded Cost Study (Applicants Chapter 8, Seres)." [4]

Applicants acknowledge Ms. Yap's concerns and would like to clarify our position on this matter.

First and foremost, it is essential to emphasize that Applicants' intention with the proposal is not to introduce errors, but rather to provide a comprehensive approach in addressing external inflationary effects on O&M and Capital costs related to transmission and storage. The proposed escalation factors are sourced from IHS/Markit Global Insight, and it is important to

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2 Long Beach Testimony Ch. 4 (Neal) at 4–5:8-10.

3 *Id*. at 4–6:1-2.

4 Ex. SCGC-01 (Yap) at 25:1-7.

note that these factors have been selected to maintain consistency with Scott Wilder's 2024 GRC Cost Escalation testimony[5] and the escalation rates utilized by the PTY testimony[6].

To ensure an accurate reflection of external inflation and align O&M and Capital costs with current market conditions, Applicants employ escalation factors. Neglecting to adjust for inflation during PTY years would mean utilizing 2021 nominal costs without accounting for changes in purchasing power over time. We are dedicated to upholding the study's validity and precision by incorporating dependable escalation factors.

3. TURN

The Applicants have proposed an inflation adjustment to the embedded storage and transmission costs from 2025-2027,[7] while Mr. Florio suggests basing the post-test year increase on 2024 authorized transmission and storage requirements.[8]

Applicants submit that this is not possible due to the unavailability of authorized revenue requirement data by function from 2024 GRC decision, and the problem of double counting since TURN recommends using authorized 2024 GRC revenue requirements which include Pipeline Safety Enhancement (PSEP) costs. It is important to know that the embedded cost study excludes PSEP. PSEP costs are either allocated directly to customer classes through balancing account amortization or are removed from the GRC base margin and reallocated functionally based on the GRC PSEP costs. When they are added to the embedded backbone transmission cost functionally, the resulting total is then utilized as the numerator in the calculation of the Backbone Transportation Service (BTS) rate.[9] Adopting TURN’s method results in double counting of PSEP costs in the BTS rate for which customers pay to transport natural gas from receipt to delivery points in Applicants’ transmission system. This double counting of PSEP costs would also be replicated in Applicants’ local transmission cost and storage cost.

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5 A. 22-05-015, Ex. SCG-36 Direct Testimony of Scott R. Wilder (Cost Escalation) at SRW-5.

6 A. 22-05-015, Ex. SCG-40-WP Khai Nguyen Post Test Year Ratemaking.

7 Applicants’ Ch.8a (Seres) at 19, n.61 and n.62.

8 Ex. TURN-01 (Florio) at 32:16-18 states “The SEUs should, as I have discussed above, follow PG&Es lead and set transmission and storage rates for the attrition years based on the actual revenue requirements authorized in the GRF for those years.”

9 *See* SoCalGas Schedule No. G-BTS – Backbone Transportation Service, *available at:* https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/G-BTS.pdf.

B. Reallocation of Backbone to Local Transmission

1. SCGC

SCGC's testimony claims that "The Applicants Make an Error in Calculating Their Proposed Reallocation of Backbone Transmission to Local Transmission (Applicants Chapter 8, Seres)" [10]

In this regard, Applicants would note that SCGC does not challenge the reallocation of the backbone to local transmission. However, SCGC suggests an alternative methodology, deviating from the methodology adopted by the Applicants in A.08-02-001.[11] Furthermore, in the context Firm Access Rights (FAR) Update D.11-04-032 it should be noted that the comment on page 22 does not question the methodology, but rather the weather data utilized.[12]

> "*It is not possible to verify SDG&E's/SoCalGas' assumption that customers served directly from the backbone comprise the same percentage of system demand under both average and cold year peak day demand conditions. However, that this assumption cannot be verified does not justify allocating zero transmission system costs to local transmission. To do so will continue to include local transmission costs that should not be included in the backbone transmission revenue requirement."*[13]

The methodology employed by the Applicants was updated to incorporate cold year annual average throughput for years 2024-2027. This update was necessary because we now have available data to confirm the assumption stated in FAR Update decision. By incorporating this updated information, we have enhanced the reliability and accuracy of our methodology.

SCGC also raises a question regarding the application of the percentage of EG volumes served from the backbone.[14] Specifically, Ms. Yap asks why it is applied as a percentage of total system throughput rather than total EG throughput.[15] In response, the Applicants explain that the percentage applied to the total system throughput accurately represents the demand supported

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[10] Ex. SCGC-01 (Yap) at 21:6-7.

[11] A.08-02-001 Phase 2, Prepared Direct Testimony of Rodger Schwecke at 31-33.

[12] D.11-04-032 at 22.

[13] *Id.*

[14] Ex. SCGC-01 (Yap) at 22:10-11.

[15] *Id.*

directly from the backbone. This methodology is also unchanged from when it was introduced by SoCalGas in A.08-02-001.[16]

SCGC has proposed the revision of calculations to include the 2022 CGR, page 23, lines 5 through 6 "The calculation should be updated to the 2022 CGR which was available prior to the Applicants filing their cost allocation testimony...." Following this recommendation, the Applicants have subsequently incorporated the 2022 CGR into the calculation, yielding the following preliminary results[17]:

Table 21- Updated to 2022CGR				
% of Backbone Allocated to Local Transmission Function				
(A)	(B)	C = A x B	(D)	(E)= C /D
Cold Year Annual Average Demand (MMcfd) 2024 -2027	Demand Served Directly from Backbone (%)[18]	Demand Served Directly from Backbone (MMcfd)	Envoy Total Backbone Receipt Capacity (MMcfd)	% of Backbone Allocated to Local Transmission Function
2,348	22%	522	3,435	15%

% of Backbone Allocated to Local Transmission Function Table 21 A				
	(A)	(B)	C = (A) + (B)	Remaining BB costs minus 15% out of Combined BB costs.
	SoCalGas	SDG&E	Combined Backbone Costs	15%
	($000)	($000)	($000)	
Backbone Transmission Costs	357,483	67,819	425,302	360,624

Illustrative Firm BTS Rate				
PSEP costs	Total BB costs	Throughput Assumption	Annual Throughput Assumption	Illustrative BTS Rate
		MDth/d	MDth	$/Dth
$99,322	459,946	2,532	924,292	0.4976

16 A.08-02-001 Phase 2, Prepared Direct Testimony of Rodger Schwecke at 31.

17 Applicants' Ch. 17 Rebuttal Frank Seres 2022 CGR update to BB to LT, which is attached hereto as Attachment A.

18 This value remains unchanged because the Applicants' testimony for the specific percentage relied on the 2022 CGR, not 2020 CGR.

Applicants would like to note that the 2022 CGR was available only two months before the official filing of the CAP and acknowledge the potential challenges and implications associated with updating such a study within a two-month timeframe. Given the intricacies involved, it is advised against undertaking such an update due to its potential impact on various other chapters.

2. TURN

Addressing the re-allocation of Backbone to Local Transmission Section VI. B, pg.42 Mr. Florio appears to misinterpret the relocation study by pointing out Applicants' eight transmission lines that are already separated into Backbone and Local Transmission and allocated accordingly.

However, it is crucial to recognize that there is a certain percentage of backbone transmission assets that are performing the local transmission function, and it is right for Applicants to allocate a percentage of the costs of those assets to the local transmission plant. And while it is true that all customers are ultimately responsible for the full backbone and local transmission costs, it is not true that all gas supplies are brought into the system by end-use customers. Shippers may transport supplies with backbone-only costs to the SoCalGas City Gate for use by end-use customers that are unable or unwilling to subscribe for backbone transmission capacity. Therefore, the backbone transmission costs need to reflect no more than the functional purpose those assets provide.

Additionally, Mr. Florio's argument against the utilization of a 1-in-10 year cold day in the relocation study pg. 45-46 is misguided. Indeed, a review of Applicants' workpaper demonstrates that Applicants did not end up using a 1-in-10-year cold day approach. [19]Instead, the Applicants based their analysis on the new data encompassing the daily Electric Generation (EG) cold year demand, commonly referred to as the cold year annual average throughput. This data serves as substantial evidence supporting the Applicants' position and invalidates Mr. Florio's critique.

[19] Applicants' Ch.8a Workpapers at 17 (Table 21). See averages used from Daily EG Cold Year Demand Forecast Data.

3. Embedded Cost Term

Mr. Florio presents a conceptual framework and understanding derived from his experience. Nonetheless, the Applicants assert that a significant disparity exists between the theoretical propositions advanced by Mr. Florio and the pragmatic realities pertaining to cost allocation. This disparity encompasses the inherent variation in cost allocation timing, as well as the availability and reliability of relevant data and methodologies.

In Section III, B., beginning on page 6, Mr. Florio introduces an anecdotal interpretation of the meaning of embedded cost.[20] The Applicants, however, employ the term "embedded" cost in a different manner. It is crucial to emphasize that the Applicants have been utilizing the concept of embedded cost since 1986, as stated in D. 86-12-009. Mr. Florio's reluctance to acknowledge this fact contributes to the prevailing confusion regarding the divergent usage of embedded cost term and method between the Applicants and his own definition.

Here, it bears emphasizing that this clarification is provided given that the existing Cost Allocation Proceeding (CAP) framework has its origins dating back to the late 1980s. During this time, the Commission adopted a "hybrid" form of embedded cost, which impartially distributes costs across all market segments.

Thus, note that embedded cost of service for Applicants pertains to historical or existing costs associated with the provision of utility services, encompassing costs that have already been incurred by the utility company. *The Applicants have relied on historical costs as the foundation for calculating embedded cost,* a practice that has been recognized as a reasonable approach for allocating costs between market segments since the issuance of D.86-12-009.[21] "Temporary use of historical embedded costs is reasonable basis for cost allocation between market segments."

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20 "It is called "embedded" cost because its starting point is the set of costs embedded in the current or proposed revenue requirement, including return, depreciation and taxes on the past undepreciated investments reflected in the utility's rate base, as well as currently authorized (or proposed) Operations and Maintenance (O&M) and Administrative and General (A&G) expenses. These costs are functionalized and allocated, such that the final result is an allocation of costs to customer classes that *matches the revenue requirement* that was the starting point of the exercise." Ex. TURN-01 (Florio) at 6-10.

21 D.86-12-009 at 75 (FOF 2).

4. Latest Embedded Cost Data at the Time of Filling.

Applicants based their transmission and storage costs on the most recent data available at the time of their application, which was the 2021 FERC Form 2 & Form 1 data. This Application was filed on September 30, 2022. However, it should be noted that the 2022 FERC data was not released until April 2023, which means the Applicants could not utilize this data. Instead, Applicants used 2021 embedded cost, actual historical data for transmission and storage costs.

Although Mr. Florio expressed concerns about the utilization of older data, calling it "stale" on pages 21 and 33, it is essential to highlight that the Applicants diligently incorporated the most current information available throughout the Application process. Currently, the CAP process often necessitates the use of data that is approximately 2.3 years old or older, given the CAP filing date of September 30, 2022, with base year 2021 data and the projected decision date to the CAP is in January 2024.

5. TURN's Proposed "Fairer" Approach for Embedded Cost Is Unsupported

Mr. Florio's conceptual framework proposes a "fairer" approach on pages 14-16, but the Applicants point out two main difficulties. Firstly, Applicants lack a 2024 GRC decision to utilize an approved revenue requirement during the 2024 Cost Allocation Proceedings. Secondly, the Results of Operations (RO) model does not allow for the separation of transmission and storage revenue requirements at the required level of granularity, i.e., converting GRC filing data based on specific "cost centers" into FERC accounts that form the basis for embedded cost analysis.

6. Depreciation Expense and GRC Witness

In section V.C., pages 19-21, Mr. Florio makes reference to GRC witness Dane A. Watson - Depreciation (Ex. SCG-32-2R at DAW-1), which appears to present conflicting messages. Notably, in the GRC Rebuttal depreciation testimony of Dane A. Watson, TURN expresses significant criticism, particularly pertaining to the process, principles, and mathematical aspects of the depreciation forecast. These concerns are specifically highlighted in SCG-232 Rebuttal Testimony of Dane A Watson (Depreciation), page DAW-7. Furthermore, it is crucial to note that Mr. Florio's testimony omits the significant variation in total depreciation expense for the test year 2024, ranging from $69,068 million to $174,333 million, as indicated in the Rebuttal Testimony of Dane A. Watson, page DAW-1, Table DAW-1 - Summary of Differences.

While acknowledging the potential for a higher range in total depreciation expense, it is worth emphasizing that the magnitude of the difference within the range is significant, thereby supporting the preference for embedded cost analysis.

Furthermore, on page 20, lines 17-19, and page 21, line 1, Mr. Florio appears to conflate hypotheses with facts when asserting that the rate of growth in depreciation for transmission and storage significantly surpasses that of distribution and general plant. It should be emphasized that depreciation is a forecasted projection, as highlighted in the rebuttal testimony of Dane A. Watson. Additionally, there exists a notable degree of variation in the total depreciation figures presented, as evidenced in the rebuttal provided by Dane A. Watson.

C. Storage Functionalization Study Remains Valid

Applicants disagree with TURN's proposal in Section VI, C to adjust the allocation factors based on TURN's study. There are several reasons supporting this disagreement, as detailed below:

1. The Applicants maintain that their current method of allocating storage costs to inventory, injection, and withdrawal functions is justified. Storage operations experts analyzed the various activities and compiled information required to form the basis for the functionalization and allocation of costs on cost causation principles. The summarized study can be referenced in A.18-07-24, Appendix G. specifically on pages G-3 through G-7.
2. Wells & Lines (Capital 352 & 353 & O&M 816, 817, 832, and 833): The Applicants presently allocate 50% to withdrawal, 25% to injection, and 25% to inventory. In contrast TURN proposes an allocation of 60% to withdrawal, 30% to injection, and 10% to inventory. The Applicants argue that withdrawal cost allocation should be double that of injection, considering that twice as many wells are required for withdrawal. The proposed allocation of 25% for inventory and 25% to injection is appropriate as the field requires a sufficient number of wells to achieve the required working inventory. For practical purposes, to achieve the required working inventory in the storage field, one needs to have a sufficient number of wells. Although one well could be used to increase the inventory, the

field requires a sufficient number of wells to reach and minimally cycle a working inventory; a 10% allocation of wells and lines to inventory is too low to perform this. The numbers of wells and lines benefits injection and inventory equally and; thus, well costs should be allocated equally between these two categories/functions.

3. Accounts 351 and 357: The capital assets associated with Account 351 (Structures and Improvements) and Account 357 (Other Equipment) primarily serve the purpose of providing a working gas inventory. Therefore, the Applicants contend that the allocation of costs associated with these accounts and the associated O&M accounts should be 100% attributed to inventory.

4. Account 117.1: The purpose of cushion gas is to maintain sufficient pressure in the field for minimum deliverability at zero inventory and to enable the complete utilization of the working inventory. Hence, the Applicants propose an equal allocation of cushion gas costs between deliverability and inventory, with a balanced 50/50 split.

Based on these justifications, the Applicants firmly disagree with TURN's proposal to adjust the allocation factor. Furthermore, it should be noted that adjusting the allocation factor would negatively impact noncore customers. The current allocation methodology aligns with the specific operational and cost causality associated with the storge operations.

D. Asset Retirement Obligations (ARO) are to be Included in the Embedded Cost Study per D.20-02-045

1. Understanding ARO: An In-Depth Analysis of Financial Obligations

TURN opposes the inclusion of ARO in the embedded cost analysis despite the fact that AROs are an integral part of utility operations. [22]

ARO is an obligation related to the retirement/decommissioning of an asset. Certain assets cannot simply be abandoned but require special decommissioning. For example, a hazardous waste site cannot just be abandoned in place. When a facility is decommissioned, the company has the legal and financial obligation to clean up the site. The amount expected to be spent on properly decommissioning the site (clean-up cost) will be the basis for the ARO.

[22] Ex. TURN-01 (Florio) at 34:6-9.

An ARO is calculated as follows: First, assume a hazardous waste site will be closed in 2050 and it will cost $10 million to clean up the site then. The present value (PV) of this liability is calculated by dividing the 2050 future cost of $10 million by (1+discount rate)^n, using 6% discount rate for illustrative purposes. Also, the intervening 27 years between 2023 to 2050 are also factored into the calculation, in this illustration, n = (2050 – 2023) = 27. Based on these assumptions, the present value of this legal and financial obligation is approximately $2 million. As the decommissioning date of an asset approaches, n decreases which then increases the illustrative present value of $2 million ARO, based on the above formula. [23]
Therefore, a liability must be recorded on the company's balance sheet to reflect the cost of the company's obligation to properly dispose of the asset. The $2 million present value of this liability is recorded as Asset Retirement Obligations (ARO) as follows:

<u>Journal Entry for ARO Recognition:</u>

Asset Retirement Cost (ARC) (Asset)	$2,000,000	→ Depreciated monthly
ARO (Liability)	$2,000,000	→ Amortized monthly

2. Depreciation: A Key Revenue Requirement Component

One of the components of SoCalGas/SDG&E's General Rate Case (GRC) revenue requirement is depreciation, which is the return *<u>of</u>* capital. The original investment minus accumulated depreciation equals the net book value of an asset. Likewise, as shown above in the journal entry for ARO recognition, the Asset Retirement Cost (ARC) is also depreciated monthly similar to any existing asset placed in service by SoCalGas/SDG&E to provide distribution, transmission services to customers and also storage services to SoCalGas's customers. As shown above, ARC is an asset that corresponds directly with ARO in the journal entry and matches exactly with ARO, a liability in financial statements to disclose the discounted cost of future legal and financial obligations upon the decommissioning an asset. TURN states that ARO does not earn a return on rate base and has no taxes associated with it.[24] That is true because no cost outlays have been incurred prior to decommissioning a specific asset. Once the asset is decommissioned, the associated ARO and Asset Retirement Cost (ARC) will be reduced

[23] The present value increases because it is based on the future value (numerator) being divided by a smaller number (1+discount rate)^n where n decreases as the decommissioning date of the project approaches.

[24] Ex. TURN-01 (Florio) at 39:1-3.

accordingly. However, in the interim, ARO should be included in SoCalGas/SDG&E's embedded cost analyses. ARO is indisputably a cost which is required to provide utility services to customers, similar to existing infrastructure and therefore is an integral part of utility operations. TURN correctly states that depreciation expense reflects costs of the ARO, therefore, the ARC (ARO) should be included in SoCalGas/SDG&E's embedded cost studies per Ordering Paragraph 4(d) of Decision 20-02-045.

3. Distribution: Largest Asset Category in SoCalGas's Total Net Book Value

As discussed in Section II.D.1, ARO is initially recorded in present value terms. This grows in a compounding fashion, reflecting its lower initial cost, when ARO is first recognized and recorded which later increases as the decommissioning date approaches.

The fact that distribution ARO (FERC account 388) is higher than transmission ARO (FERC account 372) and storage ARO (FERC account 358) is primarily because distribution assets as a percentage of total net book value ***excluding ARO is also*** the largest component (52%) of total SoCalGas net book value. Therefore, it should not surprise anyone that future distribution ARO liabilities would follow a similar trend when ARO is included. See Table 1 below:

Table 1
SOUTHERN CALIFORNIA GAS COMPANY
2021 Utility Gas Plant in Service
Functional Allocation of Net Book Value
As a % of Total SoCalGasNet Book Value

	Including ARO	Excluding ARO
Intangibles	0%	0
Storage	11%	15%
Transmission	22%	25%
Distribution	61%	52%
General Plant	6%	8%
Total	100%	100%

As described earlier, ARO increases as the decommissioning date approaches to better reflect the costs to be incurred. Therefore, distribution ARO could also be larger than transmission and storage ARO because of its closer proximity to the decommissioning schedule relative to transmission's and storage's decommissioning schedule.

For all the reasons discussed above, the Commission should continue to adopt the inclusion of ARO in SoCalGas/SDG&E's embedded cost studies as specified in D.20-02-045.[25]

This concludes my prepared rebuttal testimony.

[25] D. 20-02-045 at 103 (OP 4(d)).

ATTACHMENT A

2022 CGR Update BB to LT

Ch.17 Frank Seres 2022 CGR Update

Daily EG Demand Forecast for the Year and Data from 2022 CGR

	2024		2025		2026		2027			
	SoCalGas and SDG&E		SoCalGas and SDG&E		SoCalGas and SDG&E		SoCalGas and SDG&E		Average	
EG Demand Served Directly from Backbone --->>	Percent Total	22.5%	Percent Total	22.3%	Percent Total	22.3%	Percent Total	21.9%	average	22%
	Cold-Year Annual Average Demand (MMcfd)	2,404	Cold-Year Annual Average Demand (MMcfd)	2,359	Cold-Year Annual Average Demand (MMcfd)	2,328	Cold-Year Annual Average Demand (MMcfd)	2,300	average	2,348
A x B --->>	Direct from Backbone (MMcfd)	541	Direct from Backbone (MMcfd)	526	Direct from Backbone (MMcfd)	519	Direct from Backbone (MMcfd)	504	average	522
Envoy Total Backbone Receipt Capacity ---->>	Total Receipt Capacity (MMcfd)	3,435	Total Receipt Capacity (MMcfd)	3,435	Total Receipt Capacity (MMcfd)	3,435	Total Receipt Capacity (MMcfd)	3,435	average	3,435
C / D --->>	% of Backbone w/Local Transmission Function	15.7%	% of Backbone w/Local Transmission Function	15.3%	% of Backbone w/Local Transmission Function	15.1%	% of Backbone w/Local Transmission Function	14.7%	average	15%

Table 21- Updated to 2022CGR				
% of Backbone Allocated to Local Transmission Function				
(A)	(B)	C = A x B	(D)	(E)= C /D
Cold Year Annual Average Demand (MMcfd) 2024 -2027	Demand Served Directly from Backbone (%)	Demand Served Directly from Backbone (MMcfd)	Envoy Total Backbone Receipt Capacity (MMcfd)	% of Backbone Allocated to Local Transmission Function
2,348	22%	522	3,435	15%

% of Backbone Allocated to Local Transmission Function Table 21 A				
	(A)	(B)	C = (A) + (B)	Remanining BB costs minus 15% out of Combined BB costs.
	SoCalGas	SDG&E	Combined Backbone Costs	15%
	($000)	($000)	($000)	
Backbone Transmission Costs	357,483	67,819	425,302	360,624

Illustrative Firm BTS Rate				
PSEP costs	Total BB costs	Througput Assumption	Annual Througput Assumption	Illustrative BTS Rate
		MDth/d	MDth	$/Dth
$99,322	459,946	2,532	924,292	0.4976