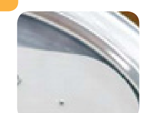
FINAL REPORT | April 22, 2020

The City of SAN DIEGO

Electric and Gas Franchise Agreements Consultant Report

City of San Diego, California



PREPARED BY:

NewGen Strategies & Solutions

IN ASSOCIATION WITH:

Advisian Worley Group

MRW & Associates

www.newgenstrategies.net

ECONOMICS STRATEGY STAKEHOLDERS SUSTAINABILITY

Table of Contents

PROJECT SUMMARY

ELECTRIC AND GAS FRANCHISE AGREEMENTS CONSULTANT REPORT PROJECT SUMMARY

Introduction

The City of San Diego (City) franchise agreements with San Diego Gas and Electric (SDG&E) to provide electric and gas utility services to the City are due to expire on January 17, 2021. To prepare for the upcoming expiration of the franchise agreements, the City retained a consulting team led by NewGen Strategies and Solutions (NewGen) to: (1) perform a preliminary valuation of the existing electric and gas distribution infrastructure owned by SDG&E in the City, (2) estimate the cost to physically separate (i.e., sever) that portion of the SDG&E infrastructure within the City from the remainder of the SDG&E electric and gas systems located outside the City boundaries to allow for non-SDG&E ownership and operation of the utility infrastructure serving the City, (3) evaluate the economic feasibility of municipal acquisition and operation of the electric and gas distribution infrastructure in the City, and (4) perform a survey to assess franchise best practices used by other cities.

This report provides the task reports in their entirety from NewGen, Advisian, and MRW & Associates, LLC (MRW). Each task report includes an executive summary at the beginning of that report.

In preparing the task reports, NewGen, Advisian, and MRW relied on publicly available information and data provided by the City and SDG&E. A complete description of the data and assumptions relied upon are described in each task report. The results and conclusions described in the draft task reports should be considered preliminary.

The scope of work for the project included the following four tasks:

Task 1: Value of SDG&E Electric and Gas Distribution Infrastructure Serving the City (NewGen)

Conduct a high-level valuation of existing electric and gas distribution utility infrastructure owned by SDG&E in the City.

Task 2: Severance Analysis (Advisian)

Develop a range of estimates around the capital costs associated with severing the electric and natural gas systems located within the City from the rest of SDG&E assets.

Task 3: Economic Feasibility of Municipal Acquisition of Gas and Electric Assets in the City (MRW)

Prepare a financial analysis and recommendations regarding purchase of the electric and gas distribution utility systems by the City, including departing load costs and prospective finance costs through bonds or other mechanisms, as an alternative to granting franchises.

Task 4: Franchise Benchmark Survey (NewGen)

Perform a benchmarking study of the 20 most populous cities in California and five cities outside California to compare franchise fees for electric and gas services and assess best practices for setting franchise fees, including forms of incentives and enforcement mechanisms used by other cities. The findings of the franchise benchmark survey were summarized in matrices provided to the City for further additional analysis; no written report was prepared for this task.

Task 1: Value of SDG&E Electric and Gas Distribution Infrastructure Serving the City

Approaches to Valuation

NewGen conducted a high-level valuation of existing electric and gas utility distribution infrastructure owned by SDG&E in the City. NewGen developed indicators of value using the following three generally accepted approaches to valuation.

- **Cost Approach** – Value is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the property being valued. This approach was represented in the analysis based on the following methods:
  - Reproduction Cost New Less Depreciation (RCNLD)
  - Original Cost Less Depreciation (OCLD) (i.e., the approximate value of SDG&E's rate base)
- **Income Approach** – Value is estimated by capitalizing or determining the present worth of the prospective net earnings from the property. This approach was represented in the analysis based on the following method:
  - Discounted Cash Flow Analysis
- **Market Approach** – Value is estimated based on recent fair market sales of similar facilities under similar circumstances. This approach was represented in the analysis based on the following method:
  - Guideline Sales Transactions

In addition, the City asked NewGen to develop indicators of value under the following two assumptions:

- **Perpetual Franchise Assumption** – Going concern value; does not consider the expiration of SDG&E's electric and gas franchise agreement with the City due to expire in January 2021.
- **One-Year Franchise Assumption** – Value based on one year remaining in SDG&E's existing 50-year electric and gas franchise agreements with the City; assumes that SDG&E has a duty to remove its facilities under the existing franchise agreements if it does not obtain new or extended franchises.

Effect of Utility Rate Regulation on Value

Under utility rate regulation, SDG&E is allowed to charge rates based on SDG&E's cost of service that produce forecasted revenues equal to the utility's revenue requirement. SDG&E is allowed to recover its reasonable operating expenses, depreciation, and taxes, and the opportunity to earn SDG&E's authorized rate of return times rate base.

Rate base is approximately equal to the original cost less (minus) depreciation (OCLD) value of SDG&E's plant investment, less (minus) customer contributed capital. When property is sold, the value is recorded on the buyer's books for rate setting purposes at OCLD.

As a result of rate regulation, the income value of utility property is typically close to the rate base value of the property if it is assumed that the franchise is perpetual.

Preliminary Indicators of Value

Based on the results of analyses and assumptions described in the Task 1 report, NewGen estimated the preliminary indicators of value of SDG&E electric and gas distribution infrastructure in the City as shown in Table 1.

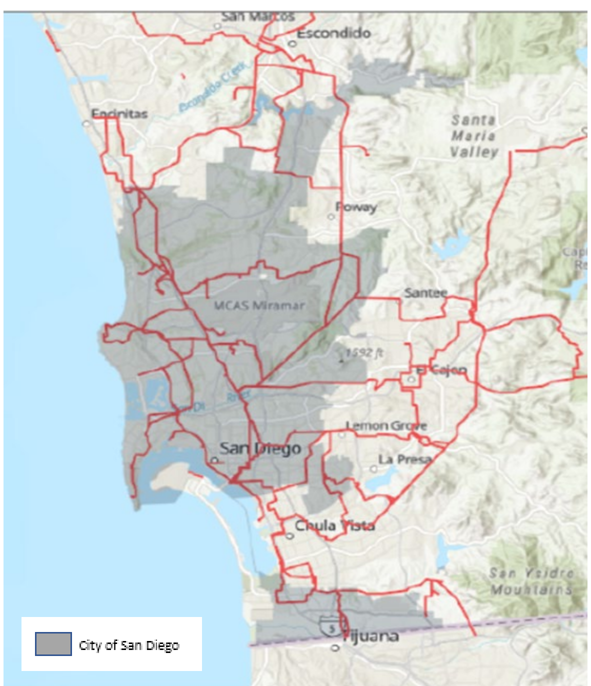
Table 1
Value of SDG&E Utility Infrastructure in City

Description	Electric Distribution	Gas Distribution
Cost Approach		
RCNLD[1]	$2,784,463,000	$1,109,630,000
OCLD	$1,585,378,000	$498,601,000
Income Approach		
Perpetual Franchise Assumption	$2,237,751,000	$652,898,000
One-Year Franchise Assumption	$208,333,000	$57,742,000
Market Approach	$2,086,955,000	$632,523,000
Estimated Range of Value		
Perpetual Franchise Assumption	$1.6 billion to $2.2 billion	$499 million to $653 million
One-Year Franchise Assumption	$208,333,000	$57,742,000

1 RCNLD values do not include an adjustment for economic obsolescence due to rate regulation.

Task 2: Severance Analysis

Advisian developed a range of estimates around the capital costs associated with severing SDG&E's electric and natural gas systems located within the City from the rest of SDG&E assets.



What is Severance?

If an entity other than SDG&E wins the franchise bid or the City chooses to provide utility service within its boundaries, that portion within the City boundaries would have to be physically separated (i.e., severed) from the remainder of SDG&E electric and gas operations. An example map showing City of San Diego corporate limits and SDG&E 69-kV electric transmission lines (in red) is shown at left.

Advisian's work did not include a detailed walk-down or physical inspection of the systems. Advisian did not have access to proprietary and sensitive GIS data about the electric and gas systems or electric substations from SDG&E due to Federal Critical Infrastructure Protection regulations (NERC CIP).

Advisian developed a preliminary estimate of severance costs using several top down, parametric approaches for various elements within the electric and natural gas systems.

- Electric distribution severance based on a benchmark figure per mile of boundary.
- Two boundary cases were used:
  - Unmodified (natural boundary of City).
  - Modified – assumed some portions of boundary would not require severance, e.g. border with Mexico and unpopulated areas around Scripps Ranch.

Estimated capital costs to sever electric and natural gas systems located within the City from the remainder of SDG&E assets are shown in Table 2.

Table 2
Estimated Capital Costs to Sever Electric and Natural Gas Systems from SDG&E

Type	Lower Bound Estimate	Upper Bound Estimate	Comments
Electric Distribution	$189.5 million	$899.2 million	Lower bound assumes modified boundary and primarily physical separation via metering. Upper bound assumes unmodified boundary and that new substations will be required to achieve severance.
Electric Transmission	$0	$1.5 billion	Lower bound assumes NO transmission severance is required.Upper bound assumes every transmission line boundary crossing point requires severance.
Natural Gas	$29.7 million	$52.8 million	Lower bound assumes that all transfer points are low gas volume transfer points. Upper bound assumes high volume transfer points.
Total	**$219.2 million**	**$2.45 billion**	Low bound is sum of all low estimates.Upper bound is sum of all upper bound estimates.

Task 3: Economic Feasibility of Municipal Acquisition of Gas and Electric Assets in the City

MRW prepared financial analyses and recommendations regarding the economic feasibility of the purchase of the electric and gas distribution infrastructure by the City of San Diego, including departing load costs and prospective finance costs, as an alternative to granting franchises. Municipal utiliy entities included:

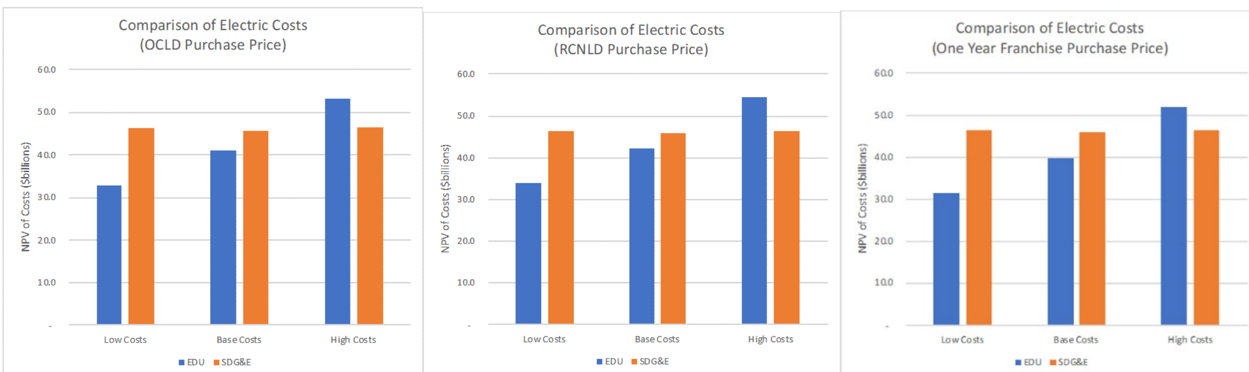
- Electric Distribution Utility (EDU)
- Gas Distribution Utility (GDU)

Results of EDU Feasibility Analysis

The graphs in Figure 1 depict the comparison of electric customer costs under the EDU and SDG&E based on alternative purchase price scenarios under three different sets of assumptions regarding the costs of owning and operating those assets (i.e., Low, Base, and High Cost assumptions).

Figure 1
Comparison of Customer Costs Under EDU and SDG&E

OCLD Purchase Price | **RCNLD Purchase Price** | **One Year Purchase Price**



As shown in Figure 1:

- Customer costs under the EDU are lower than under SDG&E in the Low Cost and Base Case scenarios for all purchase price assumptions examined.
- Customer costs under the EDU are higher than under SDG&E in the High Cost scenario for all purchase price assumptions examined.
- The purchase price assumption does not have significant effect on the cost customers would pay for EDU service. This is because EDU fixed asset costs (e.g., annual debt service are a small portion of the total cost of service for the EDU. Purchased power supply costs are the largest portion of cost of service for the EDU.

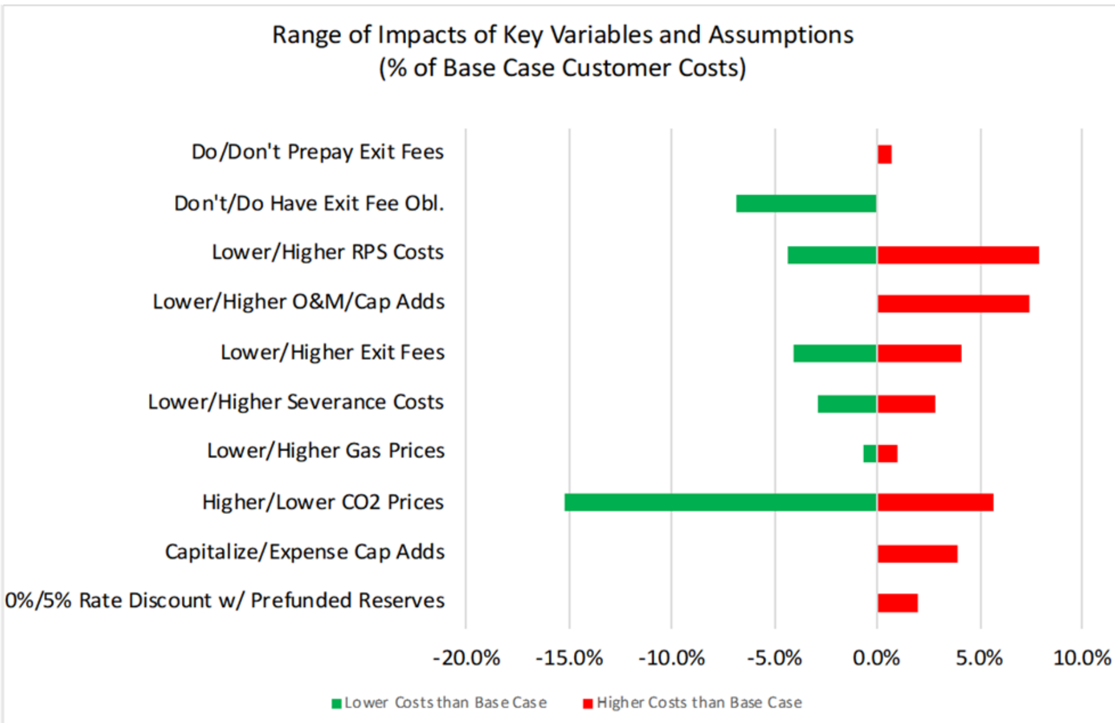
The range of potential EDU rate discounts for different purchase price and cost assumptions is shown in Table 3.

Table 3
Range of Potential EDU Rate Discounts

	RCNLD	OCLD	One-Year Franchise
Low Costs	21.8%	25.5%	29.8%
Base Case	4.4%	8.2%	12.5%
High Costs	(35.0%)	(31.4%)	(27.2%)

There is significant uncertainty in the cost assumptions used to develop the rate discounts shown in Table 3 and changes in those assumptions will result in changes in operating costs for the EDU, which would ultimately result in changes in the rate discounts that could be offered. Key variables affecting customer costs and sensitivity analysis test impacts are shown in Figure 2.

Figure 2
Range of Impacts of Key Variables and Assumption in EDU Analysis

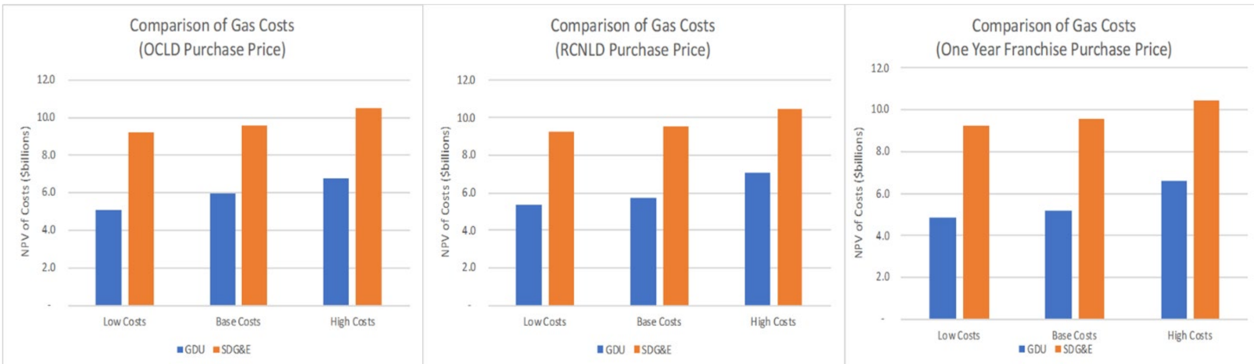


Results of GDU Analysis

The graphs in Figure 3 depict the comparison of gas customer costs under the GDU and SDG&E based on alternative purchase price scenarios under three different sets of assumptions regarding the costs of owning and operating those assets (i.e., Low, Base, and High Cost assumptions).

Figure 3
Comparison of Customer Costs Under GDU and SDG&E

OCLD Purchase Price | **RCNLD Purchase Price** | **One Year Purchase Price**



As shown in Figure 3, customer costs under GDU are less than under SDG&E for all cost scenarios and acquisition cost assumptions.

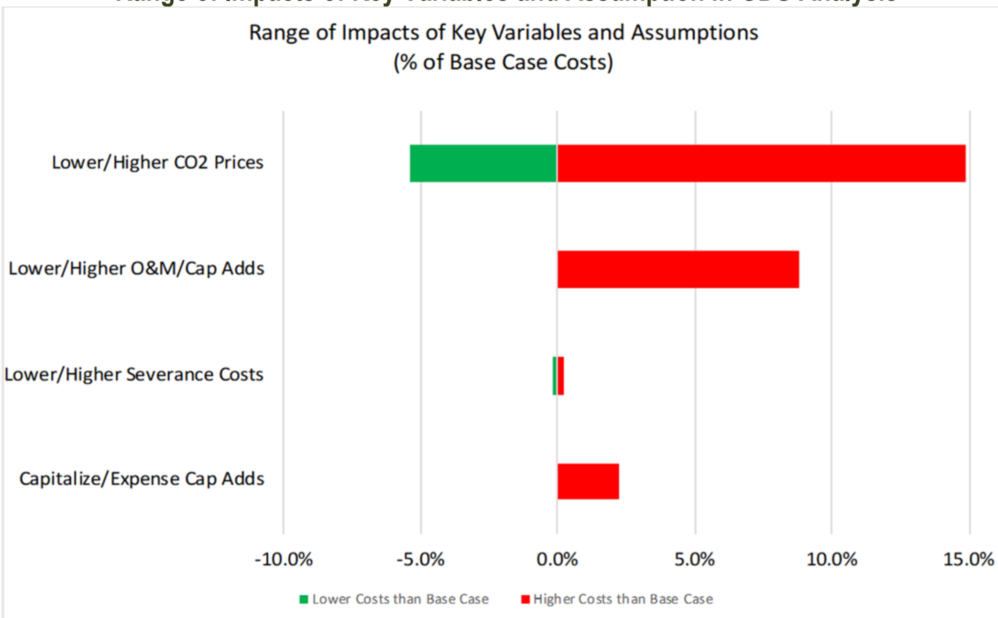
The range of potential GDU rate discounts for different purchase price and cost assumptions are shown in Table 4.

Table 4
Range of Potential GDU Rate Discounts

	RCNLD	OCLD	One-Year Franchise
Low Costs	27.2%	36.6%	41.1%
Base Case	27.0%	36.5%	40.9%
High Costs	16.0%	25.4%	29.2%

Like the EDU analysis, there is significant uncertainty in the cost assumptions used to develop the rate discounts shown in Table 4; changes in those assumptions will result in changes in operating costs for the GDU. Key variables affecting customer costs and sensitivity analysis test impacts in the GDU analysis are shown in Figure 4.

Figure 4
Range of Impacts of Key Variables and Assumption in GDU Analysis



Feasibility Analysis Conclusions

- Electric Distribution Utility
  - The City could acquire SDG&E's electric distribution assets, establish an EDU, and offer customers lower rates than SDG&E under the Low Cost or Base Case scenarios if the purchase price was less than RCNLD.
    - Rate discounts would be less if the assets were purchased at RCNLD than at OCLD.
  - EDU is not feasible under the High Cost scenario regardless of the purchase price.
- Gas Distribution Utility
  - City could acquire SDG&E's gas distribution assets, establish a GDU, and offer customers significantly lower rates than SDG&E under all cost scenarios if the purchase price was less than RCNLD.

Task 4: Franchise Benchmark Survey

NewGen obtained electric and gas franchises from 13 of the 20 most populous charter cities in California (including two counties) and four cities outside California. In addition, a few cities sent back detailed survey responses. NewGen prepared a full matrix to track the terms and conditions of 17 electric and 17 gas franchise agreements from California and other U.S. cities. The findings were provided to the City for additional analysis. No written task report was prepared for Task 4.

PRESENTATION

March 27, 2020 (FINAL REPORT)

CITY OF SAN DIEGO, CALIFORNIA
ELECTRIC AND GAS FRANCHISE AGREEMENTS CONSULTANT REPORT

NewGen Strategies & Solutions

1

PROJECT OVERVIEW – TASK REPORTS

Task 1: Value of SDG&E Electric Distribution and Gas Infrastructure Serving the City

Task 2: Severance Analysis

Task 3: Economic Feasibility of Municipal Acquisition of Gas and Electric Assets in the City

Task 4: Franchise Benchmark Survey

NewGen Strategies & Solutions

Advisian

MRW & Associates

2

PROJECT OVERVIEW

- Relied on publicly available information and data provided by the City and SDG&E
- Plant data for SDG&E electric and gas distribution assets in the City were not available for the study
  - Assumed City is 42% of total SDG&E electric distribution system (based on relative number of meters and annual load)
  - Assumed City is 50% of total SDG&E gas distribution system (based on relative annual revenues)
- Data and assumptions relied upon are described in each task report
- Results and conclusions are preliminary

TASK 1

Value of SDG&E Electric and Gas Distribution Infrastructure Serving the City of San Diego

NewGen Strategies & Solutions

VALUATION ANALYSIS

- Conduct a high-level valuation of existing electric and gas distribution infrastructure owned by SDG&E in the City

APPROACHES TO VALUATION

- **Cost Approach** – value is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the property being valued
  - Reproduction Cost New Less Depreciation
  - Original Cost Less Depreciation (Value of Utility Rate Base)
- **Income Approach** – value is estimated by capitalizing or determining the present worth of the prospective net earnings from the property
  - Discounted Cash Flow Analysis
- **Market Approach** – value is estimated based on recent fair market sales of similar facilities under similar circumstances
  - Guideline Sales Transactions

EFFECT OF UTILITY RATE REGULATION ON VALUE

- Under utility rate regulation, SDG&E is allowed to charge rates based on cost of service that produce forecasted revenues equal to the utility's revenue requirement
  - Allowed to recover reasonable operating expenses, depreciation, and taxes
  - Allowed to earn SDG&E's authorized rate of return times rate base
  - Rate base is approximately equal to the original cost less (minus) depreciation (OCLD) value of utility's plant investment less (minus) customer contributed capital
  - When property is sold, the value is recorded on the buyer's books at OCLD
- As a result of rate regulation, the income value of utility property is typically close to the rate base value of the property if it is assumed that the franchise is perpetual

PRELIMINARY INDICATORS OF VALUE

Value of SDG&E Utility Infrastructure in City

	Electric Distribution	Gas Distribution
Cost Approach		
RCNLD (1)	$2,784,463,000	$1,109,630,000
OCLD	$1,585,378,000	$498,601,000
Income Approach:		
Perpetual Franchise Assumption	$2,237,751,000	$652,898,000
One-Year Franchise Assumption	$208,333,000	$57,742,000
Market Approach	$2,086,955,000	$632,523,000
Estimated Range of Value:		
Perpetual Franchise Assumption	$1.6 billion to $2.2 billion	$499 million to $653 million
One-Year Franchise Assumption	$208,333,000	$57,742,000

(1) RCNLD values do not include an adjustment for economic obsolescence due to rate regulation.

TASK 2

Severance Analysis

Advisian
Worley Group

SEVERANCE COST

What is severance?

If entity other than SDG&E wins the franchise bid or City chooses to provide utility service within its boundaries, that portion within the City boundaries would have to be physically separated (severed) from the remainder of SDG&E electric and gas operations

Example map showing City of San Diego corporate limits and SDG&E 69- kV electric transmission lines (in red)

City of San Diego

SEVERANCE COST

- Severance analysis
  - Work did not include a detailed walk-down or physical inspection of the systems
  - Advisian did not have access to proprietary and sensitive GIS data about the electric and gas systems or electric substations from SDG&E due to Federal Critical Infrastructure Protection regulations (NERC CIP)
  - Preliminary estimate developed using several top down, parametric approaches for various elements within the electric and natural gas systems
    - Electric distribution severance based on a benchmark figure per mile of boundary
    - Two boundary cases were used
      - Unmodified (natural boundary of City)
      - Modified- assumed some potions of boundary would not require severance, i.e. border with Mexico and unpopulated areas around Scripps Ranch

SEVERANCE

COST-ESTIMATED CAPITAL COSTS TO SEVER ELECTRIC AND NATURAL GAS SYSTEMS LOCATED WITHIN CITY FROM THE REMAINDER OF SDG&E ASSETS

	Lower Bound Estimate	Upper Bound Estimate	Comments
Electric Distribution	$189.5 million	$899.2 million	Lower bound assumes modified boundary and primarily physical separation via metering. Upper bound assumes unmodified boundary and that new substations will be required to achieve severance.
Electric Transmission	$0	$1.5 billion	Lower bound assumes NO transmission severance is required. Upper bounds assumes every transmission line boundary crossing point requires severance.
Natural Gas	$29.7 million	$52.8 million	Lower bound assumes that all transfer points are low gas volume transfer points. Upper bound assumes high volume transfer points.
Total	**$219.2 million**	**$2.45 billion**	Low bound is sum of all low estimates; upper bound is sum of all upper bound estimates.

TASK 3

Economic Feasibility of Municipal Acquisition
of Gas and Electric Assets in the City

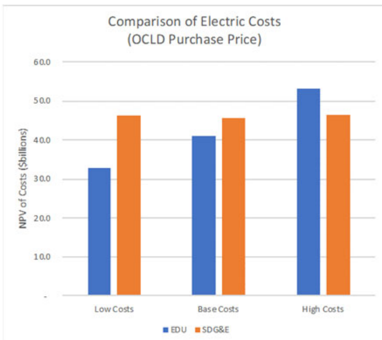
MRW & Associates

ECONOMIC FEASIBILITY ANALYSIS

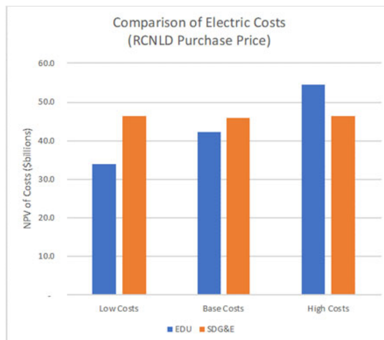
- Prepare financial analysis and recommendations regarding purchase of the electric and gas distribution systems by the City of San Diego, including departing load costs and prospective finance costs, as an alternative to granting franchises
- Municipal utility entities
  - Electric Distribution Utility (EDU)
  - Gas Distribution Utility (GDU)

COMPARISON OF CUSTOMER COSTS UNDER EDU AND SDG&E - ELECTRIC

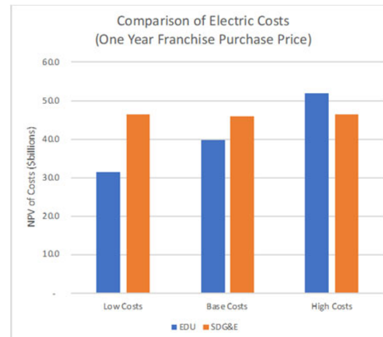
OCLD Purchase Price



RCNLD Purchase Price



One Year Purchase Price



RESULTS OF EDU FEASIBILITY ANALYSIS

- Customer costs under EDU are lower than under SDG&E in Low Cost and Base Case scenarios
- Customer costs under EDU are higher than under SDG&E in High Cost scenario
- Purchase price assumption does not have significant effect on cost customers would pay for EDU service
  - EDU fixed asset costs (e.g., annual debt service, capital expenditures) are small portion of total cost of service for EDU
  - Purchased power supply costs are largest portion of cost of service for EDU

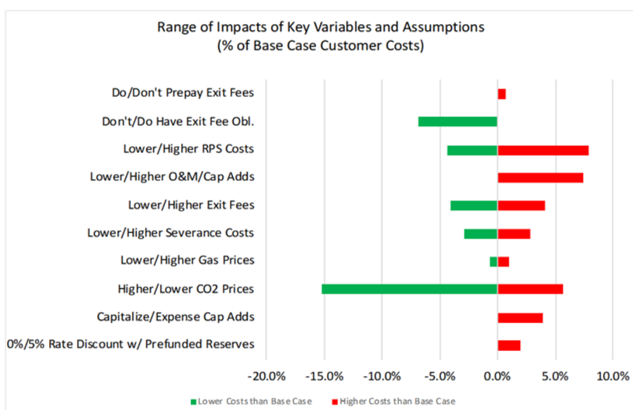
RESULTS OF EDU FEASIBILITY ANALYSIS

- Range of potential EDU rate discounts for different purchase price and cost assumptions:

	RCNLD	OCLD	One Year Franchise
Low Costs	21.8%	25.5%	29.8%
Base Case	4.4%	8.2%	12.5%
High Costs	(35.0%)	(31.4%)	(27.2%)

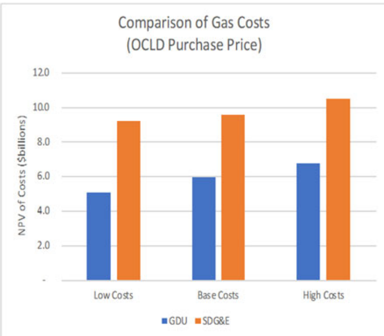
EDU FEASIBILITY ANALYSIS

- Key variables affect customer costs; sensitivity analysis tests impacts

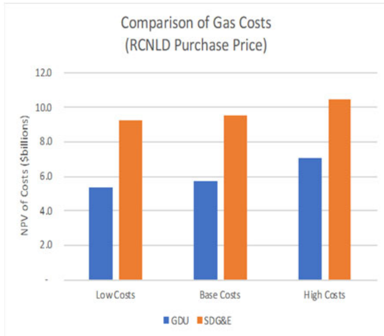


COMPARISON OF CUSTOMER COSTS UNDER GDU AND SDG&E - GAS

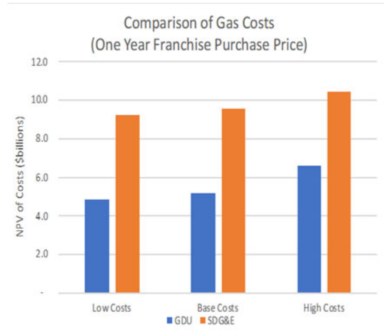
OCLD Purchase Price



RCNLD Purchase Price



One Year Purchase Price



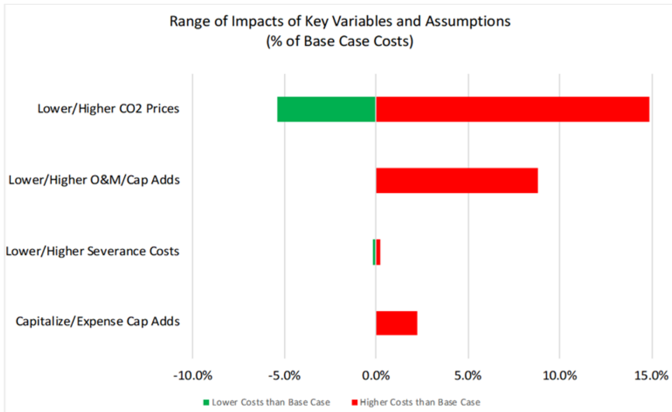
RESULTS OF GDU FEASIBILITY ANALYSIS

- Customer costs under GDU are less than under SDG&E for all cost scenarios and acquisition cost assumptions
- Range of potential GDU rate discounts for different purchase price and cost assumptions:

	RCNLD	OCLD	One Year Franchise
Low Costs	27.2%	36.6%	41.1%
Base Case	27.0%	36.5%	40.9%
High Costs	16.0%	25.4%	29.9%

GDU FEASIBILITY ANALYSIS

- Key variables affect customer costs; sensitivity analysis tests impacts



FEASIBILITY ANALYSIS CONCLUSIONS

- Electric Distribution Utility
  - City could acquire SDG&E's electric distribution assets, establish an EDU, and offer customers lower rates than SDG&E under the Low Cost or Base Case scenarios
    - Rate discounts would be less if the assets were purchased at RCNLD than at OCLD
  - EDU is not feasible under the High Cost scenario regardless of the purchase price
- Gas Distribution Utility
  - City could acquire SDG&E's gas distribution assets, establish a GDU, and offer customers significantly lower rates than SDG&E under all cost scenarios
    - Rate discounts would be less if the assets were purchased at RCNLD than at OCLD

TASK 4

Franchise Benchmark Survey

FRANCHISE BENCHMARK SURVEY

- Obtained electric and gas franchises from 13 of the 20 most populous charter cities in California (including two counties) and four cities outside California
- In addition, a few cities sent back detailed survey responses
- NewGen prepared a full matrix to track terms and conditions of 17 electric and 17 gas franchise agreements from California and other U.S. cities
- Findings were provided to the City for additional analysis

Task 1: NewGen
VALUE OF SDG&E ELECTRIC DISTRIBUTION AND GAS INFRASTRUCTURE SERVING THE CITY

Final Report | February 12, 2020

Value of SDG&E Electric and Gas Distribution Infrastructure Serving the City of San Diego

City of San Diego, California

Prepared by:

NewGen Strategies & Solutions

Table of Contents

ABOUT NEWGEN STRATEGIES AND SOLUTIONS, LLC

NewGen Strategies and Solutions, LLC (NewGen) is a management and economic consulting firm serving the utility industry and market. NewGen has offices in Austin, Dallas, Denver, Nashville, Orlando, and Seattle. NewGen provides financial, due diligence, cost of service and rate design, appraisal and valuation, depreciation, strategy, expert witness, stakeholder, and sustainability consulting services to its clients. NewGen has three Accredited Senior Appraisers (ASAs), Public Utility Discipline, certified by the American Society of Appraisers on its staff.

Value of SDG&E Electric and Gas Distribution Infrastructure Serving the City of San Diego

NewGen Strategies and Solutions, LLC (NewGen) performed a high-level valuation study to estimate the range of value for San Diego Gas & Electric's (SDG&E) electric and gas distribution assets in the City of San Diego (City).

The methodology, assumptions, and analyses NewGen performed to develop indicators of value under each approach are described in detail in this report. Key assumptions and limiting conditions used in the valuation study include:

- NewGen relied on publicly available information and data provided by the City to perform the valuation study. As additional information becomes available, the valuation results should be updated.
- Inventory data for SDG&E electric distribution and gas distribution plant assets located in the City were not available at the time we performed this study. Therefore, NewGen used an allocation approach to estimate the value of SDG&E electric distribution and gas distribution assets in the City. Specifically, we assumed that the City represents 42% of the total SDG&E electric distribution system based on the relative number of electric meters and annual load, and 50% of the total SDG&E gas system based on annual revenues.
- The indicators of value shown in Table ES-1 do not include an allocation of SDG&E common and general plant assets. It is not known what SDG&E-owned common and general plant assets, if any, are needed to operate a stand-alone electric distribution and/or gas utility serving the City. For example, SDG&E computer and communications systems are likely proprietary to SDG&E and would not be acquired by the new utility; however, the cost of these facilities would presumably be included as start-up costs for the new utility.
- The Reproduction Cost New Less Depreciation (RCNLD) values shown in Table ES-1 do not include an adjustment for economic obsolescence due to rate regulation, which NewGen would include if performing an appraisal of the assets. In addition, no adjustment was made to the preliminary cost approach indicators of value for functional obsolescence because a condition assessment of the SDG&E assets has not yet been performed.

NewGen developed indicators of value using the following three generally accepted approaches to valuation below:

- **Cost approach** – the value of the property is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the property being valued.
- **Income approach** – the value of the property is estimated by capitalizing or determining the present worth of the prospective net earnings from the property.
- **Market approach** – the value of the property is estimated based on recent fair market sales of similar facilities under similar circumstances.

In addition, the City asked NewGen to develop indicators of value under two assumptions:

- **Perpetual Franchise Assumption** – going concern value; does not consider the expiration of SDG&E's electric and gas franchise agreements with the City due to expire in January 2021.
- **One-Year Franchise Assumption** – value based on one year remaining in SDG&E's existing 50-year electric and gas franchise agreements with the City; assumes that SDG&E has a duty to remove its facilities under the existing franchise agreements if it does not obtain new or extended franchises.

Based on the results of the analyses and assumptions described in this report, NewGen estimated preliminary indicators of value using generally accepted approaches to valuation. These indicators of value are summarized in Table ES-1 below.

Table ES-1
Summary of Indicators of Value

	Electric Distribution	Gas Distribution
Cost Approach:		
RCNLD (1)	$2,784,463,000	$1,109,630,000
OCLD	$1,585,378,000	$498,601,000
Income Approach:		
Perpetual Franchise Assumption (2)	$2,237,751,000	$652,898,000
One-Year Franchise Assumption (3)	$208,333,000	$57,742,000
Market Approach (2)	$2,086,955,000	$632,523,000
Estimated Range of Value:		
Perpetual Franchise Assumption (2)	$1.6 billion to $2.2 billion	$499 million to $653 million
One-Year Franchise Assumption (3)	$208,333,000	$57,742,000

(1) The RCNLD values shown in the table above do not include an adjustment for economic obsolescence due to rate regulation. Such an adjustment is appropriate when appraising the value of rate regulated utility assets. The unadjusted RCNLD values are shown above because SDG&E may claim the value of the assets is equal to RCNLD without any adjustment for economic obsolescence.

(2) Going concern value does not consider the expiration of SDG&E's existing electric and gas franchise agreements with the City in January 2021.

(3) Value based on SDG&E's existing franchise agreements with City which expire in January 2021 and assumes the existing agreements require SDG&E to remove its facilities if it does not obtain new or extended franchises.

The results shown in Table ES-1 provide a preliminary estimate of the range of fair market value and book cost for the SDG&E distribution assets in the City. However, as the City obtains more data about the inventory, age, and condition of the SDG&E assets, we expect the RCNLD and Original Cost Less Depreciation (OCLD) values will change, which will likely affect the other indicators of value. Therefore, we recommend that the City update the preliminary valuation analyses as more detailed information about the SDG&E assets becomes available. NewGen would be pleased to assist the City in this regard.

As discussed later in this report, the effect of utility rate regulation is an important consideration in valuing public utility property. Under standard ratemaking procedures, rate regulated utilities are allowed to earn a fair and reasonable rate of return on their rate base (approximately OCLD). Operating expenses are essentially a pass-through cost recovered through rates. Thus, in theory, (using the Perpetual Franchise Assumption) the income value for rate regulated utility property on a going concern basis is generally close to its OCLD value since this is the value of the utility's investment on which it is allowed to earn its authorized rate of return or profit. The income values shown in Table ES-1 support paying a price that is slightly higher than OCLD (1.41 times OCLD for electric distribution and 1.31 times OCLD for gas) due to projected growth in earnings.

The RCNLD values shown in Table ES-1 do not include an adjustment for economic obsolescence due to rate regulation. Such an adjustment is appropriate for rate regulated assets in an appraisal. NewGen chose not to adjust the RCNLD values for economic obsolescence in this preliminary valuation report because SDG&E will likely claim that the value of the assets is equal to the RCNLD value without any adjustment for economic obsolescence; therefore, the RCNLD value shown in Table ES-1 is an estimate of the values that SDG&E may claim for the electric and gas distribution systems in the City.

A preliminary estimate of the book cost (i.e., OCLD value) of the SDG&E infrastructure in the City is equal to $1.6 billion for the electric distribution system and $499 million for the gas system.

Under the Perpetual Franchise Assumption, based on the information available and assumptions and analyses described in this valuation report, a preliminary estimate of the range of fair market value of SDG&E's distribution infrastructure in the City is equal to $1.6 billion to $2.2 billion for the electric distribution system and $499 million to $653 million for the gas distribution system.

Under the One-Year Franchise Assumption, the estimated value of SDG&E distribution infrastructure under SDG&E's existing franchise agreements with the City, which expire in January 2021, is equal to $208,333,000 for the electric distribution system and $57,742,000 for the gas distribution system. The One-Year Franchise Assumption assumes that the existing franchise agreements require SDG&E to remove its facilities if it does not obtain new or extended franchises. NewGen offers no opinion on matters requiring legal interpretation of the existing franchise agreements.

VALUE OF SDG&E ELECTRIC AND GAS DISTRIBUTION INFRASTRUCTURE SERVING THE CITY OF SAN DIEGO

Introduction

NewGen Strategies and Solutions, LLC (NewGen) performed a high-level valuation study to estimate the range of value for San Diego Gas & Electric's (SDG&E) electric and gas distribution assets in the City of San Diego (City).

The City's franchise agreements with SDG&E to provide electric and gas utility services to customers in the City are due to expire on January 17, 2021. The City is required by Charter to put the electric and gas franchises out for bid when the existing franchise agreements expire. In addition, municipal ownership of the electric and/or gas systems is an alternative for the City to consider.

The purpose of this report is to provide the City with a high-level estimate of the fair market value and book value of the SDG&E electric and gas distribution assets in the City and to identify key uncertainties and unknowns for further analysis. This information will be used by the City and other consultants on the project team to further evaluate the financial feasibility of the City acquiring the SDG&E assets.

Scope of Work

NewGen developed indicators of value using the following three generally accepted approaches to valuation:

- **Cost approach** – the value of the property is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the property being valued.
- **Income approach** – the value of the property is estimated by capitalizing or determining the present worth of the prospective net earnings from the property.
- **Market approach** – the value of the property is estimated based on recent fair market sales of similar facilities under similar circumstances.

In addition, the City asked NewGen to develop indicators of value under two assumptions:

- **Perpetual Franchise Assumption** – going concern value; does not consider the expiration of SDG&E's electric and gas franchise agreements with the City due to expire in January 2021.
- **One-Year Franchise Assumption** – value based on one year remaining in SDG&E's existing 50-year electric and gas franchise agreements with the City; assumes that SDG&E has a duty to remove its facilities under the existing franchise agreements if it does not obtain new or extended franchises.

The analyses NewGen prepared to estimate preliminary indicators of value under each approach are described later in this report.

The preliminary valuation study and the analyses described in this report do not constitute an appraisal.

An inventory of the SDG&E assets was not available at the time this report was prepared. Data regarding the age and condition of the SDG&E assets was also not available. Therefore, as described in the Methodology section of this report, NewGen used an allocation approach to develop a preliminary estimate of the value of SDG&E electric and gas distribution assets in the City. This approach is reasonable to use for a preliminary estimate of value of SDG&E's electric and gas distribution assets in the City.

Based on the results of the analyses and assumptions described in this report, NewGen estimated preliminary indicators of value using generally accepted approaches to valuation.

Data Reviewed

NewGen relied upon the following publicly available data to develop the preliminary valuation study:

- Federal Energy Regulatory Commission (FERC) Form 1 Annual Reports for SDG&E Electric Utility for the years ending December 31, 2013 through 2018
- FERC Form 2 Annual Reports for SDG&E Natural Gas Utility for the years ending December 31, 2014 through 2018
- SDG&E General Rate Case (GRC) filings to the California Public Utilities Commission (CPUC)
  - SDG&E 2019 General Rate Case (GRC) Phase I rate filing, A.17-10-007
  - SDG&E 2020 Cost of Capital filing, A.19-04-017
  - SDG&E GRC Phase 2 Application, A.19-03-002
- *Blue Chip Economic Indicators*, October 2019
- *Handy-Whitman Index of Public Utility Construction Costs*, Whitman, Requardt and Associates
- Modified Accelerated Cost Recovery System (MACRS), IRS Publication 946 (2018)

In addition, we relied on the following data which is not generally publicly available:

- Data provided by the City regarding number of customers and retail electricity deliveries to end users in San Diego
- Franchise fee data provided by the City (SDGE Database_FY20_v1.xlsx)
- Projected annual capital expenditures for the electric and gas distribution utilities serving the City, developed by MRW & Associates, LLC (MRW)

Summary of Key Assumptions

Following is a list of key assumptions NewGen used to develop preliminary estimates of value under the cost and income approaches to valuation.

Cost Approach

Table 1
Cost Approach Key Assumptions

Category	Assumption	Source/Notes
Plant in Service (Original Cost)		
Electric Distribution and Gas Distribution (total SDG&E)	As shown in Exhibit 1	A.19-03-002 GRC Phase 2 Application 3_4_2019, Appendix D
Accumulated Depreciation (Original Cost)		
Electric Distribution and Gas Distribution (total SDG&E)	As shown in Exhibit 1	A.19-03-002 GRC Phase 2 Application 3_4_2019, Appendix D
Reproduction Cost New (RCN)		
Electric Distribution and Gas Distribution (total SDG&E)	Original cost escalated based on Handy-Whitman Index for relevant FERC accounts, or CPI for land and land rights, based on estimate of age by FERC account from SDG&E General Rate Case 2019, Phase I, Exhibit SDG&E-34 (WP MVanderbilt - Depreciation_ vol1), page 4 and 5, as of December 31, 2016.	Handy-Whitman Electric Utility Construction Costs, Pacific Region (E-6) Handy-Whitman Gas Utility Construction Costs, Pacific Region (G-6) CPI-All Urban Consumers (Current Series), All items in U.S. city average, all urban consumers, not seasonally adjusted, July values for each year
Accumulated Depreciation for RCN		
Electric Distribution and Gas Distribution (total SDG&E)	Escalated the same as RCN	Same as RCN
Allocation to CCSF		
Electric Distribution	Allocated 42% to City based on estimated 2017 customer counts: ▪ All SDG&E = 1,434,024 ▪ City = 605,357	All SDG&E count from 2017 FERC Form 1 Annual Report (pp. 300-301) City count from CCA 2017 customer and load data for City of San Diego
Gas Distribution	Allocated 50% to City based on estimated 2017 revenues: ▪ All SDG&E = 450,872,763 ▪ City = 225,683,875	All SDG&E revenue from SDG&E 2017 FERC Form 2 Annual Report (pp 300-301) City revenue from worksheet provided by City (SDGE Database FY20_v1.xlsx)
Reproduction Cost New Less Depreciation		
All RCNLD values	RCNLD values shown in analysis are adjusted for physical depreciation, but NOT economic obsolescence	

Income Approach

Table 2
Income Approach Key Assumptions

Category	Assumption	Source/Notes
Plant In Service Forecast		
Original Cost – BOY 2019	As developed in the Cost Approach	
Additions	2020 to 2028 additions from MRW analysis; times 42% for electric utility to reflect the portion estimated to be in the City and times 50% for gas utility to reflect the portion estimated to be in the City 2019 additions based on 2020 additions trended back to 2019 based on 3.24% annual capital inflation for electric distribution plant and 2.97% annual capital inflation for gas distribution plant	MRW analysis Capital inflation based on Handy Whitman Index from 2008 to 2018
Retirements	Based on fixed percent of annual Additions: ▪ 9.82% of Additions for electric distribution plant ▪ 7.53% of Additions for gas distribution plant	FERC Form 1 average electric distribution retirements for all SDG&E from 2013 through 2018 FERC Form 2 average gas distribution retirements for all SDG&E from 2014 through 2015
Depreciation Reserve – BOY 2019	As developed in the Cost Approach	
Depreciation	Depreciation as % of Average Plant (BOY and EOY) based on depreciation for all SDG&E: ▪ 3.83% for electric distribution ▪ 2.39% for gas distribution	SDG&E 2019, GRC A.17-10-007, SDG&E/Depreciation/Exh No: SDG&E-34-WP/Witness: M. Vanderbilt, pages 6-8
Cost of Removal	Cost of removal based on weighted average net salvage rates times retirements ▪ -71% for electric distribution ▪ -50% for gas distribution	SDG&E 2019 GRC Application, SDG&E/Depreciation/Exh No.: SDG&E-34-WP/Witness: M. Vanderbilt
Revenue Requirement		
Rate Base	Net Utility Plant plus cash working capital at 45 days of O&M less accumulated deferred income tax (ADIT)	Does not include some components that add to or reduce rate base, such as inventory, plant held for future use, or customer deposits
After-Tax Rate of Return on Rate Base (WACC)	7.55%	2020 CPUC Cost of Capital Decision 19-12-056 December 19, 2019
Net-to-Gross Multiplier for before tax return	1.3886	1/(1-TR), where TR is the combined Federal and State corporate income tax marginal rates, or 27.98%

Table 2
Income Approach Key Assumptions

Category	Assumption	Source/Notes
Distribution O&M Expenses	Based on a percent of gross distribution plant: ▪ 2.3% for electric ▪ 3.6% for gas	FERC Form 1, Average 2013 through 2018 FERC Form 2, Average 2014 through 2018
Customer and A&G O&M Expenses	Based on a percent of gross distribution plant: ▪ 12.3% for electric ▪ 8.7% for gas	FERC Form 1, Average 2013 through 2018 FERC Form 2, Average 2014 through 2018
Taxes Other than Income Taxes	Based on a percent of revenues: ▪ 2.6% for all	FERC Form 1, 2013 through 2018
Tax Depreciation		
MACRS 20-Year	As shown in Exhibit 2, Table 4	Modified Accelerated Cost Recovery System (MACRS), IRS Publication 946 (2018), Table A-1 (Half-Year Convention); Electric distribution plant is Asset Class 49.11 uses 20-year MACRS
Capitalization Rate for Terminal Value		
Earnings Growth Rate	2.10%	October 10, 2019 Blue Chip Economic Indicator Report, page 14, GDP Chained Price Index, five-year averages for 2021-2025 and 2026-2030

Analyses

Definition of Value

California Code of Civil Procedure Section 1263.320 defines Fair Market Value as follows:

a) The fair market value of the property taken is the highest price on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available.

b) The fair market value of property taken for which there is no relevant, comparable market is its value on the date of valuation as determined by any method of valuation that is just and equitable.

Book Value is the recorded cost of an asset or group of assets minus the accumulated provision for depreciation of these assets. The FERC Uniform System of Accounts (USOA) states that electric plant recorded on a utility's books, "shall be stated at the cost incurred by the person who first devoted the property to utility service".[1] When electric plant is purchased or sold, the cost of the plant and the accumulated provision for depreciation is recorded on the books of the acquiring utility at original cost.[2] A utility's rate base is primarily composed of the book cost of the utility's plant in service.

Methodology for Preliminary Valuation Study

The preliminary valuation study estimated the value of the SDG&E assets in the City based on an allocated share of SDG&E total system electric and gas distribution plant. As stated previously, an inventory of SDG&E electric and gas distribution assets in the City was not available at the time we performed the preliminary valuation study; therefore, we used an allocation approach to prepare a preliminary estimate of the fair market value and book value (or range of values) of the SDG&E assets for the preliminary valuation study.

NewGen considered three allocation factors for the electric system: customers, sales and annual revenues, which are shown in Table 3 below. The only data available for gas service in the City was annual revenues.

Table 3
City as a Percentage of Total SDG&E System

Allocation Factor	City	SDG&E	City/SDG&E
Electric System			
Average Meters	605,357 (1)	1,434,024 (2)	42.2%
Annual Sales (MWh)	6,571,415 (1)	15,623,083 (2)	42.1%
Annual Revenue ($000)	$1,550,856 (3)	$3,281,733 (2)	47.3%
Gas System			
Annual Revenue ($000)	$225,684 (3)	$450,873 (4)	50.1%

Source:
(1) City of San Diego, Community Choice Aggregation (CCA) 2017 customer and load data
(2) SDG&E 2017 FERC Form 1 Annual Report
(3) Franchise data provided by City (SDGE Database FY20_v1.xlsx)
(4) SDG&E 2017 FERC Form 2 Annual Report

NewGen assumed that the City represents 42% of the total SDG&E electric distribution system based on the relative number of electric meters and annual load, and 50% of the total SDG&E gas system based on annual revenues.

Effect of Utility Rate Regulation on Value

When estimating the fair market value of regulated utility property, it is important to understand utility rate regulation and how regulated utility rates are generally determined. In exchange for being granted the right to be the monopoly service provider, the utility agrees to have its rates regulated by the state public utilities commission, in this case the CPUC.

Under utility rate regulation, a utility is allowed to charge rates based on cost of service that produces forecasted revenues equal to the utility's total revenue requirement. The term "revenue requirement"

---

[1] FERC USOA, 18 CFR Part 101, Electric Plant Instructions, Section 2.
[2] Ibid, Section 5.

refers to the utility's total cost of serving its customers, including a reasonable rate of return. Under the utility approach to ratemaking used by investor-owned utilities (IOUs) and adopted by the CPUC and FERC, the total revenue requirement is generally equal to the utility's reasonable operating expenses, depreciation expense and taxes, plus the utility's authorized rate of return times rate base.

Rate base is the value of property on which a utility is allowed to earn its authorized rate of return and is generally equal to the OCLD value of the utility's plant in service, plus working capital and materials and supplies, and minus customer advances and deferred taxes. The utility's authorized rate of return is developed based on a weighted average cost of capital (WACC).

As a result of rate regulation and the way utility rates are developed, the income value of regulated utility property is typically close to the rate base value of the property, as described below.

The income approach estimates the value of property by capitalizing or determining the present worth of anticipated economic benefits from the property as a going concern. Under the direct capitalization of earnings method, the income value of the property is estimated by capitalizing (i.e., dividing) the net income associated with the property for a one-year period by an appropriate capitalization rate. This shown in Equation (1) below:

$$(1) \qquad Value = \frac{(Revenues - Expenses)}{Capitalization\ Rate}$$

The capitalization rate shown in Equation (1) is equal to the WACC for a hypothetical buyer of the property less growth in earnings. In theory, using the Perpetual Franchise Assumption, the income value for a regulated utility should equal its rate base value, since this is the value of the utility's investment on which it is allowed to earn its authorized rate of return. Generally speaking, rate base is approximately equal to the original cost of plant in service less accumulated depreciation.

Under cost of service ratemaking procedures approved by the CPUC and FERC, utility rates are designed to produce revenues that recover the utility's operating expenses plus a return on rate base, as shown in Equation (2) below:

$$(2) \qquad Revenues = Expenses + (Rate\ of\ Return)(Rate\ Base)$$

Equation (2) can be restated as follows:

$$(3) \qquad Rate\ Base = \frac{(Revenues - Expenses)}{Rate\ of\ Return}$$

By comparing Equations (1) and (3), one can see that, using the Perpetual Franchise Assumption, the capitalized income value for regulated utility property is generally equivalent to its rate base value with an adjustment for expected future growth.

Under the principle of substitution, an informed buyer would pay no more than the cost of producing a substitute property with the same utility as the property being valued. However, an informed buyer would also pay no more than the income value of the property. Therefore, in the case of rate regulated utility property, the income value is generally close to the rate base or OCLD value, assuming that utility rates are based on cost of service. This is because the net income (return) a utility can earn is determined based on the utility's authorized rate of return multiplied by the value of its rate base, which is primarily OCLD.

Cost Approach

The cost approach is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the property being valued. Two indicators of value that are commonly considered under the cost approach when valuing regulated public utility property are the RCNLD value and the OCLD value.

RCNLD is defined as the cost of reproducing a new replica of the property at current prices with the same or closely related materials, less accrued depreciation. In contrast, replacement cost is defined as the current cost of a similar new property having the nearest equivalent utility as the property being appraised. Since there have not been major changes in the way electric systems are constructed, there is typically not a significant difference between replacement cost and reproduction cost, and the terms are often used interchangeably.

OCLD is defined as the original cost of the property when it was first put into service as a public utility, less accrued depreciation. The OCLD value is equal to the net book value of the property. For rate regulated utility property, such as the SDG&E assets, the OCLD value is a relevant indicator of value because it is generally an approximation of the rate base value of the property, which is the value of the property on which the regulated utility is allowed to earn a return.

The cost approach indicators of value are adjusted for depreciation, which is the estimated loss in value of an asset, compared with a new asset. There are three basic types or causes of depreciation:

- **Physical deterioration** – the loss in value or usefulness resulting from the wear and tear of an asset in operation and exposure to various elements.
- **Functional obsolescence** – the loss in value or usefulness caused by inefficiencies or inadequacies of the property itself, when compared to a more efficient or less costly replacement property that new technology has developed.
- **Economic obsolescence** – the loss in value caused by factors external to the property.[3]

The estimated OCLD and RCNLD values of the SDG&E assets developed in this preliminary valuation study reflect an adjustment for physical depreciation, but not functional obsolescence or economic obsolescence. Currently, NewGen has no information about the SDG&E assets that suggests whether there is any functional obsolescence or not.

The SDG&E assets are subject to economic obsolescence due to the existence of utility rate regulation, which restricts the earnings of the utility to an allowed rate of return times rate base.[4] For the purpose of estimating a range of value in this preliminary valuation study, we did not make a specific adjustment for economic obsolescence in the Cost Approach; however, the relationship between the between the OCLD (approximate rate base) value and income value for regulated utility property was discussed in the previous section of this report and the summary of results.

To develop the OCLD and RCNLD values for the SDG&E electric and gas distribution assets, NewGen employed a trended original cost analysis. First, NewGen summarized the original cost and accumulated depreciation for all SDG&E electric distribution assets and gas distribution assets by FERC account as of September 30, 2018, as provided in an SDG&E GRC.[5] Subtracting accumulated depreciation from original cost yielded OCLD for all SDG&E electric and gas distribution assets by FERC account.

Next, an estimated age of plant by FERC account was developed from an SDG&E GRC document.[6] The average age of SDG&E total electric distribution plant was estimated to be 13.6 years and the average age

[3] American Society of Appraisers, *Valuing Machinery and Equipment*, Second Edition, pages 66-67.

[4] Woolery, *Valuation of Railroad and Utility Property*, page 44.

[5] A.19-03-002 GRC Phase 2 Application 3_4_2019, Appendix D

[6] SDG&E General Rate Case 2019, Phase I, Exhibit SDG&E-34 (WP MVanderbilt - Depreciation_ vol1), page 4 and 5, as of December 31, 2016.

of SDG&E total gas distribution plant was estimated to be 16.0 years. Given the estimated age of the plant in each FERC account, NewGen used a relevant cost inflation index to trend the original costs to reproduction costs new. The primary cost inflation index used for this purpose was the Handy-Whitman Index of Public Utility Construction Costs (Handy-Whitman) for the Pacific Region (E-6 and G-6), which provides data for most electric and gas FERC accounts. However, Handy-Whitman is a construction cost index and does not have data for land and land rights. Therefore, NewGen used the Consumer Price Index[7] to adjust the costs for land and land rights. The relevant cost inflation index was also used to trend the accumulated depreciation on original costs to accumulated depreciation on reproduction costs new. This allowed for the calculation of RCNLD.

After establishing the original cost, OCLD, reproduction cost new, and RCNLD for all SDG&E electric and gas distribution assets, NewGen allocated each value to the City (42% electric distribution and 50% gas distribution) to reflect the value of SDG&E assets in the City.

The estimated OCLD and RCNLD indicators of value for the SDG&E assets are shown in Table 4 below. A supporting schedule showing the calculation of the OCLD and RCNLD values are provided in Exhibit 1.

Table 4
Cost Approach Indicators of Value

Plant	Original Cost	OCLD	Reproduction Cost New	RCNLD
Electric Distribution	$2,823,843,000	$1,585,378,000	$5,047,460,000	$2,784,463,000
Gas Distribution	914,599,000	498,601,000	2,052,827,000	1,109,630,000
Total	**$3,738,442,000**	**$2,083,979,000**	**$7,100,287,000**	**$3,894,093,000**

Income Approach

The income approach estimates the value of property by capitalizing or determining the present worth of anticipated economic benefits from the property as a going concern. Under the DCF method, the direct economic benefits derived from continued ownership of the property being valued are expressed in terms of free cash flow, which represents the total cash flow generated by the going concern that is available to the providers of both debt and equity capital.

The DCF model used to estimate the value of the SDG&E assets, using the Perpetual Franchise Assumption, is essentially an after-tax cash flow model of annual revenues and expenses over a ten-year period beginning in 2019 and ending in 2028.

[7] Specifically, CPI-All Urban Consumers (Current Series), Series ID: CUUR0000SA0, All items in U.S. city average, all urban consumers, not seasonally adjusted, data in July for each year.

The calculation of free cash flow is illustrated as follows:

(1) Annual Operating Revenues
(2) Less: Annual Operating Expenses
(3) Equals: Pre-tax Net Operating Income
(4) Less: Income Taxes
(5) Equals: Earnings Before Interest, Depreciation & Amortization (EBIDA)
(6) Less: Future Capital Expenditures
(7) Less: Net Changes in Working Capital
(8) Equals: Free Cash Flow

Table 5 shows the calculation of the income value for the SDG&E Electric Distribution plant in the City using the DCF method. (See also Exhibit 2 for copies of the DCF analyses for electric and gas distribution plant).

Table 5
Discounted Cash Flow Indicator of Value – City Electric Distribution

Line No.			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Electric Distribution**											
2	Retail Rate Revenue	a	$ 717,792,158	$ 745,850,428	$ 774,777,101	$ 803,071,426	$ 829,084,233	$ 852,714,581	$ 873,859,122	$ 893,942,336	$ 914,493,396	$ 935,478,107
3	Other Operating Revenue	a	-	-	-	-	-	-	-	-	-	-
4	Total Operating Revenue		$ 717,792,158	$ 745,850,428	$ 774,777,101	$ 803,071,426	$ 829,084,233	$ 852,714,581	$ 873,859,122	$ 893,942,336	$ 914,493,396	$ 935,478,107
5												
6	Operating Expenses	a	$ 412,281,032	$ 432,032,977	$ 452,424,885	$ 473,364,007	$ 493,469,973	$ 512,682,989	$ 530,940,654	$ 548,177,858	$ 565,877,619	$ 584,052,351
7	Taxes Other Than Income Taxes	a	18,662,596	19,392,111	20,144,205	20,879,857	21,556,190	22,170,579	22,720,337	23,242,501	23,776,828	24,322,431
8	Depreciation Expense (book, includes net salvage)	b	110,743,926	116,009,370	121,430,529	126,814,183	131,971,433	136,886,252	141,541,914	146,124,400	150,829,856	155,661,581
9	Expenses Before Interest & Income Taxes		$ 541,687,554	$ 567,434,458	$ 593,999,619	$ 621,058,047	$ 646,997,596	$ 671,739,820	$ 695,202,906	$ 717,544,759	$ 740,484,303	$ 764,036,363
10												
11	**Income Tax Calculation**											
12	Operating Income		$ 176,104,604	$ 178,415,970	$ 180,777,482	$ 182,013,380	$ 182,086,638	$ 180,974,760	$ 178,656,216	$ 176,397,577	$ 174,009,093	$ 171,441,744
13	Add Back: Book Depreciation with net salvage		110,743,926	116,009,370	121,430,529	126,814,183	131,971,433	136,886,252	141,541,914	146,124,400	150,829,856	155,661,581
14	Less: Tax Depreciation (plant)		(89,541,366)	(178,181,091)	(176,576,008)	(175,041,220)	(173,095,258)	(170,796,395)	(168,081,610)	(165,439,851)	(169,915,301)	(176,062,978)
15	Less: Cost of Removal	b	(10,459,637)	(10,798,530)	(11,088,306)	(10,647,109)	(10,174,248)	(9,668,341)	(9,127,957)	(9,372,904)	(9,624,424)	(9,882,694)
16	Operating Income for Tax Purposes		$ 186,847,528	$ 105,445,720	$ 114,543,697	$ 123,139,234	$ 130,788,565	$ 137,396,276	$ 142,988,564	$ 147,709,222	$ 145,299,223	$ 141,157,654
17												
18	Combined Income Tax Rate	c	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%
19												
20	Income Taxes		$ 52,286,665	$ 29,507,508	$ 32,053,450	$ 34,458,791	$ 36,599,349	$ 38,448,424	$ 40,013,348	$ 41,334,358	$ 40,659,953	$ 39,500,993
21												
22	**Earnings and Cash Flow**											
23	Operating Income		$ 176,104,604	$ 178,415,970	$ 180,777,482	$ 182,013,380	$ 182,086,638	$ 180,974,760	$ 178,656,216	$ 176,397,577	$ 174,009,093	$ 171,441,744
24	Income Taxes (at statutory rates)		52,286,665	29,507,508	32,053,450	34,458,791	36,599,349	38,448,424	40,013,348	41,334,358	40,659,953	39,500,993
25	Net Income		$ 123,817,939	$ 148,908,462	$ 148,724,032	$ 147,554,589	$ 145,487,289	$ 142,526,336	$ 138,642,868	$ 135,063,219	$ 133,349,139	$ 131,940,751
26												
27	Plus: Depreciation Expense (book, includes net salvage)	d	$ 110,743,926	$ 116,009,370	$ 121,430,529	$ 126,814,183	$ 131,971,433	$ 136,886,252	$ 141,541,914	$ 146,124,400	$ 150,829,856	$ 155,661,581
28	Earnings before Interest, Depr & Amort		$ 234,561,866	$ 264,917,832	$ 270,154,561	$ 274,368,772	$ 277,458,722	$ 279,412,588	$ 280,184,783	$ 281,187,619	$ 284,178,995	$ 287,602,332
29												
30	Less: Capital Expenditures	b	$ 150,019,180	$ 154,879,801	$ 159,035,974	$ 152,708,024	$ 145,925,932	$ 138,669,881	$ 130,919,318	$ 134,432,515	$ 138,039,988	$ 141,744,266
31	Less: Changes in Working Capital	e	-	2,435,171	2,514,071	2,581,536	2,478,818	2,368,728	2,250,945	2,125,135	2,182,162	2,240,720
32	Free Cash Flow		$ 84,542,686	$ 107,602,859	$ 108,604,517	$ 119,079,213	$ 129,053,973	$ 138,373,979	$ 147,014,520	$ 144,629,969	$ 143,956,845	$ 143,617,346
33												
34	Discount Rate		7.55%									
35	Growth Rate		2.10%									
36	Capitalization Rate for Terminal Value		5.45%									
37												
38	Net Present Value of Cash Flows (2019 - 2028)		$ 840,280,862									
39	Terminal Value		2,690,519,451									
40	Present Value of Terminal Value		1,397,469,711									
41												
42	Estimated Income Value - Electric Dist		$ 2,237,750,573									
43												
44	Income Value Divided by OCLD		1.41									

Under the DCF method, using the Perpetual Franchise Assumption, the income indicator of value is equal to the sum of the present value of the projected cash flows plus the present value of the projected terminal value. The series of annual cash flows from 2019 to 2028 was discounted using a 7.55% discount rate, which is equal to SDG&E's authorized rate of return (WACC). For the terminal (or residual) value, the projected cash flow in year 2028 was capitalized into perpetuity at the discount rate less a growth rate equal to 2.1%, which is the projected rate of growth in earnings, and then discounted back to 2019.

As shown in Table 5, the income value of the SDG&E electric distribution plant in the City, using the Perpetual Franchise Assumption, is equal to approximately $2,237,751,000.

Table 6 shows the calculation of the income value of the SDG&E gas plant in the City using the Perpetual Franchise Assumption.

Table 6
Discounted Cash Flow Indicator of Value – City Gas Distribution

Line No.			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A	B	C	D	E	F	G	H	I	J	K	L	M
46	**Gas Distribution**											
47	Retail Rate Revenue	a	$ 196,068,650	$ 204,299,592	$ 212,720,206	$ 220,819,491	$ 228,138,903	$ 234,663,480	$ 240,378,145	$ 245,722,756	$ 251,110,008	$ 256,526,855
48	Other Operating Revenue	a	-	-	-	-	-	-	-	-	-	-
49	Total Operating Revenue		$ 196,068,650	$ 204,299,592	$ 212,720,206	$ 220,819,491	$ 228,138,903	$ 234,663,480	$ 240,378,145	$ 245,722,756	$ 251,110,008	$ 256,526,855
50												
51	Operating Expenses	a	$ 112,495,700	$ 117,731,329	$ 123,122,456	$ 128,598,869	$ 133,759,228	$ 138,592,163	$ 143,086,023	$ 147,228,869	$ 151,437,254	$ 155,712,215
52	Taxes Other Than Income Taxes	a	5,097,785	5,311,789	5,530,725	5,741,307	5,931,611	6,101,250	6,249,832	6,388,792	6,528,860	6,669,698
53	Depreciation Expense (book, includes net salvage)	b	22,367,585	23,400,022	24,455,852	25,489,262	26,460,156	27,366,295	28,205,390	29,016,749	29,840,944	30,678,178
54	Expenses Before Interest & Income Taxes		$ 139,961,070	$ 146,443,140	$ 153,109,034	$ 159,829,438	$ 166,150,995	$ 172,059,709	$ 177,541,244	$ 182,634,410	$ 187,807,059	$ 193,060,091
55												
56	**Income Tax Calculation**											
57	Operating Income		$ 56,107,580	$ 57,856,452	$ 59,611,172	$ 60,990,053	$ 61,987,908	$ 62,603,771	$ 62,836,901	$ 63,088,346	$ 63,302,949	$ 63,466,764
58	Add Back: Book Depreciation with net salvage		22,367,585	23,400,022	24,455,852	25,489,262	26,460,156	27,366,295	28,205,390	29,016,749	29,840,944	30,678,178
59	Less: Tax Depreciation (plant)		(26,209,882)	(52,233,251)	(51,894,938)	(51,515,077)	(50,941,420)	(50,199,097)	(49,277,443)	(48,339,066)	(49,461,780)	(51,057,774)
60	Less: Cost of Removal	b	(1,733,117)	(1,784,591)	(1,812,822)	(1,708,201)	(1,599,816)	(1,487,574)	(1,371,380)	(1,393,075)	(1,415,113)	(1,437,500)
61	Operating Income for Tax Purposes		$ 50,532,166	$ 27,238,632	$ 30,359,264	$ 33,256,037	$ 35,906,828	$ 38,283,395	$ 40,393,468	$ 42,372,954	$ 42,267,001	$ 41,649,668
62												
63	Combined Income Tax Rate	c	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%
64												
65	Income Taxes		$ 14,140,719	$ 7,622,350	$ 8,495,615	$ 9,306,236	$ 10,048,023	$ 10,713,072	$ 11,303,547	$ 11,857,478	$ 11,827,828	$ 11,655,076
66												
67	**Earnings and Cash Flow**											
68	Operating Income		$ 56,107,580	$ 57,856,452	$ 59,611,172	$ 60,990,053	$ 61,987,908	$ 62,603,771	$ 62,836,901	$ 63,088,346	$ 63,302,949	$ 63,466,764
69	Income Taxes (at statutory rates)		14,140,719	7,622,350	8,495,615	9,306,236	10,048,023	10,713,072	11,303,547	11,857,478	11,827,828	11,655,076
70	Net Income		$ 41,966,861	$ 50,234,102	$ 51,115,557	$ 51,683,816	$ 51,939,885	$ 51,890,699	$ 51,533,354	$ 51,230,868	$ 51,475,121	$ 51,811,688
71												
72	Plus: Depreciation Expense (book, includes net salvage)	d	$ 22,367,585	$ 23,400,022	$ 24,455,852	$ 25,489,262	$ 26,460,156	$ 27,366,295	$ 28,205,390	$ 29,016,749	$ 29,840,944	$ 30,678,178
73	Earnings before Interest, Depr & Amort		$ 64,334,446	$ 73,634,124	$ 75,571,409	$ 77,173,079	$ 78,400,040	$ 79,256,994	$ 79,738,744	$ 80,247,617	$ 81,316,065	$ 82,489,865
74												
75	Less: Capital Expenditures	b	$ 46,032,324	$ 47,399,484	$ 48,149,330	$ 45,370,541	$ 42,491,784	$ 39,510,590	$ 36,424,439	$ 37,000,663	$ 37,586,002	$ 38,180,601
76	Less: Changes in Working Capital	e	-	645,489	664,660	675,174	636,209	595,841	554,037	510,762	518,842	527,050
77	Free Cash Flow		$ 18,302,122	$ 25,589,152	$ 26,757,420	$ 31,127,363	$ 35,272,048	$ 39,150,563	$ 42,760,268	$ 42,736,193	$ 43,211,221	$ 43,782,214
78												
79	Discount Rate		7.55%									
80	Growth Rate		2.10%									
81	Capitalization Rate for Terminal Value		5.45%									
82												
83	Net Present Value of Cash Flows (2019 - 2028)		$ 226,874,692									
84	Terminal Value		820,213,590									
85	Present Value of Terminal Value		426,023,178									
86												
87	Estimated Income Value - Gas Distribution		$ 652,897,870									
88												
89	Income Value Divided by OCLD		1.31									

As shown in Table 6, the income value of SDG&E gas plant in the City using the DCF method is equal to approximately $652,898,000.

Copies of the DCF analyses for electric and gas distribution plant in the City are provided in Exhibit 2.

The value of SDG&E's existing franchise agreements which expire in January 2021, using the One-Year Franchise Assumption, were estimated using a one-year direct capitalization of cash flows. This analysis is shown in Table 6 of Exhibit 2.

The estimated value of SDG&E distribution infrastructure under SDG&E's existing franchise agreements with the City, using the One-Year Franchise Assumption, is equal to $208,333,000 for the electric distribution system and $57,742,000 for the gas distribution system. The One-Year Franchise Assumption assumes that the existing franchise agreements require SDG&E to remove its facilities if it does not obtain new or extended franchises. NewGen offers no opinion on matters requiring legal interpretation of the existing franchise agreements.

Market Approach

The guideline transaction method under the market approach involves review of recent sales of similar facilities between a willing buyer and a willing seller, who are unrelated, as an indication of the market price for such facilities. The guideline transaction method is primarily applicable to property that is readily substitutable and where a number of similar type properties have recently been sold. Caution must be exercised when using the comparable sales method as an indicator of value for utility property. Normally, the appraiser will, when necessary, make adjustments to the guideline sales transactions in order to correlate the sales price to the characteristics of the property being valued. However, there are many factors that can influence sales price including, among others, market area, age, and other considerations that may be reflected in the sales price. Each party's motivation can affect the negotiation and the terms of the sale. Strategic objectives are the driving motivator for some sales. These objectives are often kept confidential and are not available to an appraiser for evaluation. For this reason, we generally use the comparable sales method as a test of the reasonableness of values produced by the cost and income approaches.

Table 7 shows select sales transactions involving electric utility distribution property that occurred from 2008 through 2018. All of the sales shown in Table 7 were negotiated sales and did not involve the exercise of eminent domain. To the best of our knowledge, none of the sales shown in Table 7 involved utility property with franchise agreements due to expire within one year of the sales transaction. There is a wide variation in the size, location, and type of plant (i.e., some sales include generation and transmission plant) for these sales and no attempt was made to adjust the sales to correlate with the characteristics of the SDG&E assets. More information regarding the guideline sales transactions is provided in Exhibit 3.

While many of the sales transactions in Table 7 vary in size compared to the SDG&E assets, examining the ratio of purchase price to net plant (OCLD) provides insight into the valuation of property between regulated utilities in willing buyer/willing seller transactions using the Perpetual Franchise Assumption. The average (mean) ratio results in a purchase price equal to 1.32 times net plant. Most of the sales are within plus or minus one standard deviation from the mean, i.e. 0.96 to 1.67 times net plant, which corresponds to a range of value under the market approach for the SDG&E assets of approximately $1.53 billion to $2.64 billion based on an OCLD (net plant) value of electric plant of $1,585,378,000. The average (mean) ratio of 1.32 times net plant when applied to the SDG&E electric distribution assets yields a purchase price equal to approximately $2.09 billion.

Table 7
Electric Utility Sale Transactions

No.	Year	State	Seller	Purchaser	Purchase Price	Net Plant	Purchase Price/ Net Plant
1	2008	VA	Delmarva Power & Light Company	A&N Electric Cooperative, Inc. & Old Dominion Electric Cooperative	$54,200,000	$46,375,000	1.17
2	2010	VA	Potomac Edison (Allegheny Energy, Inc.)	Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative	$499,483,000	$389,222,800	1.28
3	2010	WV	Shenandoah Valley Electric Cooperative	Monongahela Power (Allegheny Energy, Inc.)	$14,500000	$12,003,000	1.21
4	2010	TX	Southwest Public Service Company	Lubbock Power and Light	$87,000,000	$62,400,000	1.39
5	2011	CA	Sierra Pacific Power Co.	California Pacific Electric Co.	$132,000,000	$121,206,000	1.09
6	2011	CA	Mountain Utilities	Kirkwood Meadows Public Utility District	$1,956,400	$966,700	2.02
7	2011	OH	Wright Patterson AFB	Dayton Power & Light, Inc.	$18,700,000	$18,929,000	0.99
8	2011	OH	Dayton Power & Light, Inc.	AES Corporation	$4,750,000,000	$2,742,193,400	1.73
9	2012	NH	Granite State Electric Co.	Liberty Energy NH	$83,000,000	$99,498,000	0.83
10	2015	IA,MN	Interstate Power & Light	Southern Minnesota Energy Cooperative	$129,000,000	$105,189,000	1.23
11	2018	FL	Gulf Power Company	NextEra Energy	$5,657,000,000	$3,605,426,000	1.57
12	2018	AK	Anchorage Municipal Light & Power	Chugach Electric Association	$767,800,000	$715,400,000	1.07
13	2019	ME	Emera Maine	ENMAX	$1,309,000,000	712,000,000	1,84
14	2019	TX	Oncor Electric Delivery Company, LLC	AEP Texas, Inc.	$17,956,000	$17,956,000	1.00

Table 8 shows select sales transactions involving gas utility distribution property that occurred from 2015 through 2018. Like the electric sales transaction data, all of the gas system sales shown in Table 8 were negotiated sales and did not involve the exercise of eminent domain. The size and location of the sales vary, and no attempt was made to adjust the sales to correlate with the characteristics of the SDG&E assets. More information regarding the guideline sales transactions is provided in Exhibit 3.

Table 8
Gas Utility Sale Transactions

No.	Year	State	Seller	Purchaser	Purchase Price	Net Plant	Purchase Price/ Net Plant
1	2014	WI, IL, MN, MI	Integrys Energy Group	Wisconsin Energy Corporation	$9,100,000,000	$6,500,000,000	1.40
2	2015	KY	Public Gas Company, Lexington, KY	Kentucky Frontier Gas LLC	$1,900,000	$2,088,937	0.91
3	2015	NC, SC	Piedmont Natural Gas	Duke Energy	$6,700,000,000	$4,348,049,000	1.54
4	2017	DC	WGL Holdings, Inc. (Washington Gas)	AltaGas Ltd.	$7,100,000,000	$4,100,000,000	1.73
5	2018	MD	Elkton Gas Company (Pivotal Utility Holdings, Inc. subsidiary of Southern Company Gas)	South Jersey Industries, Inc.	$10,000,000	$11,329,735	0.88
6	2018	NJ	Elizabethtown Gas Company (Pivotal Utility Holdings, Inc. subsidiary of Southern Company Gas)	South Jersey Industries, Inc.	$1,690,000,000	$1,432,203,390	1.18
7	2018	IN, OH	Vectren	CenterPoint Energy	$7,479,500,000	$4,276,700,000	1.18
8	2019	MD	Elkton Gas Company (South Jersey Industries, Inc.)	Chesapeake Utilities Corp.	$15,000,000	$11,329,735	1.32

The average (mean) ratio for the gas distribution sales transactions shown in Table 8 results in a purchase price, using the Perpetual Franchise Assumption, equal to 1.27 times net plant. Most of the sales are within plus or minus one standard deviation from the mean, i.e., 0.98 to 1.56 times net plant, which corresponds to a range of value under the market approach for the SDG&E gas plant of approximately $486 million to $779 million based on an OCLD (net plant) value of $498,601,000. The average (mean) ratio of 1.27 times net plant when applied to the SDG&E gas plant yields a purchase price equal to approximately $633 million.

Summary of Results

Based on the results of the analyses and the assumptions described in this valuation report, NewGen estimated preliminary indicators of value using generally accepted approaches to valuation. These indicators of value are summarized in Table 9.

Table 9
Summary of Indicators of Value

	Electric Distribution	Gas Distribution
Cost Approach:		
RCNLD (1)	$2,784,463,000	$1,109,630,000
OCLD	$1,585,378,000	$498,601,000
Income Approach:		
Perpetual Franchise Assumption (2)	$2,237,751,000	$652,898,000
One-Year Franchise Assumption (3)	$208,333,000	$57,742,000
Market Approach (2)	$2,086,955,000	$632,523,000
Estimated Range of Value:		
Perpetual Franchise Assumption (2)	$1.6 billion to $2.2 billion	$499 million to $653 million
One-Year Franchise Assumption (3)	$208,333,000	$57,742,000

(1) The RCNLD values shown in the table above do not include an adjustment for economic obsolescence due to rate regulation. Such an adjustment is appropriate when appraising the value of rate regulated utility assets. The unadjusted RCNLD values are shown above because SDG&E may claim the value of the assets is equal to RCNLD without any adjustment for economic obsolescence.

(2) Going concern value does not consider the expiration of SDG&E's existing electric and gas franchise agreements with the City in January 2021.

(3) Value based on SDG&E's existing franchise agreements with City which expire in January 2021 and assumes the existing agreements require SDG&E to remove its facilities if it does not obtain new or extended franchises.

The indicators of value shown in Table 9 do not include an allocation of SDG&E common and general plant assets. It is not known what SDG&E-owned common and general plant assets, if any, are needed to operate a stand-alone electric distribution and/or gas utility serving the City. For example, SDG&E computer and communications systems are likely proprietary to SDG&E and would not be acquired by the new utility; however, the cost of these facilities would presumably be included as start-up costs for the new utility.

The results shown in Table 9 provide a preliminary estimate of the range of fair market value and book cost for the SDG&E distribution assets in the City. However, as the City obtains more data about the inventory, age, and condition of the SDG&E assets, we expect the RCNLD and OCLD values will change, which will likely affect the other indicators of value. Therefore, we recommend that the City update the preliminary valuation analyses as more detailed information about the SDG&E assets becomes available. NewGen would be pleased to assist the City in this regard.

As discussed earlier in this report, the effect of utility rate regulation is an important consideration in valuing public utility property. Under standard ratemaking procedures, rate regulated utilities are allowed to earn a fair and reasonable rate of return on their rate base (approximately OCLD). Operating expenses are essentially a pass-through cost recovered through rates. Thus, in theory, the income value (using the Perpetual Franchise Assumption) for rate regulated utility property on a going concern basis is generally close to its OCLD value since this is the value of the utility's investment on which it is allowed to earn its authorized rate of return or profit. The income values shown in Table 9 support paying a price that is slightly higher than OCLD (1.41 times OCLD for electric distribution and 1.31 times OCLD for gas) due to projected growth in earnings.

The RCNLD values shown in Table 9 do not include an adjustment for economic obsolescence due to rate regulation, which NewGen would likely include if performing an appraisal of the assets. In addition, no adjustment was made to the preliminary cost approach indicators of value for functional obsolescence because a condition assessment of the SDG&E assets has not yet been performed.

NewGen chose not to adjust the RCNLD values for economic obsolescence in this preliminary valuation report because SDG&E will likely claim that the value of the assets is equal to the RCNLD value without any adjustment for economic obsolescence; therefore, the RCNLD value shown in Table 9 is an estimate of the values that SDG&E may claim for the electric and gas distribution systems in the City.

A preliminary estimate of the book cost (i.e., OCLD value) of the SDG&E infrastructure in the City is equal to $1.6 billion for the electric distribution system and $499 million for the gas system.

Under the Perpetual Franchise Assumption, based on the information available and assumptions and analyses described in this valuation report, a preliminary estimate of the range of fair market value of SDG&E's distribution infrastructure in the City is equal to $1.6 billion to $2.2 billion for the electric distribution system and $499 million to $653 million for the gas distribution system.

Under the One-Year Franchise Assumption, the estimated value of SDG&E distribution infrastructure under SDG&E's existing franchise agreements with the City, which expire in January 2021, is equal to $208,333,000 for the electric distribution system and $57,742,000 for the gas distribution system. The One-Year Franchise Assumption assumes that the existing franchise agreements require SDG&E to remove its facilities if it does not obtain new or extended franchises. NewGen offers no opinion on matters requiring legal interpretation of the existing franchise agreements.

Exhibit 1
COST APPROACH

Exhibit 1
Preliminary Estimate of OCLD and RCNLD Value

Line No.		Original Cost (OC)	Accumulated Deprec & Amort	Original Cost Less Depreciation (OCLD)	Handy-Whitman Index Line No.	Handy-Whitman Index In Service Year	Handy-Whitman Index Value In Service	Handy-Whitman Index Value 2019	Reproduction Cost New (RCN)	Accumulated Deprec & Amort	Reproduction Cost New Less Depreciation * (RCNLD)
A	B	C	D	E	F	G	H	I	J	K	L
1	Total SDG&E Electric Distribution (9/30/2018)										
2	(360) Land and Land Rights	$ 104,970,819	$ 44,060,804	$ 60,910,015	CPI	2001	178	257	$ 151,732,214	$ 63,688,589	$ 88,043,624
3	(361) Structures and Improvements	9,321,203	1,619,793	7,701,410	42	2001	355	819	21,534,740	3,742,202	17,792,538
4	(362) Station Equipment	547,176,332	202,687,931	344,488,401	43	2005	473	816	944,465,123	349,853,732	594,611,391
5	(363) Storage Battery Equipment	124,269,131	26,319,167	97,949,964	42	2017	758	819	134,269,681	28,437,200	105,832,481
6	(364) Poles, Towers, and Fixtures	764,676,388	283,055,905	481,620,484	44	2006	491	672	1,047,096,348	387,597,693	659,498,655
7	(365) Overhead Conductors and Devices	743,469,939	226,021,736	517,448,203	45	2006	575	924	1,195,243,539	363,365,088	831,878,451
8	(366) Underground Conduit	1,318,884,753	507,723,367	811,161,386	46	2003	397	669	2,221,104,845	855,045,771	1,366,059,074
9	(367) Underground Conductors and Devices	1,606,439,000	940,155,526	666,283,473	47	2004	372	809	3,496,112,870	2,046,071,987	1,450,040,884
10	(368) Line Transformers	674,669,876	188,483,481	486,186,395	48	2007	462	1,010	1,474,637,568	411,971,592	1,062,665,976
11	(369) Services	533,563,599	372,213,030	161,350,570	50	2001	349	633	967,060,153	674,619,464	292,440,689
12	(370) Meters	255,473,598	125,669,268	129,804,330	52	2013	355	383	276,012,378	135,772,439	140,239,939
13	(371) Installations on Customer Premises	9,360,129	10,498,157	(1,138,028)	42	2000	345	819	22,220,132	24,921,712	(2,701,580) **
14	(372) Leased Property on Customer Premises	-	-	-					-	-	-
15	(373) Street Lighting and Signal Systems	31,160,189	20,217,576	10,942,613	53	1998	398	847	66,271,639	42,998,837	23,272,802
16											
17		$ 6,723,434,956	$ 2,948,725,741	$ 3,774,709,215					$ 12,017,761,230	$ 5,388,086,305	$ 6,629,674,925
18	Source	a	a			b					
19											
20	Portion of Electric Distribution Plant in City	42.0%	42.0%						42.0%	42.0%	
21	Source	c	c						c	c	
22											
23	**Value of Electric Distribution in City**	**$ 2,823,842,682**	**$ 1,238,464,811**	**$ 1,585,377,870**					**$ 5,047,459,717**	**$ 2,262,996,248**	**$ 2,784,463,468**
24											
25	Total SDG&E Gas Distribution (9/30/2018)										
26	(374) Land and Land Rights	$ 9,456,487	$ 7,189,250	$ 2,267,237	CPI	1970	39	257	$ 62,211,802	$ 47,296,232	$ 14,915,569
27	(375) Structures and Improvements	43,447	61,253	(17,806)	42	1970	80	614	333,455	470,118	(136,663) **
28	(376) Mains	1,207,988,581	401,841,604	806,146,977	44	2003	424	960	2,738,297,610	910,904,226	1,827,393,384
29	(377) Compressor Station Equipment	-	-	-	46	2019	749	749	-	-	-
30	(378) Measuring and Regulating Station Equipment-General	19,025,030	8,758,432	10,266,598	47	2005	513	833	30,892,495	14,221,781	16,670,714
31	(379) Measuring and Regulating Station Equipment-City Gate	-	-	-	48	2019	832	832	-	-	-
32	(380) Services	314,129,551	297,410,351	16,719,200	49	1994	332	762	720,984,091	682,610,505	38,373,586
33	(381) Meters	162,001,324	65,512,916	96,488,408	51	2007	227	511	364,474,358	147,392,486	217,081,871
34	(382) Meter Installations	103,635,104	44,407,723	59,227,381	52	2006	705	1,094	160,761,154	68,886,280	91,874,873
35	(383) House Regulators	-	-	-	53	2019	565	565	-	-	-
36	(384) House Regulators Installations	-	-	-	54	2019	1,067	1,067	-	-	-
37	(385) Industrial Measuring and Regulating Station Equipment	1,516,811	1,254,331	262,480	47	2001	389	833	3,252,261	2,689,466	562,795
38	(386) Other Property on Customers' Premises	-	-	-	47	2019	833	833	-	-	-
39	(387) Other Equipment	11,402,035	5,561,193	5,840,842	47	2001	389	833	24,447,606	11,923,998	12,523,608
40											
41		$ 1,829,198,369	$ 831,997,052	$ 997,201,317					$ 4,105,654,831	$ 1,886,395,093	$ 2,219,259,738
42	Source	a	a			b					
43											
44	Portion of Gas Distribution Plant in City	50.0%	50.0%						50.0%	50.0%	
45	Source	d	d						d	d	
46											
47	**Value of Gas Distribution in City**	**$ 914,599,185**	**$ 415,998,526**	**$ 498,600,658**					**$ 2,052,827,415**	**$ 943,197,546**	**$ 1,109,629,869**
48											
49	Value of Electric and Gas Distribution in City	**$ 3,738,441,866**	**$ 1,654,463,337**	**$ 2,083,978,529**					**$ 7,100,287,132**	**$ 3,206,193,795**	**$ 3,894,093,337**

Exhibit 1
Preliminary Estimate of OCLD and RCNLD Value

Notes:

a A.19-03-002 GRC Phase 2 Application 3_4_2019, Appendix D

b In Service Year based on cost-weighted average age by FERC account from SDG&E General Rate Case 2019, except Land and Land Rights, which are assumed to be same average age as Structures and Improvements

c Allocation to City based on:

	Customers	Source
All SDG&E	1,434,024	SDG&E 2017 FERC Form 1 Annual Report (pp. 300-301)
City	605,357	CCA 2017 customer and load data for City of San Diego
Portion for City	42.0%	

d Allocation to City based on:

	Revenues	Source
All SDG&E	450,872,763	SDG&E 2017 FERC Form 2 Annual Report (pp 300-301)
City	225,683,875	2017 gas revenues in City, worksheet provided by City (SDGE Database FY20_v1.xlsx)
Portion for City	50.0%	

* Less physical depreciation; RCNLD value shown in column L does not include adjustment for economic obsolescence

** Per SDG&E book depreciation study, accumulated depreciation exceeds original cost for some plant accounts; may be due to negative net salvage (A.19-03-002 GRC Phase 2 Application 3_4_2019, Appendix D)

Exhibit 2
INCOME APPROACH

Exhibit 2, Table 1
Assumptions

Line No. A	B	C	D	Notes E
1	**Plant In Service - City**			Cost Approach Analysis
2		**Electric Distribution**		
3		Original Cost (OC)	$ 2,823,842,682	
4		Original Cost Less Depreciation (OCLD)	$ 1,585,377,870	
5		**Gas Distribution**		
6		Original Cost (OC)	$ 914,599,185	
7		Original Cost Less Depreciation (OCLD)	$ 498,600,658	
8				
9	**Plant In Service - All SDG&E**			
10		**Electric Distribution**		FERC Form 1 Report, Page 206 - 207
11		Retirements as % of Additions	9.82%	Average 2013 through 2018
12				
13		City as a % of all SDG&E electric	42.00%	2017 Customers
14				
15		Net Salvage Rate	-71.00%	Source: Current Depreciation Parameters, SDG&E 2019 GRC Application, SDG&E/Depreciation/Exh No.: SDG&E-34-WP/Witness: M. Vanderbilt
16				
17		Depreciation as % of Average Plant (BOY and EOY)	3.83%	SDG&E 2019, GRC A.17-10-007, SDG&E/Depreciation/Exh No: SDG&E-34-WP/Witness: M. Vanderbilt, pages 6-8
18				
19		Annual increase construction costs	3.24%	Projected increase in Handy Whitman Index for electric distribution plant, estimated based on increase from 2008 to 2018
20				
21		**Gas Distribution**		
22		Retirements as % of Additions	7.53%	Average 2014 through 2015
23				
24		City as a % of all SDG&E gas	50.00%	2017 Revenues
25				
26		Net Salvage Rate	-50.00%	Source: Current Depreciation Parameters, SDG&E 2019 GRC Application, SDG&E/Depreciation/Exh No.: SDG&E-34-WP/Witness: M. Vanderbilt
27				
28		Depreciation as % of Average Plant (BOY and EOY)	2.39%	SDG&E 2019, GRC A.17-10-007, SDG&E/Depreciation/Exh No: SDG&E-34-WP/Witness: M. Vanderbilt, pages 6-8
29				
30		Annual increase construction costs	2.97%	Projected increase in Handy Whitman Index for gas distribution plant, estimated based on increase from 2008 to 2018 for mains (line 44)
31				
32	**Inflation Rate**		2.10%	October 10, 2019 Blue Chip Economic Indicator Report, page 14, GDP Chained Price Index, five-year averages for 2021-2025 and 2026-2030
33				
34	**Operating Ratios**			
35		Electric Distribution O&M as a % of EOY Gross Plant	2.30%	FERC Form 1, Average 2013 through 2018
36		Electric Customer and A&G O&M as a % of EOY Gross Plant	12.30%	FERC Form 1, Average 2013 through 2018
37		Gas Distribution O&M as a % of EOY Gross Plant	3.60%	FERC Form 2, Average 2014 through 2018
38		Gas Customer and A&G O&M as a % of EOY Gross Plant	8.70%	FERC Form 2, Average 2014 through 2018
39		Taxes other than income taxes as a % of Revenue	2.60%	FERC Form 1, Average 2013 through 2018
40				
41	**Income Taxes**			
42		Federal income tax rate	21.00%	Statutory rate
43		State corporate tax rate	8.84%	California statutory rate
44		Combined statutory federal and state income tax rates	27.98%	equals 1-((1-FITR)*(1-SITR))
45		Net-to-gross multiplier	1.3886	
46				
47	**Hypothetical Buyer**			
48		WACC	7.55%	2020 CPUC Cost of Capital Decision 19-12-056 December 19, 2019
49		Working Capital	45	days/365 days times O&M expense
50		Earnings Growth Rate	2.10%	Assumed Inflation Rate

Prepared by:
NewGen Strategies and Solutions

Exhibit 2, Table 2
Plant in Service in the City of San Diego

Line No.			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Compound Annual Growth
A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Electric Distribution**												
2	BOY Original Cost		$ 2,823,842,682	$ 2,959,129,978	$ 3,098,800,583	$ 3,242,219,224	$ 3,379,931,320	$ 3,511,527,325	$ 3,636,579,823	$ 3,754,642,864	$ 3,875,874,106	$ 4,000,358,567	3.9%
3	Additions	a, b	150,019,180	154,879,801	159,035,974	152,708,024	145,925,932	138,669,881	130,919,318	134,432,515	138,039,988	141,744,266	-0.6%
4	Retirements	c	(14,731,883)	(15,209,197)	(15,617,333)	(14,995,928)	(14,329,926)	(13,617,382)	(12,856,277)	(13,201,273)	(13,555,527)	(13,919,287)	-0.6%
5	EOY Original Cost		$ 2,959,129,978	$ 3,098,800,583	$ 3,242,219,224	$ 3,379,931,320	$ 3,511,527,325	$ 3,636,579,823	$ 3,754,642,864	$ 3,875,874,106	$ 4,000,358,567	$ 4,128,183,546	3.8%
6													
7	BOY Depreciation Reserve	d	$ 1,238,464,811	$ 1,324,017,217	$ 1,414,018,861	$ 1,508,743,752	$ 1,609,914,898	$ 1,717,382,157	$ 1,830,982,685	$ 1,950,540,366	$ 2,074,090,589	$ 2,201,740,494	6.6%
8	Depreciation Expense	e	110,743,926	116,009,370	121,430,529	126,814,183	131,971,433	136,886,252	141,541,914	146,124,400	150,829,856	155,661,581	3.9%
9	Retirements		(14,731,883)	(15,209,197)	(15,617,333)	(14,995,928)	(14,329,926)	(13,617,382)	(12,856,277)	(13,201,273)	(13,555,527)	(13,919,287)	-0.6%
10	Cost of Removal	h	(10,459,637)	(10,798,530)	(11,088,306)	(10,647,109)	(10,174,248)	(9,668,341)	(9,127,957)	(9,372,904)	(9,624,424)	(9,882,694)	-0.6%
11	EOY Depreciation Reserve		$ 1,324,017,217	$ 1,414,018,861	$ 1,508,743,752	$ 1,609,914,898	$ 1,717,382,157	$ 1,830,982,685	$ 1,950,540,366	$ 2,074,090,589	$ 2,201,740,494	$ 2,333,600,095	6.5%
12													
13	EOY Net Plant		$ 1,635,112,761	$ 1,684,781,722	$ 1,733,475,472	$ 1,770,016,422	$ 1,794,145,168	$ 1,805,597,138	$ 1,804,102,498	$ 1,801,783,517	$ 1,798,618,073	$ 1,794,583,452	1.0%
14													
15	Net Additions	f	$ 135,287,297	$ 139,670,605	$ 143,418,641	$ 137,712,096	$ 131,596,005	$ 125,052,498	$ 118,063,041	$ 121,231,242	$ 124,484,461	$ 127,824,979	-0.6%
16	Net Additions as % of BOY plant		4.8%	4.7%	4.6%	4.2%	3.9%	3.6%	3.2%	3.2%	3.2%	3.2%	
17													
18	**Gas Distribution**												
19	BOY Original Cost		$ 914,599,185	$ 957,165,274	$ 1,000,995,577	$ 1,045,519,262	$ 1,087,473,402	$ 1,126,765,555	$ 1,163,300,998	$ 1,196,982,676	$ 1,231,197,189	$ 1,265,952,965	3.7%
20	Additions	a, g	46,032,324	47,399,484	48,149,330	45,370,541	42,491,784	39,510,590	36,424,439	37,000,663	37,586,002	38,180,601	-2.1%
21	Retirements	i	(3,466,234)	(3,569,181)	(3,625,645)	(3,416,402)	(3,199,631)	(2,975,147)	(2,742,760)	(2,786,150)	(2,830,226)	(2,874,999)	-2.1%
22	EOY Original Cost		$ 957,165,274	$ 1,000,995,577	$ 1,045,519,262	$ 1,087,473,402	$ 1,126,765,555	$ 1,163,300,998	$ 1,196,982,676	$ 1,231,197,189	$ 1,265,952,965	$ 1,301,258,567	3.5%
23													
24	BOY Depreciation Reserve	d	$ 415,998,526	$ 433,166,760	$ 451,213,011	$ 470,230,396	$ 490,595,056	$ 512,255,765	$ 535,159,339	$ 559,250,588	$ 584,088,113	$ 609,683,718	4.3%
25	Depreciation Expense	j	22,367,585	23,400,022	24,455,852	25,489,262	26,460,156	27,366,295	28,205,390	29,016,749	29,840,944	30,678,178	3.6%
26	Retirements		(3,466,234)	(3,569,181)	(3,625,645)	(3,416,402)	(3,199,631)	(2,975,147)	(2,742,760)	(2,786,150)	(2,830,226)	(2,874,999)	-2.1%
27	Cost of Removal	h	(1,733,117)	(1,784,591)	(1,812,822)	(1,708,201)	(1,599,816)	(1,487,574)	(1,371,380)	(1,393,075)	(1,415,113)	(1,437,500)	-2.1%
28	EOY Depreciation Reserve		$ 433,166,760	$ 451,213,011	$ 470,230,396	$ 490,595,056	$ 512,255,765	$ 535,159,339	$ 559,250,588	$ 584,088,113	$ 609,683,718	$ 636,049,397	4.4%
29													
30	EOY Net Plant		$ 523,998,514	$ 549,782,566	$ 575,288,866	$ 596,878,346	$ 614,509,790	$ 628,141,659	$ 637,732,088	$ 647,109,076	$ 656,269,247	$ 665,209,170	2.7%
31													
32	Net Additions	f	$ 42,566,090	$ 43,830,303	$ 44,523,685	$ 41,954,140	$ 39,292,153	$ 36,535,443	$ 33,681,679	$ 34,214,513	$ 34,755,776	$ 35,305,602	-2.1%
33	Net Additions as % of BOY plant		4.7%	4.6%	4.4%	4.0%	3.6%	3.2%	2.9%	2.9%	2.8%	2.8%	

Notes:

a Additions in 2020 through 2028 based on MRW analysis
b Additions in first year based on 2020 MRW analysis trended back to 2019 based on 3.24%, which is consistent with the annualized change in Handy Whitman Index for electric distribution plant from 2008 to 2018
c Based on 9.82% of Additions (this percent is based on average electric distribution retirements for all SDG&E from 2013 through 2018)
d Based on Original Cost minus Original Cost Less Depreciation from Cost Approach analysis
e Based on 3.83% of average Original Cost (this percent is based on SDG&E 2019, GRC A.17-10-007, SDG&E/Depreciation/Exh No: SDG&E-34-WP/Witness: M. Vanderbilt, pages 6-8) - includes net salvage
f Additions less Retirements
g Additions in first year based on 2020 MRW analysis trended back to 2019 based on 2.97%, which is consistent with the annualized change in Handy Whitman Index for gas distribution plant from 2008 to 2018
h Cost of removal based on weighted average net salvage rates (taken from SDG&E 2019 GRC Application, SDG&E/Depreciation/Exh No.: SDG&E-34-WP/Witness: M. Vanderbilt) times retirements
i Based on 7.53% of Additions (this percent is based on average gas distribution retirements as a percent of additions for all SDG&E from 2014 through 2015 as reported in FERC Form 2)
j Based on 2.39% of average Original Cost (this percent is based on SDG&E 2019, GRC A.17-10-007, SDG&E/Depreciation/Exh No: SDG&E-34-WP/Witness: M. Vanderbilt, pages 6-8)

Exhibit 2, Table 3

Revenue Requirement for Rate Base

Line No.			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Electric Distribution**											
2	Total Utility Plant	a	$ 2,959,129,978	$ 3,098,800,583	$ 3,242,219,224	$ 3,379,931,320	$ 3,511,527,325	$ 3,636,579,823	$ 3,754,642,864	$ 3,875,874,106	$ 4,000,358,567	$ 4,128,183,546
3	Accumulated Depreciation	a	1,324,017,217	1,414,018,861	1,508,743,752	1,609,914,898	1,717,382,157	1,830,982,685	1,950,540,366	2,074,090,589	2,201,740,494	2,333,600,095
4	Net Utility Plant		$ 1,635,112,761	$ 1,684,781,722	$ 1,733,475,472	$ 1,770,016,422	$ 1,794,145,168	$ 1,805,597,138	$ 1,804,102,498	$ 1,801,783,517	$ 1,798,618,073	$ 1,794,583,452
5												
6	Add: Cash Working Capital	b	$ 50,829,168	$ 53,264,340	$ 55,778,410	$ 58,359,946	$ 60,838,764	$ 63,207,492	$ 65,458,437	$ 67,583,572	$ 69,765,734	$ 72,006,454
7	Add: Inventory		-	-	-	-	-	-	-	-	-	-
8	Less: Deferred Income Tax	g	(6,151,251)	(36,208,199)	(64,890,513)	(92,224,268)	(118,133,053)	(142,559,500)	(165,431,462)	(186,781,865)	(208,581,368)	(231,276,365)
9	Less: Customer Deposits		-	-	-	-	-	-	-	-	-	-
10	Rate Base		$ 1,679,790,678	$ 1,701,837,863	$ 1,724,363,370	$ 1,736,152,100	$ 1,736,850,879	$ 1,726,245,130	$ 1,704,129,474	$ 1,682,585,224	$ 1,659,802,438	$ 1,635,313,540
11												
12	After-tax Rate of Return (WACC)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
13	Allowed Return (after income tax)		$ 126,824,196	$ 128,488,759	$ 130,189,434	$ 131,079,484	$ 131,132,241	$ 130,331,507	$ 128,661,775	$ 127,035,184	$ 125,315,084	$ 123,466,172
14	Return (before income tax)	c	176,104,604	178,415,970	180,777,482	182,013,380	182,086,638	180,974,760	178,656,216	176,397,577	174,009,093	171,441,744
15												
16	Dist O&M Expenses	d	$ 64,948,382	$ 68,059,989	$ 71,272,413	$ 74,571,042	$ 77,738,420	$ 80,765,128	$ 83,641,336	$ 86,356,786	$ 89,145,104	$ 92,008,247
17	Cust and A&G O&M Expense	h	347,332,650	363,972,987	381,152,472	398,792,965	415,731,552	431,917,861	447,299,318	461,821,072	476,732,515	492,044,104
18	Taxes Other Than Income Taxes	e	18,662,596	19,392,111	20,144,205	20,879,857	21,556,190	22,170,579	22,720,337	23,242,501	23,776,828	24,322,431
19	Depreciation Expense	a	110,743,926	116,009,370	121,430,529	126,814,183	131,971,433	136,886,252	141,541,914	146,124,400	150,829,856	155,661,581
20	Total Operating Expenses		$ 541,687,554	$ 567,434,458	$ 593,999,619	$ 621,058,047	$ 646,997,596	$ 671,739,820	$ 695,202,906	$ 717,544,759	$ 740,484,303	$ 764,036,363
21												
22	Gross Revenue Requirement		$ 717,792,158	$ 745,850,428	$ 774,777,101	$ 803,071,426	$ 829,084,233	$ 852,714,581	$ 873,859,122	$ 893,942,336	$ 914,493,396	$ 935,478,107
23												
24	Less Other Revenues		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25												
26	Net Revenue Requirement - Electric Dist		**$ 717,792,158**	**$ 745,850,428**	**$ 774,777,101**	**$ 803,071,426**	**$ 829,084,233**	**$ 852,714,581**	**$ 873,859,122**	**$ 893,942,336**	**$ 914,493,396**	**$ 935,478,107**
27												
28	**Gas Distribution**											
29	Total Utility Plant	a	$ 957,165,274	$ 1,000,995,577	$ 1,045,519,262	$ 1,087,473,402	$ 1,126,765,555	$ 1,163,300,998	$ 1,196,982,676	$ 1,231,197,189	$ 1,265,952,965	$ 1,301,258,567
30	Accumulated Depreciation	a	433,166,760	451,213,011	470,230,396	490,595,056	512,255,765	535,159,339	559,250,588	584,088,113	609,683,718	636,049,397
31	Net Utility Plant		$ 523,998,514	$ 549,782,566	$ 575,288,866	$ 596,878,346	$ 614,509,790	$ 628,141,659	$ 637,732,088	$ 647,109,076	$ 656,269,247	$ 665,209,170
32												
33	Add: Cash Working Capital	b	$ 13,869,333	$ 14,514,821	$ 15,179,481	$ 15,854,655	$ 16,490,864	$ 17,086,705	$ 17,640,743	$ 18,151,504	$ 18,670,346	$ 19,197,396
34	Add: Inventory		-	-	-	-	-	-	-	-	-	-
35	Less: Deferred Income Tax	g	(2,680,308)	(12,428,066)	(21,861,459)	(30,973,525)	(39,723,042)	(48,076,284)	(55,997,018)	(63,486,336)	(71,118,335)	(79,022,742)
36	Less: Customer Deposits		-	-	-	-	-	-	-	-	-	-
37	Rate Base		$ 535,187,539	$ 551,869,321	$ 568,606,888	$ 581,759,476	$ 591,277,612	$ 597,152,080	$ 599,375,812	$ 601,774,244	$ 603,821,258	$ 605,383,825
38												
39	After-tax Rate of Return (WACC)		7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%	7.55%
40	Allowed Return (after income tax)		$ 40,406,659	$ 41,666,134	$ 42,929,820	$ 43,922,840	$ 44,641,460	$ 45,084,982	$ 45,252,874	$ 45,433,955	$ 45,588,505	$ 45,706,479
41	Return (before income tax)	c	56,107,580	57,856,452	59,611,172	60,990,053	61,987,908	62,603,771	62,836,901	63,088,346	63,302,949	63,466,764
42												
43	Dist O&M Expenses	f	$ 32,925,571	$ 34,457,950	$ 36,035,841	$ 37,638,693	$ 39,149,042	$ 40,563,560	$ 41,878,836	$ 43,091,376	$ 44,323,099	$ 45,574,307
44	Cust and A&G O&M Expense	i	79,570,129	83,273,379	87,086,615	90,960,176	94,610,186	98,028,603	101,207,187	104,137,493	107,114,155	110,137,908
45	Taxes Other Than Income Taxes	e	5,097,785	5,311,789	5,530,725	5,741,307	5,931,611	6,101,250	6,249,832	6,388,792	6,528,860	6,669,698
46	Depreciation Expense	a	22,367,585	23,400,022	24,455,852	25,489,262	26,460,156	27,366,295	28,205,390	29,016,749	29,840,944	30,678,178
47	Total Operating Expenses		$ 139,961,070	$ 146,443,140	$ 153,109,034	$ 159,829,438	$ 166,150,995	$ 172,059,709	$ 177,541,244	$ 182,634,410	$ 187,807,059	$ 193,060,091
48												
49	Gross Revenue Requirement		$ 196,068,650	$ 204,299,592	$ 212,720,206	$ 220,819,491	$ 228,138,903	$ 234,663,480	$ 240,378,145	$ 245,722,756	$ 251,110,008	$ 256,526,855
50												
51	Less Other Revenues		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52												
53	Net Revenue Requirement - Gas Dist		**$ 196,068,650**	**$ 204,299,592**	**$ 212,720,206**	**$ 220,819,491**	**$ 228,138,903**	**$ 234,663,480**	**$ 240,378,145**	**$ 245,722,756**	**$ 251,110,008**	**$ 256,526,855**
54												
55	Net Revenue Requirement - Total		$ 913,860,808	$ 950,150,020	$ 987,497,306	$ 1,023,890,918	$ 1,057,223,137	$ 1,087,378,061	$ 1,114,237,267	$ 1,139,665,091	$ 1,165,603,404	$ 1,192,004,962

Prepared by:
NewGen Strategies and Solutions

Notes:

- a Source: Exhibit 2, Table 2
- b Based on an assumed 45 days O&M
- c Based on the combined statutory federal and state income tax rates
- d Based on 2.3% of gross electric distribution plant, which is based on O&M from FERC Form 1, Average 2013 through 2018
- e Based on 2.6% of revenues, which is based on average taxes other than income taxes in FERC Form 1, 2013 through 2018
- f Based on 3.6% of gross gas distribution plant, which is based on O&M from FERC Form 2, Average 2014 through 2018
- g Source: Exhibit 2, Table 4
- h Based on 12.3% of gross electric distribution plant, which is based on O&M from FERC Form 1, Average 2013 through 2018
- i Based on 8.7% of gross gas distribution plant, which is based on O&M from FERC Form 2, Average 2014 through 2018

Exhibit 2, Table 4
Depreciation for Tax Purposes

Line No.												
A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Total Plant Tax Depreciation Basis**		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
2	MACRS 20-Year	a	0.03750	0.07219	0.06677	0.06177	0.05713	0.05285	0.04888	0.04522	0.04462	0.04461
3												
4			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
5	**Electric Distribution Capital**											
6	Initial Purchase by IOU	b	$ 2,237,750,573	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Annual Capital Additions	c	150,019,180	154,879,801	159,035,974	152,708,024	145,925,932	138,669,881	130,919,318	134,432,515	138,039,988	141,744,266
8			$ 2,387,769,753	$ 154,879,801	$ 159,035,974	$ 152,708,024	$ 145,925,932	$ 138,669,881	$ 130,919,318	$ 134,432,515	$ 138,039,988	$ 141,744,266
9												
10	**Electric Distribution Annual Tax Depreciation**											
11	Initial Purchase & Year 1 Capital		$ 89,541,366	$ 172,373,098	$ 159,431,386	$ 147,492,538	$ 136,413,286	$ 126,193,631	$ 116,714,186	$ 107,974,948	$ 106,542,286	$ 106,518,409
12	Capital Additions - Year 2			5,807,993	11,180,773	10,341,324	9,566,925	8,848,283	8,185,398	7,570,525	7,003,665	6,910,737
13	Capital Additions - Year 3				5,963,849	11,480,807	10,618,832	9,823,652	9,085,725	8,405,051	7,773,678	7,191,607
14	Capital Additions - Year 4					5,726,551	11,023,992	10,196,315	9,432,775	8,724,209	8,070,619	7,464,368
15	Capital Additions - Year 5						5,472,222	10,534,393	9,743,474	9,013,845	8,336,748	7,712,185
16	Capital Additions - Year 6							5,200,121	10,010,579	9,258,988	8,565,639	7,922,210
17	Capital Additions - Year 7								4,909,474	9,451,066	8,741,483	8,086,886
18	Capital Additions - Year 8									5,041,219	9,704,683	8,976,059
19	Capital Additions - Year 9										5,176,500	9,965,107
20	Capital Additions - Year 10											5,315,410
21			$ 89,541,366	$ 178,181,091	$ 176,576,008	$ 175,041,220	$ 173,095,258	$ 170,796,395	$ 168,081,610	$ 165,439,851	$ 169,915,301	$ 176,062,978
22												
23	Book Depreciation without Net Salvage	d	$ 67,559,736	$ 70,771,939	$ 74,079,137	$ 77,363,455	$ 80,509,654	$ 83,507,957	$ 86,348,161	$ 89,143,723	$ 92,014,304	$ 94,961,916
24												
25	Difference Between Book and Tax Depr		$ 21,981,629	$ 107,409,152	$ 102,496,871	$ 97,677,765	$ 92,585,604	$ 87,288,438	$ 81,733,449	$ 76,296,128	$ 77,900,997	$ 81,101,062
26												
27	**Electric Distribution Deferred Income Tax (State and Federal)**											
28	Annual		$ 6,151,251	$ 30,056,947	$ 28,682,314	$ 27,333,755	$ 25,908,785	$ 24,426,447	$ 22,871,961	$ 21,350,403	$ 21,799,504	$ 22,694,997
29	Accumulated		6,151,251	36,208,199	64,890,513	92,224,268	118,133,053	142,559,500	165,431,462	186,781,865	208,581,368	231,276,365
30												
31			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
32	**Gas Distribution Capital**											
33	Initial Purchase by IOU	b	$ 652,897,870	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Annual Capital Additions	c	46,032,324	47,399,484	48,149,330	45,370,541	42,491,784	39,510,590	36,424,439	37,000,663	37,586,002	38,180,601
35			$ 698,930,194	$ 47,399,484	$ 48,149,330	$ 45,370,541	$ 42,491,784	$ 39,510,590	$ 36,424,439	$ 37,000,663	$ 37,586,002	$ 38,180,601
36												
37	**Gas Distribution Annual Tax Depreciation**											
38	Initial Purchase & Year 1 Capital		$ 26,209,882	$ 50,455,771	$ 46,667,569	$ 43,172,918	$ 39,929,882	$ 36,938,461	$ 34,163,708	$ 31,605,623	$ 31,186,265	$ 31,179,276
39	Capital Additions - Year 2			1,777,481	3,421,769	3,164,864	2,927,866	2,707,933	2,505,063	2,316,887	2,143,405	2,114,965
40	Capital Additions - Year 3				1,805,600	3,475,900	3,214,931	2,974,184	2,750,771	2,544,692	2,353,539	2,177,313
41	Capital Additions - Year 4					1,701,395	3,275,299	3,029,391	2,802,538	2,592,019	2,397,833	2,217,712
42	Capital Additions - Year 5						1,593,442	3,067,482	2,837,176	2,624,718	2,427,556	2,245,691
43	Capital Additions - Year 6							1,481,647	2,852,270	2,638,122	2,440,569	2,257,240
44	Capital Additions - Year 7								1,365,916	2,629,480	2,432,060	2,249,938
45	Capital Additions - Year 8									1,387,525	2,671,078	2,470,534
46	Capital Additions - Year 9										1,409,475	2,713,333
47	Capital Additions - Year 10											1,431,773
48			$ 26,209,882	$ 52,233,251	$ 51,894,938	$ 51,515,077	$ 50,941,420	$ 50,199,097	$ 49,277,443	$ 48,339,066	$ 49,461,780	$ 51,057,774
49												
50	Book Depreciation without Net Salvage	d	$ 16,631,743	$ 17,399,427	$ 18,184,504	$ 18,952,911	$ 19,674,833	$ 20,348,607	$ 20,972,528	$ 21,575,826	$ 22,188,668	$ 22,811,205
51												
52	Difference Between Book and Tax Depr		$ 9,578,139	$ 34,833,825	$ 33,710,433	$ 32,562,166	$ 31,266,587	$ 29,850,491	$ 28,304,915	$ 26,763,240	$ 27,273,112	$ 28,246,569
53												
54	**Gas Distribution Deferred Income Tax (State and Federal)**											
55	Annual		$ 2,680,308	$ 9,747,758	$ 9,433,393	$ 9,112,066	$ 8,749,517	$ 8,353,242	$ 7,920,734	$ 7,489,318	$ 7,631,999	$ 7,904,407
56	Accumulated		2,680,308	12,428,066	21,861,459	30,973,525	39,723,042	48,076,284	55,997,018	63,486,336	71,118,335	79,022,742

Notes:

a Modified Accelerated Cost Recovery System (MACRS), IRS Publication 946 (2018), Table A-1 (Half-Year Convention); Electric distribution plant is Asset Class 49.11 uses 20-year MACRS

b Source: Exhibit 2, Table 5

c Source: Exhibit 2, Table 2

d Book depreciation with the amounts for net salvage removed

Exhibit 2, Table 5

Discounted Cash Flow Indicator of Value

Line No.			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Electric Distribution**											
2	Retail Rate Revenue	a	$ 717,792,158	$ 745,850,428	$ 774,777,101	$ 803,071,426	$ 829,084,233	$ 852,714,581	$ 873,859,122	$ 893,942,336	$ 914,493,396	$ 935,478,107
3	Other Operating Revenue	a	-	-	-	-	-	-	-	-	-	-
4	Total Operating Revenue		$ 717,792,158	$ 745,850,428	$ 774,777,101	$ 803,071,426	$ 829,084,233	$ 852,714,581	$ 873,859,122	$ 893,942,336	$ 914,493,396	$ 935,478,107
5												
6	Operating Expenses	a	$ 412,281,032	$ 432,032,977	$ 452,424,885	$ 473,364,007	$ 493,469,973	$ 512,682,989	$ 530,940,654	$ 548,177,858	$ 565,877,619	$ 584,052,351
7	Taxes Other Than Income Taxes	a	18,662,596	19,392,111	20,144,205	20,879,857	21,556,190	22,170,579	22,720,337	23,242,501	23,776,828	24,322,431
8	Depreciation Expense (book, includes net salvage)	b	110,743,926	116,009,370	121,430,529	126,814,183	131,971,433	136,886,252	141,541,914	146,124,400	150,829,856	155,661,581
9	Expenses Before Interest & Income Taxes		$ 541,687,554	$ 567,434,458	$ 593,999,619	$ 621,058,047	$ 646,997,596	$ 671,739,820	$ 695,202,906	$ 717,544,759	$ 740,484,303	$ 764,036,363
10												
11	**Income Tax Calculation**											
12	Operating Income		$ 176,104,604	$ 178,415,970	$ 180,777,482	$ 182,013,380	$ 182,086,638	$ 180,974,760	$ 178,656,216	$ 176,397,577	$ 174,009,093	$ 171,441,744
13	Add Back: Book Depreciation with net salvage		110,743,926	116,009,370	121,430,529	126,814,183	131,971,433	136,886,252	141,541,914	146,124,400	150,829,856	155,661,581
14	Less: Tax Depreciation (plant)		(89,541,366)	(178,181,091)	(176,576,008)	(175,041,220)	(173,095,258)	(170,796,395)	(168,081,610)	(165,439,851)	(169,915,301)	(176,062,978)
15	Less: Cost of Removal	b	(10,459,637)	(10,798,530)	(11,088,306)	(10,647,109)	(10,174,248)	(9,668,341)	(9,127,957)	(9,372,904)	(9,624,424)	(9,882,694)
16	Operating Income for Tax Purposes		$ 186,847,528	$ 105,445,720	$ 114,543,697	$ 123,139,234	$ 130,788,565	$ 137,396,276	$ 142,988,564	$ 147,709,222	$ 145,299,223	$ 141,157,654
17												
18	Combined Income Tax Rate	c	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%
19												
20	Income Taxes		$ 52,286,665	$ 29,507,508	$ 32,053,450	$ 34,458,791	$ 36,599,349	$ 38,448,424	$ 40,013,348	$ 41,334,358	$ 40,659,953	$ 39,500,993
21												
22	**Earnings and Cash Flow**											
23	Operating Income		$ 176,104,604	$ 178,415,970	$ 180,777,482	$ 182,013,380	$ 182,086,638	$ 180,974,760	$ 178,656,216	$ 176,397,577	$ 174,009,093	$ 171,441,744
24	Income Taxes (at statutory rates)		52,286,665	29,507,508	32,053,450	34,458,791	36,599,349	38,448,424	40,013,348	41,334,358	40,659,953	39,500,993
25	Net Income		$ 123,817,939	$ 148,908,462	$ 148,724,032	$ 147,554,589	$ 145,487,289	$ 142,526,336	$ 138,642,868	$ 135,063,219	$ 133,349,139	$ 131,940,751
26												
27	Plus: Depreciation Expense (book, includes net salvage)	d	$ 110,743,926	$ 116,009,370	$ 121,430,529	$ 126,814,183	$ 131,971,433	$ 136,886,252	$ 141,541,914	$ 146,124,400	$ 150,829,856	$ 155,661,581
28	Earnings before Interest, Depr & Amort		$ 234,561,866	$ 264,917,832	$ 270,154,561	$ 274,368,772	$ 277,458,722	$ 279,412,588	$ 280,184,783	$ 281,187,619	$ 284,178,995	$ 287,602,332
29												
30	Less: Capital Expenditures	b	$ 150,019,180	$ 154,879,801	$ 159,035,974	$ 152,708,024	$ 145,925,932	$ 138,669,881	$ 130,919,318	$ 134,432,515	$ 138,039,988	$ 141,744,266
31	Less: Changes in Working Capital	e	-	2,435,171	2,514,071	2,581,536	2,478,818	2,368,728	2,250,945	2,125,135	2,182,162	2,240,720
32	Free Cash Flow		$ 84,542,686	$ 107,602,859	$ 108,604,517	$ 119,079,213	$ 129,053,973	$ 138,373,979	$ 147,014,520	$ 144,629,969	$ 143,956,845	$ 143,617,346
33												
34	Discount Rate		7.55%									
35	Growth Rate		2.10%									
36	Capitalization Rate for Terminal Value		5.45%									
37												
38	Net Present Value of Cash Flows (2019 - 2028)		$ 840,280,862									
39	Terminal Value		2,690,519,451									
40	Present Value of Terminal Value		1,397,469,711									
41												
42	Estimated Income Value - Electric Distribution		$ 2,237,750,573									
43												
44	Income Value Divided by OCLD		1.41									
45												
46	**Gas Distribution**											
47	Retail Rate Revenue	a	$ 196,068,650	$ 204,299,592	$ 212,720,206	$ 220,819,491	$ 228,138,903	$ 234,663,480	$ 240,378,145	$ 245,722,756	$ 251,110,008	$ 256,526,855
48	Other Operating Revenue	a	-	-	-	-	-	-	-	-	-	-
49	Total Operating Revenue		$ 196,068,650	$ 204,299,592	$ 212,720,206	$ 220,819,491	$ 228,138,903	$ 234,663,480	$ 240,378,145	$ 245,722,756	$ 251,110,008	$ 256,526,855
50												
51	Operating Expenses	a	$ 112,495,700	$ 117,731,329	$ 123,122,456	$ 128,598,869	$ 133,759,228	$ 138,592,163	$ 143,086,023	$ 147,228,869	$ 151,437,254	$ 155,712,215
52	Taxes Other Than Income Taxes	a	5,097,785	5,311,789	5,530,725	5,741,307	5,931,611	6,101,250	6,249,832	6,388,792	6,528,860	6,669,698
53	Depreciation Expense (book, includes net salvage)	b	22,367,585	23,400,022	24,455,852	25,489,262	26,460,156	27,366,295	28,205,390	29,016,749	29,840,944	30,678,178
54	Expenses Before Interest & Income Taxes		$ 139,961,070	$ 146,443,140	$ 153,109,034	$ 159,829,438	$ 166,150,995	$ 172,059,709	$ 177,541,244	$ 182,634,410	$ 187,807,059	$ 193,060,091

Prepared by:
NewGen Strategies and Solutions

Exhibit 2, Table 5
Discounted Cash Flow Indicator of Value

Line No.			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
A	B	C	D	E	F	G	H	I	J	K	L	M
55												
56	**Income Tax Calculation**											
57	Operating Income		$ 56,107,580	$ 57,856,452	$ 59,611,172	$ 60,990,053	$ 61,987,908	$ 62,603,771	$ 62,836,901	$ 63,088,346	$ 63,302,949	$ 63,466,764
58	Add Back: Book Depreciation with net salvage		22,367,585	23,400,022	24,455,852	25,489,262	26,460,156	27,366,295	28,205,390	29,016,749	29,840,944	30,678,178
59	Less: Tax Depreciation (plant)		(26,209,882)	(52,233,251)	(51,894,938)	(51,515,077)	(50,941,420)	(50,199,097)	(49,277,443)	(48,339,066)	(49,461,780)	(51,057,774)
60	Less: Cost of Removal	b	(1,733,117)	(1,784,591)	(1,812,822)	(1,708,201)	(1,599,816)	(1,487,574)	(1,371,380)	(1,393,075)	(1,415,113)	(1,437,500)
61	Operating Income for Tax Purposes		$ 50,532,166	$ 27,238,632	$ 30,359,264	$ 33,256,037	$ 35,906,828	$ 38,283,395	$ 40,393,468	$ 42,372,954	$ 42,267,001	$ 41,649,668
62												
63	Combined Income Tax Rate	c	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%	27.98%
64												
65	Income Taxes		$ 14,140,719	$ 7,622,350	$ 8,495,615	$ 9,306,236	$ 10,048,023	$ 10,713,072	$ 11,303,547	$ 11,857,478	$ 11,827,828	$ 11,655,076
66												
67	**Earnings and Cash Flow**											
68	Operating Income		$ 56,107,580	$ 57,856,452	$ 59,611,172	$ 60,990,053	$ 61,987,908	$ 62,603,771	$ 62,836,901	$ 63,088,346	$ 63,302,949	$ 63,466,764
69	Income Taxes (at statutory rates)		14,140,719	7,622,350	8,495,615	9,306,236	10,048,023	10,713,072	11,303,547	11,857,478	11,827,828	11,655,076
70	Net Income		$ 41,966,861	$ 50,234,102	$ 51,115,557	$ 51,683,816	$ 51,939,885	$ 51,890,699	$ 51,533,354	$ 51,230,868	$ 51,475,121	$ 51,811,688
71												
72	Plus: Depreciation Expense (book, includes net salvage)	d	$ 22,367,585	$ 23,400,022	$ 24,455,852	$ 25,489,262	$ 26,460,156	$ 27,366,295	$ 28,205,390	$ 29,016,749	$ 29,840,944	$ 30,678,178
73	Earnings before Interest, Depr & Amort		$ 64,334,446	$ 73,634,124	$ 75,571,409	$ 77,173,079	$ 78,400,040	$ 79,256,994	$ 79,738,744	$ 80,247,617	$ 81,316,065	$ 82,489,865
74												
75	Less: Capital Expenditures	b	$ 46,032,324	$ 47,399,484	$ 48,149,330	$ 45,370,541	$ 42,491,784	$ 39,510,590	$ 36,424,439	$ 37,000,663	$ 37,586,002	$ 38,180,601
76	Less: Changes in Working Capital	e	-	645,489	664,660	675,174	636,209	595,841	554,037	510,762	518,842	527,050
77	Free Cash Flow		$ 18,302,122	$ 25,589,152	$ 26,757,420	$ 31,127,363	$ 35,272,048	$ 39,150,563	$ 42,760,268	$ 42,736,193	$ 43,211,221	$ 43,782,214
78												
79	Discount Rate		7.55%									
80	Growth Rate		2.10%									
81	Capitalization Rate for Terminal Value		5.45%									
82												
83	Net Present Value of Cash Flows (2019 - 2028)		$ 226,874,692									
84	Terminal Value		820,213,590									
85	Present Value of Terminal Value		426,023,178									
86												
87	Estimated Income Value - Gas Distribution		$ 652,897,870									
88												
89	Income Value Divided by OCLD		1.31									
90												
91	**Electric and Gas Distribution**											
92	Estimated Income Value		$ 2,890,648,443									
93												
94	Income Value Divided by OCLD		1.39									

Notes:
- a Source: Exhibit 2, Table 3
- b Source: Exhibit 2, Table 2
- c Based on the combined statutory federal and state income tax rates
- d Depreciation is added back because it is a non-cash expense
- e Based on an assumed 45 days O&M

Exhibit 2, Table 6
Income Indicator of Value
Based on One Year Remaining in Franchise

Line No.			2020
A	B	C	D
1	**Electric Distribution**		
2	Retail Rate Revenue	a	$ 745,850,428
3	Other Operating Revenue	a	-
4	Total Operating Revenue		$ 745,850,428
5			
6	Operating Expenses	a	$ 432,032,977
7	Taxes Other Than Income Taxes	a	19,392,111
8	Depreciation Expense (book, excludes net salvage)	e	70,771,939
9	Cost of Removal	a	10,798,530
10	Expenses Before Interest & Income Taxes		$ 532,995,557
11			
12	**Earnings and Cash Flow**		
13	Operating Income		$ 212,854,871
14	Income Taxes (at statutory rates)	b	59,564,456
15	Net Income		$ 153,290,416
16			
17	Plus: Depreciation Expense (book, excludes net salvage)	c	$ 70,771,939
18	Earnings before Interest, Depr & Amort		$ 224,062,355
19			
20	Less: Capital Expenditures	d	$ -
21	Less: Changes in Working Capital	d	-
22	Free Cash Flow		$ 224,062,355
23			
24	Discount Rate (one year)		7.55%
25			
26	Estimated Income Value - Electric Distribution		$ 208,333,199
27			
28	Income Value Divided by OCLD		0.13
29			
30	**Gas Distribution**		
31	Retail Rate Revenue	a	$ 204,299,592
32	Other Operating Revenue	a	-
33	Total Operating Revenue		$ 204,299,592
34			
35	Operating Expenses	a	$ 117,731,329
36	Taxes Other Than Income Taxes	a	5,311,789
37	Depreciation Expense (book, excludes net salvage)	e	17,399,427
38	Cost of Removal	a	1,784,591

Prepared by:
NewGen Strategies and Solutions

Exhibit 2, Table 6
Income Indicator of Value
Based on One Year Remaining in Franchise

Line No.			2020
A	B	C	D
39	Expenses Before Interest & Income Taxes		$ 142,227,135
40			
41	**Earnings and Cash Flow**		
42	Operating Income		$ 62,072,457
43	Income Taxes (at statutory rates)	b	17,370,108
44	Net Income		$ 44,702,349
45			
46	Plus: Depreciation Expense (book, excludes net salvage)	c	$ 17,399,427
47	Earnings before Interest, Depr & Amort		$ 62,101,775
48			
49	Less: Capital Expenditures	d	$ -
50	Less: Changes in Working Capital	d	-
51	Free Cash Flow		$ 62,101,775
52			
53	Discount Rate (one year)		7.55%
54			
55	Estimated Income Value - Gas Distribution		$ 57,742,237
56			
57	Income Value Divided by OCLD		0.12
58			
59	**Electric and Gas Distribution**		
60	Estimated Income Value		$ 266,075,435
61			
62	Income Value Divided by OCLD		0.13

Notes:
- a Source: Exhibit 2, Table 5
- b Based on the combined statutory federal and state income tax rates
- c Depreciation is added back because it is a non-cash expense
- d No capital expenditures or additions to reserves because only one year operation
- e Source: Exhibit 2, Table 4

Exhibit 3
MARKET APPROACH

Exhibit 3, Table 1
Analysis of Guideline Sales Transactions
Electric Utility Property

Transaction Number	Year	State	Seller	Type (1)	Purchaser	Type (1)	Asset (2)	Type of Transaction	Sale Price	Net Plant	No. of Customers	Price/ Net Plant	Price/ Customer	Comments
1	2008	VA	Delmarva Power & Light Company	IOU	A&N Electric Cooperative, Inc. & Old Dominion Electric Cooperative	CP	T,D	Cash	$54,200,000	$46,375,000	22,295	1.17	2,431	Delmarva sold its retail electric distribution assets/business on the Eastern Shore of Virginia, consisting of 22,295 customer meters, to A&N Electric Cooperative, Inc., and its wholesale electric transmission assets/business to Old Dominion Electric Cooperative. Total consideration paid for these transactions equaled $54,200,000 with $48,800,000 paid for distribution assets and $5,400,000 paid for transmission assets.
2	2010	VA	Potomac Edison (Allegheny Energy, Inc.)	IOU	Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative	CP	D	Cash	$499,482,972	$389,222,834	102,000	1.28	4,897	Sale will allow Allegheny Power to focus on serving customers in PA, WV and MD, and generation fleet.
3	2010	WV	Shenandoah Valley Electric Cooperative	CP	Monongahela Power (Allegheny Energy, Inc.)	IOU	D	Cash	$14,500,000	$12,003,000	2,500	1.21	5,800	SVEC sold WV distribution assets and rights to Monongahela Power. Sale was negotiated at same time as Potomac Edison sale of VA assets to Rappahannock and Shenandoah Electric Cooperatives.
4	2010	TX	Southwest Public Service Company (Xcel Energy)	IOU	Lubbock Power and Light (LPL)	M	D	Cash	$87,000,000	$62,369,000	21,000	1.39	4,143	Purchase agreement included 25-year Partial Requirements Power Service agreement with Xcel, Xcel purchase of treated effluent water from City as cooling water for Xcel power plant, and Xcel to donate downtown office building (NBV=$415,000) to Texas Tech University. Approved on August 2010 per PUCT Docket 37901 and SOAH Docket 473-10-2349. Includes 685 miles of distribution line and 21 distribution substations.
5	2011	CA	Sierra Pacific Power Co. (d/b/a NV Energy)	IOU	California Pacific Electric Co. (d/b/a Liberty Energy)	IOU	G,D	Cash	$132,000,000	$121,206,000	47,000	1.09	2,809	SPPC requested bids to sell utility property in CA. Rate base value of assets = $121,206,000. In connection with sale of assets, SPPC entered into a separate 5-year purchase power agreement to sell energy to CalPeco.
6	2011	CA	Mountain Utilities	IOU	Kirkwood Meadows Public Utility District	PUD	G,D	Cash	$1,956,420	$966,666	1,000	2.02	1,956	Transaction included sale of electric and propane gas systems. Amounts shown reflect allocation of purchase price to electric system. OCLD value is cost of electric distribution assets only.
7	2011	OH	Wright Patterson Air Force Base	M	Dayton Power & Light, Inc.	IOU	T,D	Cash	$18,700,000	$18,929,000		0.99		Completed purchase March 1, 2011. Property sold did not include electric meters, which will continue to be owned by the federal government.
8	2011	OH	Dayton Power & Light, Inc.	IOU	AES Corporation	IOU	G,T,D	Cash and assumption of debt	$4,750,000,000	$2,742,193,371	500,000	1.73	9,500	Nov 28, 2011, AES paid $3.5 billion cash ($30/share) and assumed $1.25 billion DPL debt (2011 FERC Form 1).

Exhibit 3, Table 1
Analysis of Guideline Sales Transactions
Electric Utility Property

Transaction Number	Year	State	Seller	Type (1)	Purchaser	Type (1)	Asset (2)	Type of Transaction	Sale Price	Net Plant	No. of Customers	Price/ Net Plant	Price/ Customer	Comments
9	2012	NH	Granite State Electric Company (National Grid)	IOU	Liberty Energy NH	IOU	G, T, D	Cash	$83,000,000	$99,498,000	43,000	0.83	1,930	National Grid was interested in selling due to adverse regulatory climate in state, could not earn "acceptable" returns on investment. Also sold gas operation in NH for same reason.
10	2015	IA, MN	Interstate Power & Light (Alliant)	IOU	Southern Minnesota Energy Cooperative	CP	D	Cash	$129,000,000	$105,189,000	43,000	1.23	3,000	Filed for approval at Minnesota PUC on 4/15/14. Data reflects only electric system. Alliant also sold gas system.
11	2018	FL	Gulf Power Company (Southern Company)	IOU	NextEra Energy	IOU	G, T, D	Cash and assumption of debt	$5,657,000,000	$3,605,426,401	459,050	1.57	12,323	Completed 1/1/19
12	2018	AK	Anchorage Municipal Light & Power	M	Chugach Electric Association	CP	G, T, D	Cash	$767,800,000	$715,400,000	30,932	1.07	24,822	Pending, letter of intent signed 10/1/18. Waiting for approval from Regulatory Commission of Alaska.
13	2019	ME	Emera Maine	IOU	ENMAX	IOU	T, D	Cash and assumption of debt	$1,309,000,000	$712,000,000	159,000	1.84	8,233	Pending regulatory approaval.
14	2019	TX	Oncor Electric Delivery Company, LLC (80% owned by Sempra Energy)	IOU	AEP Texas, Inc.	IOU	D	Cash	$17,956,000	$17,956,000	3,000	1.00	5,985	Transaction approved in PUCT Docket 49402.

Summary of Sales Data	No.
Total Sales from IOU to IOU	6
Total Sales from IOU to Municipal Utility	1
Total Sales from IOU to Public Utility District	1
Total Sales IOU to Cooperative	3
Total Sales from Municipal Utility to IOU	1
Total Sales from Public Utility District to IOU	0
Total Sales from Cooperative to IOU	1
Total Sales from Municipal Utility to Cooperative	1
Total Number of Sales	14

[1] IOU - Investor-owned Utility; M - Municipal; CP - Cooperative; PUD - Public Utility District, PRV - Private Investor
[2] G - Generation; T - Transmission; D - Distribution
[3] Neg - Negotitated sale; ED - Eminent Domain

Analysis of Price/Net Plant	All Sales
High	2.02
Low	0.83
Mean	1.32
Median	1.22
Standard Dev. Above Mean	1.67
Standard Dev. Below Mean	0.96

Analysis of Price/Customer	All Sales
High	24,822
Low	1,930
Mean	6,756
Median	4,897
Standard Dev. Above Mean	13,038
Standard Dev. Below Mean	474

Exhibit 3, Table 2
Analysis of Guideline Sales Transactions
Gas Distribution Utility Property

Transaction Number	Year	State	Seller	Type (1)	Purchaser	Type (1)	Asset (2)	Type of Transaction	Sale Price	Net Plant	No. of Customers	Price/ Net Plant	Price/ Customer	Comments
1	2014	WI, IL, MN, MI	Integrys Energy Group	IOU	Wisconsin Energy Corporation	IOU	G, T, D, Gas	Cash	$9,100,000,000	$6,500,000,000	2,143,000	1.40	4,246	Integrys (TEG) includes: Wisconsin Public Service, Peoples Gas, North Shore Gas, Minnesota Energy Resources, Michigan Gas Utilities, and 34% ownership in American Transmission Company. According to WEC, new company earnings are 99% regulated business. WEC cited strong geographic and operational fit with TEG. Regulated enterprise value = 1.55 times rate base. Integrys has 445,000 electric customers and 1,698,000 gas customers.
2	2015	KY	Gas Natural Inc. (Public Gas Company/Lexington, KY)	IOU	Kentucky Frontier Gas LLC	IOU	GD	Cash	$1,900,000	$2,088,937	4,000	0.91	475	Public Gas Company annually distributes 147.4 million cu ft of gas to 4,000 distribution and farm tap customers in nine counties.
3	2015	NC, SC	Piedmont Natural Gas	IOU	Duke Energy	IOU	GD	Cash	$6,700,000,000	$4,348,049,000	1,000,000	1.54	6,700	
4	2017	DC	WGL Holdings, Inc. (Washington Gas)	IOU	AltaGas Ltd.	IOU	GD	Cash	$7,100,000,000	$4,100,000,000	1,100,000	1.73	6,455	Washington Gas provides retail gas service in DC, MD and VA. Acquisition also included some midstream facilities and non-regulated business.
5	2018	MD	Elkton Gas Company (Pivotal Utility Holdings, Inc., subsidary of Southern Company Gas)	IOU	South Jersey Industries, Inc.	IOU	GD	Cash	$10,000,000	$11,329,735	6,720	0.88	1,488	Net plant and customer count at 12/31/17 (MD PSC Case 9488).
6	2018	NJ	Elizabethtown Gas Company (Pivotal Utility Holdings, Inc., subsidiary of Southern Company Gas)	IOU	South Jersey Industries, Inc.	IOU	GD	Cash	$1,690,000,000	$1,432,203,390	295,000	1.18	5,729	Net plant data was not available, amount shown was estimated based on purchase price divided by 1.18 transaction value/assets ratio at completion of deal reported by SNL.
7	2018	IN, OH	Vectren	IOU	CenterPoint Energy	IOU	GD, ED	Cash plus Debt	$7,479,500,000	$4,276,700,000	1,022,000	1.18	7,318	Vectren provides gas and electric utility servcies in Indiana and Ohio. Gas utility is largest share of business. Total assets at 12/31/17: $3.5 billion gas (64%), $1.8 billion electric (33%), and $0.2 billion other (3%).
8	2019	MD	Elkton Gas Company (South Jersey Industries, Inc.)	IOU	Chesapeake Utilities Corp.	IOU	GD	Cash	$15,000,000	$11,329,735	6,720	1.32	2,232	Net plant and customer count is at 12/31/17 per most recent available rate case (MD PSC Case 9488).

Summary of Sales Data	No.
Total Sales from IOU to IOU	8
Total Sales from IOU to Municipal Utility	0
Total Sales from IOU to Public Utility District	0
Total Sales IOU to Cooperative	0
Total Sales from Municipal Utility to IOU	0
Total Sales from Public Utility District to IOU	0
Total Sales from Cooperative to IOU	0
Total Sales from Municipal Utility to Cooperative	0
Total Number of Sales	8

Analysis of Price/Net Plant	All Sales
High	1.73
Low	0.88
Mean	1.27
Median	1.25
Standard Dev. Above Mean	1.56
Standard Dev. Below Mean	0.98

Analysis of Price/Customer	All Sales
High	7,318

Prepared by:
NewGen Strategies and Solutions

Exhibit 3, Table 2
Analysis of Guideline Sales Transactions
Gas Distribution Utility Property

Transaction Number	Year	State	Seller	Type (1)	Purchaser	Type (1)	Asset (2)	Type of Transaction	Sale Price	Net Plant	No. of Customers	Price/ Net Plant	Price/ Customer	Comments

[1] IOU - Investor-owned Utility; M - Municipal; CP - Cooperative;
PUD - Public Utility District, PRV - Private Investor
[2] G - Generation; T - Transmission; D - Distribution; GD - Gas Distribution
[3] Neg - Negotitated sale; ED - Eminment Domain

	Sale Price
Low	475
Mean	4,330
Median	4,988
Standard Dev. Above Mean	6,959
Standard Dev. Below Mean	1,702

Prepared by:
NewGen Strategies and Solutions

Task 2: Advisian
SEVERANCE COSTS

San Diego Severance Analysis

Final Report for the City of San Diego- Private and Confidential

January 4, 2020

418010-00017

Advisian
Worley Group

advisian.com

Disclaimer

This report has been prepared on behalf of and for the exclusive use of NewGen Strategies and Solutions, LLC and the City of San Diego and is subject to and issued in accordance with the agreement between NewGen Strategies and Solutions, LLC and Advisian. Advisian accepts no liability or responsibility whatsoever for it in respect of any use of or reliance upon this report by any third party. Copying this report without the permission of NewGen Strategies and Solutions, LLC, the City of San Diego and Advisian is not permitted.

Project- 418010-00017: San Diego Severance Analysis

Rev	Description	Author	Review	Advisian approval	Revision date	Client approval	Approval date
	Final	RK Rajib Kundu		GLL G. Leatherman	01/02/2020	[Initial. Surname]	[Appr date]

Table of contents

Table list

Figure list

Executive Summary

The City of San Diego (City) franchise agreements with San Diego Gas and Electric (SDG&E) to provide electric and gas utility services to the City are due to expire on January 17, 2021. To prepare for the upcoming expiration of the franchise agreements, the City retained a consulting team to perform various analyses around valuation of the existing electric and gas infrastructure owned by SDG&E, which services the City. Should an entity other than SDG&E win the franchise agreement bid or the City choose municipalization of gas and electric systems within its boundaries, that portion within the City boundaries would have to be physically separated (severed) from the remainder of the SDG&E gas and electric systems located outside the City boundaries to allow for independent ownership and operations. This report develops a range of estimates around the capital costs (and only those capital costs) associated with severing the natural gas and electric systems that reside within the boundaries of San Diego from the rest of SD&E assets.

The work did not include a detailed walk down or physical inspection of the systems in question. Nor did Advisian have access to proprietary and sensitive GIS data around the electric and natural gas distribution systems or electric substations. In the absence of this information, we used a number of top down, parametric approaches to estimate severance costs for the various transmission and distribution elements within the natural gas and electric systems. These estimates appear in the table below.

Table ES-1, Severance Cost Estimates

Case	Lower Bound Estimate	Upper Bound Estimate
Natural Gas	$29.7 million	$52.8 million
Electricity Transmission	$0	$1.5 billion
Electricity Distribution	$189.5 million	$899.2 million
Totals	**$219.2 million**	**$2.45 billion**

Based on our experience, we believe the ultimate value will be closer to the lower bound than the upper bound, but a more definitive answer awaits a more detailed analysis.

1 Introduction

The City of San Diego (City) franchise agreements with San Diego Gas and Electric (SDG&E) to provide electric and gas utility services to the City are due to expire on January 17, 2021. To prepare for the upcoming expiration of the franchise agreements, the City retained a consulting team to perform various analyses around valuation of the existing electric and gas infrastructure owned by SDG&E, which services the City. The City is required by Charter to put the electric and gas franchises out for bid when the existing franchise agreements expire, and municipal ownership of the electric and/or gas systems is an alternative to be considered.

Should an entity other than SDG&E win the franchise agreement bid or the City choose municipalization of the gas and electric systems within its boundaries, that portion within the City boundaries would have to be physically separated (severed) from the remainder of the SDG&E gas and electric systems located outside the City boundaries to allow for independent ownership and operations. Severance issues arise when there are customers that must be served by one company (e.g. they are in SDG&E service territory) and are currently connected to assets that are necessary to serve the customers of the other entity (e.g. are used to serve customers inside the City's service territory) or vice-versa.

For the purposes of this analysis, severance costs include the capital costs (engineering, equipment, and construction) to sever those assets inside the City boundaries from those SDG&E assets outside the boundary. This includes all capital costs required to conduct the separations. It makes no assumptions about which entity or entities would be responsible for various aspects of the severance costs amongst SDG&E, the City, a putative 3rd party winner of the franchise agreement or other entity. This report does not include any operations & maintenance costs associated with the assets once severance is complete.

In addition, this analysis does not include any transition or start-up costs associated with the City or other entity taking over the ownership/operations of the natural gas and electric systems within the City's boundaries. These transition and start-up costs, which are not within the scope of this study, may include:

- setting up a main and backup control centers including the standard complement of information technology (IT) and operational technology (OT) systems,
- acquiring building space to house the corporate staff and the control centers,
- setting up maintenance/field service center facilities (including warehouses, storage yards, vehicle depots, etc.),
- acquiring an initial stock of materials and supplies required to run the business (including spare parts, vehicles, tools, consumables, etc.),
- hiring and training of utility staff (field personnel, management, back office support, etc.), and
- other costs (branding, legal fees, office equipment and supplies, etc.).

The severance costs are discussed for the natural gas system (Section 2), and the electric system (Section 3), respectively, below in this report.

2 Natural Gas System Severance

In assessing the potential cost of severance for the natural gas system our approach was based on developing an estimate for the unit cost of severance for a single separation, i.e. one point where the two systems would be required to be separated at the City boundary. Since a detailed walk-down of the actual pipeline system was outside the scope of this analysis, we developed lower and upper bounds for the capital cost of a single point separation. We then developed an estimate for the total number of separation points required based on maps of the natural gas system, publicly available from SDG&E (https://services3.arcgis.com/bWPjFyq029ChCGur/ArcGIS/rest/services/Natural_Gas_Pipeline/FeatureServer/0).

Unit Cost Analysis

For purposes of this analysis, it was assumed that a single severance point could be best approximated with the costs required to install new custody transfer stations as required to transition the ownership or operation of an existing natural gas distribution system between parties. Natural gas custody transfer stations would generally be required at points throughout the system where gas supply will be provided from an existing gas transmission pipeline to feed the existing gas distribution pipeline system. Custody transfer stations typically consist of equipment that will measure the gas flow into the system, sample the gas quality coming into the system, and also regulate the pressure of the gas coming from the transmission source (higher pressure) to the downstream distribution network (lower pressure). These estimates were compiled using previously designed custody transfer stations that would be representative of the design and equipment required to install new custody transfer points throughout the existing natural gas distribution system.

Generally, a custody transfer station for a distribution gas system would be required at the points where a higher-pressure gas transmission pipeline is delivering gas to the generally lower pressure gas distribution system. The volume of gas flowing through a custody transfer station impacts the equipment sizing required for the station. For the purpose of this estimate, two sizes of custody transfer stations were used to accommodate higher and lower volumes of gas flowing through each type of station. The two types of custody transfer stations used for this estimate both serve the same functions: gas measurement, gas quality sampling, and gas pressure regulation, the only difference being the volume of gas flowing through each. The high-volume custody transfer station estimate is based off of a 30″ diameter transmission pipeline supplying gas into a 16″ diameter distribution pipeline. The low-volume custody transfer station estimate is based off of a 16″ diameter transmission pipeline supplying gas into a 4″ diameter distribution pipeline.

Assumptions used to build the detailed estimates are as follows:

- Operation and maintenance costs are excluded from this estimate.
- Costs for engineering, design, materials, construction, land, freight, sales/use tax, and contractor markups are included as part of this estimate.
- In addition to the costs mentioned above, an estimated contingency of 20% has been included as part of this estimate.
- Costs for materials and labor required to hot-tap an existing transmission pipeline to provide a gas feed to the distribution system are included for each custody transfer station.

- Redundant metering costs if required by the existing transmission pipeline owner are not included as part of this estimate.
- Land/Real Estate cost for each site is assumed at $300,000 per acre. A 1-acre lot for high-volume and a 3/4-acre lot for low-volume custody transfer stations are assumed.

Table 2-1, below, shows the build up of the cost estimates for both the low-volume and high-volume custody transfer stations. The estimates give an all-in cost for the low-volume transfer station of $2.7 million and the high-volume transfer station an all-in cost of $4.8 million.

Table 2-1. Custody Transfer Station Cost Estimate

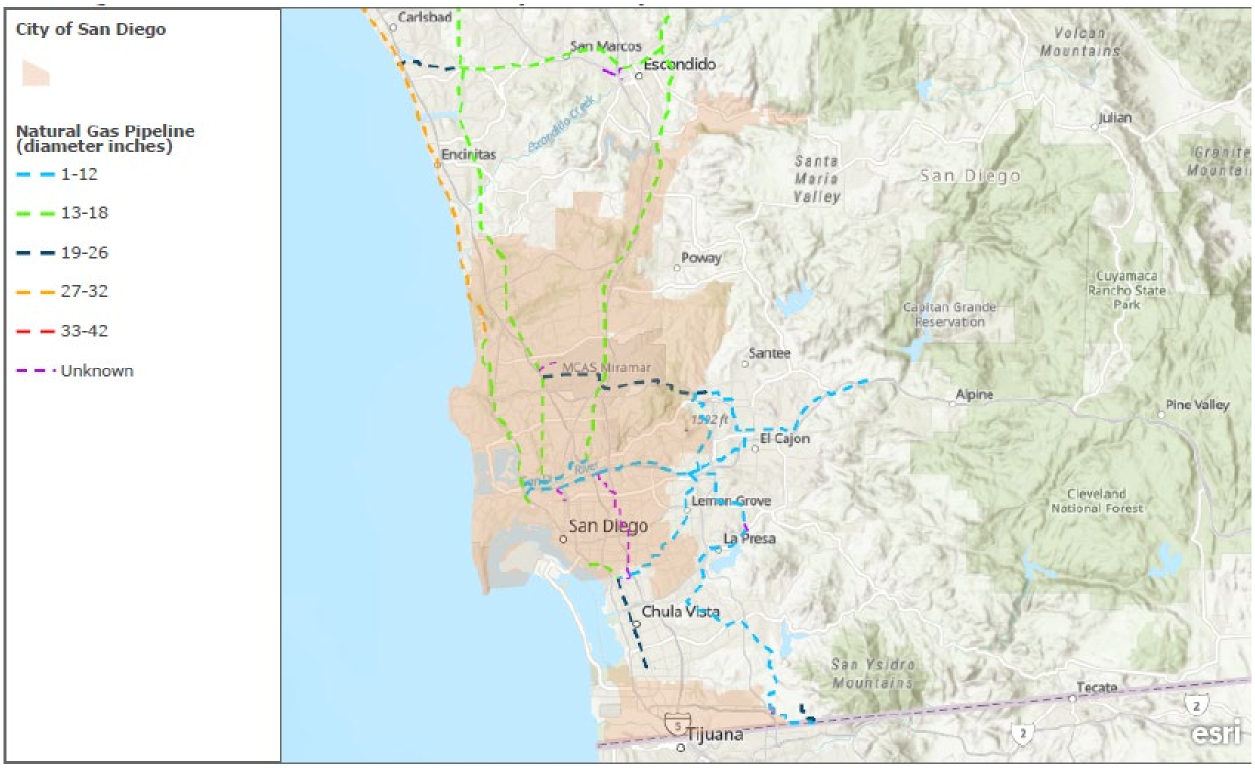
Cost Element	Low-Volume Case	High-Volume Case
Material and Construction Direct Cost	$1,023,005	$2,280,015
Engineering/Design Cost	$171,091	$302,707
Construction Indirect Cost	$687,901	$747,052
Land Cost	$225,000	$300,000
Miscellaneous Costs	$182,449	$427,794
Contingency (20%)	$410,554	$742,432
Total	**$2,700,000**	**$4,800,000**

Note that the category, "Construction Indirect Costs", is not a fixed percentage of direct material and construction costs. It includes fixed costs such as safety equipment, safety training, and leasing of construction equipment that are identical for both cases and costs that are a percentage of the elements of the direct costs such as fringe benefits for labor. The category, "Miscellaneous Costs", includes cost elements such as freight, taxes, etc.

<u>Severance Points Analysis</u>

In order to estimate the number of points where severance is required, the map of the SDG&E natural gas system was superimposed over a map showing the City boundary using ARCGIS software. This is shown in Figure 2-1, below. The publicly available data from SDG&E includes only the transmission and high-pressure distribution lines. The data does not include the smaller distribution lines that supply gas to individual houses. This is due to federal critical infrastructure protection regulations prohibiting pubic dissemination of detailed infrastructure maps etc. Examination of the map shows that the SDG&E natural gas system crosses the City boundary eleven times. We based our subsequent estimations of severance costs on this number of separation points.

Figure 2-1. SDG&E Natural Gas System



Severance Costs

We bounded the severance costs by applying the low-volume cost to all eleven severance points to create a lower bound. The high-volume cost was applied to all eleven severance points to create the upper bound. Table 2-2 shows the severance estimate bounds for the natural gas system. While not being able to assess any potential distribution level severance, we believe our estimates should bound the situation given that non-technical, administrative and/or relatively low-cost metering may be able to create virtual severance at the distribution level, should it be required.

Table 2-2. Natural Gas Severance Cost Estimate Bounds

Case	Analysis	Totals
Lower Bound	11 severance points @ $2.7 million per point	$29.7 million
Upper Bound	11 severance points @ $4.8 million per point	$52.8 million

3 Electric System Severance

Transmission and distribution severance costs were determined by two different approaches:

1. Transmission- For the transmission system, we used an approach analogous to our approach for natural gas, wherein a unit cost per severance point was estimated and then the number of severance points determined based on maps of the transmission system, publicly available from SDG&E (https://services3.arcgis.com/bWPjFyq029ChCGur/ArcGIS/rest/services/Transmission_Line/FeatureServer).
2. Distribution- For the distribution system, we used a somewhat different approach since distribution level data was not available and a physical inspection of the distribution assets was outside the scope of this analysis. Examining data from previous work on other cities, we developed a feeder boundary density parameter. That is, we developed a metric around average feeder crossing points per mile of border from this data and applied it to the land border of the City. We also developed unit costs for distribution level severance.

Below find our approach and cost estimates for electric system transmission and distribution severance.

Transmission Severance

In developing the unit cost for transmission severance, we based our severance estimate on previous client work for which severance costs were developed for a single severance point, requiring development of a new 230-kV substation, connecting to a 115 kV distribution system. The estimate assumed the costs as shown in Table 3.1, below.

Table 3-1. 230 kV Substation Cost Estimate

System / Component	Quantity	Unit Cost	Total Cost
115 kV Cabling	4.005 miles	$18,793,306/mile	$ 75,267,270
Other Cabling/connection	2.8 miles	$821,063/mile	$ 2,298,976
Tie Bus Breakers and 115 kV Breakers	7 units	$821,063/unit	$ 5,747,441
12 kV Breakers	3 units	$181,811/unit	$ 545,433
Control Room (both City and SDG&E)	2 control rooms	$790,193/unit	$ 1,580,386
Transformers (115 kV/12 kV)	60 units	$35,900	$ 2,154,000
Subtotal			$ 87,593,506
Other Owner's Costs (11%)			$ 9,635,285
Contingency (10%)			$ 9,722,879
Total			**$106,951,670**

For calculation purposes we used $107 million as the basis for the unit cost per 230 kV severance point.

SDG&E, in addition to 230 kV, also has transmission lines of 69 kV and 500 kV crossing the City boundaries. We scaled the costs for these voltages using data from "Capital Costs for Transmission and Substations- Updated Recommendation for WECC Transmission Expansion Planning" (WECC 2014, https://www.wecc.org/reliability/2014_teppc_transmission_capcost_report_b+v.pdf) to develop scaling factors. The results can be found in Table 3.2, below.

Table 3-2. Transmission Substation Severance Costs by Voltage

Voltage	Total Cost
69 kV Substation/Severance	$ 34,668,000
230 kV Substation/Severance	$107,000,000
500 kV Substation/Severance	$248,891,000

In order to estimate the number of points where severance is required, the map of the SDG&E electric transmission system was superimposed over a map showing the City boundary using ARCGIS software. This is shown in Figure 3-1 below. In order to give more detail on the 69 kV transmission lines, Figure 3-2 shows just the 69 kV system.

Figure 3-3. SDG&E Transmission System

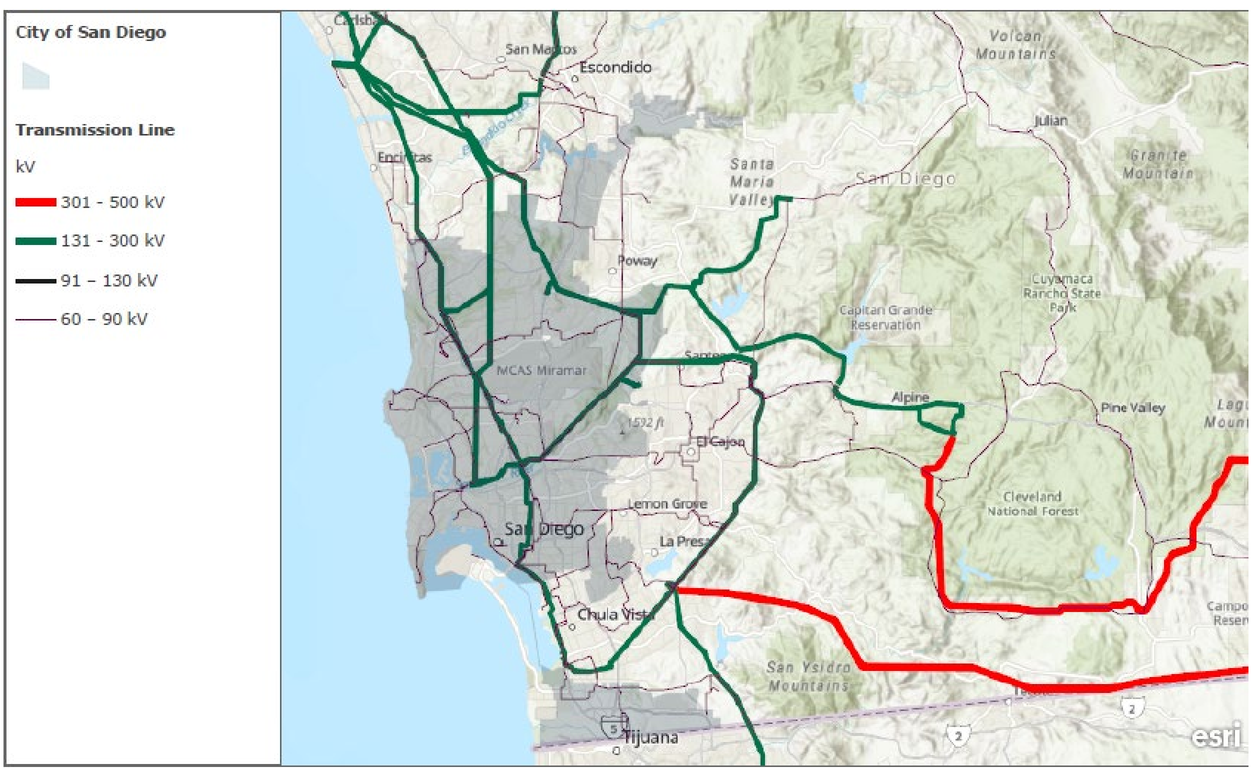
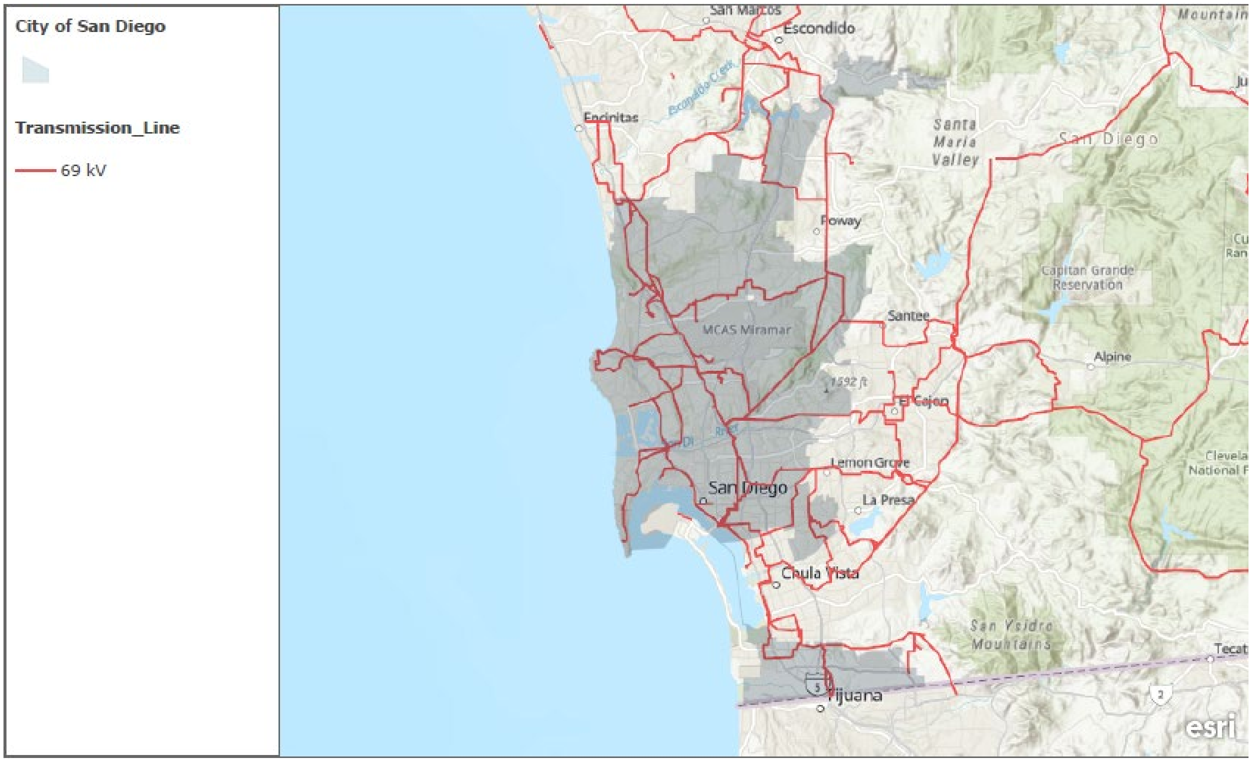


Figure 3-4. SDG&E 69 kV Transmission System



In analyzing the maps, we identified the following number of severance points:

a) 69 kV- 22 severance points

b) 230 KV- 5 severance points

c) 500 kV- 1 severance point.

However, without a detailed analysis and review of substation locations, engineering drawings, and detailed visual inspection of the transmission system (all outside the scope of this effort) it is not possible to determine which potential severance points, if any, require actual severance infrastructure. To that end we bounded our analysis on the lower end by assuming that no severance infrastructure would be required at each putative transmission severance point. We bounded the upper end by assuming that each and every putative severance point required the severance work costed in Table 3.2. The results are shown in Table 3.3, below.

Table 3-3. Transmission Severance Costs Bounds

Voltage	Severance Points	Lower Bound Estimate	Upper Bound Estimate
69 kV Substation/Severance	22	$0	$762,696,000
230 kV Substation/Severance	5	$0	$535,000,000
500 kV Substation/Severance	1	$0	$248,891,000

This analysis puts the estimate for transmission severance between zero and $1.5 billion. While it is recommended that a more detailed analysis including site surveys etc. be conducted to put a finer point on these numbers, our experience points to the actual transmission severance cost being much closer to the lower end of the spectrum than the upper end. For instance, in our work for another U.S. city, it was found that only one severance point (at 230 kV) was identified after a thorough and detailed analysis and site survey.

Distribution Severance

For distribution severance, we used data from previous work for another U.S. city. We developed a low-cost case assuming only the use of meters and protection equipment to sever the systems. We used a high-cost case assuming the construction of new feeders and associated distribution level substations. This is shown in Table 3-4, below.

Table 3-4. Distribution Severance Unit Costs

System / Component	Unit Cost	Quantity Low Case	Cost Low Case	Quantity High Case	Cost High Case
Severance Feeders	$531,019/mile	3.56 miles	$1,890,428	3.56 miles	$1,890,428
New Disconnections (switches)	$14,733/unit	36 units	$530,388	36 units	$530,388
New Connections (switches)	$14,733/unit	35 units	$515,655	35 units	$515,655
Autotransformers	$77,643/unit	1 unit	$77,643	1 unit	$77,643
Protection and Meters	$183,505/unit	5	$917,525	0	0
New Feeders	$235,805/mile	0	0	22.37	$5,274,958
Ductwork	$823,884/mile	0	0	7.458	$6,144,527
12 kV Switch	$65,747/unit	0		6	$394,482
12 kV Switchgear	$181,811/unit	0	0	7	$1,272,677
115 kV Switchgear	$487,234/unit	0	0	2	$974,468
12 kV Aux cell	$70,604/unit	0	0	2	$141,208
Transformers 115 kV/12 kV	$35,900/unit	0	0	40	$1,436,000
Subtotals			**$3,931,639**		**$18,652,434**
Owner's Costs (11%)			$432,480		$2,051,768
Contingency (10%)			$436,412		$2,070,420
TOTALS			**$4,800,531**		**$22,774,622**

As can be seen, there is some common work required for both cases. Using these numbers and metrics around the density of distribution severance points on municipal boundaries from previous work, we developed a cost metric of $914,387/mile of city boundary for the low case and a metric of $4,338,023/mile of city boundary for the high case.

Using ARCGIS, we determined that the land boundary of the City of San Diego was 249 miles in length. We used this length of boundary as our upper bound for length of boundary. The City has a large undeveloped area around the Scripps Ranch. There is also the border on the south with Mexico and the boundary on Coronado Island with the U.S. Naval facility. These areas are extremely unlikely to have any distribution severance points. If we exclude these areas of the boundary, the boundary length modified by removing these areas becomes 207.28 miles. We used this modified length as our lower bond for the length of the City land boundary. Using these values of boundary length with severance costs per mile metrics produces the results in Table 3.5, below.

Table 3-5. Distribution Severance Costs Bounds

Case	Boundary Length	Severance Cost/Mile	Severance Cost
Full Boundary/High Severance Cost	249 miles	$4,338,023/mile	$1,080,168,000
Full Boundary/Low Severance Cost	249 miles	$914,387 /mile	$227,682,000
Modified Boundary/High Severance Cost	207.28 miles	$4,338,023/mile	$899,185,000
Modified Boundary/Low Severance Cost	207.28 miles	$914,387/mile	$189,534,000

Task 3: MRW
ASSESSMENT OF CASH FLOWS AND RATES ASSOCIATED WITH ACQUISITION OF GAS AND ELECTRIC ASSETS

Assessment of Economic Feasibility of Municipal Acquisition of Gas and Electric Assets in the City of San Diego

MRW & Associates, LLC
1736 Franklin Street, Suite 700
Oakland, CA 94612

April 15, 2020

About MRW & Associates, LLC

MRW & Associates, LLC (MRW) is internationally recognized for its broad expertise in electric power and fuel markets. MRW consultants combine an in-depth knowledge of these markets with rigorous economic and technical analysis to help clients in the areas of power market analysis, regulatory and litigation support, natural gas market analysis, and retail market support.

MRW is widely respected for its independent, technical analysis of complex issues. Both the California Public Utilities Commission and the California Energy Commission have directly engaged MRW's support to evaluate highly controversial issues, including the costs, benefits, and risks of the Sunrise transmission project and the state's nuclear power plants. MRW consultants are known for having a deep knowledge of the utility, regulatory, and market structures in California and how these interface in areas such as energy costs, retail energy rates, and power plant development.

MRW has provided consulting services related to electric, natural gas and other utility-related issues to the City of San Diego since 1989. MRW assisted with consideration of its current Franchise Fees with San Diego Gas and Electric. MRW has also assisted the City of San Diego with the evaluation of the establishment of a Community Choice Aggregation program. In addition, MRW has also represented the City of San Diego before the California Public Utilities Commission in various rate and energy policy issues.

Established in Oakland, California in 1986, MRW early on built a solid reputation for delivering local insights on power and fuel markets in the western United States. Organizations turn to MRW to benefit from the knowledge and insights acquired over 30 years of deep involvement with the western U.S. energy markets and regulatory systems. MRW consultants employ the insights gained through this experience to advise clients on regulatory and business strategy and to provide expert testimony before regulatory agencies, courts, and arbitration panels.

This analysis reflects current assessments of future market and economic conditions, financial parameters, and regulatory requirements, electricity sales forecasts, and financing rates. In developing this analysis, MRW has sought to apply assumptions that best reflect currently available public information. Nonetheless, these results should be seen as indicative and not predictive.

Contents

Figures

Tables

Executive Summary

MRW & Associates, LLC (MRW) prepared financial analyses and recommendations regarding the economic feasibility of the purchase of the electric and gas distribution infrastructure that currently serves the citizens and businesses located within the political boundaries of the City of San Diego (City) and establishing municipally-owned electric and natural gas distribution utilities (EDU and GDU, respectively) to provide electric and gas service to those customers. Upon acquiring the EDU and GDU assets, all customers that currently take service (either bundled service or delivery-only service) would become customers of the new EDU and GDU. The EDU is assumed to provide bundled distribution and commodity power service to its customers that currently take bundled service from SDG&E; for customers that only take delivery services (i.e., Direct Access customers), the EDU would continue to provide delivery services to those customers and the customer would continue to receive commodity service from a third party. The bundled service customers of the EDU would receive their commodity electric supply from an entity that would be analogous to San Diego Clean Power, which is a Community Choice Aggregator (CCA) being formed to serve customers within the City of San Diego and other cities. The GDU is assumed to provide bundled commodity natural gas plus delivery services to "Core" customers and would provide delivery services to "Non-Core" customers in the same way that SDG&E currently provides service.

The goal of this analysis is to compare the cost of service for electric and natural gas service that would be paid by citizens and businesses within the boundaries of the EDU and GDU against their costs assuming that they continue to pay for service as customers of SDG&E.

MRW worked as a subconsultant to NewGen Strategies and Solutions, LLC (NewGen) on this project. NewGen provided MRW with estimated range of value (i.e., purchase price) for the assets of the EDU and GDU. Advisian, another subconsultant on the project team, provided MRW with estimates of severance costs for the EDU and GDU assets.

MRW developed estimates of the operating and maintenance (O&M) costs, debt service costs, cash reserves, and capital additions for the EDU and GDU. In addition, MRW developed estimates of other costs (e.g., Exit Fees) for the EDU.[1] Revenues for the EDU and GDU were estimated based on MRW's forecast of future rates for service to bundled service customers.[2] These costs and revenues were included in a *pro forma* income statement, which provided the basis for the determination of the financial benefits to customers associated with establishment of the EDU and GDU.

MRW relied on publicly-available information to develop its estimates of cash flows and rates. MRW used these publicly-available data as inputs to MRW's proprietary rate and financial models.

Using these models, MRW calculates the cash available to the City (as owner of the EDU and GDU) under different sets of assumptions about rates and operating costs for the EDU and GDU. A portion of the available cash is used to pay debt service associated with the acquisition of the EDU and GDU. Any remaining funds are assumed to be added to reserve funds for the EDU and GDU. The analysis

[1] For this analysis, MRW assumed that there would not be any exit fees related to the acquisition of the GDU assets from SDG&E.
[2] For SDG&E's Non-Core natural gas service rate schedules, MRW estimated delivery-only rates.

makes no assumptions regarding how the reserve funds are used but one logical use is to provide customers of the EDU and GDU with discounted rates relative to SDG&E.

In addition, MRW compares the costs for customers of the EDU and GDU relative to the costs that those customers would pay if they remain as customers of SDG&E. For this comparison, MRW assumes that the "costs" of the EDU and GDU equal the costs paid by customers of the EDU plus the present value of any outstanding debt issued by the EDU or GDU at the end of the forecast period minus the present value of the reserve accounts. MRW examined these costs for three cost scenarios: Base Case, Low EDU/GDU Costs, and High EDU/GDU Cost scenarios. For each cost scenario, MRW also examined three purchase price scenarios provided by NewGen: Original Cost Less Depreciation (OCLD), Reproduction Cost New Less Depreciation (RCNLD) and a value NewGen was asked to provide by the City of San Diego that is equal to the income assuming the franchise expires in 2021 (One Year Franchise).

MRW uses these models to estimate the maximum rate discount that the City could offer customers if it acquires the assets of the EDU and GDU given assumptions about operating costs, debt service costs, and financing requirements for the EDU and GDU.

Finally, MRW performed sensitivity analyses to understand the impact of different uncertain variables on the costs that customers would have to pay if the City were to acquire the EDU and GDU.

The following results and conclusions should be considered preliminary. As discussed more fully in the report, MRW has had to make various simplifying assumptions that should be revisited (e.g., start-up costs, the degree to which revenues from the EDU and GDU have to replace franchise fee and property tax revenues that the City currently receives from SDG&E). For those reasons, readers should view the results and conclusions of this report as draft and preliminary.

Results for EDU

Using its assumptions regarding costs of operating the EDU and SDG&E's future rates, MRW derived the costs that EDU customers would pay when taking service from the EDU and from SDG&E, respectively, assuming the three purchase prices and three scenarios for operating costs. The following figures present those results.

Figure 1: Comparison of EDU and SDG&E Costs (OCLD Purchase Price)

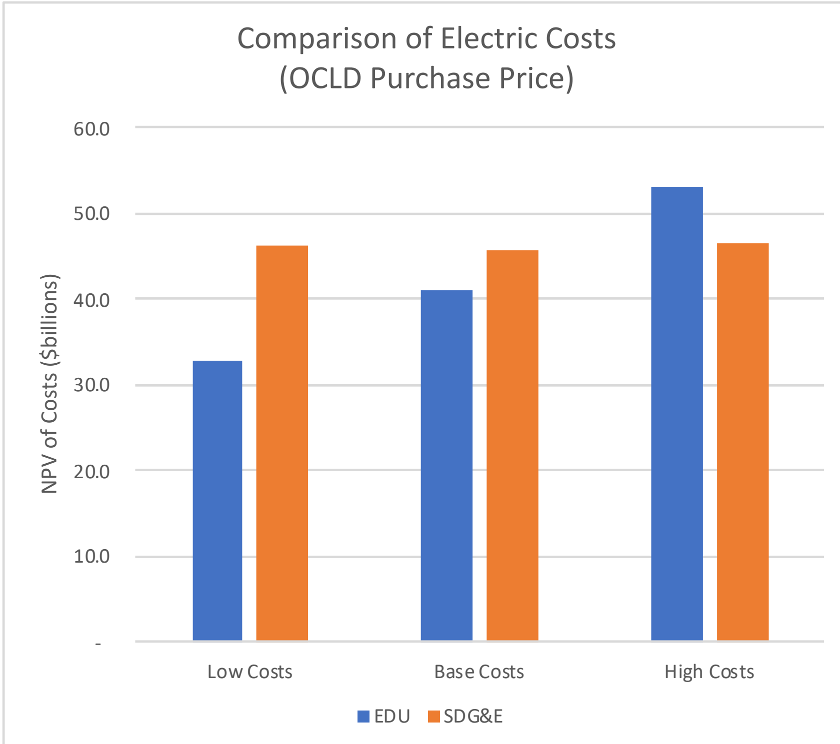


Figure 2: Comparison of EDU and SDG&E Costs (RCNLD Purchase Price)

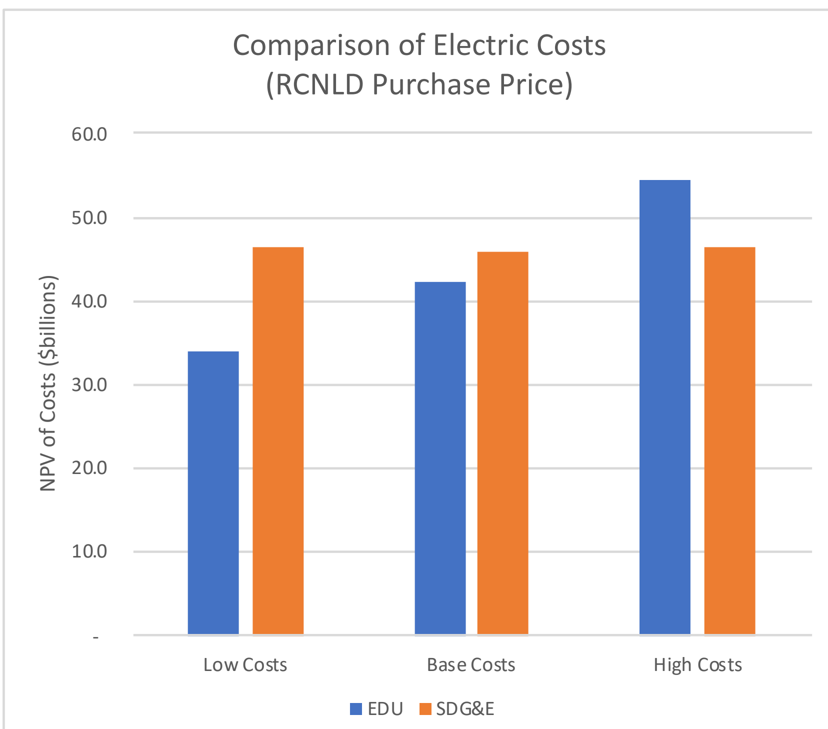
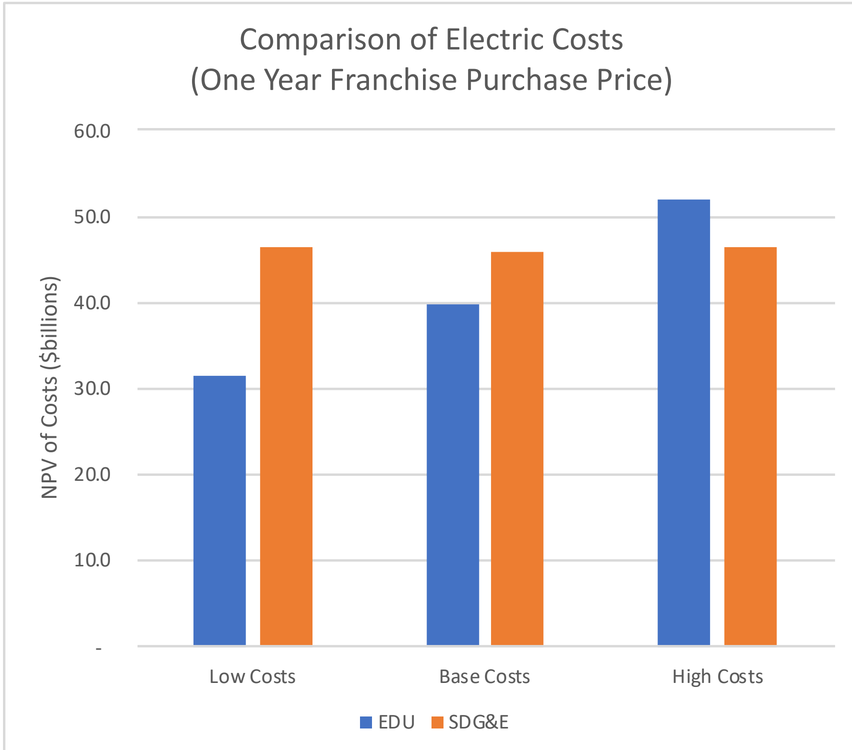


Figure 3: Comparison of EDU and SDG&E Costs (One Year Franchise Purchase Price)

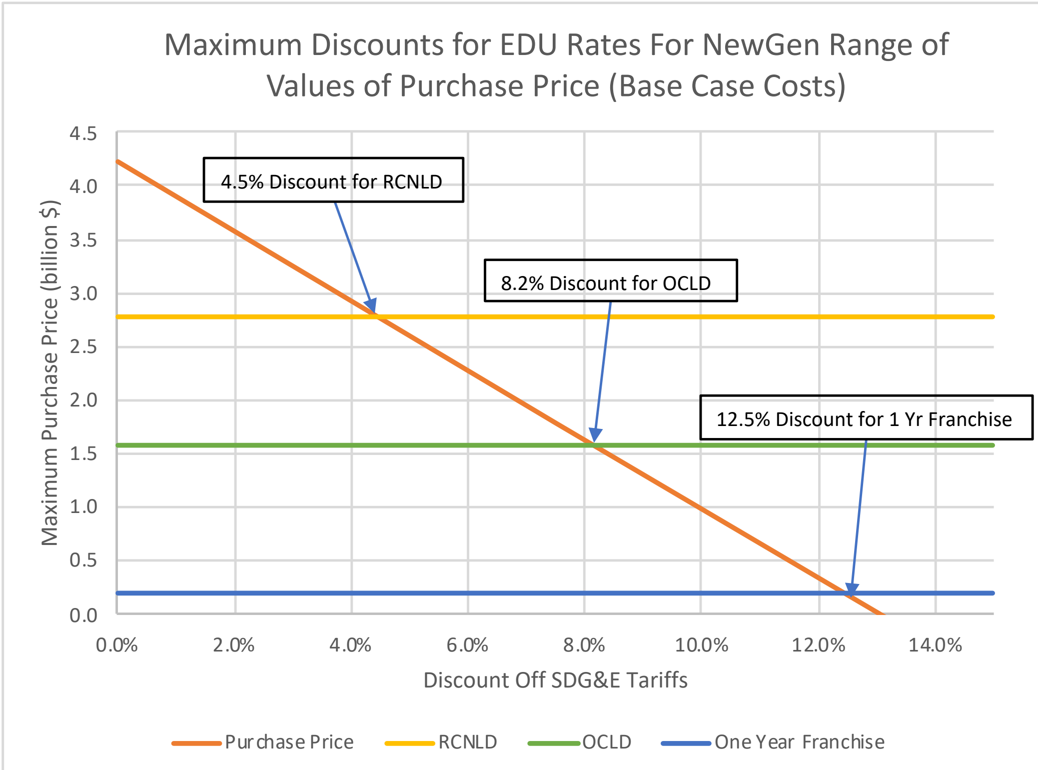


Figures 1 through 3 show that customers of the EDU would have lower costs than if they were to remain customers of SDG&E under the Low Cost and Base Case scenarios for all purchase price assumptions. As expected, the costs of the EDU's customers increase when moving from the Low Cost scenario to the High Cost scenario. However, SDG&E's costs do not increase monotonically between the Low EDU Cost and High EDU Cost scenarios due to the effect of CO2 allowance prices. Both SDG&E and the EDU receive free GHG allowances and use those to meet GHG requirements for their supply portfolios. However, the EDU is assumed to have a generation portfolio that is more CO2-free than SDG&E, meaning that the EDU would have more GHG allowances that it can sell than does SDG&E, thereby providing additional revenue for the EDU (i.e., effectively reducing the EDU's costs of service). Higher CO2 prices (in the Low EDU Cost scenario) gives the EDU greater sales revenues than in the High EDU Cost scenario (which has lower CO2 prices).

Figures 1 through 3 above also show that there are not significant differences in the costs that customers would pay for EDU service under different purchase price assumptions. This is because the costs of the EDU's fixed assets are a relatively small portion of the overall costs of service of the EDU. For example, the debt service costs of the EDU in the Base Case cost scenario (assuming an OCLD purchase price) are only about 23% of the total costs that customers pay. This is because the EDU's power supply costs are expensed by the EDU, which is different than SDG&E, which owns power generating facilities that have fixed costs that are recovered through SDG&E's rates.

Using its Base Case assumptions, MRW developed estimates for the maximum discount to SDG&E rates that the EDU could offer and still meet all cost and financing requirements. Figure 4 shows the maximum discount that the EDU can offer under the Base Case for each of the three purchase price scenarios.

Figure 4: Maximum Discounts by EDU for Different Purchase Prices Under Base Case Cost Assumptions



In Figure 4 above, the retail rates for the EDU at the far left of the figure have the smallest discount relative to SDG&E's rates, meaning that they are the highest rates examined by MRW.[3] Moving to the right in the figure, the amount of the discount in the EDU's rates relative to SDG&E's rates increases (i.e., the EDU's rates get lower relative to SDG&E's rates), meaning that the revenue for the EDU decreases as the rate discount increases. Since the EDU's costs are assumed to be constant in this figure, reducing retail rates (and revenues) means that there is less net income available for debt service, which means that the feasible purchase price for the EDU decreases as rate discounts increase. It is for this reason that line showing the purchase price for the EDU slopes downward as rate discounts increase (i.e., moving from left to right in the figure).

As seen in the figure, the line representing the purchase price for the EDU crosses the line representing the Reproduction Cost New Less Depreciation (RCNLD) at a rate discount of approximately 4.5%. This means that if the EDU paid SDG&E a purchase price equal to RCNLD for the distribution system assets in the City limits, the EDU could meet its debt service costs and financing requirements and still offer its customers a rate discount of approximately 4.5% relative to SDG&E's rates.

Similarly, the figure shows that the line for the purchase price for the EDU crosses the horizontal line representing OCLD at a rate discount of approximately 8.2% relative to SDG&E's rates. In other

[3] MRW assumes that for the purposes of this analysis, the EDU and GDU would not offer rates that were higher than those offered by SDG&E. There may be reasons to offer higher rates (e.g., greater levels of renewable generation) but MRW did not examine such scenarios.

words, if the EDU acquired the SDG&E electric assets at OCLD (which is less than RCNLD), then the EDU could offer a larger rate discount to customers relative to SDG&E's rates and still meet its debt service costs and financing requirements than if it purchased the SDG&E electric assets at RCNLD. In addition, because the purchase price assuming One Year Franchise is even lower than OCLD, the potential rate discount under that assumption is even greater than OCLD: 12.5%.

The following table summarizes these results.

Table 1: Maximum Rate Discount for Different EDU Purchase Prices Using Base Case Costs

Purchase Price	Potential Rate Discount Relative to SDG&E
OCLD	8.2%
RCNLD	4.5%
One Year Franchise	12.5%

It is important to note that Figure 4 and Table 1 above present results using MRW's Base Case cost assumptions except for the discount in EDU rates relative to SDG&E's rates.

There is significant uncertainty in the cost assumptions in the above figures. Changes in those assumptions will result in changes in operating costs for the EDU. MRW has identified several key variables that will impact the maximum purchase price for the EDU:

1. **Natural Gas Prices.** MRW assumes that the level of generation that is tied to the cost of natural gas purchased by the EDU decreases over time. SDG&E also purchases a certain amount of natural gas-fired generation. However, MRW assumes that the EDU and SDG&E have different resource portfolios with different amounts of natural gas-fired generation. Thus, changes in gas prices will have different impacts on the EDU's revenues and costs.
2. **CO2 Allowance Prices.** The EDU is impacted by the cost of greenhouse gas. Higher CO2 allowance prices provide the EDU with additional revenues via allowance sales. Higher CO2 prices are also reflected in higher wholesale power market purchase prices and higher prices for utility-owned natural gas power generation.
3. **Costs for Renewable Generation.** MRW assumes that the EDU's generation supply portfolio becomes more "green" over time at a faster rate than SDG&E. Because of this assumption, changes in renewable costs can have different impacts on the EDU's operating costs, which affects the maximum amount that can be paid for the EDU for a given level of retail revenue.
4. **EDU Operating Costs and Capital Additions.** The costs to operate and maintain the EDU are both important and uncertain. The greater the operating costs and capital addition costs, the less revenue that is available for debt service. MRW explored the impact of different levels of operating costs for the EDU.
5. **Exit Fees.** The EDU may or may not be subject to two major Exit Fees: the Power Cost Indifference Adjustment (PCIA) and the Wildfire Liability non-bypassable charge. By not having to pay exit fees, the EDU would have much lower costs, meaning that the maximum purchase price would increase. In addition, the future levels of exit fees are themselves uncertain. MRW examined the impact of different levels of exit fees.
6. **Treatment of Capital Expenses.** There is some uncertainty associated with the manner in which the EDU would "pay" for its ongoing capital additions. Annual capital additions for the EDU start at $231 million. If the EDU pays for these capital additions as a cash expense,

then the EDU's costs are much higher in the near-term compared to if the EDU were to finance its capital additions using tax-free debt. MRW analyzed two methods for paying for capital additions: (1) the annual capital additions are paid as incurred (i.e., they are expensed), and (2) the EDU issues tax-free debt to pay for capital additions, meaning that the EDU's costs are equal to debt service costs plus the costs of financing the capital additions.

7. **Alternate Severance Costs.** The severance cost estimates for the establishment of the EDU vary greatly. Because these severance costs are financed, they contribute to the debt service costs of the EDU, meaning that higher severance costs will increase debt service and result in a lower maximum purchase prices for a given level of retail revenue.

The following table summarizes the impacts on the costs for ratepayers of the EDU of changes to these uncertain factors.

Table 2: Impact of Change in Uncertain Variables on EDU Costs

	Change in Variable	Impact on EDU Costs
Natural Gas Prices	Lower/Higher Gas Prices	Reduces/Increases
CO2 Allowance Prices	Higher/Lower CO2 Allowance Prices	Reduces/Increases
Costs for Renewable Generation	Lower/Higher Costs for Renewable Generation	Reduces/Increases
Operating Costs and Capital Additions	Lower/Higher O&M and Capital Additions	Reduces/Increases
Exit Fees	Lower/Higher Exit Fees	Reduces/Increases
Payment for Capital Additions	Capitalizing/Expensing Capital Additions	Reduces/Increases
Severance Costs	Lower/Higher Severance Costs	Reduces/Increases

When alternate assumptions regarding key uncertain variables are combined into High Cost and Low Cost scenarios, MRW finds that the potential discount that the EDU can offer relative to SDG&E's rates are very different than when using Base Case assumptions. The following table summarizes the potential rate discount that could be offered to EDU customers using different cost scenarios and purchase prices.

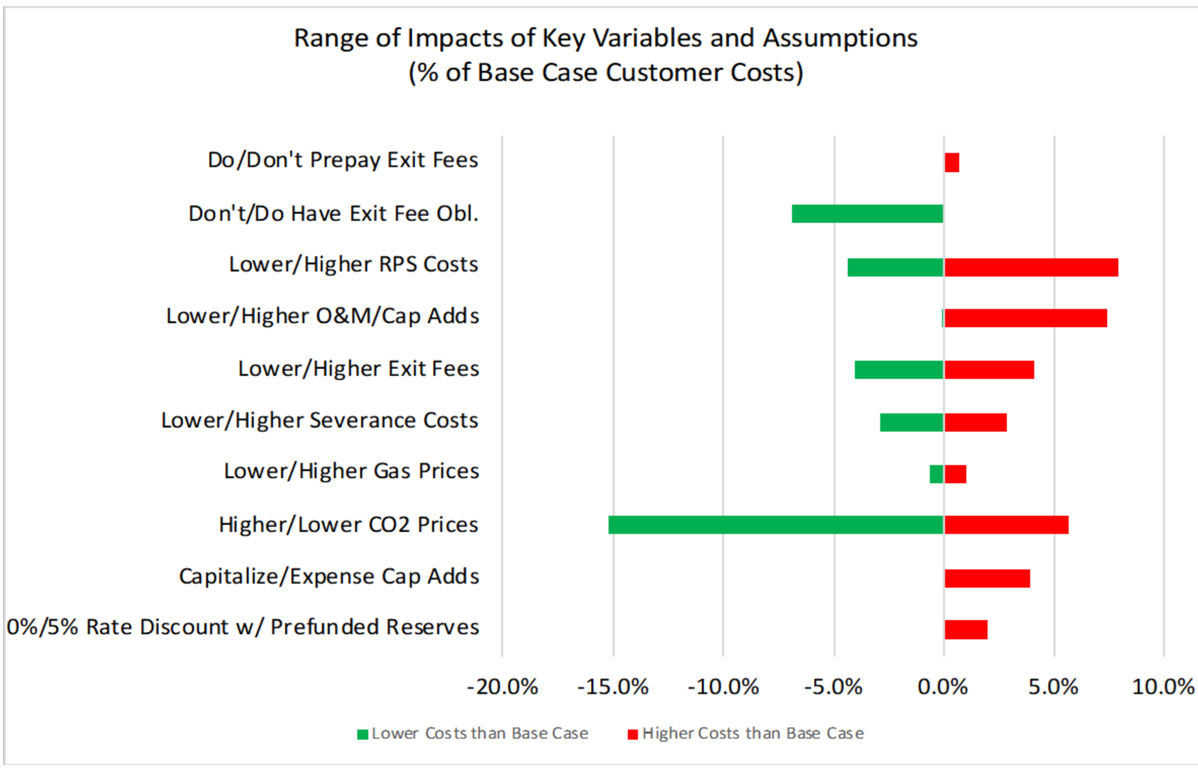
Table 3: Range of Maximum EDU Rate Discounts for Different Cost Scenarios and Purchase Prices

	RCNLD	OCLD	One Year Franchise
Low Costs	21.8%	25.5%	29.8%
Base Case	4.4%	8.2%	12.5%
High Costs	-35.0%	-31.4%	-27.2%

Table 3 above shows that in the Low Cost scenario, the maximum rate discount ranges from 21.8% to 29.8% for purchase prices equal to RCNLD and the One Year Franchise price, respectively. For the High Cost scenario, it would be necessary to raise rates relative to SDG&E by between 27.2% and 35.0% in order to cover the costs of the EDU for the RCNLD and One Year Franchise purchase prices, respectively.

It is important to note that the High- and Low Cost scenarios are extreme: it is very unlikely that all the key variables will align either positively or negatively. Rather, these scenarios illustrate the full range of potential outcomes. To understand the impact of the individual uncertain variables discussed above, MRW explored the impact of each uncertain variable on the costs for customers of the EDU.[4] To do this, MRW assumed the purchase price for the EDU was equal to OCLD and then calculated the change in the present value of EDU customer costs resulting from changing each variable relative to the value in the Base Case. This allowed MRW to identify the quantitative effect of the variables on the viability of the EDU. The following figure presents the percentage change in customer costs under these different assumptions.

Figure 5: Range of Impacts of Key Variables on EDU Customer Costs



As seen from Figure 5 above, MRW finds that for the EDU:

- The largest increase in customer costs is due to higher costs for renewable resources and higher O&M and capital additions.[5] O&M and capital addition costs are a significant part of the EDU's costs, which is why increasing them causes such a large increase in customer costs. Higher or lower costs for renewable resources have very large impacts on EDU customer costs because the EDU is assumed to have a very renewable-rich resource portfolio.

[4] As mentioned above, "costs" in this case are equal to costs paid by EDU customers plus the present value of any outstanding debt at the end of the analysis period less the present value of any reserves held by the EDU at the end of the analysis period.
[5] MRW assumes that its Base Case estimate of O&M and capital additions is also its Low Case estimate.

- The results also show that higher CO2 allowance prices significantly reduce the EDU's costs. This occurs because the EDU's Greenhouse Gas (GHG) compliance obligations are less than SDG&E's, which would allow the EDU to sell its excess GHG allowances, thereby reducing its net costs.
- Exit fees have a very large effect on customer costs; higher or lower exit fees result in major increases or decreases in customer costs. Naturally, if the EDU does not have any exit fee obligation, its customers sees even larger savings than in the low exit fee sensitivity case.

Results for GDU

MRW used a similar analytical approach to examine the financial feasibility of the GDU as it used to analyze the EDU. Based on its Base Case assumptions, MRW derived the following estimates of costs for the GDU and SDG&E.

Figure 6: Comparison of GDU and SDG&E Costs (OCLD Purchase Price)

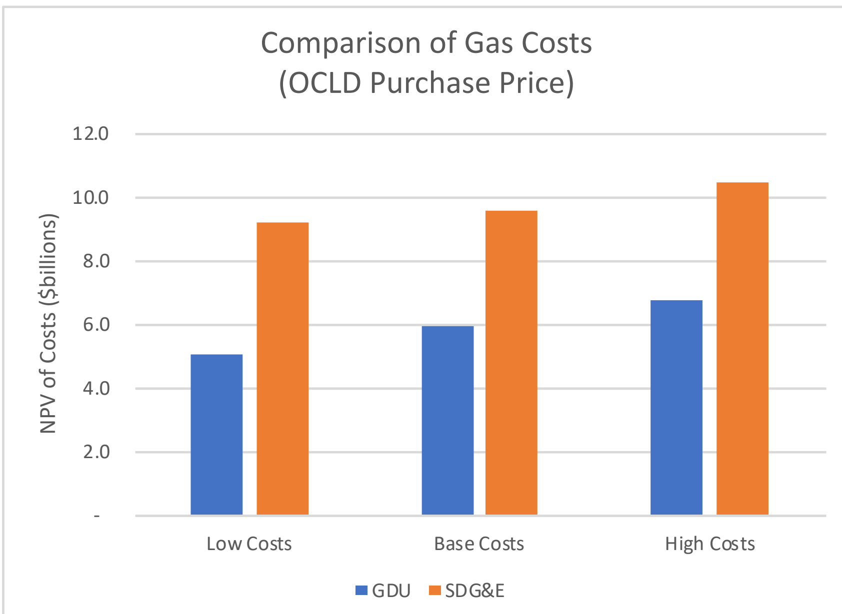


Figure 7: Comparison of GDU and SDG&E Costs (RCNLD Purchase Price)

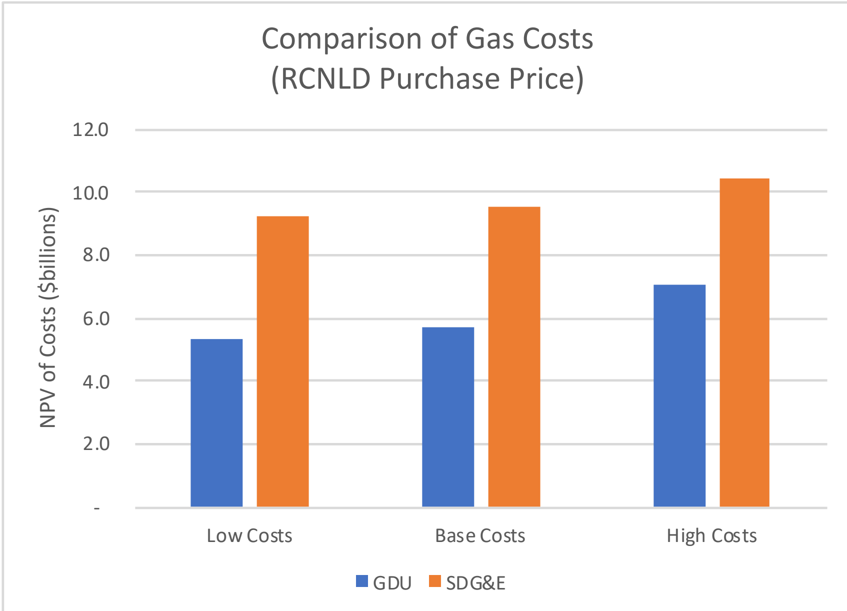
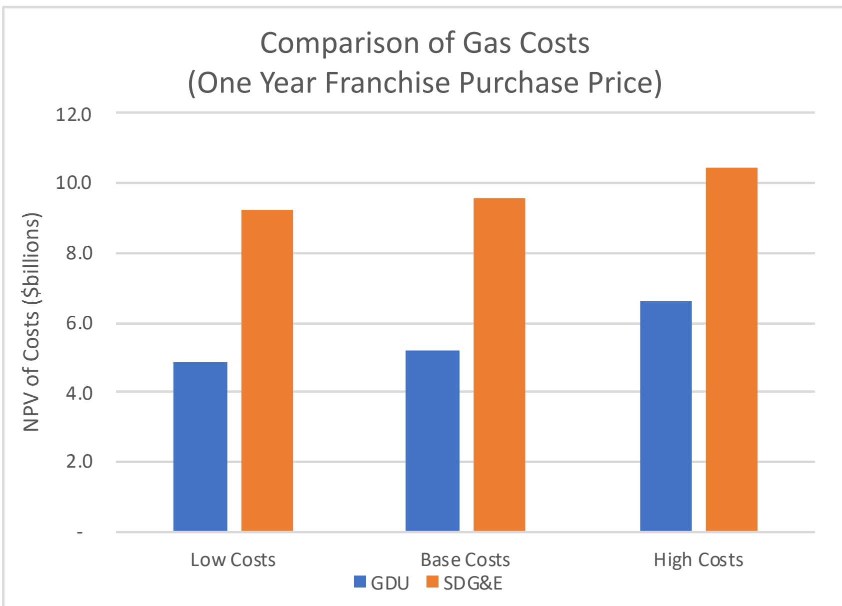


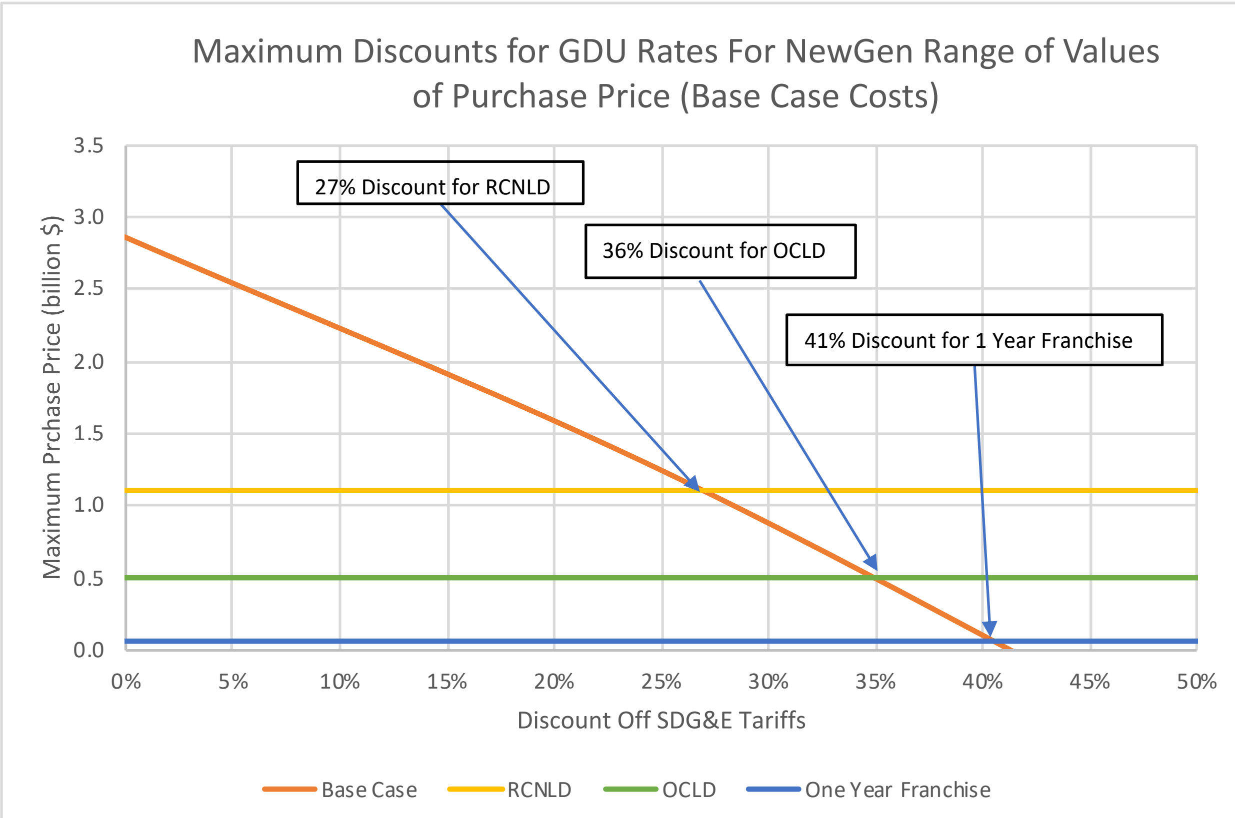
Figure 8: Comparison of GDU and SDG&E Costs (One Year Franchise Purchase Price)



Figures 6 through 8 above show that customers would pay less under a GDU than under SDG&E under all cost scenarios and GDU acquisition cost assumptions.

As in its analysis of the EDU, MRW derived the following maximum purchase prices for the GDU assuming different levels of retail rates.

Figure 9: Maximum Discounts by GDU for Different Purchase Prices Under Base Case Cost Assumptions



As seen in Figure 9 above, the line representing the Base Case purchase price crosses the lines representing RCNLD, OCLD, and One Year Franchise at rate discounts relative to SDG&E of about 27%, 36%, and 41%, respectively. This means that if the GDU paid SDG&E a purchase price equal to RCNLD, OCLD, or One Year Franchise purchase prices, the GDU could meet its expenses, debt service costs, and financing requirements and offer its customers significant rate discounts relative to SDG&E's rates.

The following table summarizes these results:

Table 4: Maximum Rate Discount for Different GDU Purchase Prices Using Base Case Costs

Purchase Price	Maximum Rate Discount Relative to SDG&E
OCLD	27.0%
RCNLD	36.5%
One Year Franchise	40.9%

As with the EDU, there is significant uncertainty in the Base Case assumptions underlying these results. MRW has identified several key variables[6] that will impact the costs for the GDU:

1. **CO2 Allowance Prices.** The GDU is impacted by the cost of greenhouse gas. Higher CO2 allowance prices mean that the GDU must pay more for natural gas, which will increase the GDU's rates.[7]
2. **GDU Operating Costs and Capital Additions.** As with the EDU, the costs to operate and maintain the GDU are both important and uncertain. The greater the operating costs and capital addition costs, the less revenue that is available for debt service.
3. **Treatment of Capital Expenses.** As with the EDU, there is some uncertainty associated with the manner in which the GDU would "pay" for its ongoing capital additions. Annual capital additions for the GDU start at $19 million. If the GDU pays for these capital additions as a cash expense, then the GDU's costs are much higher in the near-term compared to if the GDU were to finance its capital additions using tax-free debt.
4. **Alternate Severance Costs.** The severance cost estimates for the establishment of the GDU have a much narrower range than for the EDU. Because these severance costs are financed, they contribute to the debt service costs of the GDU, meaning that higher severance costs will increase debt service and result in a lower maximum purchase prices for a given level of retail revenue.

The following table summarizes the impacts on the costs for the GDU of changes to these uncertain factors.

Table 5: Impact of Change in Uncertain Variables on Costs for GDU

	Change in Variable	Impact on GDU Costs
CO2 Allowance Prices	Lower/Higher CO2 Allowance Prices	Reduces/Increases
Operating Costs and Capital Additions	Lower/Higher O&M and Capital Additions	Reduces/Increases
Payment for Capital Additions	Capitalizing/Expensing Capital Additions	Increases/Decreases
Severance Costs	Lower/Higher Severance Costs	Reduces/Increases

When alternate assumptions regarding key uncertain variables are combined into High Cost and Low Cost scenarios, MRW finds that the potential discount that the GDU can offer relative to SDG&E's rates are very different than when using Base Case assumptions. The following table summarizes the potential rate discount that could be offered to GDU customers using different cost scenarios and purchase prices.

[6] Note that the key uncertain variables for the GDU are a subset of those for the EDU. Also note that, unlike the EDU, higher CO2 prices increase costs for GDU customers.

[7] SDG&E has to pay similar GHG-related costs for gas that it supplies. Thus, changes in GHG costs do not affect the price of natural gas for the GDU relative to SDG&E: both rise or fall with increases or decreases in GHG Allowance prices.

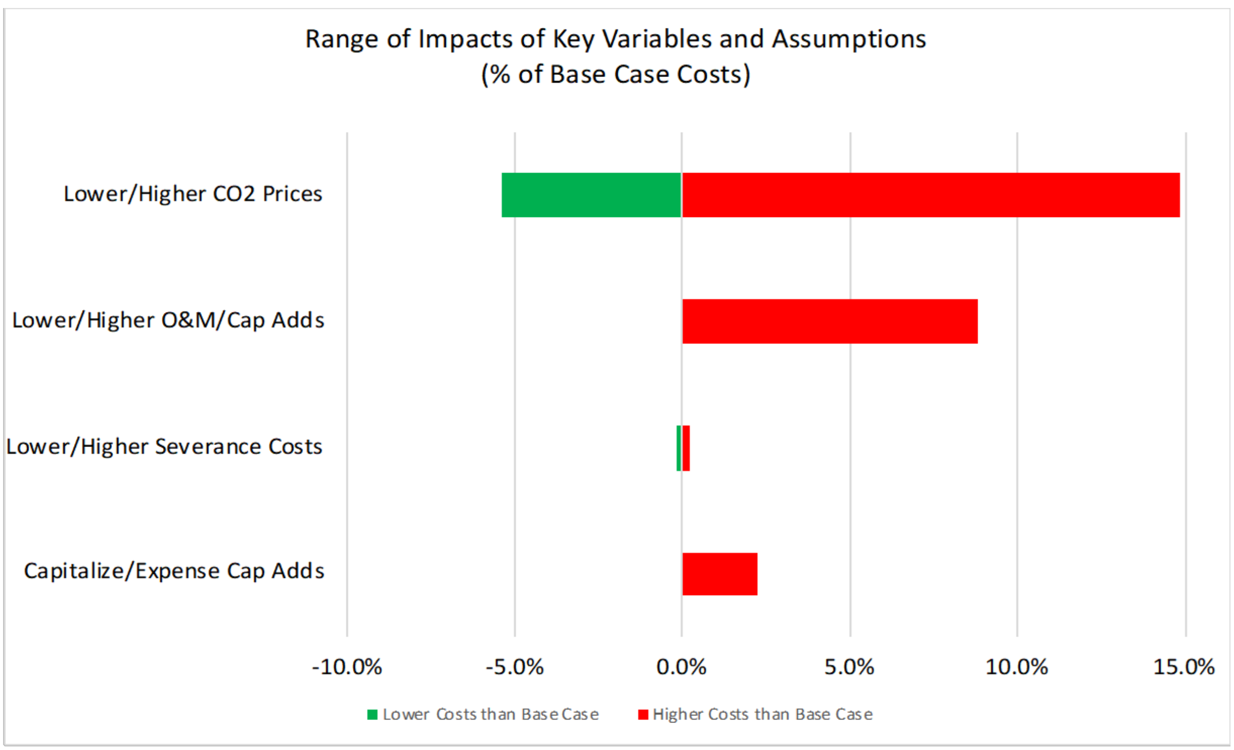
Table 6: Range of Potential GDU Rate Discounts for Different Cost Scenarios and Purchase Prices

	RCNLD	OCLD	One Year Franchise
Low Costs	27.2%	36.6%	41.1%
Base Case	27.0%	36.5%	40.9%
High Costs	16.0%	25.4%	29.9%

Table 6 above shows that in the Low Cost scenario, the maximum potential rate discount ranges from 27.2% to 41.1% for purchase prices equal to RCNLD and the One Year Franchise price, respectively. For the High Cost scenario, the maximum potential rate discount ranges from 16.0% to 29.9% for purchase prices equal to RCNLD and the One Year Franchise price, respectively.

As noted above for the EDU, it is very unlikely that all the key variables for the GDU will align either positively or negatively. As with the EDU, MRW explored the impact of each uncertain variable individually. The following figure presents the percentage change in the costs for GDU's customers under these different assumptions.

Figure 10: Range of Impacts of Key Variables on GDU Customer Costs



These results show the largest increase in the costs for GDU customers results from higher CO2 prices and higher O&M/Capital Additions relative to the Base Case. Assuming that the GDU expenses its Capital Additions rather than financing them causes a somewhat smaller increase in costs. Finally, severance costs have very little impact on the final costs for GDU customers.

Feasibility of EDU and GDU

Given the valuation range for the EDU and GDU assets provided by NewGen, severance costs provided by Advisian, and other assumptions, MRW's preliminary findings are that the City can, under many (but not all) circumstances, purchase the SDG&E electric and gas assets located within the City limits at the values provided by NewGen while still offering lower rates than SDG&E.

The following table summarizes the conditions under which the purchase of the EDU and GDU are feasible (i.e., that the assets can be purchased and rates will be lower than those offered by SDG&E):

Table 7: Maximum Rate Discounts for EDU Based on Different Purchase Price and Cost Assumptions

	RCNLD	OCLD	One Year Franchise
Low Cost Case	21.8%	25.5%	29.8%
Base Case	4.5%	8.2%	12.5%
High Cost Case	<0% (infeasible)	< 0% (infeasible)	< 0% (infeasible)

Table 8: Maximum Rate Discounts for GDU Based on Different Purchase Price and Cost Assumptions

	RCNLD	OCLD	One Year Franchise
Low Cost Case	27.2%	36.6%	41.1%
Base Case	27.0%	36.5%	40.9%
High Cost Case	16.0%	25.4%	29.9%

As seen from Tables 7 and 8:

- The City could acquire SDG&E's assets, establish an EDU, and offer customers lower rates than SDG&E under the Low Cost or Base Case scenarios. Rate discounts would be less if the assets were acquired at RCNLD than at OCLD.
- The City could acquire SDG&E's assets, establish an GDU, and offer customers significantly lower rates than SDG&E under all cost scenarios. Rate discounts would be less if the assets were acquired at RCNLD than at OCLD.
- The EDU is infeasible under the High Cost scenario regardless of the purchase price.

Introduction

MRW & Associates, LLC (MRW) prepared financial analyses and recommendations regarding the economic feasibility of the purchase of the electric and gas distribution infrastructure that currently serves the citizens and businesses located within the political boundaries of the City of San Diego (City) and establishing municipally-owned electric and natural gas distribution utilities (EDU and GDU, respectively) to provide electric and gas service to those customers. Upon acquiring the EDU and GDU assets, all customers that currently take service (either bundled service or delivery-only service) would become customers of the new EDU and GDU. The EDU is assumed to provide bundled distribution and commodity power service to its customers that currently take bundled service from SDG&E; for customers that only take delivery service (i.e., Direct Access customers), the EDU would continue to provide delivery service to those customers and the customer would continue to receive commodity service from third parties. The bundled service customers of the EDU would receive their commodity electric supply from an entity that would be analogous to San Diego Clean Power, which is a Community Choice Aggregator (CCA) being formed to serve customers within the City of San Diego and other cities. The GDU is assumed to provide bundled commodity natural gas plus delivery services to "Core" customers and would provide delivery services to "Non-Core" customers in the same way that SDG&E currently provides service.

The goal of this analysis is to compare the cost of service for electric and natural gas service that would be paid by citizens and businesses within the boundaries of the EDU and GDU against their costs assuming that they continue to pay for service as customers of SDG&E.[8]

MRW worked as a subconsultant to NewGen Strategies and Solutions, LLC (NewGen) on this project. NewGen provided MRW with estimated range of value (i.e., purchase price) for the assets of the EDU and GDU. Advisian, another subconsultant on the project team, provided MRW with estimates of severance costs for the EDU and GDU assets.

MRW's analysis of the revenues, costs, and expenses associated with the GDU and EDU are part of a broader project managed by NewGen to provide consulting services related to the existing electric and gas utility franchise agreements with SDG&E, which expire in January 2021.

MRW developed estimates of the operating and maintenance (O&M) costs, debt service costs, cash reserves, and capital additions for the EDU and GDU. In addition, MRW developed estimates of other costs (e.g., Exit Fees) for the EDU.[9] Revenues for the EDU and GDU were estimated based on MRW's forecast of future rates for service to bundled service customers.[10] These costs and revenues were included in a *pro forma* income statement, which provided the basis for the determination of the financial benefits to customers associated with establishment of the EDU and GDU.

MRW recognizes that a significant amount of retail electric load in the footprint of the City is served by Energy Service Providers (ESPs) under California's Direct Access (DA) program. In addition, larger natural gas customers typically procure their own natural gas commodity supplies while SDG&E provides delivery services. MRW has no information about the rates that those customers

[8] MRW assumes that the "cost of service" as customers of SDG&E is equal to the bills paid by those customers.
[9] For this analysis, MRW assumed that there would not be any exit fees related to the acquisition of the GDU assets from SDG&E.
[10] For SDG&E's Non-Core natural gas service rate schedules, MRW estimated delivery-only rates.

pay to their respective ESPs or gas suppliers for commodity services. Thus, this analysis examines customer retail rates for bundled service customers (i.e., customers that take both commodity and wires electric services from SDG&E and customers that take both commodity and pipeline gas services from SDG&E on the gas side) as well as delivery service rates (i.e., rates for the use of SDG&E's wires or pipeline network for delivery of energy supplied by others).

Following this brief introduction, the report is organized in the following sections:

- "Methodology and Common Assumptions" describes the approach used to perform these analyses. A similar approach was used to examine both the EDU and GDU. There are also certain assumptions that are common to the analysis of the EDU and GDU.
- "EDU Assumptions and Results" describes the assumptions used to analyze the feasibility of acquiring the EDU as well as the results of MRW's analysis of such an acquisition. It also presents the range of costs for the EDU and SDG&E under different cost assumptions. This section also presents potential purchase prices for the EDU assets based on different levels of discounts off of MRW's forecast of SDG&E's retail rates. This section also presents the range of potential costs for the EDU associated with owning and operating the EDU assuming a purchase price equal to Original Cost Less Depreciation (OCLD) and various assumptions for key input variables to the analysis.
- "GDU Assumptions and Results" describes the assumptions used to analyze the feasibility of acquiring the EDU as well as the results of MRW's analysis of such an acquisition. This section also presents the range of costs for the GDU and SDG&E under different cost assumptions. This section also presents potential costs for the GDU assuming a purchase price equal to OCLD and various assumptions for key input variables to the analysis.
- "Summary and Conclusion."
- Appendix A describes MRW's methodology for forecasting SDG&E's retail electric and natural gas rates.
- Appendix B provides an assessment of cap-and-trade program implications for the EDU and GDU's financial viability.
- Appendix C provides *pro forma* income statement for the Base Case cost scenario assuming purchase prices for the EDU and GDU equal to OCLD.

Methodology and Common Assumptions

This chapter describes the structure of the analyses of the revenues, costs, and maximum purchase prices for a hypothetical GDU and EDU.

The MRW methodology for estimating the revenues and expenses for the GDU and EDU are outlined below:

1. <u>Define customers of EDU and GDU.</u> For this analysis, MRW assumed that all bundled service and DA customers of SDG&E would become customers of the EDU. For the EDU, MRW assumed that all bundled service customers would continue to take bundled service from the EDU and that DA customers would take wires-only service from the EDU. For the GDU analysis, MRW assumed that all core gas customers of SDG&E would remain bundled service gas customers of the GDU and that non-core gas customers would take pipeline services from the GDU (in a manner analogous to that for DA electric customers).

2. Define customer classes to be served. MRW assumed that the same customer classes that are currently being served by SDG&E's gas and electric departments would be served by the GDU and EDU.
3. Determine annual going-forward costs for the GDU and EDU. MRW has identified the major cost categories for the GDU and EDU. Tables in the following chapters of this report summarize the main data sources for the various costs that make up the total going-forward costs for the GDU and EDU. These costs serve as a key input into (1) the determination of the costs that customers of the GDU and EDU would pay relative to costs that they would pay if they remained customers of SDG&E, (2) the maximum rate discount that the EDU and GDU could offer given different purchase prices and assumptions about operating costs, and (3) the positive (or negative) changes in costs paid by customers of the EDU and GDU under different assumptions.
4. Determine annual sales and maximum demands. MRW developed forecasts of sales to end-use customers of the GDU and EDU based on past sales by SDG&E to both bundled service and "unbundled" customers (e.g., DA electric customers).[11] These forecasts were based on publicly-available data regarding natural gas demands and delivery requirements by customer class as well as hourly and monthly electric demands for both commodity electricity and delivery services by customer class for both SDG&E and the EDU and GDU.
5. Develop rates for gas and electric customers. MRW developed forecasts of SDG&E's natural gas and electric rates for both bundled service and delivery-only customers. These forecasts use assumptions that are consistent with the assumptions used in MRW's forecasts of costs to serve customers under the EDU and GDU.
6. Determine revenue for EDU/GDU based on SDG&E's bundled service rates. Based on the forecasts of demand discussed above, MRW derived estimated annual average costs per MWh and costs per MMBtu for the EDU and GDU, respectively.[12] MRW also examined revenues from EDU and GDU customers at different levels of discounts relative to costs assuming that the EDU and GDU customers continue to take service from SDG&E at its full retail rates.
7. Determine costs of service for the GDU, EDU, and SDG&E. MRW derived potential costs of service for the GDU, EDU, and SDG&E based on its evaluation of revenues, going-forward costs, purchase price, and debt service costs for the EDU and GDU subject to constraints related to minimum debt service coverage ratios and requirements for cash-on-hand over the forecast period. For this analysis, the EDU and GDU's costs are defined as (1) the present value of revenue received from customers of the EDU and GDU less (2) the present value of any reserve funds held by the GDU or EDU at the end of the forecast period plus (3) the present value of any outstanding debt held by the GDU or EDU at the end of the forecast period. Costs of service under SDG&E rates is simply equal to the customer costs at SDG&E's rates.
8. Determine maximum rate discounts relative to SDG&E rates that the GDU and EDU can offer based on different assumptions about the purchase price for those assets. MRW derived maximum rate discounts purchase prices for the GDU and EDU based on its evaluation of revenues, going-forward costs, and debt service costs for the EDU and GDU subject to constraints related to minimum debt service coverage ratios and

[11] MRW assumed that non-core natural gas customers would continue to self-procure commodity natural gas on their own behalf, consistent with the current unbundled gas market for natural gas customers of SDG&E.
[12] MRW relied on SDG&E's Non-Core natural gas transportation rates for customers not taking natural gas commodity service from SDG&E.

requirements for cash-on-hand over the forecast period. NewGen provided MRW with estimates of potential purchase prices for SDG&E's assets in the City's political boundary. Using those estimates, MRW derived the maximum rate discount that the EDU and GDU could offer and still meet their financing constraints associated with owning and operating the EDU and GDU.

9. Examine impact of uncertain assumptions on costs of EDU and GDU. MRW changed the value of various uncertain assumptions to understand the sensitivity of the costs paid by customers of the EDU and GDU to those assumptions. To do this, MRW used OCLD as a purchase price, Base Case cost assumptions (except for individual variables that were changed one at time) and determined the maximum rate discount relative to SDG&E's rates that the EDU and GDU could charge. From that, MRW determined the change in EDU and GDU customer costs relative to Base Case costs. This sensitivity analysis provides relative changes in customer costs as a result of different key assumptions.

MRW analyzed these revenues and costs over a 30-year term (2021-2050).

MRW used various common assumptions for its analysis of the EDU and GDU. For example, MRW assumed that the EDU and GDU would continue to serve the customers in the same manner as they are currently being served by SDG&E (i.e., bundled service customers would continue to take bundled service from the EDU and GDU, while delivery-only customers would continue to take only delivery services from the EDU and GDU). Table 9 below summarizes the key assumptions in this analysis that apply to both the EDU and GDU.

Table 9: Summary of Assumptions Common to Analysis of EDU or GDU

	All Cases	Source/Notes
Initial Bond Borrowing (Taxable)		
Interest Rate	3.25%	City of San Diego
Term, years	30	City of San Diego
Financing Costs	2%	MRW
Min. Debt Service Coverage Ratio	1.2	MRW
Minimum working cash	90 days	MRW
Incremental Debt (Non-Taxable)		
Interest Rate	2.85%	City of San Diego
Term, years	30	City of San Diego
Financing Costs	2%	MRW
Min. Debt Service Coverage Ratio	1.2	MRW
Interest Rate on Cash	0%	MRW
Discount Rate	5%	MRW

MRW assumed the interest rate on debt was equal to the current rates provided by the City: 2.85% or 3.25% for tax-free or taxable debt, respectively, for debt with a tenor of 30 years. Taxable debt was used for the initial acquisition of the EDU or GDU (i.e., purchase of assets, payment of separation costs, and start-up costs). Non-taxable debt was used for costs incurred during acquisition (e.g., working capital, initial funding of reserve accounts, pre-payment of exit fees) and any incremental debt issued after the start-up of the EDU or GDU, such as financing of future capital additions. MRW additionally assumed that the debt originating/financing fees would add 2% to the total debt. MRW assumed that the debt covenants would require that the EDU and GDU would need to maintain a minimum debt service coverage ratio (DSCR) of 1.2 and a minimum working cash on hand equal to three months of operating expenses plus capital additions over the term of the debt.

For this preliminary analysis, some of the assumptions are highly uncertain. For example, the start-up costs for the EDU and GDU were based on the allocated portion of SDG&E's general and common costs as derived by NewGen. However, this assumption may under- or overstate start-up costs. Should further investigation into the feasibility of acquiring the EDU and GDU be needed, MRW recommends revisiting these key assumptions used in the analysis.

Analysis of EDU

This chapter describes the analysis of the revenues and costs associated with a hypothetical EDU. The chapter starts with discussion of key assumptions related to the EDU, including the primary data sources relied on for the analysis. The key assumptions addressed are: the sales forecasts for the EDU, the EDU's costs to serve its customers, the electric and gas rates that SDG&E is expected to charge its bundled service and Direct Access customers in the future, and potential exit fees that the EDU would have to pay. Following the discussion of key assumptions for the EDU, the report presents the results of the analysis of the EDU, including comparison of customer costs for the EDU relative to those if customers took service from SDG&E, discussion the maximum rate discount that the EDU could offer given different assumptions regarding purchase price, and the sensitivity of customer costs to changes in key input assumptions.

Key Assumptions for EDU

The key assumptions for the modeling of the EDU are presented in the following table.

Table 10: Data Sources for EDU Cost of Service

Data Category	Initial Value	Source	Escalator
% of SDG&E System in GDU	42%	NewGen	
Acquisition Costs (B$)	$1.6 (OCLD) - $2.7 (RCNLD)[13]	NewGen	Annualize using assumed cost of debt for EDU
Start-Up Costs – Electric (B$)	$0.21	NewGen/MRW	One-Time Charge
Fuel and Purchased Power (B$)	$0.48	MRW	Escalates sales and with weighted average increases in costs of renewable- and natural gas-fired generation
Transmission Access Charges ($B)	$0.2	CAISO tariff	Escalates with sales and general inflation
Capital Additions (B$)	$0.23	SDG&E 2019 GRC Phase 1	Either (1) paid as incurred or (2) annualized at cost of debt for GDU. Escalated based on SDG&E's most recent Post-Test Year ratemaking methodology and underlying data
O&M Costs (net of Cap. Adds)	$0.27	SDG&E 2019 GRC Phase 1	Escalated based on SDG&E post-test year ratemaking methodology and underlying data
Working Capital and other cash start-up costs (B$)	$0.29	90 days expenses (net of Cap. Adds)	
Separation Costs (B$)	$0.19 - $2.4	Advisian	Annualize using assumed cost of taxable debt for EDU
PCIA (B$)	$0.27	MRW	Escalates with changes in market prices, renewable prices, capacity value, and costs of SDG&E portfolio
Revenue from Carbon Allowances (B$)	$0.05	MRW	Based on sale of excess allowances
Lost Franchise Fees in 2021 (MM$)	$123	Franchise Agreement	Escalate with revenues
Payment in Lieu of Taxes in 2021(MM$)	$4	SDG&E[14]	Based on OCLD; escalate with revenues

MRW performed this analysis on an apples-to-apples basis that assumes service of SDG&E's full electric load for each customer class. Thus, MRW's analysis implicitly assumes that the City incurs costs to operate and maintain the electric utility assets acquired from SDG&E in proportion to the portion of SDG&E's system that the City acquires. That is, if the City acquires 42 percent of SDG&E's electric utility assets, the City will incur 42 percent of SDG&E's (1) annual necessary capital additions and (2) annual O&M costs. The analysis assumes that the City finances its capital expenditures (i.e., it issues tax-free debt annually to pay for the EDU's capital additions and amortizes that debt over 30 years rather than paying the full cost of capital additions on a cash basis in the year in which they occur) and that O&M costs increase on a percentage basis according to escalation rates consistent with those expected for SDG&E's rates. The analysis incorporates a forecast of SDG&E's electric rates developed based on a bottoms-up analysis of SDG&E's electric revenue requirements, including both base costs and fuel and purchased power costs. The electric rate forecast is discussed in further detail below.

Although this analysis focuses on the City's acquisition of SDG&E's distribution assets, it is important to reflect the cost of purchasing power as a revenue and expense (i.e., as a pass through of commodity costs) in the analysis because, as the operating utility serving the area, the City would take responsibility as the provider of last resort to its customers. Thus, the financial analysis includes generation rate revenue and power procurement costs. Because a significant portion of the load within the City (e.g., military bases) is served by ESPs, MRW has only included the fuel and purchased power costs associated with serving bundled service customers within the City limits.

Notably, SDG&E recovers greenhouse gas cap-and-trade program compliance costs associated with its non-renewable energy purchases and utility-owned generation through its generation rates. MRW assumes that the City would incur the same types of greenhouse gas cap-and-trade compliance costs as SDG&E and incorporates this into the financial analysis through its forecast of wholesale power costs. However, as discussed elsewhere, because the EDU has a power supply portfolio that is less GHG-intensive than SDG&E's portfolio, the EDU is able to resell some of the GHG allowances that it would receive as an LSE, which would give the EDU a revenue stream that would help offset EDU costs. MRW assumes that the City would purchase wholesale energy generation as a component of its cost of power and reflects cap-and-trade allowance prices in the wholesale energy generation price forecast.

EDU Electric Service Area Sales Forecast

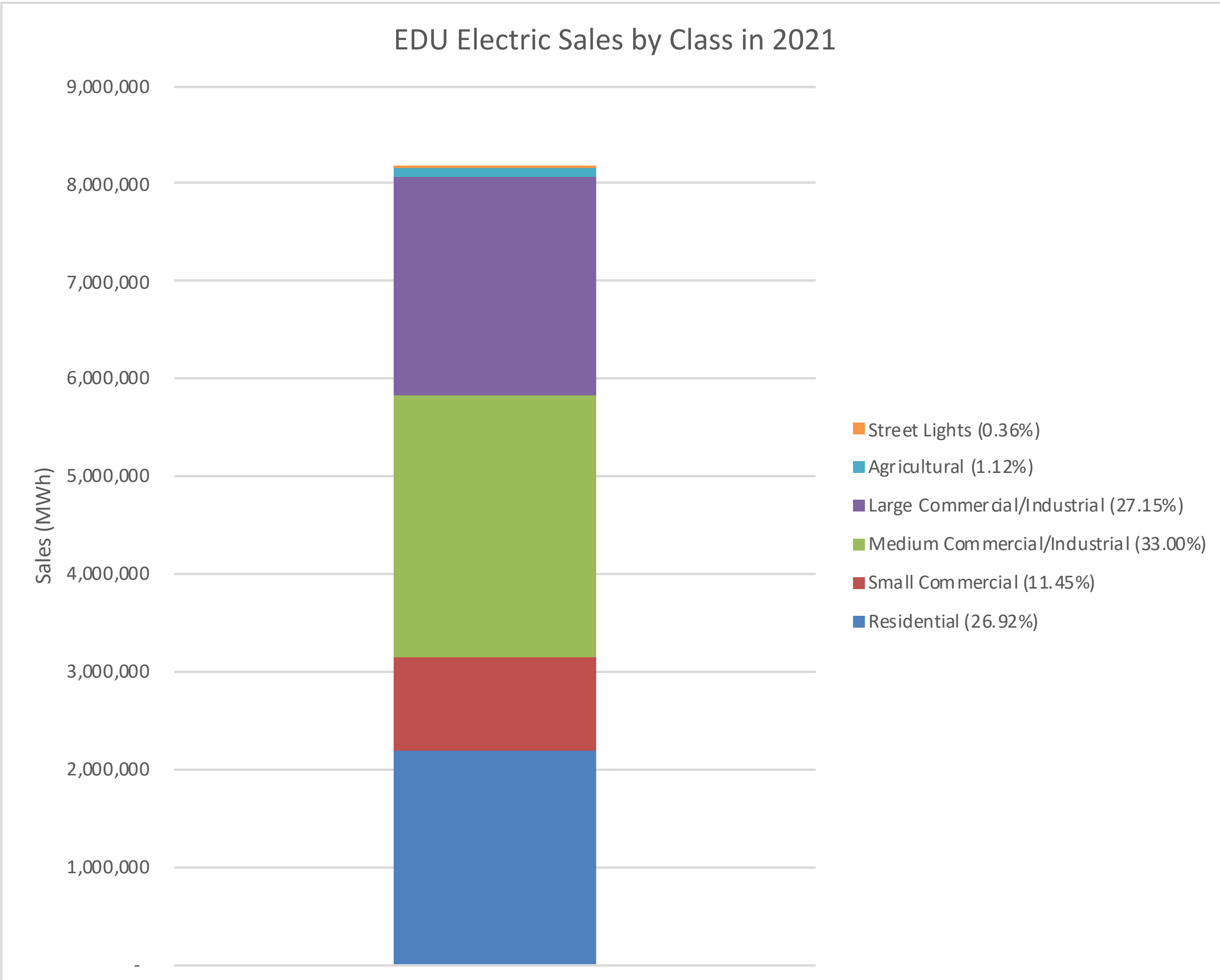
As illustrated in Figure 11 below, the EDU's customer base would be somewhat evenly split between residential, medium commercial/industrial, and large commercial/industrial customers, which make up approximately 87% of total electric sales.[15] Small commercial customers account for only about 11.5% of total sales. Sales to customers in the Agricultural class are slightly more than 1%. Streetlight sales are less than 0.4% of sales.

[13] MRW also examined an acquisition cost equal to NewGen's estimate of value based on a one year remaining term for the franchise ($208 million)

[14] https://www.sdge.com/sites/default/files/regulatory/Chapter%203%20-%20Revenue%20Requirement%20Final.pdf

[15] Sales include both sales to bundled service customers and to Direct Access customers.

Figure 11: EDU Electric Annual Sales by Customer Class (forecast 2021)



Source: MRW based on City-specific load data provided to City of San Diego by SDG&E.[16]

The figure above combines both sales to bundled service customers and to Direct Access customers. Direct Access customers account for about 22% of the total electric sales within the City limits, with the remainder of the sales to bundled service customers. The rate of growth in sales is based on most recently-adopted the mid-case load forecast by the California Energy Commission for SDG&E. This means that MRW assumes that sales are essentially flat throughout the study period.

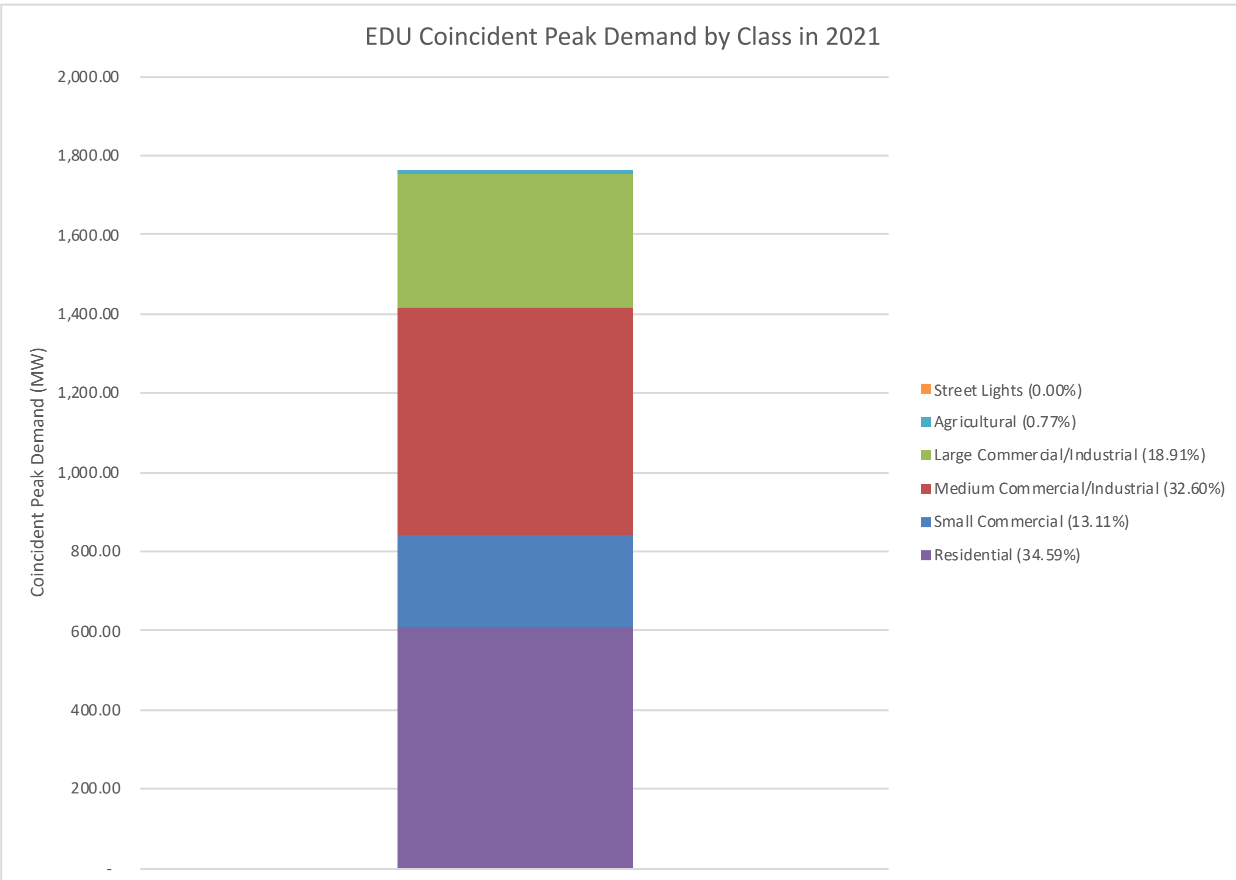
Based on the sales forecast shown in the figure above, MRW developed estimated coincident peak demands[17] by customer class (see Figure 12 below). As can be seen from this figure, the coincident maximum peak demand is about 1,764 MW, with the largest class peak being residential (34.6% of

---

[16] MWh = 1,000 kWh; GWh = 1,000,000 kWh
[17] Coincident peak demand by customer class is the customer class demand at (or coincident with) hour of system peak demand. Non-coincident peak demand is the maximum customer class for the year, regardless of when it occurs. Non-coincident peak demands are always equal to or greater than coincident peak demands for each customer class.

the total). As with sales, the residential, medium commercial/industrial, and large commercial/industrial customer classes account for the vast majority of coincident peak demand (86% of the total). As discussed further below, coincident peak demand is the key driver of the amount of generating capacity that the EDU will need to have available either through power purchase agreements or self-owned generation.

Figure 12: EDU Coincident Peak Demand by Customer Class (forecast 2021)



Source: MRW based on City-specific load data provided to City of San Diego by SDG&E.

The following table compares coincident and non-coincident peak demands for the EDU in 2021.

Table 11: Coincident and Non-Coincident Peak Demand Forecasts for 2021 (MW)

	Coincident Peak Demand	Non-Coincident Peak Demand
Residential	610	739
Small Commercial	231	246
Medium Commercial/Industrial	575	604
Large Commercial/Industrial	334	414
Agricultural	14	20
Street Lights	-	7
Total	1,764	2,031

Source: MRW based on SDG&E Data provided to City of San Diego.

The EDU's Ongoing Costs

The ongoing (or going-forward) costs of operating and maintaining the EDU's system, administrative and general costs, capital additions, and customer service costs were derived from similar cost estimates for SDG&E, scaled based on the estimated fraction of the SDG&E system that will make up the EDU. Escalation for these costs are based on weighted-average escalation of SDG&E's costs. MRW assumes that SDG&E's fire hardening activities will end by the end of its next General Rate Case, which will result in a reduction in the rate of growth in the EDU's capital additions and O&M costs.

Transmission Access Charges

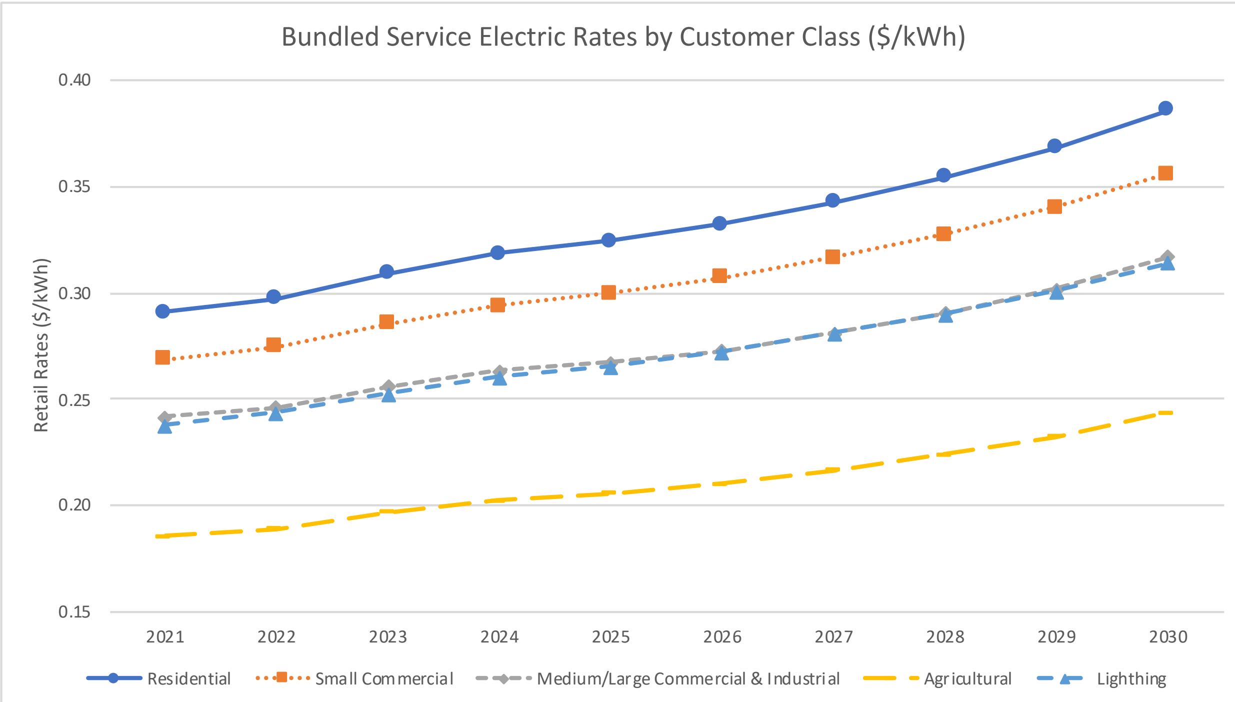
Transmission access charges provide transmission asset owners revenue to operate and maintain the state's transmission system. Because the EDU will interconnect to SDG&E's system at 60kV, EDU will pay both the high-voltage and low-voltage transmission access charges. These amounts average out to slightly less than the transmission charges on SDG&E's retail electric bills.

Long-Term SDG&E Rate Forecast for Electric Customers

To develop this forecast, MRW examined the key cost drivers of each of SDG&E's rate components. The details of MRW's rate forecast are included in Appendix A.

The following figure presents MRW's expected bundled service electric rates by customer class for SDG&E for 2021-2030.

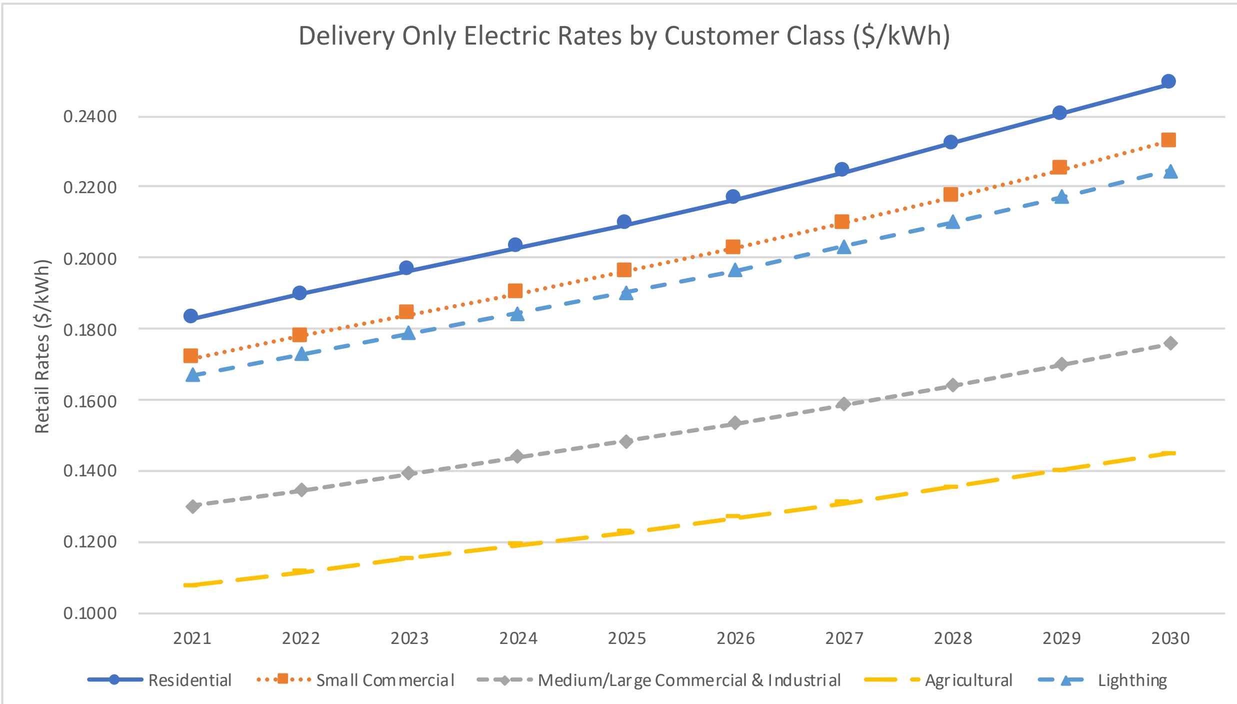
Figure 13: SDG&E Bundled Service Electric Rates by Customer Class



Source: MRW.

Note that in Figure 13 above, the rates for the Medium/Large Commercial & Industrial and the Lighting customer classes are very similar; rates for residential customers are the highest rates shown. The follow figure present MRW's expected delivery-only rates for SDG&E for the period from 2021 to 2030.

Figure 14: SDG&E Delivery-Only Electric Rates by Customer Class



Source: MRW.

Over the forecast period, MRW forecasts that SDG&E's commodity and non-generation rates for all customer classes will escalate by about 2.6% and 3.3% per year from 2021-2030, respectively.

Greenhouse Gas Cap-and-Trade Program Allowance Revenues

California has had a mandatory greenhouse gas cap-and-trade program in place since 2012. MRW conducted a review of the impacts of the program for the EDU and incorporated these impacts into the MRW analysis. As discussed further in Appendix B, both SDG&E and the EDU will be eligible to receive free greenhouse gas allowances, which can be monetized via auction or bilateral sales, and which are intended to offset the utilities' cap-and-trade program liabilities. However, since the EDU is assumed to have a power supply portfolio with more renewable and carbon-free resources than SDG&E, the EDU would need fewer allowances to meet its GHG obligations than SDG&E, thereby giving the EDU a revenue source.

Generation Costs for EDU Customers

Because the EDU would provide generation service to its customers, a forecast of power costs to serve these customers is needed. MRW relied upon a simplified generation cost model, which based the energy cost to serve the customers on CAISO wholesale power market prices. To those power costs we added incremental amounts to account for compliance with the states' renewable portfolio standard (RPS) and Resource Adequacy requirements. The first ten years' forecast generation costs are shown in Table 12, below

Table 12: EDU Power Costs, $/MWh

Year	Power Cost ($/MWh)
2021	55.45
2022	56.97
2023	58.21
2024	60.20
2025	61.65
2026	64.44
2027	67.53
2028	79.94
2029	91.16
2030	105.42

Source: MRW

Exit Fees Paid to SDG&E

For purposes of this analysis, the Base Case assumes that the EDU would pay exit fees.

The Power Charge Indifference Adjustment (PCIA)

The PCIA is an exit fee charged to customers intended to meet the statutory requirement to prevent cost shifting between customers who depart from SDG&E's generation service and "bundled service" customers who continue to obtain all their electrical service from SDG&E.[18] It is designed to share stranded costs from SDG&E's power procurement among all customers on whose behalf the costs were incurred.[19] The forecast of PCIA is included in Appendix B.

In addition to the PCIA, the EDU customer would be subject to the Nuclear Decommissioning Charge (NDC). The NDC is modest, on the order of hundredths of a cent per kWh, but it is included in the EDU analysis.

Because it is possible that the EDU would not be responsible for any PCIA, it is important to understand the potential impact of applying a departing load charge to the EDU's customers. As a scenario, MRW examined the costs and rates for the EDU assuming that the EDU's customers either do or do not have to pay the PCIA. In addition, many observers have concluded that the PCIA level is excessive to the intended purpose. As a scenario, MRW examined the impact of alternate levels of PCIA on the ratepayer costs under the EDU.

The Wildfire Liability Non-Bypassable Charge

Assembly Bill (AB) 1054, signed into law by Governor Newsom on July 12, 2019, takes several new actions to address electric utility-caused wildfires and resulting monetary damages. The most immediately significant of these would be the establishment of a new state Wildfire Fund separate from the state treasury or general fund. It will be funded by bonds issued by the Department of Water Resources (DWR), to be repaid by electric ratepayers (similar to the energy crisis bonds issued by DWR and repaid by ratepayers), and by contributions by the utilities themselves.

---

[18] *See* California Public Utilities Code § 366.2(a)(4) and § 366.2(d).

[19] CPUC Decision D. 08-09-012, pp. 9-10.

The ultimate impact of the Wildfire Fund for electric ratepayers is that the current DWR bond charge of $0.00503 per kWh would be extended beyond 2021, when it is currently scheduled to expire. Furthermore, the CPUC has the authority to adjust the rate as required to collect up to $10.5 billion in order to meet the revenue requirement associated with the Wildfire Fund.[20] The precise rate that will be charged going forward is uncertain at this time, but for this analysis we assume that the Wildfire Liability Non-Bypassable Charge will continue at 0.5¢/kWh throughout the study period.

While this surcharge is generally framed as "non-bypassable" by the CPUC, this assertion has not been tested. It is fully reasonable that a newly formed public electric utility such as EDU would face its own wildfire liability issues and should not be forced to fund SDG&E's via this non-bypassable charge. Additionally, given the relatively urban makeup of the EDU's service territory, it is possible that the EDU's wildfire liability is much less than that of SDG&E. As a scenario, MRW examined the financial viability of the EDU assuming no wildfire liability either from SDG&E or on its own.

Treatment of Exit Fees in Analysis

In the cases where we assume that the PCIA and Wildfire Liability non-bypassable charges are applicable, we calculate the net present value of the PCIA and Wildfire Liability obligations over the study period. As a scenario, we examine the impact on financial viability if, instead of pre-paying this obligation (as part of the initial financing of the EDU), the EDU pays these charges as they are incurred.

Uncertainty in Input Assumptions

MRW recognizes that the input assumptions to this analysis are uncertain. MRW has identified several key variables that will have a significant impact on the ability of the EDU to cover its costs with its revenues:

1. **Natural Gas Prices.** MRW assumes that the level of generation that is tied to the cost of natural gas purchased by the EDU decreases over time. SDG&E also purchases a certain amount of natural gas-fired generation. However, MRW assumes that the EDU and SDG&E have different resource portfolios with different amounts of natural gas-fired generation. Thus, changes in gas prices will have different impacts on the EDU's revenues and costs.
2. **CO2 Allowance Prices.** The EDU is impacted by the cost of greenhouse gas. Higher CO2 allowance prices provide the EDU with additional revenues via allowance sales. Higher CO2 prices are also reflected in higher wholesale power market purchase prices and higher prices for utility-owned natural gas power generation.
3. **Costs for Renewable Generation.** MRW assumes that the EDU's generation supply portfolio becomes more "green" over time at a faster rate than SDG&E. Because of this assumption, changes in renewable costs can have different impacts on the EDU's operating costs, which affects the maximum amount that can be paid for the EDU for a given level of retail revenue.
4. **EDU Operating Costs and Capital Additions.** The costs to operate and maintain the EDU are both important and uncertain. The greater the operating costs and capital addition costs, the less revenue that is available for debt service. MRW explored the impact of different levels of operating costs for the EDU.
5. **Exit Fees.** The EDU may or may not be subject to two major Exit Fees: the Power Cost Indifference Adjustment (PCIA) and the Wildfire Liability non-bypassable charge. By not

[20] *Ibid.*, p. 16.

having to pay exit fees, the EDU would have much lower costs, meaning that the maximum purchase price would increase. In addition, the future levels of exit fees are themselves uncertain. MRW examined the impact of different levels of exit fees.

6. **Treatment of Capital Expenses.** There is some uncertainty associated with the manner in which the EDU would "pay" for its ongoing capital additions. Annual capital additions for the EDU start at $231 million. If the EDU pays for these capital additions as a cash expense, then the EDU's costs are much higher in the near-term compared to if the EDU were to finance its capital additions using tax-free debt. MRW analyzed two methods for paying for capital additions: (1) the annual capital additions are paid as incurred (i.e., they are expensed), and (2) the EDU issues tax-free debt to pay for capital additions, meaning that the EDU's costs are equal to debt service costs plus the costs of financing the capital additions.
7. **Alternate Severance Costs.** The severance cost estimates for the establishment of the EDU vary greatly. Because these severance costs are financed, they contribute to the debt service costs of the EDU, meaning that higher severance costs will increase debt service and result in a lower maximum purchase prices for a given level of retail revenue.

The following table summarizes the impacts on the costs for ratepayers of the EDU of changes to these uncertain factors.

Table 13: Impact of Change in Uncertain Variables on EDU Costs

	Change in Variable	Impact on EDU Costs
Natural Gas Prices	Lower/Higher Gas Prices	Reduces/Increases
CO2 Allowance Prices	Higher/Lower CO2 Allowance Prices	Reduces/Increases
Costs for Renewable Generation	Lower/Higher Costs for Renewable Generation	Reduces/Increases
Operating Costs and Capital Additions	Lower/Higher O&M and Capital Additions	Reduces/Increases
Exit Fees	Lower/Higher Exit Fees	Reduces/Increases
Payment for Capital Additions	Capitalizing/Expensing Capital Additions	Reduces/Increases
Severance Costs	Lower/Higher Severance Costs	Reduces/Increases

In order to assess the impacts of these uncertain variables, MRW combined these assumptions into three cases: a Low Cost case, a Base Case, and a High Cost case. In the Low Cost case, we use the most advantageous assumptions for the customers of the EDU: low costs and expenses, no exit fees, capitalization of capital additions, and lower severance costs. In the High Cost case, we use the most adverse assumptions: higher costs and expenses, being subject to higher-than-expected exit fees and prepaying for those exit fees, paying capital additions as expenses (rather than capitalizing them), and higher severance costs. The Base Case uses MRW's expected assumptions for these important variables.

Results of the EDU Analysis

As described in the methodology section, MRW's model takes the assumed acquisition cost of the EDU assets, assumes the EDU issues debt to pay for the assets, amortizes the acquisition and other start-up costs over the term of the debt, adds in operating costs, and derives the total cost of service for the EDU. MRW then tests to ensure that the EDU's revenue is sufficient to meet financing requirements for the EDU's debt (i.e., its Debt Service Coverage Ratio requirements and its Cash-on-Hand requirements). MRW starts with rates equal to SDG&E's retail rates. If there is insufficient revenue to meet the financing requirements, then MRW increases rates until financing requirements are met. On the other hand, if there is excess revenue at SDG&E's retail rates relative to what is needed to meet financing requirements, then MRW reduces retail rates until the EDU has just enough revenue to meet its financing requirements. MRW then compares the costs that the EDU customers would pay against the costs that customers would incur if they were customers of SDG&E. If the EDU's annual revenues exceed costs, then the annual excess revenues are added to a reserve account for the EDU. However, if the annual revenues are less than costs, then funds are withdrawn from the reserve account to ensure that all costs are covered and financing requirements are met.

Using these models, MRW calculates the present value of the costs incurred by the EDU customers against the costs that those customers would incur as SDG&E customers. To ensure a fair comparison, MRW increases the costs for the EDU's customers by the present worth of any debt that is outstanding at the end of the forecast period (i.e., 2050). In addition, MRW reduces the costs for the EDU's customers by the present worth of any cash reserves at the end of 2050. As discussed further below, MRW performed this analysis for various sets of cost assumptions and purchase prices for the EDU.

In addition, MRW uses these models to estimate the maximum rate discount that the EDU could offer relative to SDG&E's retail rates and still cover its costs, pay debt service, and meet its financing requirements. MRW examined different these maximum rate discounts for different assumed purchase prices for the assets of the EDU.

The following results should be considered preliminary. As discussed more fully in the report, MRW has had to make various simplifying assumptions that should be revisited (e.g., start-up costs, the degree to which revenues from the EDU and GDU have to replace franchise fee and property tax revenues that the City currently receives from SDG&E). For those reasons, readers should view the results and conclusions of this report as draft and preliminary.

Using its assumptions regarding costs of operating the EDU and SDG&E's future rates, MRW derived the costs that EDU customers would pay when taking service from the EDU and from SDG&E, respectively, assuming the three purchase prices and three scenarios for operating costs. The following figures present those results.

Figure 15: Comparison of EDU and SDG&E Costs (OCLD Purchase Price)

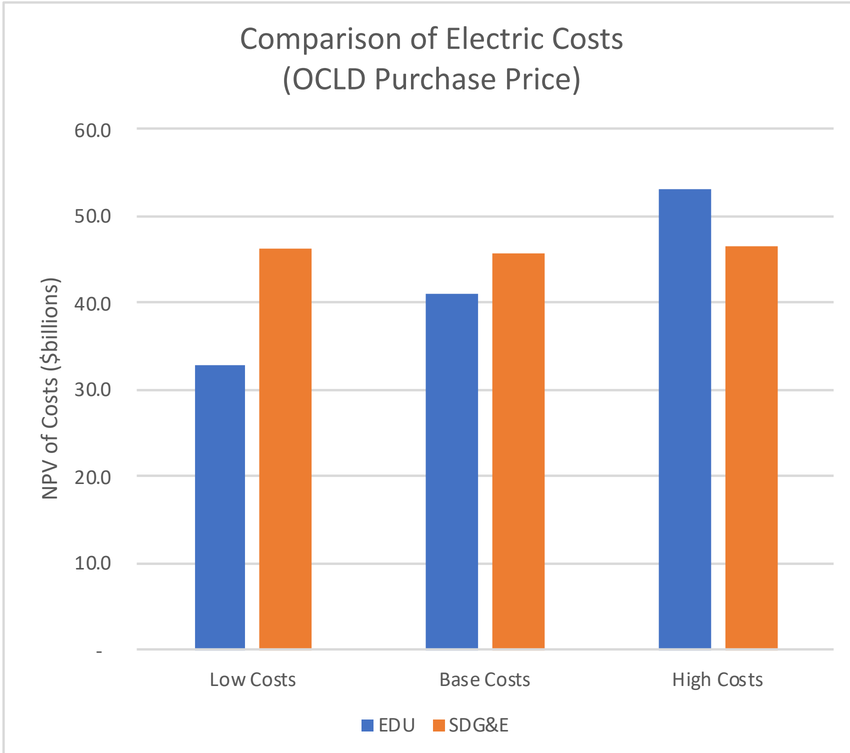


Figure 16: Comparison of EDU and SDG&E Costs (RCNLD Purchase Price)

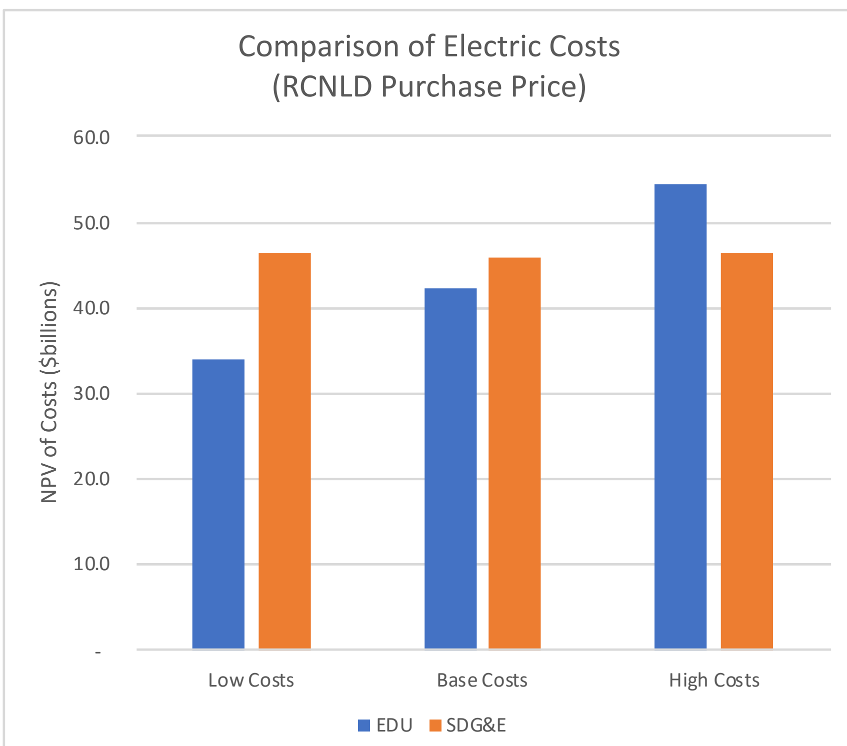
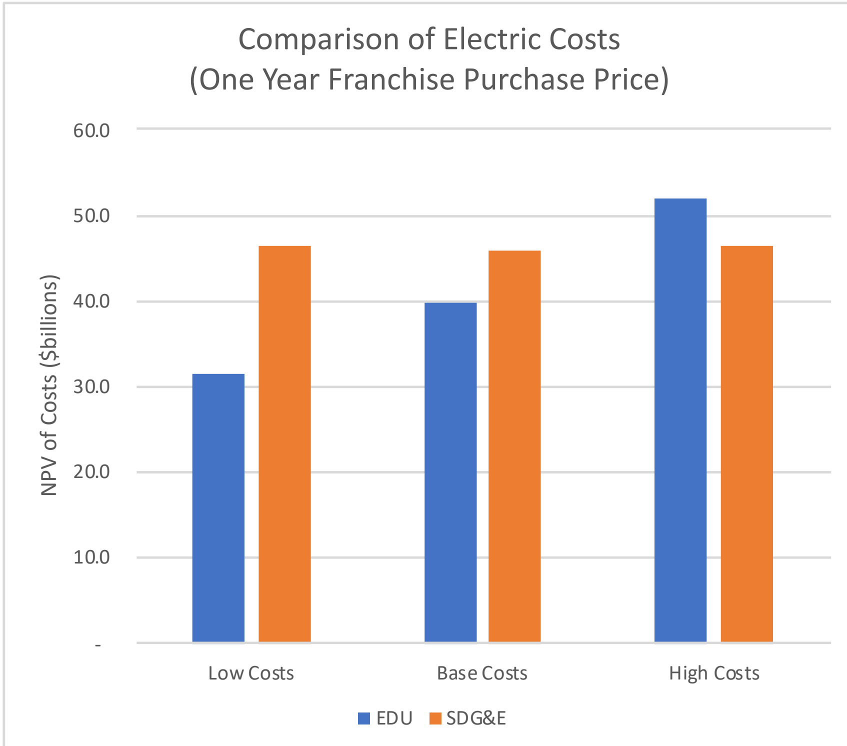


Figure 17: Comparison of EDU and SDG&E Costs (One Year Franchise Purchase Price)

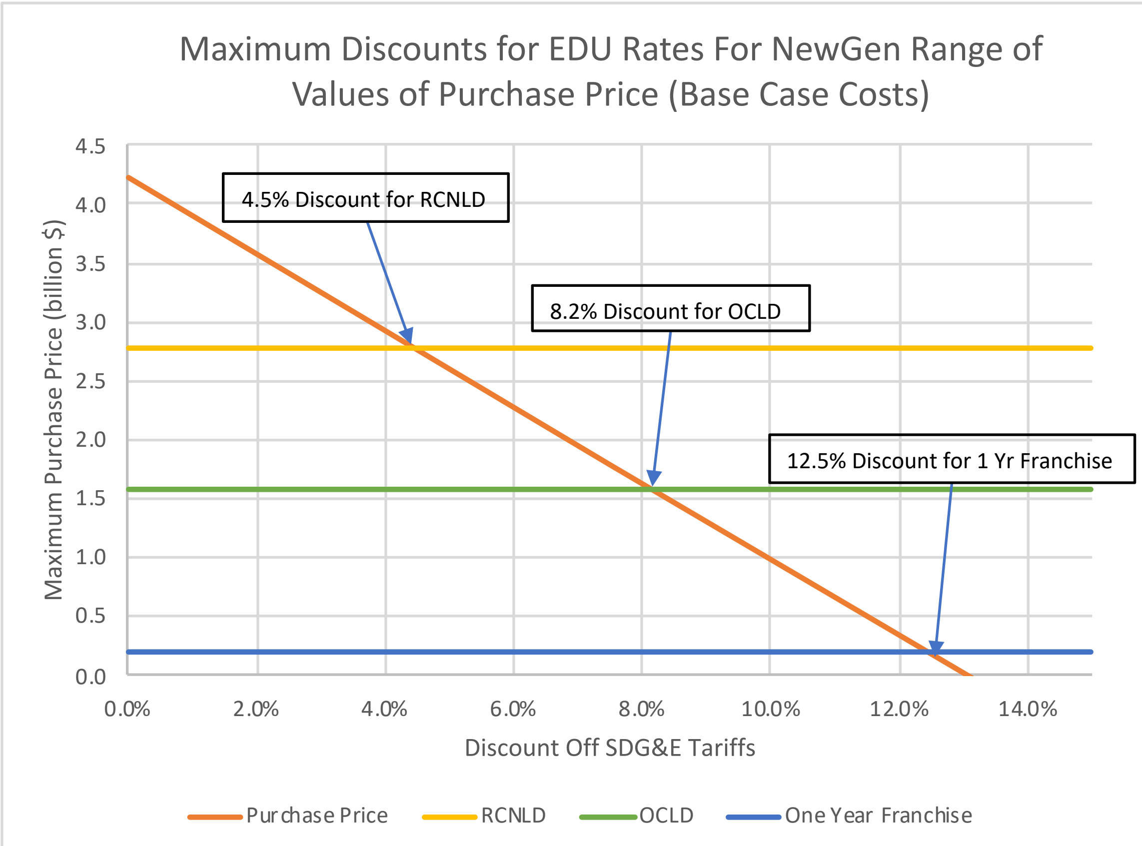


Figures 15 through 17 show that customers of the EDU would have lower costs than if they were to remain customers of SDG&E under the Low Cost and Base Case cost scenarios for all purchase price assumptions. As expected, the costs of the EDU's customers increase when moving from the Low Cost scenario to the High Cost scenario. However, SDG&E's costs do not increase monotonically between the Low EDU Cost and High EDU cost scenarios due to the effect of CO2 allowance prices. Both SDG&E and the EDU receive free GHG allowances and use those to meet GHG requirements for their supply portfolios. However, the EDU is assumed to have a generation portfolio that is more CO2-free than SDG&E, meaning that the EDU would have more GHG allowances that it can sell than does SDG&E, thereby providing additional revenue for the EDU (i.e., effectively reducing the EDU's costs of service). Higher CO2 prices (in the Low EDU Cost scenario) gives the EDU greater sales revenues than in the High EDU Cost scenario (which has lower CO2 prices).

Figures 15 through 17 above also show that there are not significant differences in the costs that customers would pay for EDU service under different purchase price assumptions. This is because the costs of the EDU's fixed assets are a relatively small portion of the overall costs of service of the EDU. For example, the debt service costs of the EDU in the Base Case cost scenario (assuming an OCLD purchase price) are only about 23% of the total costs that customers pay. This is because the EDU's power supply costs are expensed by the EDU, which is different than SDG&E, which owns power generating facilities that have fixed costs that are recovered through SDG&E's rates.

Using its Base Case assumptions, MRW developed estimates for the maximum discount to SDG&E rates that the EDU could offer and still meet all cost and financing requirements. Figure 18 shows the maximum discount that the EDU can offer under the Base Case for each of the three purchase price scenarios.

Figure 18: Maximum Discounts by EDU for Different Purchase Prices Under Base Case Cost Assumptions



In Figure 18 above, the retail rates for the EDU at the far left of the figure have the smallest discount relative to SDG&E's rates, meaning that they are the highest rates examined by MRW.[21] Moving to the right in the figure, the amount of the discount in the EDU's rates relative to SDG&E's rates increases (i.e., the EDU's rates get lower relative to SDG&E's rates), meaning that the revenue for the EDU decreases as the rate discount increases. Since costs are assumed to be constant in this figure, reducing retail rates (and revenues) means that there is less net income available for debt service, which means that the feasible purchase price for the EDU decreases as rate discounts increase. It is for this reason that line showing the purchase price for the EDU slopes downward as rate discounts increase (i.e., moving from left to right in the figure).

As seen in the figure, the line representing the purchase price for the EDU crosses the line representing the Reproduction Cost New Less Depreciation (RCNLD) at a rate discount of approximately 4.5%. This means that if the EDU paid SDG&E a purchase price equal to RCNLD, the EDU could meet its debt service costs and financing requirements and still offer its customers a rate discount of approximately 4.5% relative to SDG&E's rates.

[21] MRW assumes that for the purposes of this analysis, the EDU and GDU would not offer rates that were higher than those offered by SDG&E. There may be reasons to offer higher rates (e.g., greater levels of renewable generation) but MRW did not examine such scenarios.

Similarly, the figure shows that the line for the purchase price for the EDU crosses the horizontal line representing Original Cost Less Depreciation (OCLD) at a rate discount of approximately 8.2% relative to SDG&E's rates. In other words, if the EDU acquired the SDG&E electric assets at OCLD (which is less than RCNLD), then the EDU could offer a larger rate discount to customers relative to SDG&E's rates and still meet its debt service costs and financing requirements than if it purchased the SDG&E electric assets at RCNLD. In addition, because the purchase price assuming One Year Franchise is even lower than OCLD, the potential rate discount under that assumption is even greater than OCLD: 12.5%.

The following table summarizes these results.

Table 14: Maximum Rate Discount for Different EDU Purchase Prices Using Base Case Costs

Purchase Price	Potential Rate Discount Relative to SDG&E
OCLD	8.2%
RCNLD	4.5%
One Year Franchise	12.5%

It is important to note that Figure 18 and Table 14 above presents results using MRW's Base Case cost assumptions except for the discount in EDU rates relative to SDG&E's rates.

As discussed previously, the input assumptions to the modeling are uncertain. To understand the impact of these uncertain variables on results, MRW developed two additional scenarios that combined assumptions into High Cost and Low Cost cases. The following table summarizes the range of assumptions used in these two bounding cases as well as the Base Case.

Table 15: Assumptions for Uncertainty Analysis of Maximum EDU Rate Discount

Key Assumption	High Cost Case	Base Case	Low Cost Case
Natural Gas Prices	70% higher	Base Case	50% lower
CO2 Allowance Prices	Annual escalation 5% lower than Base Case	Base Case	Annual escalation 5% higher than Base Case
Renewable Resource Prices	30% higher	Base Case	30% lower
O&M/Cap Add Costs	20% higher	Base Case	Base Case
Level of Exit Fees	60% higher	Base Case	60% lower
Obligated to Pay Exit Fees	Yes	Yes	No
Severance Costs	$2.4 billion	$1.3 billion	$0.19 billion

When alternate assumptions regarding key uncertain variables are combined into the High Cost and Low Cost scenarios, MRW finds that the potential discount that the EDU can offer relative to SDG&E's rates are very different than when using Base Case assumptions. The following table summarizes the potential rate discount that could be offered to EDU customers using different cost scenarios and purchase prices.

Table 16: Range of Potential EDU Rate Discounts for Different Cost Scenarios and Purchase Prices

	RCNLD	OCLD	One Year Franchise
Low Costs	21.8%	25.5%	29.8%
Base Case	4.5%	8.2%	12.5%
High Costs	-22.0%	-18.9%	-15.4%

Table 16 above shows that in the Low Cost scenario, the maximum rate discount ranges from 21.8% to 29.8% for purchase prices equal to RCNLD and the One Year Franchise price, respectively. For the High Cost scenario, it would be necessary to raise rates relative to SDG&E by between 27.2% and 35.0% in order to cover the costs of the EDU for the RCNLD and One Year Franchise purchase prices, respectively.

It is important to note that the High- and Low Cost scenarios are extreme: it is very unlikely that all the key variables will align either positively or negatively. Rather, these scenarios illustrate the full range of potential outcomes. To understand the impact of the individual uncertain variables discussed above, MRW explored the impact of each uncertain variable on the costs for customers of the EDU.[22] To do this, MRW assumed the purchase price for the EDU was equal to OCLD and then calculated the change in the present value of EDU customer costs resulting from changing each variable relative to the value in the Base Case. This allowed MRW to identify the quantitative effect of the variables on the viability of the EDU. The following figure presents the percentage change in customer costs under these different assumptions.

[22] As mentioned above, "costs" in this case are equal to costs paid by EDU customers plus the present value of any outstanding debt at the end of the analysis period less the present value of any reserves held by the EDU at the end of the analysis period.

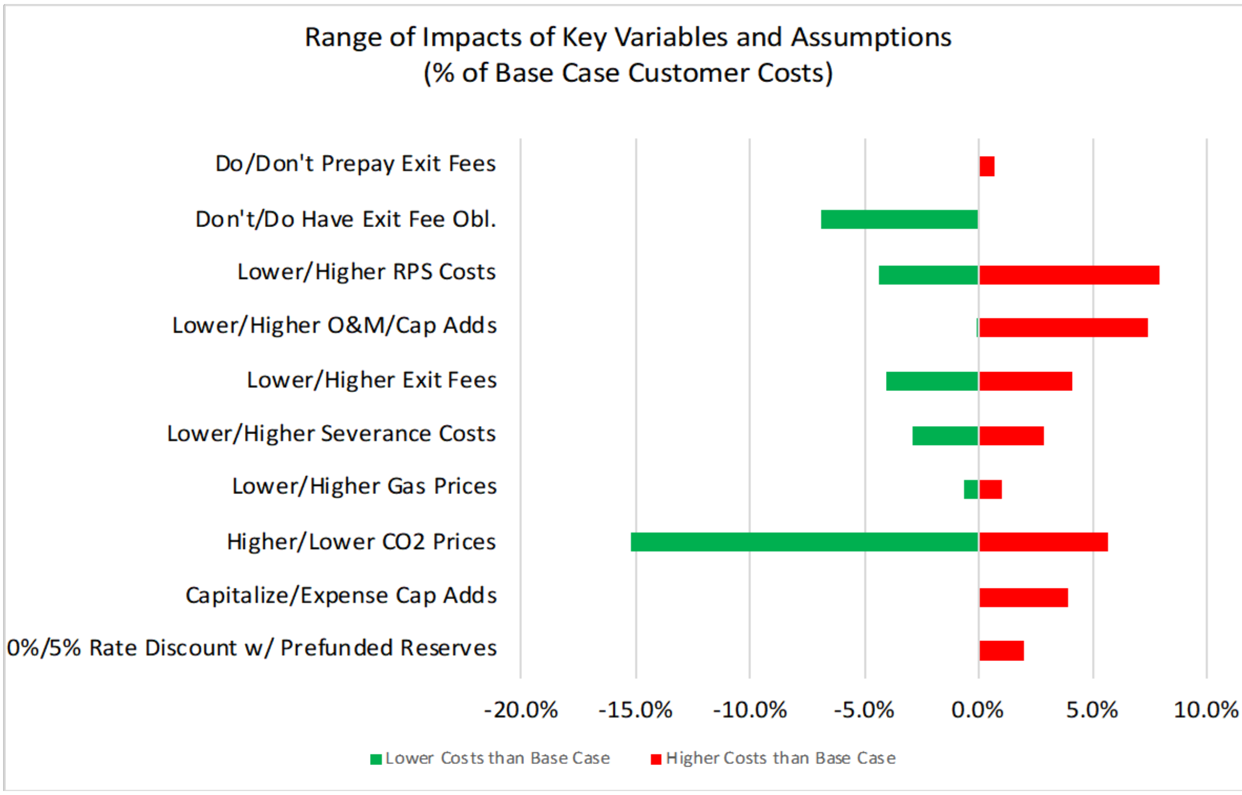
Table 17: Impact of Individual Key Assumptions on EDU Customer Costs

Variable	Change in Variable	Change in EDU Customer Costs (NPV MM$)	% change in EDU Customer Costs (%)
High Gas Prices	70% higher	392	1%
Low Gas Prices	50% lower	(245)	-1%
High CO2 Prices	5%/yr higher growth	(5,942)	-15%
Low CO2 Prices	5%/yr lower growth	2,204	6%
Higher RPS Costs	30% higher	3,076	8%
Lower RPS Costs	30% lower	(1,705)	-4%
Higher O&M/Cap Adds Costs	20% higher	2,896	7%
Lower O&M/Cap Adds Costs	0% lower	(0)	0%
Higher Exit Fees	60% higher	1,603	4%
Lower Exit Fees	60% lower	(1,603)	-4%
High Severance Costs	yes	1,127	3%
Low Severance Costs	yes	(1,127)	-3%
No Exit Fees for Electric	$1.5B lower	(2,672)	-7%
No Prepayment of Exit Fees	No Exit Fees	287	1%
Non-Capitalized Capital Additions	Pay CapEx as Incurred	-	4%

This table presents the absolute dollar and percentage change in the costs that customers of the EDU incur resulting from changing each variable shown in the table in the manner indicated.

The following figure also presents in graphical form the relative changes in final net cash reserves on a percentage basis for each variable or assumption.

Figure 19: Range of Impacts of Key Variables on EDU Customer Costs



To put these changes in context, MRW also examined a scenario where the EDU offers a 5% discount off of SDG&E's retail rates. To do this, the EDU would have to pre-fund a reserve account to ensure that the EDU met its debt service constraints. This case would result in a 2% increase in EDU customer costs and would require a pre-funded reserve account of $1.1 billion.

As seen from Table 17 and Figure 19 above, MRW finds that for the EDU:

- The largest increase in customer costs is due to higher costs for renewable resources and higher O&M and capital additions.[23] O&M and capital addition costs are a significant part of the EDU's costs, which is why increasing them causes such a large increase in customer costs. Higher or lower costs for renewable resources also have very large impacts on EDU customer costs because the EDU is assumed to have a very renewable-rich resource portfolio.
- The results also show that higher CO_2 allowance prices significantly reduce the EDU's costs. This occurs because the EDU's Greenhouse Gas (GHG) compliance obligations are less than SDG&E's, which would allow the EDU to sell its excess GHG allowances, thereby reducing its net costs.
- Exit fees have a very large effect on customer costs; higher or lower exit fees result in major increases or decreases in customer costs. Naturally, if the EDU does not have an exit fee obligation, its customers see even larger savings than in the low exit fee sensitivity case.

[23] MRW assumes that its Base Case estimate of O&M and capital additions is also its Low Case estimate.

Analysis of GDU

This chapter describes the structure of the analysis of the revenues and costs associated with a hypothetical GDU, the primary data sources relied on for the analysis, and the assumptions adopted in the Base Case analysis. The chapter starts with discussion of key assumptions related to the GDU, including the primary data sources relied on for the analysis. The key assumptions addressed are: the sales forecasts for the GDU, the GDU's costs to serve its customers, and the gas rates that SDG&E is expected to charge its bundled service and delivery-only customers in the future. Following the discussion of key assumptions for the GDU, the report presents the results of the analysis of the GDU, including comparison of costs of the GDU relative to those of SDG&E, discussion of the maximum rate discount that the GDU could offer given different assumptions regarding purchase price as well as the sensitivity of the results to changes in key input assumptions.

Key Assumptions for GDU

The key assumptions related to the GDU are presented in the following table:

Table 18: Data Sources for GDU Cost of Service

Data Category	Initial Value	Source	Escalator/Annualization Factor
% of SDG&E System in GDU	50%	NewGen	
Acquisition Costs (MM$)[24]	$500 (OCLD), $1,109 (RCNLD), $57 (One Year Franchise)	NewGen	Annualize using assumed cost of taxable debt for GDU
Start-Up Costs (MM$)	$57	NewGen/MRW	One-Time Charge
Fuel and Storage Costs (Core Customers) (MM$)	$77	SDG&E Core Procurement Rate	Escalates with sales and Natural Gas Futures (Intercontinental Exchange)
Capital Additions (MM$)	$41	SDG&E 2019 GRC Phase 1	Either (1) paid as incurred or (2) annualized at cost of debt for GDU. Escalated based on SDG&E's most recent Post-Test Year ratemaking methodology and underlying data
O&M Costs (net of Cap. Adds) ($MM)	$115	SDG&E 2019 GRC Phase 1	Escalated based on SDG&E post-test year ratemaking methodology and underlying data
Working Capital and other cash start-up costs (MM$)	$51	90 days expenses (net of Cap. Adds)	
Separation Costs (MM$)	$29.7 - $52.8	Advisian	Annualize using assumed cost of taxable debt for GDU
GHG Compliance Costs (MM$)	$25.3	SDG&E Advice Letter 2673-G-C	Cost scaled in proportion to GDU sales volume and escalated based on MRW CO2 allowance price forecast
Lost Franchise Fees in 2021 (MM$)	$12.3	Franchise Agreement	Escalate with revenues
Payment in Lieu of Taxes in 2021 (MM$)	$7.6	SDG&E[25]	Based on OCLD; escalate with revenues

MRW performed this analysis on an apples-to-apples basis that assumes service of SDG&E's full sales volume of natural gas for each customer class. Thus, MRW's analysis implicitly assumes that

[24] MRW also examined an acquisition cost equal to NewGen's estimate of value based on a one year remaining term for the franchise ($208 million)

the City incurs costs to operate and maintain the gas utility assets acquired from SDG&E in proportion to the portion of SDG&E's system that the City acquires. That is, because MRW assumes that the City acquires 50 percent of SDG&E's gas utility assets, the City will incur 50 percent of SDG&E's (1) annual necessary capital additions and (2) annual O&M costs.

The Base Case analysis assumes that the GDU's O&M costs are paid as an annual expense (i.e., it pays for O&M on a cash basis in the year in which they occur) and that O&M costs increase on a percentage basis according to escalation rates consistent with those expected for SDG&E's rates. The escalation rates used for O&M expenses are based on the Post-Test Year ratemaking methodology adopted in SDG&E's 2019 General Rate Case Phase 1 proceeding before the California Public Utilities Commission. The O&M cost escalation reflects the approximate weighted average of non-medical and medical O&M escalation rates incorporated in SDG&E's General Rate Case. This results in a relatively steady escalation of costs at slightly above inflation throughout the period of analysis in the Base Case, with escalation being slightly higher in the earliest three years of the forecast than in later years.

The Base Case analysis assumes that the GDU makes capital expenditures and issues debt annually to cover the costs of those expenses (i.e., the GDU does not pay for capital expenditures on a cash basis in the year in which they occur). In the short-term, MRW forecasts the GDU's annual capital expenditures escalation rate based on a combination of currently forecasted capital additions and recent historical capital additions. MRW has extended this cost escalation into the long-term using both SDG&E's short-term expectations and "business as usual" escalation rates consistent with the post-test year revenue requirement escalation adopted by the CPUC. This reflects the expectation that in the near-term, significant new investments will continue to be necessary in order to update aging infrastructure on SDG&E's system, but that these expenditures to "harden" the SDG&E system will taper down over the next General Rate Case cycle as projects are completed.[26] Ultimately, the Base Case escalation in this analysis reflects escalation exceeding the rate of inflation throughout the period of analysis although the escalation rate is at a higher rate in the earliest years of the forecast.

Although this analysis focuses on the City's acquisition of SDG&E's distribution assets, it is important to reflect the cost of procuring natural gas as a revenue and expense (i.e., as a pass through of commodity costs) in the analysis because as the operating utility serving the area, the City would take responsibility for providing core procurement service as well as acting as the provider of last resort to its customers. Thus, the financial analysis includes commodity procurement rate revenue and commodity procurement expenses consistent with SDG&E's cost of core natural gas procurement.

Notably, SDG&E recovers costs related to greenhouse gas cap-and-trade compliance in its gas transportation rates. Only a subset of SDG&E's natural gas sales incur cap-and-trade compliance costs, as SDG&E is not responsible for directly covered entities. MRW's analysis assumes that the City would incur the same cap-and-trade compliance cost as SDG&E does as an expense in operating the natural gas distribution system. In order to incorporate this expense, the financial

[25] https://www.sdge.com/sites/default/files/regulatory/Chapter%203%20-%20Revenue%20Requirement%20Final.pdf

[26] MRW made downward adjustments to the capital additions in SDG&E's Post-Test Year Ratemaking model to account for SDG&E's historic over-forecasting of capital additions. MRW also excluded general and common costs from capital additions, consistent with the approach used by NewGen.

model assumes a 2018 cost equivalent to SDG&E's filed compliance cost revenue requirement, scaled to the relative volume of gas usage that the GDU is expected to serve, and escalates this value based on (1) MRW's forecast of greenhouse gas cap-and-trade allowance prices and (2) MRW's forecast of annual natural gas sales in order to capture the impact of changing prices and volumes on the total compliance cost.

The analysis assumes no public good costs for the GDU. Should the City develop public good programs with respect to gas service, this would result in incremental costs to the GDU.

GDU Gas Service Area Sales Forecast

Currently, SDG&E provides bundled natural gas service (i.e., commodity gas plus transportation/delivery services) to Core customers. The CPUC defines Core customers as those that take less than 250,000 Therms/year.[27] For perspective, Core customers range in size from residential customers up to colleges and large commercial buildings. SDG&E forecasts that it will deliver approximately 520,000 mTherms to Core customers in 2019.[28]

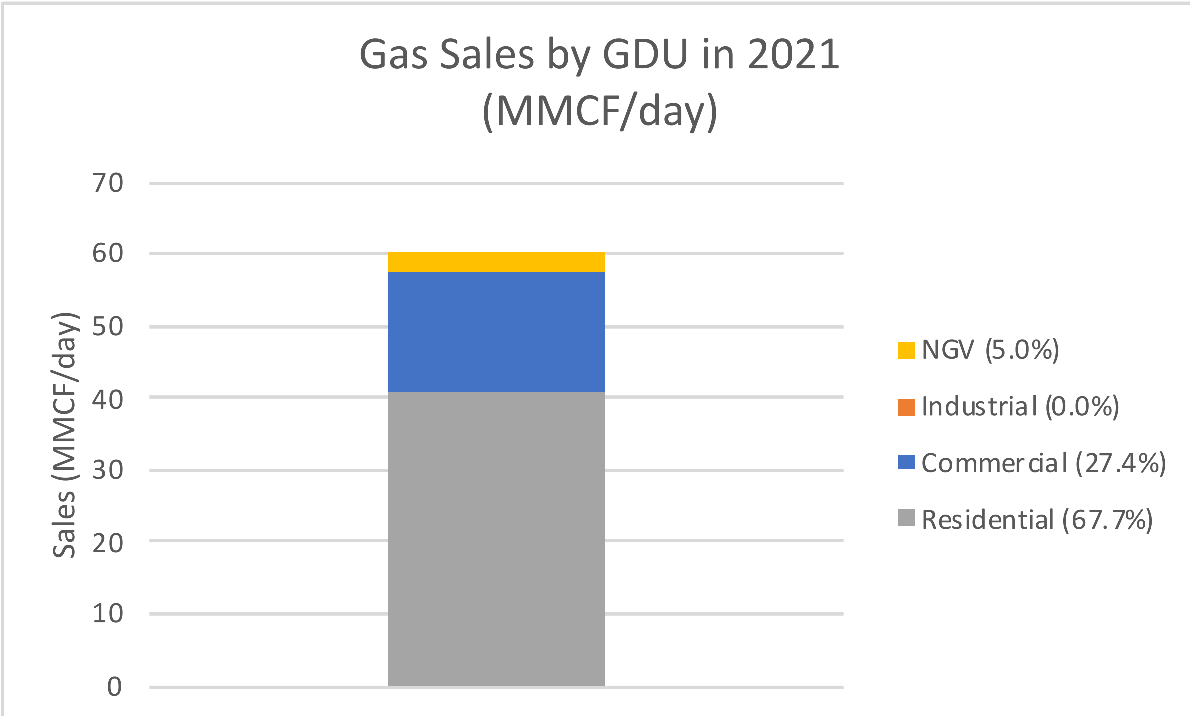
SDG&E provides transportation /deliver services to Non-Core customers. Those customers acquire their own commodity gas that is delivered to their burnertip via SDG&E's local gas distribution system. Non-Core customers include very large commercial and industrial facilities and electric generating units that burn natural gas. SDG&E forecasts that it will deliver approximately 45,000 mTherms[29] to Non-Core customers and almost 670,000 mTherms to Electric Generators in 2019.[30]

For this study, MRW assumed that the natural gas rules under which customers take service would continue, meaning that the GDU would provide bundled commodity gas and delivery services to Core customer and that the GDU would only provide gas transportation and delivery services to Non-Core Customers.

As discussed elsewhere in this report, for this analysis, MRW assumed that 50% of SDG&E's natural gas distribution infrastructure is located within the City of San Diego, meaning that the GDU would acquire 50% of SDG&E's natural gas distribution facilities. Based on this, MRW assumes that 50% of SDG&E's gas deliveries would be to customers within the City of San Diego. The following figures summarize MRW's assumed quantities of natural gas delivered by the GDU as well as the amount of commodity natural gas sold by the GDU in 2021.

[27] https://webarchive.sdge.com/customer-choice/natural-gas/core-service
[28] SDG&E Advice Letter 2673-G-C, Attachment C.
[29] mTherm = 1,000 Therms; 1 Therm = 100,000 Btu; 1 MMBtu = 10 Therms; CF = cubic feet = 1,036 Btu
[30] SDG&E Advice Letter 2673-G-C, Attachment C.

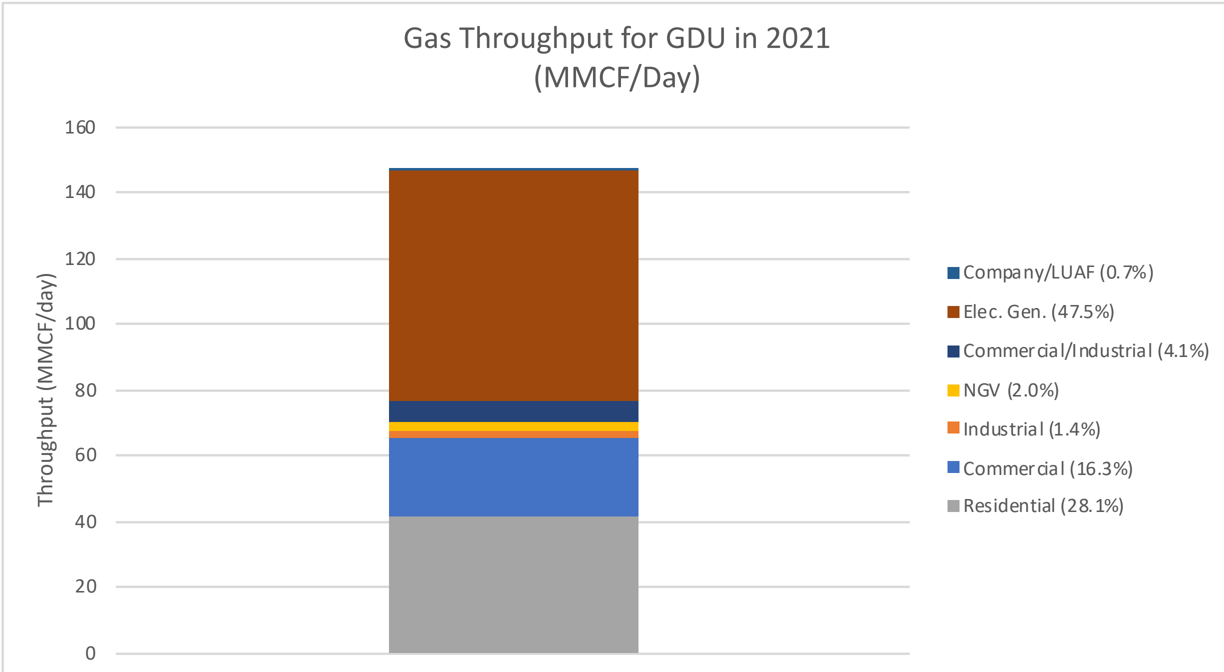
Figure 20: GDU Gas Annual Sales by Customer Class (forecast 2021)



Source: 2018 California Gas Report, pp. 128, 130

As can be seen from Figure 20 above, two-thirds of the gas assumed to be sold by the GDU would go to residential customers, about 27% to core commercial customers, and the rest to natural gas vehicles (NGVs); there is no gas sold to industrial customers or to electric generators.

Figure 21: GDU Gas Annual Throughput by Customer Class (forecast 2021)



Source: 2018 California Gas Report, pp. 128, 130

As seen from Figure 21 above, core throughput is less than 50% of total throughput. Electric generation is the class with the greatest throughput, followed by residential customers.[31]

Natural gas demand is expected to slowly decrease over the forecast period from 2021-2030, with total throughput on the SDG&E system expected to decline on average by 0.5% per year (compound average growth rate). For this study, MRW assumes a similar level of decline in gas sales and deliveries for each customer class as is assumed overall for SDG&E.

The GDU's Ongoing Costs

The ongoing costs of operating and maintaining the GDU's system, administrative and general costs, and customer service costs were derived from similar cost estimates for SDG&E, scaled based on the 50% allocation of gas assets to the GDU. Ongoing costs are escalated consistent with the escalation forecasted for SDG&E's distribution system. Specifically, this escalation rate is based on the combined medical and non-medical escalation rates applied to O&M costs in SDG&E's post-test year ratemaking methodology recently adopted by the Commission in SDG&E's General Rate Case Phase 1 proceeding.

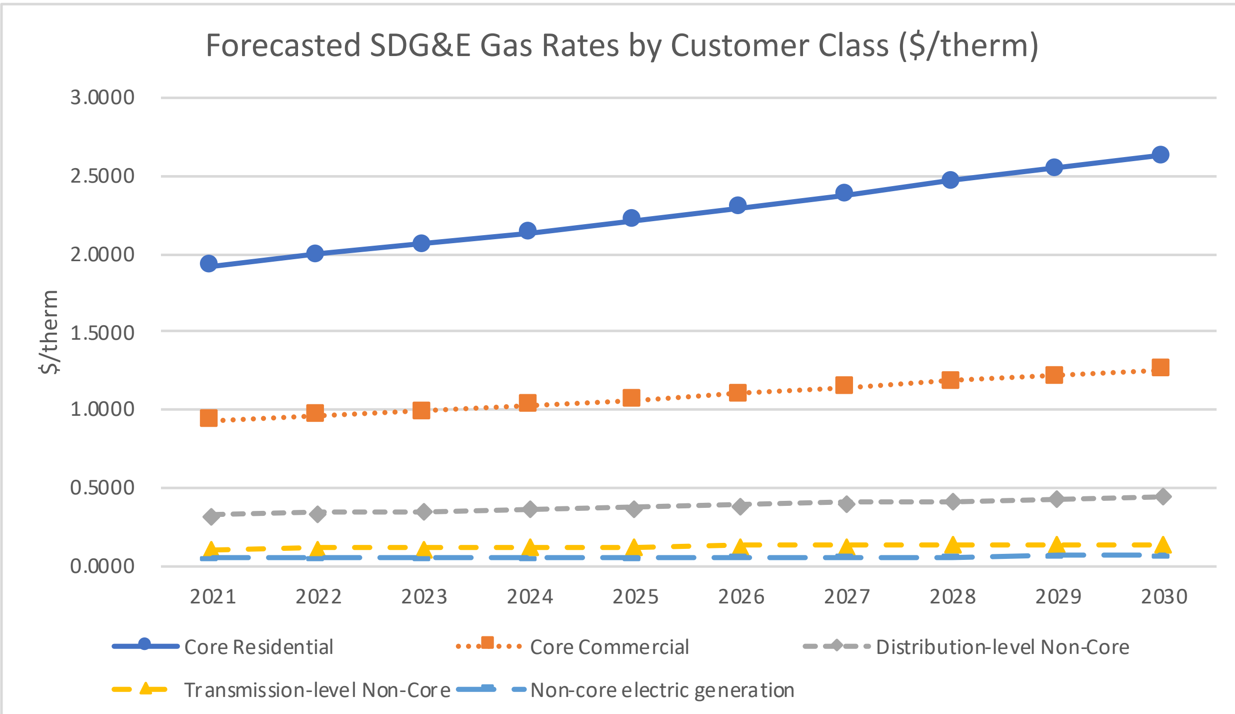
Long-Term SDG&E Rate Forecast for Gas Customers

To develop this forecast, MRW used the gas rates proposed by SDG&E to take effect in January 2020 and then escalated the for main components of the rates (commodity costs, distribution and transportation costs, Public Purpose Program surcharges, and CPUC surcharge) based on escalators specific to each component. Gas commodity costs escalate at the same rate as assumed in MRW's

[31] In this figure, core customers are residential, commercial, industrial, and NGV. Noncore consists of commercial/industrial and electric generation.

electric rate forecast. Distribution and transportation costs grow at an escalation rate equal to the weighted average growth rate of capital additions, O&M, A&G, and other delivery-related costs. examined the key cost drivers of each of SDG&E's rate components. The following figure presents MRW's forecast of natural gas rates.[32]

Figure 22: SDG&E Gas Rates by Customer Class



Source: MRW. Note: Core rates include commodity and delivery charges; Non-Core rates are delivery-only rates.

Over the 10-year period shown above, MRW forecasts that SDG&E's commodity gas costs will escalate by 2.57% per year, while the gas delivery rates will escalate by 3.13% per year.

Greenhouse Gas Cap-and-Trade Program Allowance Costs and Revenues

California has had a mandatory greenhouse gas cap-and-trade program in place since 2012. In 2018, SDG&E began reflecting the costs and revenues of this program in its natural gas rates. MRW

[32] In this figure, Core rates include both commodity and delivery charges; Non-Core rates are delivery-only rates.

conducted a review of the impacts of the program for the GDU and incorporated these impacts into the MRW analysis.[33]

Uncertainty in Input Assumptions

As with the EDU, there is significant uncertainty in the Base Case assumptions underlying these results. MRW has identified several key variables[34] that will impact the costs for the GDU:

1. **CO2 Allowance Prices.** The GDU is impacted by the cost of greenhouse gas. Higher CO2 allowance prices mean that the GDU must pay more for natural gas, which will increase the GDU's rates.[35]
2. **GDU Operating Costs and Capital Additions.** As with the EDU, the costs to operate and maintain the GDU are both important and uncertain. The greater the operating costs and capital addition costs, the less revenue that is available for debt service.
3. **Treatment of Capital Expenses.** As with the EDU, there is some uncertainty associated with the manner in which the GDU would "pay" for its ongoing capital additions. Annual capital additions for the GDU start at $19 million. If the GDU pays for these capital additions as a cash expense, then the GDU's costs are much higher in the near-term compared to if the GDU were to finance its capital additions using tax-free debt.
4. **Alternate Severance Costs.** The severance cost estimates for the establishment of the GDU have a much narrower range than for the EDU. Because these severance costs are financed, they contribute to the debt service costs of the GDU, meaning that higher severance costs will increase debt service and result in a lower maximum purchase prices for a given level of retail revenue.

The following table summarizes the impacts on the costs for the GDU of changes to these uncertain factors.

Table 19: Impact of Change in Uncertain Variables on GDU Costs

	Change in Variable	Impact on GDU Costs
CO2 Allowance Prices	Lower/Higher CO2 Allowance Prices	Reduces/Increases
Operating Costs and Capital Additions	Lower/Higher O&M and Capital Additions	Reduces/Increases
Payment for Capital Additions	Capitalizing/Expensing Capital Additions	Increases/Reduces
Severance Costs	Lower/Higher Severance Costs	Reduces/Increases

In order to assess the impacts of these uncertain variables, MRW combined these assumptions into three cases: a Low Cost case, a Base Case, and a High Cost case. In the Low Cost case, we use the

[33] The impacts of the GHG program are embedded in the starting values for natural gas rates. Because of this, it is necessary to add a cost item into *pro forma* for the GDU. The net effect is that CO2 costs for the GDU are exactly the same as for SDG&E, meaning that changes in CO2 prices should have little effect on the costs of the GDU relative to SDG&E.

[34] Note that the key uncertain variables for the GDU are a subset of those for the EDU. Also note that, unlike the EDU, higher CO2 prices increase costs for GDU customers.

[35] SDG&E has to pay similar GHG-related costs for gas that it supplies. Thus, changes in GHG costs do not affect the price of natural gas for the GDU relative to SDG&E: both rise or fall with increases or decreases in GHG Allowance prices.

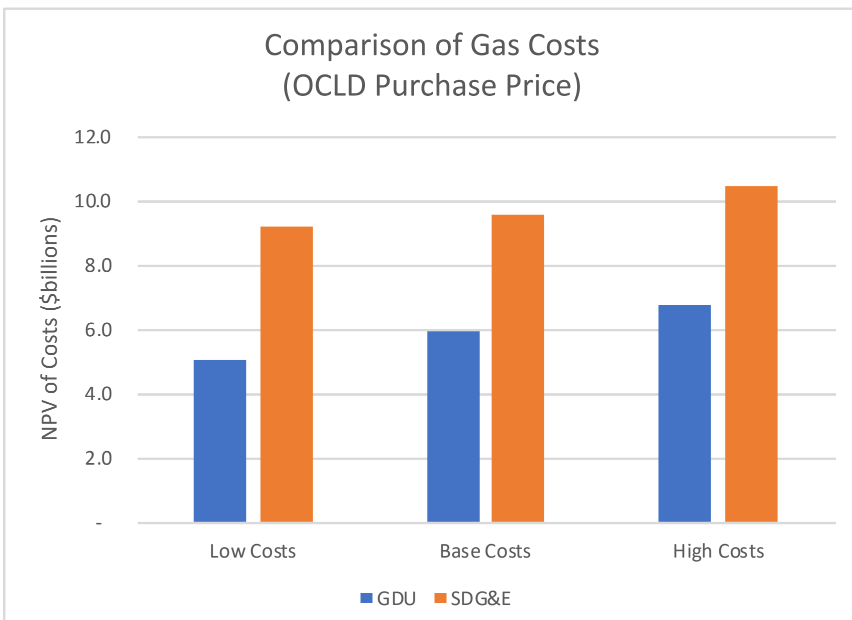
most advantageous assumptions for the customers of the GDU: low costs and expenses, expensing of capital additions, and lower severance costs.[36] In the High Cost case, we use the most adverse assumptions: higher costs and expenses, capitalizing capital additions, and higher severance costs. The Base Case uses MRW's expected assumptions for these important variables.

Results for the GDU

MRW used a similar analytical approach to examine the financial feasibility of the GDU as it used to analyze the EDU. Based on its Base Case assumptions, MRW derived the following estimates of costs for the customers when they are customers of GDU and if they remain as customers of SDG&E.

The following results should be considered preliminary. As discussed more fully in the report, MRW has had to make various simplifying assumptions that should be revisited (e.g., start-up costs, the degree to which revenues from the EDU and GDU have to replace franchise fee and property tax revenues that the City currently receives from SDG&E). For those reasons, readers should view the results and conclusions of this report as draft and preliminary.

Figure 23: Comparison of GDU and SDG&E Costs (OCLD Purchase Price)



[36] Note that for the GDU, the impact of changes in CO_2 allowance costs have the opposite effect on costs than they do for the EDU.

Figure 24: Comparison of GDU and SDG&E Costs (RCNLD Purchase Price)

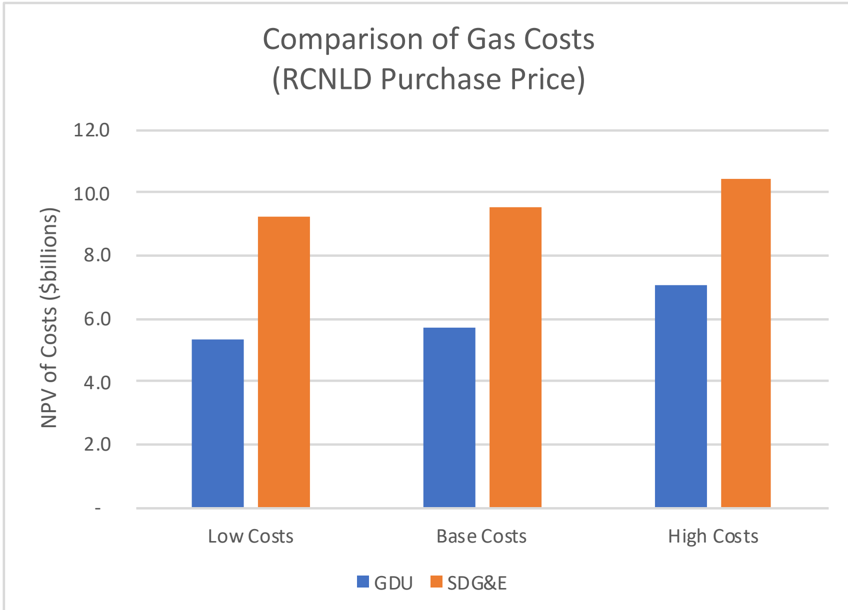
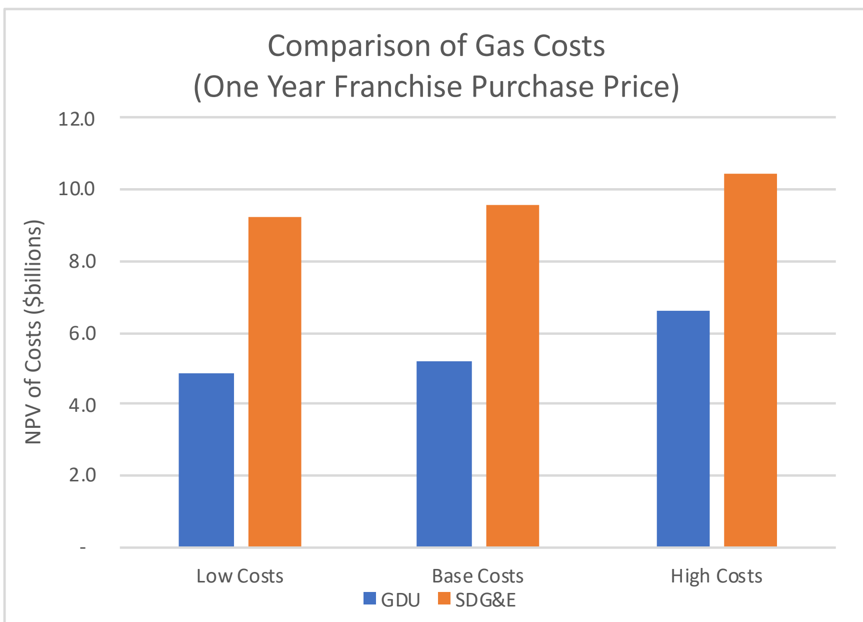


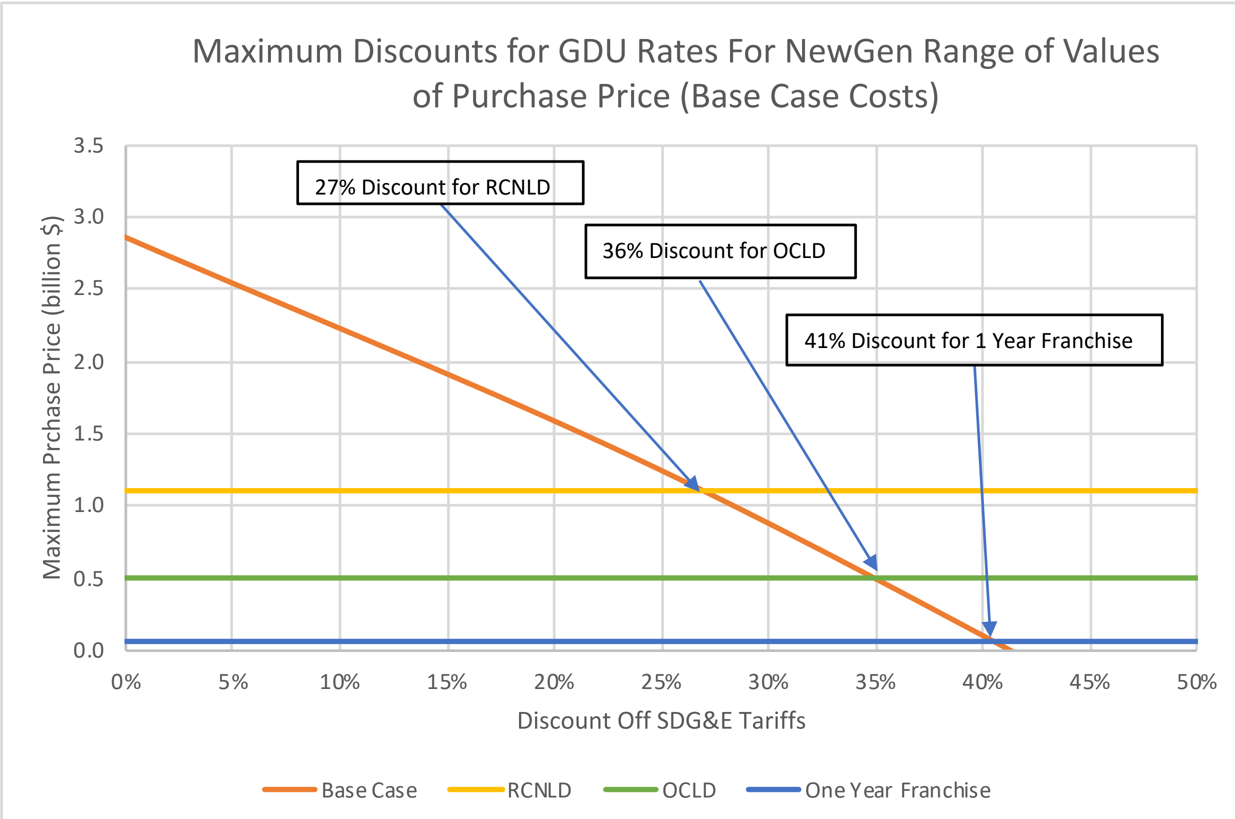
Figure 25: Comparison of GDU and SDG&E Costs (One Year Franchise Purchase Price)



Figures 23 through 25 above show that customers would pay less under a GDU than under SDG&E under all cost scenarios and GDU acquisition cost assumptions.

As in its analysis of the EDU, using its Base Case assumptions, MRW developed estimates for the maximum discount to SDG&E rates that the GDU could offer and still meet all cost and financing requirements. Figure 26 below shows the maximum discount that the GDU can offer under the Base Case for each of the three purchase price scenarios.

Figure 26: Maximum Discounts by GDU for Different Purchase Prices Under Base Case Cost Assumptions



As seen in Figure 26 above, the line representing the Base Case purchase price crosses the lines representing RCNLD, OCLD, and One Year Franchise at rate discounts off of SDG&E of about 27%, 36%, and 41%, respectively. This means that if the GDU paid SDG&E a purchase price equal to RCNLD, OCLD, or One Year Franchise purchase prices, the GDU could meet its expenses, debt service costs, and financing requirements and offer its customers significant rate discounts relative to SDG&E's rates.

The following table summarizes these results.

Table 20: Maximum Rate Discount for Different GDU Purchase Prices Using Base Case Costs

Purchase Price	Maximum Rate Discount Relative to SDG&E
OCLD	27.0%
RCNLD	36.5%
One Year Franchise	40.9%

As discussed above, the input assumptions to the modeling are uncertain. As a result, MRW developed two additional bounding case scenarios (i.e., the High Cost and Low Cost cases) to estimate the range of potential maximum purchase prices for the GDU. The following table summarizes the range of assumptions used in the two bounding cases as well as the Base Case scenarios.

Table 21: Assumptions for Uncertainty Analysis of GDU Purchase Price

Key Assumption	High Cost Case	Base Case	Low Cost Case
CO2 Allowance Prices	Annual escalation 5% higher than Base Case	Base Case	Annual escalation 5% lower than Base Case
O&M/Cap Add Costs	20% higher	Base Case	Base Case
Severance Costs	$52.8 million	$41.3 million	$29.7 million
Capitalize Cap Adds	No	Yes	Yes

When alternate assumptions regarding key uncertain variables are combined into High Cost and Low Cost scenarios, MRW finds that the potential discount that the GDU can offer relative to SDG&E's rates are very different than when using Base Case assumptions. The following table summarizes the potential rate discount that could be offered to GDU customers using different cost scenarios and purchase prices.

Table 22: Range of Potential GDU Rate Discounts for Different Cost Scenarios and Purchase Prices

	RCNLD	OCLD	One Year
Low Costs	27.2%	36.6%	41.1%
Base Case	27.0%	36.5%	40.9%
High Costs	16.0%	25.4%	29.9%

Table 22 above shows that in the Low Cost scenario, the maximum potential rate discount ranges from 27.2% to 41.1% for purchase prices equal to RCNLD and the One Year Franchise price, respectively. For the High Cost scenario, the maximum potential rate discount ranges from 16.0% to 29.9% for purchase prices equal to RCNLD and the One Year Franchise price, respectively

As noted above for the EDU, it is very unlikely that all the key variables will align either positively or negatively. As with the EDU, MRW explored the impact of each uncertain variable individually. This analysis is summarized in the following table.

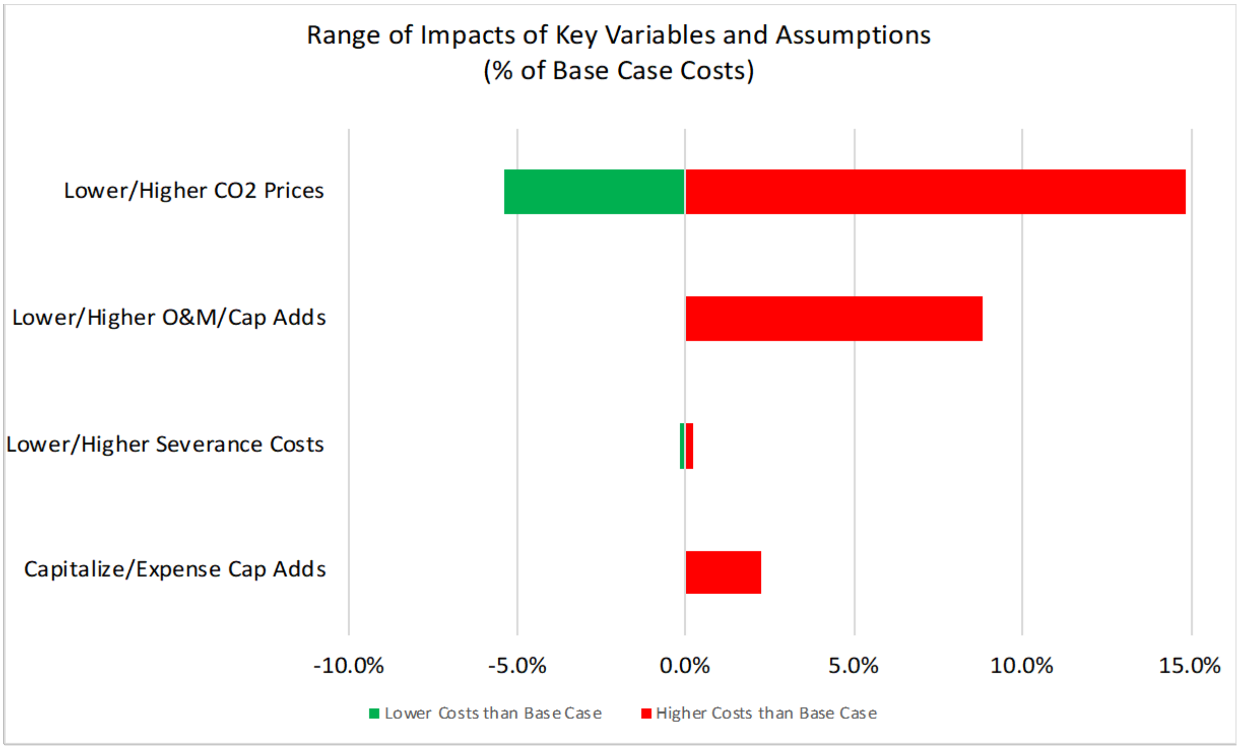
Table 23: Impact of Individual Key Assumptions on GDU Customer Costs

Variable	Change in Variable	Change in Customer Costs (NPV MM$)	% change in Customer Costs (%)
High CO_2 Prices	5%/yr higher growth	918	14.9%
Low CO_2 Prices	5%/yr lower growth	(332)	-5.4%
Higher O&M/Cap Adds Costs	20% higher	542	8.8%
Lower O&M/Cap Adds Costs	0% lower	0	0.0%
High Severance Costs	yes	12	0.2%
Low Severance Costs	yes	(13)	-0.2%
Non-Capitalized Capital Additions	yes	137	2.2%

Table 23 above presents the absolute dollar and percentage change in the present value of the costs for GDU customers resulting from changing each variable shown in the table in the manner indicated.[37] The following figure presents the same information in graphical form.

[37] As noted above, “costs” in this context are equal to the present value of GDU customers’ costs plus the present value of any debt outstanding in 2050 less the present value of any reserve funds in 2050.

Figure 27: Range of Impacts of Key Variables on GDU Customer Costs



These results show the largest increase in the costs for GDU customers results from higher CO2 prices and higher O&M/Capital Additions relative to the Base Case. Assuming that the GDU expenses its Capital Additions rather than financing them causes a somewhat smaller increase in costs. Finally, severance costs have very little impact on the final costs for GDU customers.

Summary and Conclusions

The following conclusions should be considered preliminary. As discussed more fully in the report, MRW has had to make various simplifying assumptions that should be revisited (e.g., start-up costs, the degree to which revenues from the EDU and GDU have to replace franchise fee and property tax revenues that the City currently receives from SDG&E). For those reasons, readers should view the results and conclusions of this report as draft and preliminary.

Given the valuation range for the EDU and GDU assets provided by NewGen, severance costs provided by Advisian, and other assumptions, MRW's preliminary findings are that the City can, under many (but not all) circumstances, purchase the SDG&E electric and gas assets located within the City limits at the values provided by NewGen while still offering lower rates than SDG&E.

The following table summarizes the conditions under which the purchase of the EDU and GDU are feasible (i.e., that the assets can be purchased and rates will be lower than those offered by SDG&E):

Table 24: Maximum Rate Discounts for EDU Based on Different Purchase Price and Cost Assumptions

	RCNLD	OCLD	One Year Franchise
Low Cost Case	21.8%	25.5%	29.8%
Base Case	4.5%	8.2%	12.5%
High Cost Case	<0% (infeasible)	< 0% (infeasible)	< 0% (infeasible)

Table 25: Maximum Rate Discounts for GDU Based on Different Purchase Price and Cost Assumptions

	RCNLD	OCLD	One Year Franchise
Low Cost Case	27.2%	36.6%	41.1%
Base Case	27.0%	36.5%	40.9%
High Cost Case	16.0%	25.4%	29.9%

As seen from Tables 24 and 25 above:

- The City could acquire SDG&E's assets, establish an EDU, and offer customers lower rates than SDG&E under the Low Cost or Base Case scenarios. Rate discounts would be less if the assets were acquired at RCNLD than at OCLD.
- The City could acquire SDG&E's assets, establish an GDU, and offer customers significantly lower rates than SDG&E under all cost scenarios. Rate discounts would be less if the assets were acquired at RCNLD than at OCLD.
- The EDU is infeasible under the High Cost scenario regardless of the purchase price.

Appendix A: Forecast of SDG&E's Rates

This appendix describes MRW's rate forecasting process and the results of those forecasts.

Electric Rate Forecast

SDG&E's retail electric rates are comprised primarily of generation, distribution, and transmission charges. MRW developed a separate forecast for each of these rate components for each of the years 2021-2050 based on the specific cost drivers for each component. To build this forecast, MRW used publicly available inputs, including cost data from SDG&E, and forecasts from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

Generation Charges

As noted, this preliminary report focused solely on the implications of the acquisition of transmission and distribution assets and did not address power procurement or generation rates. However, changes in commodity costs (e.g., natural gas) and renewable generation costs affect SDG&E's retail rates in a slightly different way than they affect the EDU's costs, since the EDU and SDG&E are assumed to have different generation portfolios.

Transmission and Distribution Charges and Other Charges

Several non-generation costs are incorporated into SDG&E's rates. These include costs related to transmission, distribution, public purpose programs, and bond charges stemming from purchases made during California's energy crisis.

SDG&E is interconnected to the CAISO-managed transmission grid. MRW forecasted changes to SDG&E's transmission charges consistent with the rate of CAISO cost increases identified for the EDU.

SDG&E additionally incurs substantial costs to operate and maintain its electric distribution system. As a starting point for the forecast, MRW used the adopted 2019 fixed costs for these facilities. For the period between 2020 and 2022, MRW estimated escalation rates for O&M and capital additions based on historic levels of spending. MRW adjusted SDG&E's forecast of capital additions downward to reflect SDG&E's historic over-estimation of capital expenditures in its GRC. In addition, MRW assumed that SDG&E's capital additions would fall as SDG&E completed its fire hardening of its transmission and distribution system. For this forecast, MRW assumed that capital additions would fall to a trend of baseline capital additions over SDG&E's next GRC cycle such that by 2025 SDG&E's capital additions would be at SDG&E's historic levels of capital expenditures prior to its fire hardening efforts. Over the long term, MRW assumes that capital additions will grow at a rate equal to its historic escalation in capital additions. For O&M, MRW assumes a long-term escalation rate of 2.2%, which is the annual average growth rate for these cost over the last ten years. These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

SDG&E's rates include a number of additional charges. The California Department of Water Resources (DWR) bond charge recovers costs associated with bonds that were issued over a decade ago during the California energy crisis. This charge is set at approximately 0.5 cents per kWh until cost recovery is completed in 2020 (and is thus not included in the analysis). SDG&E's Public Purpose Program (PPP) charge collects revenues that fund a variety of programs, including energy efficiency and energy-related research and demonstration projects, and SDG&E's Nuclear Decommissioning charge collects costs to complete the decommissioning of the San Onofre Nuclear Generating Station (SONGS). The rate model escalates these charges at the annual inflation rate throughout the forecast period.

Rate Development

Following the methodologies described above, MRW developed a forecast of SDG&E's distribution expenses. We then divided these expenses by the expected SDG&E sales in order to obtain a forecast of system-average generation and distribution rates. MRW forecasted rate escalators for other rate elements using the methodologies described above. MRW then applied the component-specific escalator to each of the charges currently in effect for each of the major customer classes represented in the EDU's service area. In other words, instead of applying a single system-average rate escalator to each customer class's total rate, MRW applied specific escalators to each of the applicable charges for each customer class (e.g., a generation escalator, a distribution escalator, a transmission escalator, a public purpose escalator, a bond charge escalator, etc.). This specificity is needed because the total rate for each customer class is comprised of different shares of each of the rate components.[38] Applying the escalators by rate component accounts for differences between the system-average rate and the rates in effect for the EDU's customer base.

Gas Rate Forecast

SDG&E's retail gas rates are comprised primarily of commodity, distribution and transmission charges, and other charges. MRW developed a separate forecast for each of these rate components for each of the years 2021-2050 based on the specific cost drivers for each component. To build this forecast, MRW used publicly available inputs, including cost data from SDG&E, and forecasts from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

Commodity Charges

As noted, this preliminary report focused solely on the implications of the acquisition of transmission and distribution assets. MRW estimated commodity costs to escalate at rates consistent with the escalation in gas costs from its electric forecasts. Starting values for the commodity charges were taken from SDG&E's January 2020 rates. It is important to note that MRW modeled commodity costs as a pass-through in its financial model, so these charges have no influence on the ultimate value of the utility.

Transmission and Distribution Charges and Other Charges

Several non-generation costs are incorporated into SDG&E's rates. These include costs related to transmission, distribution, and public purpose programs.

MRW relied on the approach adopted for the escalation of costs for SDG&E's gas system in its most recent General Rate Case decision. This approach relies on forecasts of future escalation based on historic escalation in O&M and capital additions. As a starting point for the forecast, MRW used the adopted 2019 fixed costs for SDG&E's facilities and then scaled them down to reflect past over-forecasts of capital additions. For the period between 2020 and 2022, MRW estimated escalation

[38] For example, generation charges comprise 43% of residential customers' electric rates, 54% of industrial customers' electric rates, and 49% of the system-average rate. Applying the system-average escalator to all customer classes would therefore over-weight the generation escalator for residential customers and under-weight it for industrial customers.

rates based on SDG&E's adopted escalation in its last GRC proceeding. For subsequent years, MRW estimated in the Base Case that SDG&E's distribution costs would increase each year by 1.6%, which is the annual average growth rate for these cost over the last ten years. These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

Rate Development

Following the methodologies described above, MRW developed a forecast of SDG&E's distribution expenses. We then divided these expenses by the expected SDG&E sales in order to obtain a forecast of system-average commodity and distribution/transmission rates. MRW forecasted rate escalators for other rate elements using the methodologies described above. MRW then applied the component-specific escalator to each of the charges currently in effect for each of the major customer classes represented in the GDU's service area. In other words, instead of applying a single system-average rate escalator to each customer class's total rate, MRW applied specific escalators to each of the applicable charges for each customer class (e.g., a commodity escalator, a distribution and transmission escalator, a public purpose escalator, etc.). This specificity is needed because the total rate for each customer class is comprised of different shares of each of the rate components. Applying the escalators by rate component accounts for differences between the system-average rate and the rates in effect for the GDU's customer base.

Appendix B: Assessment of Cap-and-Trade Program Implications for EDU Financial Analysis

In 2006, the California Legislature passed Assembly Bill 32 (AB 32), which requires California to reduce its greenhouse gas emissions to 1990 levels by 2020 and to begin work toward a longer-term goal of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. Senate Bill 350 (SB 350), passed in 2015, requires the CPUC to develop a procurement process consistent with the statewide goal of reducing greenhouse gas emissions to 40 percent below 1990 levels by 2030. The California Air Resources Board (ARB) was assigned to develop and implement polices to meet these greenhouse gas reduction goals. One of these policies is a greenhouse gas cap-and-trade program, adopted in December 2011 and implemented on a mandatory basis at the start of 2013.

Under the cap-and-trade program, statewide greenhouse gas emissions are capped at a level that declines annually. ARB creates carbon “allowances” for each year in an amount equal to this cap. Entities that are subject to the program are called “covered entities” and must obtain allowances for each metric ton of greenhouse gas that they emit. Some covered entities obtain free allowances to cover all or part of their requirement from ARB. Covered entities may also trade allowances through bilateral deals or at ARB-run auctions and may use offset credits to reduce the quantity of allowances needed for compliance by up to 8%. Offset credits are created through the reduction of greenhouse gas emissions not covered in the cap-and-trade program, following specific protocols developed by ARB.[39]

Entities that generate non-renewable power in California or that deliver power to the California electrical grid are considered covered entities unless they emit less than the equivalent of 25,000 metric tons of CO_2 per year. The requirement for covered entities to procure allowances has increased the wholesale cost of power and creates an extra cost for utility generators. To offset this cost, ARB has distributed no-cost allowances to the state’s investor-owned and municipal utilities. The investor-owned utilities must sell their free allowances in the quarterly ARB-run auctions and use the proceeds from these sales to reduce retail electric rates for residential customers, small businesses, and certain large businesses that are considered trade-exposed. Municipal utilities may use their free allowances to meet their cap-and-trade obligations, to reduce customer rates, or for other purposes determined by the utility that are for the benefit of retail ratepayers and consistent with the goals of AB 32.[40]

Allowances in ARB’s auctions are subject to a floor price that increases annually. Over time, the floor price will continue to increase, and the supply of allowances (i.e., the greenhouse gas cap) will decline. It is expected that these factors will increase the cost of allowances over the duration of the program. This, in theory, will provide covered entities with an economic incentive to improve operating efficiency or otherwise reduce emissions.

Initially, only generators located in California, entities that sold imported electricity in-state, and certain large industrial facilities were considered covered entities. In 2015, the cap-and-trade system expanded to cover distributors of transportation fuels, natural gas, and other fuels. When

[39] A forestation project that sequesters carbon is an example of a project that could produce offset credits.
[40] California Code of Regulations, Title 17, Subchapter 10 (Climate Change), Article 5, Section 95892d.

these fuels distributors joined the program, the cap on greenhouse gas emissions increased to accommodate the expanded program scope.

Allowance Provisions for the EDU

ARB has specified the following criteria for an entity to receive free allowances as part of the electricity sector allocation:[41]

1. Entities must provide electricity;
2. Entities must serve end-use customer load; and
3. Entities must receive payment for that load from end-use customers.

The Final Regulation Order for the cap-and-trade program additionally specifies that the entity must comply with ARB's greenhouse gas mandatory reporting regulations,[42] which involves reporting annual retail sales and associated greenhouse gas emissions. No further eligibility requirements are specified. Accordingly, as long as the EDU complies with reporting requirements, the EDU will be eligible to receive free allowances once it begins serving retail electric customers.

To calculate the amount of the EDU's free allowances, MRW estimated that ARB would assign to the EDU the share of SDG&E's allowances that are associated with the EDU 's customer base. In 2021 the EDU 's allowances can be expected to yield roughly $4 million in revenue.

Allowance Provisions for SDG&E

Prior to the start of the cap-and-trade program, ARB allocated free allowances to each operating electric distribution utility in California for each of the years 2013 through 2020.[43] In describing the allowance allocation methodology, staff explicitly stated that the allocations were intended to fully compensate customers of each utility for the utility's cap-and-trade related costs:[44]

> A central principle of the allowance allocation to the electricity sector is the incorporation of customer cost burden. Cost burden is expected to result from emissions costs associated with fossil, [Qualifying Facility], and non-emitting resources priced at market being passed from generators and marketers to utility customers. Under this proposal, the complete annual expected cost burden for each utility is initially allocated. Expected cost burden is calculated by first assigning an emission factor to each fossil generation resource type and non-emitting resources prices at market. Then an annual emissions profile for each utility is calculated by summing the emissions associated with the reported quantities of each resource type. <u>In this way, each utility can expect to be able to fully compensate their</u>

---

[41] California Air Resources Board. *Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector*, July 2011 ("ARB Appendix A"), page 16. See ARB's *Final Statement of Reason for California Cap-and-Trade Program*, October 2011, page 25 (http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf) for a reference to Appendix A as the adopted methodology for allocating allowances.
[42] California Code of Regulations, Title 17, Subchapter 10 (Climate Change), Article 5, Section 95890b. April 2013.
[43] The fact that ARB has already specified the number of allowances to be distributed to other utilities through 2020 does not impact the DU's eligibility to receive free allowances for earlier compliance years. ARB has established provisions for the 2013-2020 allocations to be updated over time given "unforeseen changes in the electric sector." ARB Appendix A, page 2.
[44] ARB Appendix A, page 5 *(emphasis added)*.

customers for the costs associated with the cap and trade program that are expected to be passed through to customers.

After freely providing allowances to fully cover customers' cap-and-trade cost burdens, ARB then allocated additional allowances to reward projected investments in energy efficiency and early investments in renewable energy ("early action"). As a result, each utility received allowances in excess of its anticipated cost burden.[45] For example, ARB anticipated that the allowances it provided SDG&E would be 5.5% more than SDG&E would need to meet its anticipated cost burden.[46]

For SDG&E and other investor-owned utilities, the use of auction revenues is highly restricted by California law and CPUC Decision 12-12-033 (as modified by Decision 15-07-001). SDG&E is required first to provide bill credits to certain trade-exposed entities in order to minimize leakage risk,[47] and then to provide bill credits to small businesses customers in order to offset the electricity rate increases caused by the cap-and-trade program. SDG&E is then required to return all remaining greenhouse gas allowance revenue directly to residential customers on a per-account basis via a semi-annual bill credit termed the "California Climate Credit."[48]

Because the EDU financial model bases its electric rates on SDG&E's electric rates, MRW assessed the impact that these bill credits and California Climate Credit payments will have on SDG&E rates in the EDU's service area and adjusted the SDG&E rate forecast accordingly. For this calculation, MRW assumed that the allowance allocation previously assigned to SDG&E would be reduced to 42% to account for the allowance transfer to the EDU.

Greenhouse Gas Allowance Prices

ARB has been holding quarterly auctions for greenhouse gas allowances since November 2012. Since the start of 2014, allowances have sold, on average, at 2% above the floor. The cost of allowances in the future will be driven by the complex relationship between the cost of greenhouse gas emissions reduction measures and the demand for greenhouse gas emitting activities. As a proxy, MRW assumed that allowance prices will escalate in tandem with the floor price, which is set to increase annually at 5% plus the rate of inflation.

[45] ARB Appendix A, page 11.
[46] Calculated from ARB Appendix A, pages 12-13.
[47] "Leakage" in this context refers to companies moving out-of-state or losing market share to out-of-state competition as a result of cap-and-trade-related cost increases in California.
[48] CPUC decision 15-07-001 in proceeding R.12-06-013, July 3, 2015, pages 251-254, and 337.

Appendix C: Excerpt from *Pro Formas* of Base Cases

Assumptions and scenarios

Scenario Natural gas	Base	0%	high	70%	Low	-50%
Scenario Price CO2 allowances	Base	0%	high	5%	Low	-5%
Scenario new RPS prices	Base	0%	high	30%	Low	-30%
Higher DU O&M/A&G/Cap Adds Costs	Base	0%	high	20%	Low	0%
Higher Exit Fees	Base	0%	high	60%	Low	-60%
Purchase Price for Electric ($000) from NewGen	Base	$1,585,378	high	$2,784,463	Low	$208,333
Purchase Price for Gas ($000) from NewGen	Base	$498,601	high	$1,109,630	Low	$57,742
Severance Costs (Electric) ($000)	Base	$1,317,790	high	$2,446,045	Low	$189,534
Severance Costs (Gas) ($000)	Base	$41,250	high	$52,800	Low	$29,700
Capitalize CapAdds using Tax-Free Debt?	Yes					
Obligated to Pay Exit Fees?	Yes					
Pre-Pay Exit Fees	Yes					
Electric Rate Discount	8.2%					
Gas Rate Discount	36.5%					

Assumptions	Electric	Gas
Customer Electricity Programs	5.0%	0.0%
Payments In Lieu of Taxes	7.79%	3.21%
Interest Rate on Taxable Bonds	3.25%	3.25%
Interest Rate on Non-Taxable Bonds	2.85%	2.85%
Interest Rate Income	0.0%	0.0%
Maximum contribution stabilitzation fund ($000)	3,000,000	3,000,000
Maximum balance stabilitzation fund ($000)	50,000,000	50,000,000
Flat Rate Discount over SDG&E rates	8.2%	36.5%
Operations cost in 2020 ($000)	267,113	111,903
Capital Expenses year 1 ($000) (uncapitalized)	230,759	18,871
Fraction financed using Taxable bonds	49.1%	89.9%
Purchase price, separation costs, other capital ($000)	5,930,921	596,851
Discount rate NPV	5.0%	5.0%
Min Debt Coverage Ratio	1.2	1.2
SDG&E 2020 GRC % requested increase implemented	60.0%	N/A
Renewable generation Municipality (1=SB 100, 2=Accelerated)	2	N/A
% Allocation of SDG&E O&M/A&G/CapAdds to DU (from NewGen)	42.2%	50.0%

Initial Capital Outlay	ELECTRIC	How Financed	GAS
Purchase Price ($000)	$1,585,378	Taxable	$498,601
Separation Costs ($000)	$1,317,790	Taxable	$41,250
Start-up Costs ($000)	$214,600	Taxable	$57,000
Financing ($000)	$124,432	Tax Free	$13,025
Working Capital ($000)	$290,687	Tax Free	$54,395
Initial Funding of Reserves ($000)	$0	Tax Free	$0
Pre-Pay Exit Fees ($000)	$2,813,154	Yes	$0
Initial Capital Outlay ($1000)	$6,346,040		$664,271
Cost to Finance	2%	of financed amnt.	2%
Minimum Working Capital	90	Days revenues	90

Results for Electric

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load, MWhs	**8,157,636**	**8,238,680**	**8,242,987**	**8,248,843**	**8,240,013**	**8,205,925**	**8,157,719**	**8,109,061**	**8,054,085**	**7,996,189**
Cash Flow Calculations ($000)										
Annual Cash Flow	303,546	304,914	329,956	341,631	333,497	320,192	317,817	237,964	178,008	109,535
Cumulative Cash Flow	303,546	608,460	938,415	1,280,046	1,613,543	1,933,736	2,251,553	2,489,517	2,667,525	2,777,060
Annual Cash Flow, 2019 dollars	287,699	281,824	297,620	301,027	287,263	269,660	261,712	191,651	140,239	84,470
Cumulative Cash Flow, 2019 dollars	287,699	569,524	867,143	1,168,170	1,455,433	1,725,093	1,986,804	2,178,455	2,318,694	2,403,163
Table 1 ($000)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Revenues										
Revenues from DU Customers	1,766,305	1,823,020	1,895,500	1,953,003	1,987,736	2,028,467	2,079,807	2,136,595	2,204,384	2,290,845
Revenues from GHG Allowance Sales	50,853	54,689	58,774	63,104	67,709	72,636	77,919	83,565	89,605	96,021
Interest Income	-	-	-	-	-	-	-	-	-	-
Total Revenues	**1,817,158**	**1,877,709**	**1,954,275**	**2,016,107**	**2,055,444**	**2,101,103**	**2,157,726**	**2,220,160**	**2,293,989**	**2,386,866**
Expenses										
Cost of Power	484,024	502,273	513,494	531,467	543,652	565,931	589,589	693,779	785,847	902,181
TAC services costs	184,087	195,547	201,962	198,780	198,099	197,197	192,689	189,351	187,275	185,082
O&M/A&G Costs	274,287	281,468	287,724	294,119	300,657	307,340	314,171	321,154	328,293	335,590
Public Benefit Costs	88,315	91,151	94,775	97,650	99,387	101,423	103,990	106,830	110,219	114,542
Payments In Lieu of Taxes	148,184	152,920	159,007	163,827	166,718	170,118	174,417	179,178	184,870	192,145
Exit Fees/Nonbypassable Payments to SDG&E	-	-	-	-	-	-	-	-	-	-
Total Expenses	**1,178,897**	**1,223,358**	**1,256,963**	**1,285,843**	**1,308,513**	**1,342,009**	**1,374,857**	**1,490,291**	**1,596,503**	**1,729,541**
Capital Expenditures	-	-	-	-	-	-	-	-	-	-
Debt Service	334,715	349,437	367,356	388,633	413,435	438,902	465,052	491,905	519,478	547,790
Net Cash Flow	**303,546**	**304,914**	**329,956**	**341,631**	**333,497**	**320,192**	**317,817**	**237,964**	**178,008**	**109,535**
Cash Contributions by CSDMU or Withdrawals from Rate Stab. Fund	-	-	-	-	-	-	-	-	-	-
Cash Reserves Balance	**594,233**	**899,147**	**1,229,102**	**1,570,733**	**1,904,230**	**2,224,423**	**2,542,240**	**2,780,204**	**2,958,212**	**3,067,747**
Days Cash on Hand	**184**	**268**	**357**	**446**	**531**	**605**	**675**	**681**	**676**	**647**
Debt Service Coverage Ratio	**1.91**	**1.87**	**1.90**	**1.88**	**1.81**	**1.73**	**1.68**	**1.48**	**1.34**	**1.20**
DU RevReq	1,513,612	1,572,796	1,624,319	1,674,477	1,721,947	1,780,911	1,839,909	1,982,196	2,115,981	2,277,331
Minimum Days of Cash on Hand (for goal seek)	184									
Minimum DSCR (for goal seek)	1.20	NPV of Rev Req	37,771,470	Reserves	Outstanding Debt					
NPV of Net Cash Flows Less Debt Service	$16,522,264	NPV of Debt Service	$9,772,646	4,054,865	2,812,020	8,529,801				
NPV of Net Cash Flows	$6,749,618	NPV Rev	$42,437,001.63		6,866,885					
			23.0%							

Results for Gas

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Volume, mtherms	**605,203**	**611,216**	**611,535**	**611,970**	**611,315**	**608,786**	**605,209**	**601,600**	**597,521**	**593,226**
Cash Flow Calculations ($000)										
Annual Cash Flow	6,886	10,405	14,790	17,504	19,918	21,670	22,934	24,327	25,647	26,753
Cumulative Cash Flow	6,886	17,291	32,082	49,586	69,504	91,174	114,108	138,435	164,082	190,835
Annual Cash Flow, 2019 dollars	6,527	9,617	13,341	15,424	17,157	18,250	18,886	19,593	20,205	20,631
Cumulative Cash Flow, 2019 dollars	6,527	16,144	29,485	44,908	62,065	80,315	99,201	118,793	138,998	159,629
Table 1 ($000)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Revenues										
Revenues from DU Customers	261,922	275,596	284,615	296,231	307,454	318,080	328,504	338,801	348,788	358,862
Revenues from GHG Allowance Sales	-	-	-	-	-	-	-	-	-	-
Interest Income	-	-	-	-	-	-	-	-	-	-
Total Revenues	**261,922**	**275,596**	**284,615**	**296,231**	**307,454**	**318,080**	**328,504**	**338,801**	**348,788**	**358,862**
Expenses										
Core Commodity Procurement	76,787	79,762	78,838	81,836	84,573	87,291	90,162	92,604	94,656	96,832
GHG Compliance Cost	15,663	17,012	18,292	19,654	21,065	22,505	24,000	25,585	27,248	28,990
O&M/A&G Costs	114,927	118,007	120,737	123,530	126,388	129,312	132,304	135,365	138,497	141,702
Public Benefit Costs	-	-	-	-	-	-	-	-	-	-
Payments In Lieu of Taxes	13,226	13,916	14,371	14,958	15,525	16,061	16,588	17,107	17,612	18,120
Total Expenses	**220,603**	**228,697**	**232,239**	**239,978**	**247,551**	**255,169**	**263,053**	**270,662**	**278,013**	**285,643**
Capital Expenditures	-	-	-	-	-	-	-	-	-	-
Debt Service	34,432	36,494	37,586	38,749	39,985	41,241	42,517	43,812	45,129	46,466
Net Cash Flow	**6,886**	**10,405**	**14,790**	**17,504**	**19,918**	**21,670**	**22,934**	**24,327**	**25,647**	**26,753**
Cash Contributions by CSDMU	-	-	-	-	-	-	-	-	-	-
Cash Reserves Balance	**61,282**	**71,686**	**86,477**	**103,981**	**123,899**	**145,569**	**168,503**	**192,830**	**218,477**	**245,230**
Days Cash on Hand	**101**	**114**	**136**	**158**	**183**	**208**	**234**	**260**	**287**	**313**
Debt Service Coverage Ratio	**1.20**	**1.29**	**1.39**	**1.45**	**1.50**	**1.53**	**1.54**	**1.56**	**1.57**	**1.58**
DU RevReq	255,035	265,191	269,825	278,727	287,536	296,410	305,570	314,474	323,142	332,109
Minimum Days of Cash on Hand (for goal seek)	101			Reserves	Outstanding Debt					
Minimum DSCR (for goal seek)	1.20	NPV of Rev Req	5,614,780	332,177	117,802	5,400,405				
NPV of Net Cash Flows Less Debt Service	$1,318,230	NPV of Debt Service	$766,827		449,979					
NPV of Net Cash Flows	$551,402.88									

Task 4: NewGen
FRANCHISE BENCHMARK SURVEY

(Results provided separately)