Attachment A

Margaret A. Meal
Statement of Qualifications and Resume

ATTACHMENT A

STATEMENT OF QUALIFICATIONS FOR MARGARET A. MEAL

Margaret Meal is presently employed by the City and County of San Francisco Public Utilities Commission (SFPUC) as the Manager for Business and Financial Analysis for the Power Enterprise. Since joining the SFPUC in February of 2010, Ms. Meal has been responsible for negotiating and structuring contracts for operating services and other arrangements. She is also responsible for policy development and analysis, economic analysis and business planning, and analysis and assessment of power markets and commercial opportunities. Her duties include monitoring and analyzing current and proposed state and federal energy policies and regulations, rate making, rate design and cost structures for electric utilities, and risk assessment of power supply alternatives on behalf of the SFPUC. In addition, she led the team that developed the business plan for the Power Enterprise in 2016 and the analytical team supporting Power Enterprise’s 2019 efforts to acquire PG&E’s electric delivery assets in San Francisco.

Ms. Meal has worked in the electric power industry for the entirety of her career (over thirty years), primarily as a consultant advising business interests, public agencies, investors, lenders, and regulatory agencies on financial and economic issues, including asset valuation, risk assessment, financing alternatives, utility cost of capital, and ratemaking. She has provided written and oral testimony to the California Public Utilities Commission, the Federal Energy Regulatory Commission, and various other state public utility commissions on numerous occasions.

Ms. Meal earned her B.S. in Civil Engineering from Stanford University and her M.S. from the Energy and Resources Group at the University of California, Berkeley. Her resume is also included in this attachment.

Margaret (Meg) A. Meal

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BUSINESS DECISION MAKING AND REGULATORY/LEGISLATIVE ADVOCACY

Expert in financial and business planning, legislative and regulatory interpretation and analysis, risk assessment, and development of risk mitigation strategies, with a focus on stakeholders in the electric power sector. Successful advocacy for legislative and regulatory modifications to support public policy initiatives and to improve commercial opportunities for both public and private-sector stakeholders. Provision of expert witness testimony in support of legislative and regulatory interpretation and proposed modifications, civil litigation and dispute resolution. Development of analytical tools for financial forecasting, comparison of characteristics across alternative operating and capital deployment strategies, estimates of stakeholder impacts, and scenario analyses. Proven ability to develop and execute results-oriented analysis and recommendations.

CORE COMPETENCIES

- Financial Modeling, Scenario Analysis
- Asset and Corporate Valuations
- Risk Assessment, Contract and Credit Analysis
- Infrastructure Planning for New Service Needs
- Legislative/Regulatory Analysis and Advocacy
- Utility Rate Making and Rate Design
- Expert Witness Testimony
- Training, supervision and mentoring

CAREER SUMMARY

SAN FRANCISCO PUBLIC UTILITIES COMMISSION San Francisco, CA 2010-2017, April 2018-present

The SFPUC is San Francisco's municipal power, water and sewer provider.

Manager, Business and Financial Analysis and Utility Specialist. Expertise, analysis and advocacy regarding legislative, regulatory and financial issues that affect the SFPUC's electricity operations and its clean power initiatives. Policy development and analysis, economic analysis and business planning, and analysis and assessment of power markets and commercial opportunities. Led team that developed the business plan for the Power Enterprise in 2016 (sfwater.org/modules/showdocument.aspx?documentid=14488) and analytical team supporting Power Enterprise's 2019 efforts to acquire PG&E's electric delivery assets in San Francisco.

CONSULTANT San Francisco, CA 1997-2010

Business, financial and regulatory consulting for participants in the electric power industry.

- Legislative and regulatory advocacy, review of existing and proposed statutes and regulations and analysis of likely impacts on stakeholders
- Litigation support, including development of discovery requests and analysis of responses, development of expert reports and expert testimony, and assistance with briefs and pleadings; preparation and delivery of oral and written testimony
- Economic and financial analysis, including financial structuring, risk assessment, analysis and negotiation of power purchase and other commercial agreements, due diligence, asset and corporate valuations
- Development of business plans, market and technology assessments, debt and equity offerings

MRW & ASSOCIATES, INC. Oakland, CA 1991-1997

MRW & Associates is a premier consulting firm internationally recognized for its expertise in electric power and fuel markets, power and gas market analysis, economic forecasting, regulatory advocacy and litigation support.

Senior Project Manager and Principal. Structured and negotiated debt and equity investments in renewable and conventional power facilities. Provided strategic advice to new and established market players regarding financial structuring, market potential, regulatory constraints and uncertainties, and competitive threats and opportunities. Led and supervised project teams, managed project budgets and supervised and trained junior staff.

ADDITIONAL PROFESSIONAL EXPERIENCE 1981-1991

1989-1991: Assistant Vice President for Trust Company of the West, a leading investment management firm with over $100 billion in assets under management. 1987-1989: Financial Analyst for Hansen, McOuat and Associates, a financial consulting firm representing small power producers and end users. 1986: Guest Scientist, International Energy Agency, Karlsruhe, West Germany. 1983-1985: Research Assistant, Energy Efficient Buildings Program, Lawrence Berkeley National Laboratory. 1981-1983: Energy Management Representative, Pacific Gas and Electric Company.

EDUCATION AND CREDENTIALS

- **BS, Stanford University**, Civil Engineering, with distinction
- **MS, University of California at Berkeley**, Energy and Resources
- Chartered Financial Analyst (CFA), retired

WRITTEN AND ORAL TESTIMONY

1. Before the Federal Energy Regulatory Commission in EL 15-3-000 *et al*, on behalf of the City and County of San Francisco, regarding comparative analysis of service territories and customer demographics, locations and characteristics of the City and County of San Francisco's municipal electric utility and Pacific Gas and Electric Company's investor-owned electric utility, and interpretation of legislative and regulatory language as applied San Francisco and its rights to wholesale distribution service. Declaration (October 2014, Exhibit SF-30 https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14136500), direct testimony (February 2016, Exhibits SF 29-41 https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14425636), rebuttal testimony (April 2016, Exhibits SF 144-151 https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14447463), oral cross-examination (May 2016, https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14467938).

2. Before the California Public Utilities Commission in Rulemaking 07-05-025, on behalf of the Joint Parties, on a fair and reasonable methodology to determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC), with John P. Dalessi and Mark E. Fulmer (direct testimony January 2011 and reply testimony February 2011).

3. Before the California Public Utilities Commission in Pacific Gas and Electric Company's General Rate Case Application 10-03-014, on behalf of the City and County of San Francisco, regarding PG&E's proposals for a Conservation Incentive Adjustment and to increase rates for low-income customers (October 2010, https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=201690).

4. Before the Michigan Public Service Commission, on behalf of the Michigan Wholesale Power Association, in Consumers Energy's and Detroit Edison's Renewable Energy Plan proceedings, regarding financing constraints and debt equivalence costs and penalties for bidders offering long term power purchase agreements in the utilities' proposed design of their requests for proposals and bid evaluation for procurement of renewable resources (Consumers Energy testimony March 2009, Detroit Edison testimony April 2009).

5. Before the Public Utilities Commission of Colorado, on behalf of the Colorado Independent Energy Association, in Public Service Company of Colorado's 2007 Integrated Resource Plan proceeding, regarding the impact of power purchase agreements on the credit profile of Public Service Company of Colorado and the use of proposed adders in bid evaluation (answer testimony April 2008; cross-answer testimony June 2008).

6. Before the California Public Utilities Commission in R.06-02-013, on behalf of Hercules Municipal Utility, regarding proposals for non-bypassable charges to be imposed on departing customers (April 2007).

7. Before the California Public Utilities Commission in R.06-02-013, on behalf of the Independent Energy Producers Association, regarding the impact of power purchase agreements on the credit profiles of the California investor-owned utilities (March 2007).

8. Before the Minnesota Public Utilities Commission, on behalf of Excelsior Energy, Inc., regarding the impact of a proposed power purchase agreement on the credit profile of Northern States Power Company (Minnesota) (October 2006).

9. Before the Public Utilities Commission of Colorado, on behalf of the Colorado Independent Energy Association, regarding the impact of power purchase agreements on the credit profile of Public Service Company of Colorado (August 2006).

10. Before the City and County of San Francisco Assessment Appeals Board, on behalf of the City and County of San Francisco, regarding the fair market value of the Potrero Power Plant (November 2005).

11. Before the California State Senate Energy, Utilities and Communications Committee, on behalf of The Utility Reform Network, to describe and quantify the impacts of various plans of reorganization on both PG&E's ratepayers and PG&E's shareholders (September 2003).

12. Before the California Public Utilities Commission in OII 02-04-026 (Ratemaking Implications of the PG&E Bankruptcy), on behalf of The Utility Reform Network, quantifying the cost of PG&E's proposed settlement agreement for ratepayers, and demonstrating that the excess cost generates windfall profits for PG&E's shareholders as compared to traditional cost-of-service ratemaking (August 2003).

13. Before the California Public Utilities Commission in OII 02-04-026 (Ratemaking Implications of the PG&E Bankruptcy), on behalf of The Utility Reform Network, regarding the savings potential of using a bond issuance supported by a dedicated rate component as part of a plan for Pacific Gas and Electric Company's emergence from bankruptcy (January 2003).

14. Before the New Hampshire Public Utilities Commission, New Hampshire Docket No. DR 96-150, Direct Testimony on Behalf of Cabletron Systems Regarding Interim Stranded Costs (September 1997).

15. Before the California Public Utilities Commission, CPUC Rulemaking 94-04-031 and Investigation 94-04-032, Prepared Testimony, with Paula A. Zagrecki, on Behalf of the Energy Finance Forum Regarding Uneconomic Assets and Obligations and Their Disposition in Electric Restructuring (December 1994).

[CONFERENCE AND OTHER PRESENTATIONS, SELECTED PUBLICATIONS OMITTED]

Attachment B

Leverage detail

Debt Relative to Rate Base

($ millions)

PG&E Opening Testimony 1-31-20, Table 2-1 and as noted	10-K 12/31/2016	10-Q 9/30/2017	10-K 12/31/2017	10-K 12/31/2018	Pre-Emergence Amount	Emergence Adjustment	Post-Emergence (5) Incl. Temp Debt	Post-Emergence (5) Excl. Temp Debt	
Pacific Gas & Electric Company ("Utility")									
Pre-Petition Utility Debt (1) (2)	$ 18,088	$ 17,839	$ 18,647	$ 21,344	20,668	(20,668)	-	-	
Pollution Control Bonds(3)	incl	incl	incl	incl	862	(762)	100	100	
Reinstated Utility Senior Secured Notes (1)	-	-	-	-	-	9,575	9,575	9,575	
Noteholder RSA Debt (1)	-	-	-	-	-	11,850	11,850	11,850	
DIP Facility(1)					2,000	(2,000)	-	-	
Incremental Debt at Utility(1)					-	**5,825**	5,825	5,825	
Temporary Utility Debt(1)					-	**6,000**	6,000	-	
Total Utility Debt	**$ 18,088**	**$ 17,839**	**$ 18,647**	**$ 21,344**	**$ 23,530**	**$ 9,820**	**$ 33,350**	**$ 27,350**	
PG&E Corporation ("HoldCo")									
Senior Unsecured Credit Facility(1) (2)	348	349	482	650	650	$ (650)	$ -	$ -	
New HoldCo Debt(1)						**4,750**	4,750	4,750	
Total HoldCo Debt	**$ 348**	**$ 349**	**$ 482**	**$ 650**	**$ 650**	**$ 4,100**	**$ 4,750**	**$ 4,750**	
Total HoldCo & Utility Debt	**$ 18,436**	**$ 18,188**	**$ 19,129**	**$ 21,994**	**$ 24,180**	**$ 13,920**	**$ 38,100**	**$ 32,100**	
Utility Rate Base - annual average (4)	**$ 32,400**	**$ 34,400**	**$ 34,400**	**$ 36,800**	**$ 36,800**	**$ -**	**$ 45,000**	**$ 45,000**	2020 forecast
							$ 48,000	$ 48,000	2021 forecast
Leverage Metrics:									
Holdco Debt as a % of Total Debt	2%	2%	3%	3%	3%		12%	15%	
Utility Debt / Utility Rate Base (4)	**56%**	**52%**	**54%**	**58%**	64%		**74%**	**61%**	using 2020 rate base forecast
Average 2016-2018, exludes 9/31/17		56%							
							69%	57%	using 2021 rate base forecast (assumes no debt added to support rate base growth, 20-21)
Utility Debt + Hold Co Debt / Utility Rate Base (4) (5)	**57%**	**53%**	**56%**	**60%**	66%		**85%**	**71%**	using 2020 rate base forecast
Average 2016-2018, exludes 9/31/17		57%							
							79%	67%	using 2021 rate base forecast (assumes no debt added to support rate base growth, 20-21)

Footnotes
1) PG&E Opening Testimony, January 31, 2019, Table 2.1. Utility pre-petition debt = $22.18 billion of total pre-petition debt, less PCB, less debt at PG&E Corp.
2) 2016, 2017, 2018 amounts from PG&E 10-K and 10-Q.
3) Pollution Control Bonds: outstanding balance at 12-31-18, PG&E form 10-K for 2018, page 127.
4) From PG&E earnings presentations (see Rate Base tab for detail). For period-to-period leverage comparisons, Utility Rate Base is used as a proxy for Total Capital.
5) Post-emergence debt levels assume no draws on short-term credit facilities (leverage metrics would be higher to the extent the short-term credit facilities are drawn upon).

Attachment C

Excerpts from PG&E’s 8-K, dated February 18, 2020

ended December 31, 2019 for probable cost recoveries of insurance premiums incurred in 2018 above amounts included in authorized revenue requirements.

(in millions, pre-tax)	Three Months Ended December 31, 2019	Year Ended December 31, 2019	Three Months Ended December 31, 2018	Year Ended December 31, 2018
Camp, Northern California, and Butte fire-related costs, net of insurance:				
Third-party claims	$ 4,988	$ 11,435	$ 11,500	$ 14,000
Utility clean-up and repair costs	13	278	169	209
Legal and other costs	42	152	94	245
Accelerated amortization of prepaid insurance premiums	—	—	185	185
Insurance recoveries	—	—	(1,836)	(2,229)
Subtotal Camp, Northern California, and Butte fire-related costs, net of insurance	**5,043**	**11,865**	**10,112**	**12,410**
Wildfire OII settlement	398	398	—	—
PSPS customer bill credit	86	86	—	—
2018 Insurance premium cost recovery	(189)	(189)	—	—
2017 Insurance premium cost recovery	—	—	—	(32)
Total Wildfire-related costs	**$ 5,338**	**$ 12,161**	**$ 10,112**	**$ 12,378**

(3) The Utility incurred costs of $167 million (before the tax impact of $47 million) and $773 million (before the tax impact of $216 million) during the three and twelve months ended December 31, 2019, respectively, for incremental operating expenses related to enhanced and accelerated inspections of electric transmission and distribution assets, and resulting repairs that are not probable of recovery.

(4) The Utility recorded costs of $39 million (not tax deductible) during the three and twelve months ended December 31, 2019 associated with an incremental fine payable to the State General Fund resulting from a presiding officer's decision in the Locate and Mark OII.

(5) PG&E Corporation and the Utility recorded a net benefit of $56 million (before the tax impact of $26 million) and incurred costs of $199 million (before the tax impact of $19 million) during the three and twelve months ended December 31, 2019, respectively, directly associated with their Chapter 11 Cases. This includes legal and other costs of $101 million (before the tax impact of $18 million) and $292 million (before the tax impact of $45 million) during the three and twelve months ended December 31, 2019, respectively ($38 million and $129 million of legal and other costs during the three and nine months ended December 31, 2019, respectively, are not tax deductible.) The Utility also incurred $114 million (before the tax impact of $32 million) during the twelve months ended December 31, 2019 for debtor-in-possession ("DIP") financing costs. These costs were partially offset by a reduction to interest expense on pre-petition debt of $146 million (before the tax impact of $41 million) during the three and twelve months ended December 31, 2019, and interest income of $11 million (before the tax impact of $3 million) and $60 million (before the tax impact of $17 million) recorded during the three and twelve months ended December 31, 2019, respectively.

Exhibit A: Reconciliation of PG&E Corporation's Consolidated Earnings (Loss) Attributable to Common Shareholders in Accordance with Generally Accepted Accounting Principles ("GAAP") to Non-GAAP Core Earnings

Fourth Quarter and Year to Date, 2019 vs. 2018
(in millions, except per share amounts)

(3) The Utility incurred costs of $167 million (before the tax impact of $47 million) and $773 million (before the tax impact of $216 million) during the three and twelve months ended December 31, 2019, respectively, for incremental operating expenses related to enhanced and accelerated inspections of electric transmission and distribution assets, and resulting repairs that are not probable of recovery.

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(in millions, pre-tax)	**Three Months Ended December 31, 2019**	**Year Ended December 31, 2019**
Legal and other costs	$ 101	$ 292
DIP financing costs	—	114
Reduction of interest expense on pre-petition debt	(146)	(146)
Interest income	(11)	(60)
Chapter 11-related costs	**$ (56)**	**$ 199**

(6) The Utility recorded costs of $237 million (before the tax impact of $44 million) during the three and twelve months ended December 31, 2019 for pipeline-replacement costs disallowed in the 2019 GT&S rate case as a result of spending above amounts authorized in the 2015-2018 rate case period. Due to flow-through treatment related to deductible repairs, $80 million of the loss does not generate a net tax benefit.

(7) The Utility incurred costs of $11 million (before the tax impact of $3 million) and $46 million (before the tax impact of $13 million) during the three and twelve months ended December 31, 2018, respectively, for pipeline-related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.

RECENT PROGRESS ENABLES TIMELY EMERGENCE

Plan of Reorganization Summary

Key Elements of the Plan of Reorganization

PG&E's Plan of Reorganization prioritizes wildfire victims, puts customers ahead of investors, and enables continued support of California's clean energy goals. Key elements of the Plan include:

- Satisfaction of pre-petition wildfire claims ($25.5B) and funding for participation in the statewide Wildfire Fund ($5.0B)
- Creditors made whole ($27.75B)
- Collective bargaining agreements are assumed
- Corporate and Utility governance satisfies AB1054
- Puts PG&E on path to help the state meet its clean energy goals and become the company that customers and communities expect and deserve

Plan Has Stakeholder Support

Official Committee of Tort Claimants

Attorneys representing fire victims who hold over 70% of the more than 70,000 claims that have been filed

Subrogation Claimants and Key County and Local Public Entities

Ad Hoc Noteholder Committee

Labor (IBEW)

$59 Billion in Plan Funding Sources ($B)

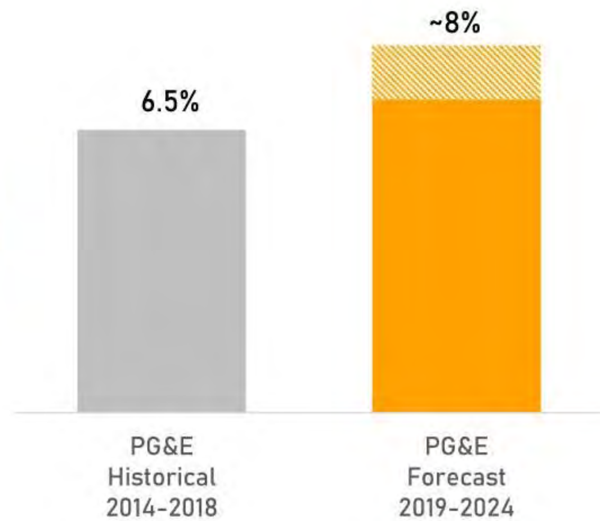
SUSTAINABLE FINANCIALS

Attractive Ratebase Profile

Sustainable Future Upon Emergence

- Industry-leading growth from investments in wildfire risk reduction, and safety and reliability
- Disciplined focus on cost optimization to balance ratebase growth and affordable rates
- Investment to support California's clean energy economy

Projected Ratebase Growth

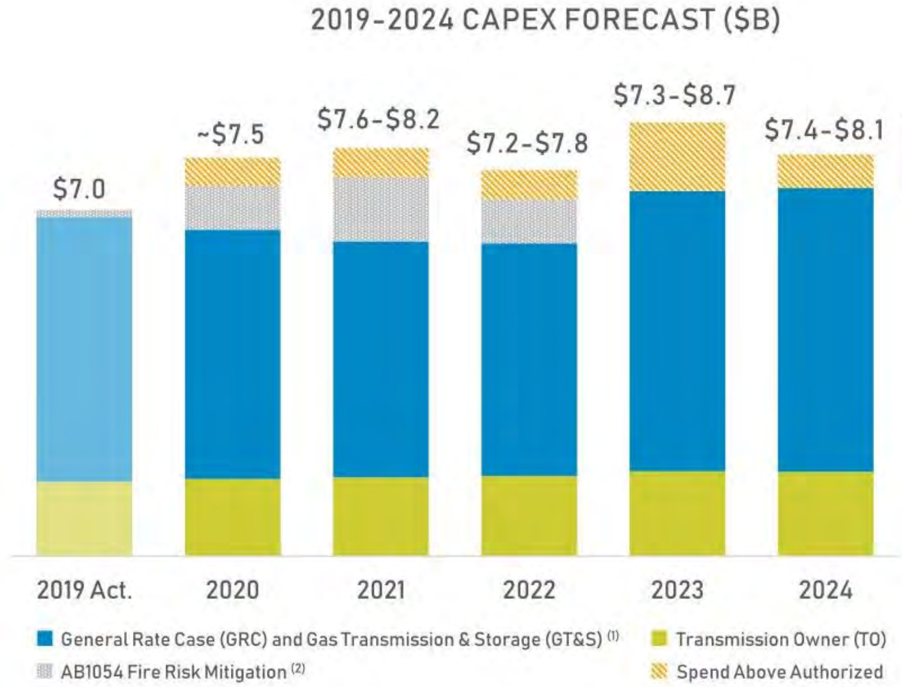


Ratebase profile is expected to support strong post-emergence earnings growth.

See the Forward-Looking Statements for factors that could cause actual results to differ materially from the guidance provided and underlying assumptions.

Substantial Capital Investments

Unprecedented level of system investments, accelerated wildfire risk reduction, and continued execution of gas safety commitments drive substantial capital investments.



Subject to Ongoing and Future Recovery Requests

Spend driven by:

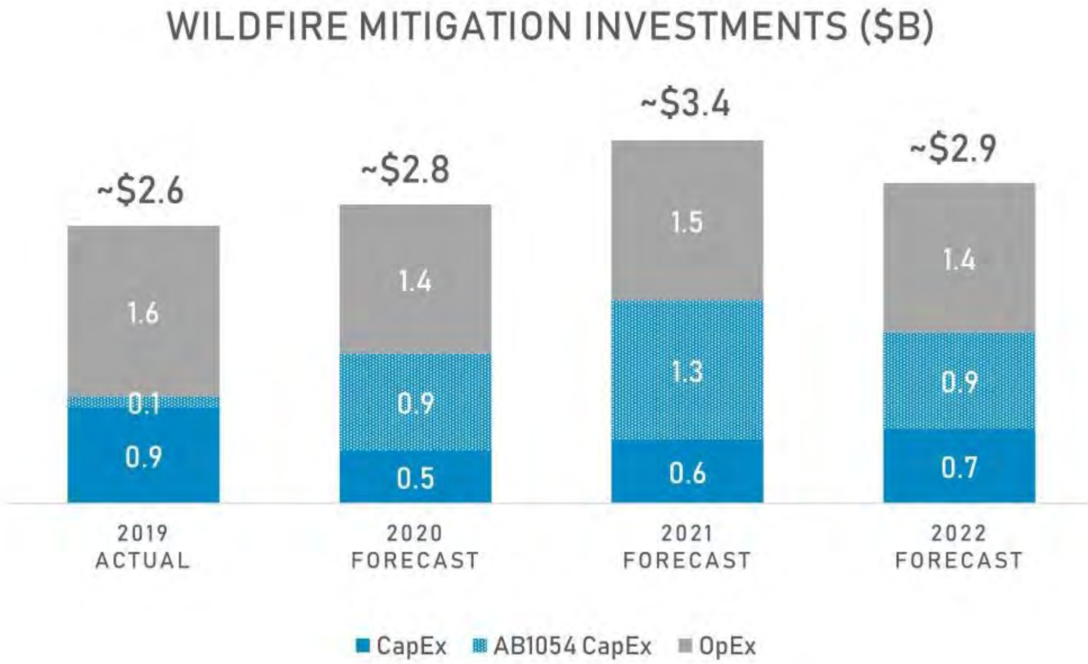
- Wildfire Mitigation Plan Memorandum Account (WMPMA)
- Catastrophic Event Memorandum Account (CEMA)

(1) The 2023 GRC will include gas transmission and storage.
(2) Capex forecast includes ~$3.2B of fire risk mitigation capital expenditures included in the Utility's approved wildfire mitigation plans on which PG&E Corporation and the Utility will not earn an equity return.
(3) Low end of the range reflects authorized capital expenditures, including the full amount recoverable through a balancing account where applicable. High end of the range includes capital spend above authorized.

See the Forward-Looking Statements for factors that could cause actual results to differ materially from the guidance provided and underlying assumptions.

2019-2022 Wildfire Mitigation Plan Investments

PG&E's AB1054-mandated fire risk mitigation capital expenditures of ~$3.2B is anticipated to be fully expended in 2022.



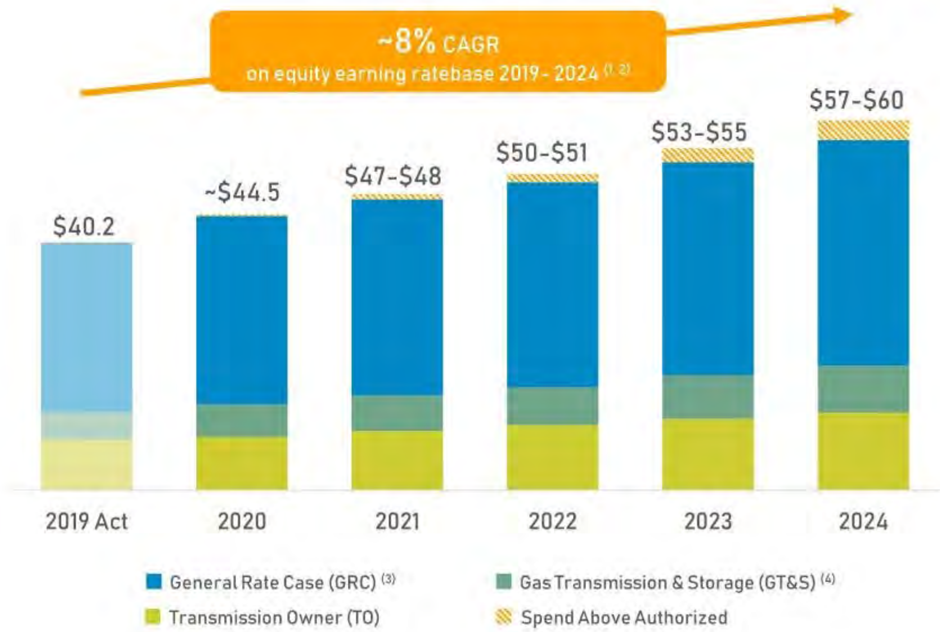
Note: The 2020 to 2022 wildfire mitigation forecast is as of December 2019 and is consistent with the 5-year forecast. The 2020-22 costs reflect program assumptions that were later updated in the 2020 Wildfire Mitigation Plan filing on February 7, 2020, which forecasts ~$2.6B of annual spend. PG&E is tracking the capex subject to the AB 1054 exclusion in the Wildfire Mitigation Plan Memorandum Account and Wildfire Mitigation Balancing Account. The AB 1054 excluded capex is dependent on the CPUC-approved amounts for PG&E's WMP capital expenditures.

See the Forward-Looking Statements for factors that could cause actual results to differ materially from the guidance provided and underlying assumptions.

SUSTAINABLE FINANCIALS

Ratebase Growth Forecast

WEIGHTED AVERAGE RATEBASE FORECAST BY RATE CASE ($B)



Potential Growth Opportunities

- Additional wildfire mitigation
- Transportation electrification (Phase II Light Duty)
- Additional distributed generation-enabled microgrids
- Grid modernization

(1) Ratebase reflects reductions for the following capital items: (a) $240M disallowance by the CPUC in the 2019 GT&S rate case; (b) $3.2B of fire risk mitigation excluded from earning a ROE, pursuant to AB 1054; and (c) $403M the Utility agreed not to seek recovery of as part of the Wildfire OII settlement.
(2) Ratebase growth including non-equity earnings ratebase is ~9%.
(3) The 2023 GRC will include gas transmission and storage and will move to a four year case cycle.
(4) Includes $400M for 2011-2014 spend subject to audit added in 2020.

See the Forward-Looking Statements for factors that could cause actual results to differ materially from the guidance provided and underlying assumptions.

2020 Earnings Overview and Assumptions

Substantial progress has been made but there remain a few critical uncertainties that affect earnings.

Shifting focus to non-GAAP core earnings and non-core earnings. Non-GAAP Core Earnings [1] in 2020 will be impacted partial period of Chapter 11 case pendency, financing, and regulatory matters.

2020 Non-GAAP Core Earnings Assumptions

($ billions)	CapEx	Ratebase
2020 GRC Settlement	$4.4	$30.5
2019 GT&S Decision	0.7	5.4
2019 TO Plan under Formula Rates	1.5	8.6
AB1054 Spend	0.9	-
Total	~$7.5	~$44.5

Financing: $6B of OpCo debt refinanced with securitization in 2021

Key remaining uncertainties

Key Factors Affecting 2020 Non-GAAP Core Earnings

Authorized CPUC ROE across the Enterprise	10.25%
Drivers of Variance from Authorized	
- Net Below the Line and Spend Above Authorized	150M-200M
- Unrecovered Interest Expense [2]	150M-250M

Key Factors Affecting Non-Core Earnings

- Chapter 11 Costs	~1B
- Wildfire Fund-Related Costs	484M
- Investigation Remedies and Delayed Cost Recovery [3]	~110M
+ GT&S Capital Audit	~(191M)

(1) Beginning with the quarter and full year periods ended December 31, 2019, PG&E Corporation and the Utility changed the name of their principal non-GAAP earnings metric from "non-GAAP earnings from operations" to "non-GAAP core earnings" in order to align more closely with the terminology used by their industry peers. Likewise, PG&E Corporation and the Utility will now refer to adjustments as "non-core items" rather than "items impacting comparability".

(2) Unrecovered Interest Expense from $4.75B HoldCo and $6B Incremental OpCo Debt. Represents interest expense from second half of 2020. OpCo debt is temporary before take out from securitization.

(3) Includes OII penalties and cost recovery associated with Paradise rebuild.

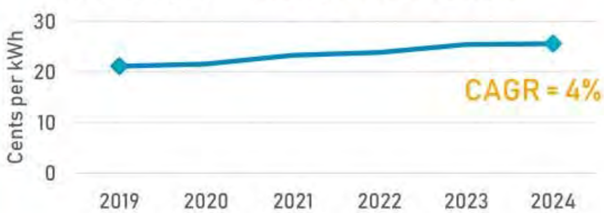
See the Forward-Looking Statements for factors that could cause actual results to differ materially from the guidance provided and underlying assumptions.

APPENDIX
Expected Residential Rate and Bill Trajectory

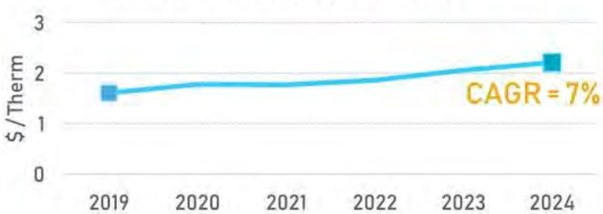
Safety-related spend is driving higher rate and bill growth. PG&E is implementing affordability initiatives and is actively identifying efficiency opportunities to mitigate bill impact.

Expected Electric and Gas Rates

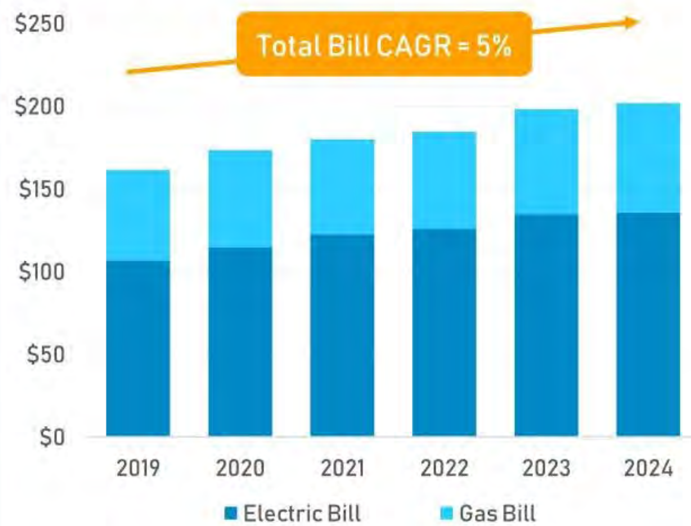
Electric System Average Bundled Rate (1)



Gas Average Residential Rate (2)



Expected Average Monthly Residential Customer Bill Growth (3)



(1) 2019 electric system average bundled rate reflects actual as of 10/1/2019.
(2) 2019 gas average residential rate reflects 2019 full year average.
(3) Average monthly residential bill is based on household usage assumptions in California Energy Demand 2020-2030 Baseline Forecast – Mid Demand Case.

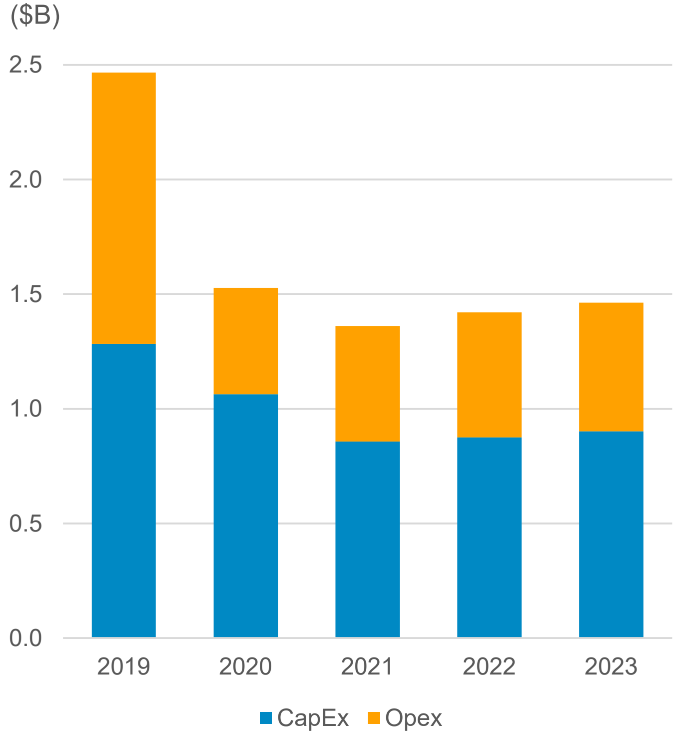
See the Forward-Looking Statements for factors that could cause actual results to differ materially from the guidance provided and underlying assumptions.

Attachment D

PG&E's 2019 First Quarter Earnings Presentation (dated May 2, 2019), Slide 3

Wildfire Safety Plan

~$8.2B planned through 2023 (1) (2) (4)



Key Plan Elements

Public Safety Power Shut-off

- Expanded Public Safety Power Shut-off program in 2019 to include up to **500 kV transmission lines**

Enhanced Inspection Program

- **Enhanced asset inspections** in HFTD(3) by May 31, 2019 (5):
  - ~685,000 distribution poles
  - ~50,000 transmission poles and towers
  - 2019 forecasted spend increased by ~$375 million in Q1 2019

Increased Situational Awareness

- **24/7 Wildfire Operations Center** during peak fire season
- **~600 HD cameras** providing coverage for >90% of HFTD(3) by 2022

System Hardening

- **~7,000 miles of system hardening** in highest wildfire threat areas over next 10 years
- **2,800 miles** of tree wire in HFTD(3) by 2023

Vegetation Management

- Enhanced vegetation management across **25,000 miles** of PG&E service territory over next 8 years
- **>2 million trees** to be trimmed or removed by 2023
- Targeted tree species removal

Expanded PSPS for short-term mitigation, combined with targeted system enhancements for long-term wildfire risk mitigation

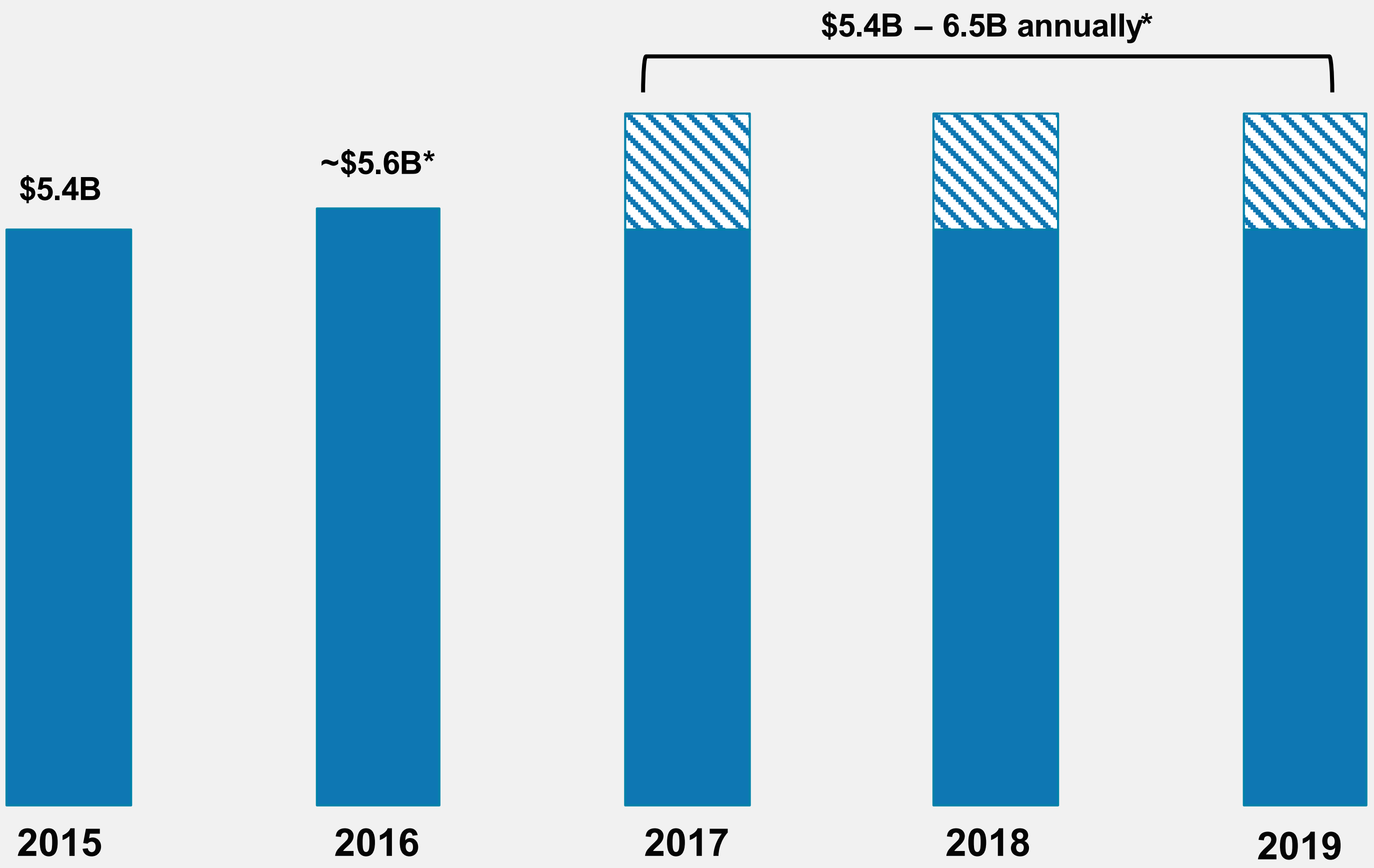
(1) Wildfire Safety Plan spend pending CPUC and FERC approval. 2019 spend reflects mid-point of proposed range of costs as outlined in the February 6, 2019 Wildfire Mitigation Plan with the exception of the Enhanced Inspection and Public Safety Power Shut-off programs, which have updated mid-point forecasts of ~$750 million (OpEx) and ~$70 million (CapEx), respectively. 2019 Enhanced Inspection Program OpEx increased from a range of ~$300-$450 million to $600-$900 million due to higher than anticipated system repairs following the enhanced inspections.
(2) Excludes forecasted base vegetation management and drought-related expense spend of ~$300 to $400 million annually.
(3) Defined as Tier 2 and 3 high fire-threat districts.
(4) 2020-2022 forecasted costs reflect amounts requested in the 2020 General Rate Case, with escalation applied to 2023. PG&E continues to evaluate the proposed wildfire mitigation plans and actual spend may vary from these forecasted amounts.
(5) Inspections expected to be completed by May 31, 2019 or, as noted in the April 25, 2019 amendment to the Wildfire Mitigation plan, as soon thereafter as is feasible in light of weather conditions and other external factors.

See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.

Attachment E

PG&E's Fourth Quarter Earnings Presentation (dated February 18, 2016), Slide 11

Capital Expenditures 2015-2019



* Ranges reflect authorized amounts, amounts requested but not yet authorized, amounts that are currently planned subject to future authorization requests, and historic spending patterns. Ranges also include ~$300 million in 2016 (total of $689 million) for estimated capital disallowed in April 9, 2015 final Penalty Decision.

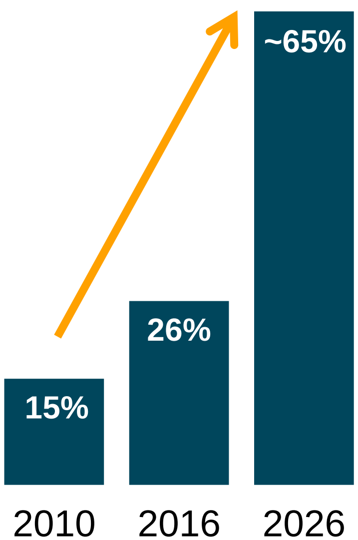
See the Safe Harbor Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.

Attachment F

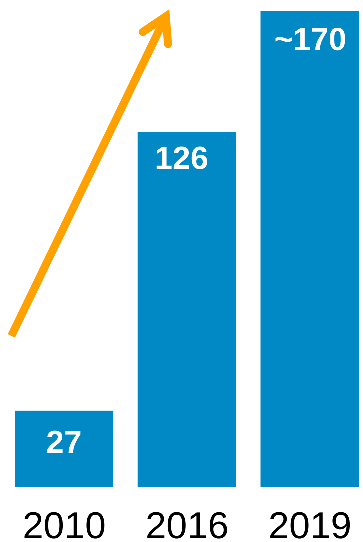
PG&E’s Business Update (dated November 3, 2017), Slide 20

Continue to Upgrade Our System

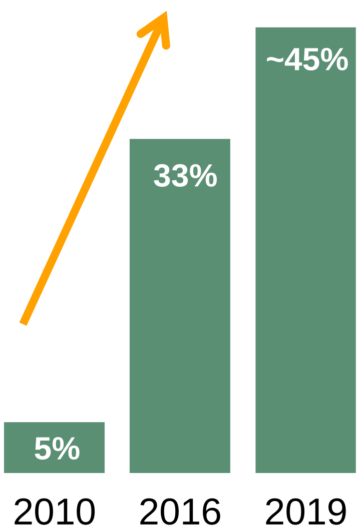
% of Gas Transmission System Piggable



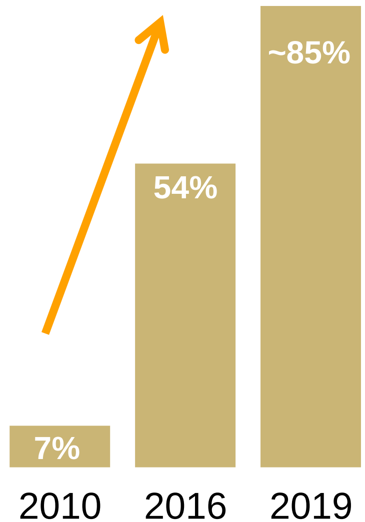
Annual Projected Miles of Gas Distribution Main Replacement



% Penetration of Automated Switches in Urban Areas



% of Urban Substations Upgraded



Investments to systematically modernize infrastructure

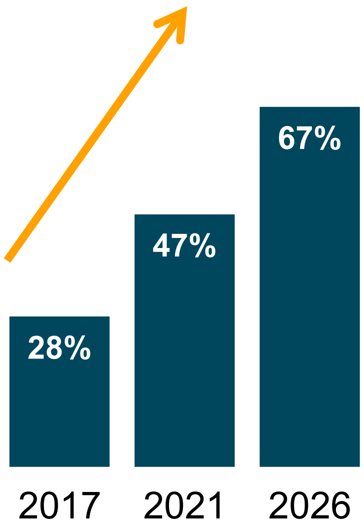
See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.

Attachment G

PG&E's Business Update (dated November 5, 2018), Slide 17

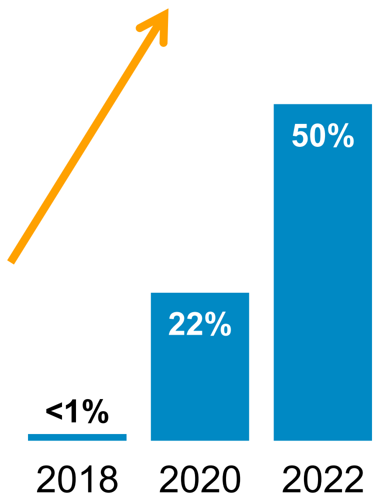
Continue to Upgrade Our Gas and Electric System

% of Gas Transmission System Piggable



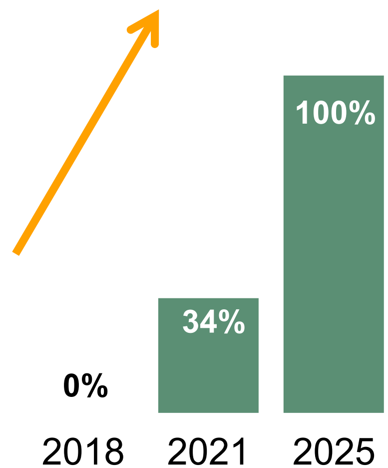
~7,000 miles of transmission pipe

Secondary Over-Pressure Protection on Distribution Reg Stations



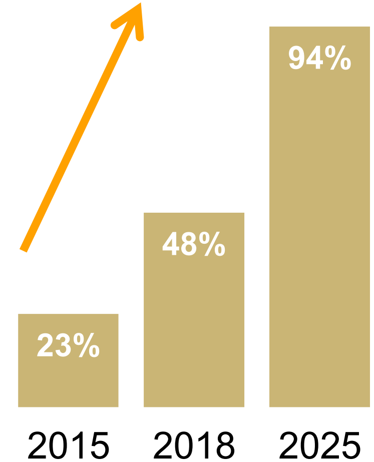
~1,300 distribution regulator stations

% Electric Transmission SCADA Switches Modernized



~1,400 automated switches

% San Francisco Substation Modernized



42 substations in San Francisco

Investments to systematically modernize infrastructure

See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.

Attachment H

Moody's, "Rating Methodology: Regulated Electric and Gas Utilities" (dated June 23, 2017)

MOODY'S
INVESTORS SERVICE

RATING
METHODOLOGY

Regulated Electric and Gas Utilities

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This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector. [1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4][5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

---

2 Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

3 Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

4 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

5 A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

6 For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

7 Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historical and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$

8 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

9 In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when “used and useful” requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.
Ba	**B**	**Caa**	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.
	Sub-Factor Weighting	**Ba**	**B**	**Caa**	**Definiitons**
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations– Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

10 In certain circumstances, analysts may also apply specific adjustments.

11 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[1310] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

[12] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[13] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[14] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma capitalization/leverage

15 See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based onlegislation that provides the utility a nearly absolute monopoly (see note 1_ within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
		Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
CFO pre-WC / Debt	15%								
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
		Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
CFO pre-WC - Dividends / Debt	10%								
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
		Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
Debt / Capitalization	7.5%								
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[1614] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility Holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, largerwaves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A longperiod of globally low interest rates, held down by monetary stimulus policies, has generally benefittedutilities, since reductions in allowed returns have been slower than reductions in incurred capital costs.Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult topredict is how regulators will respond when monetary stimulus reverses, and how well utilities will farewhen fixed income investors require higher interest rates and equity investors require higher total returnsand growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compressionof returns has been relatively steep in recent years. In Japan, the regulatory authorities are working throughthe challenges presented by the decision to shut down virtually all of the country's nuclear generationcapacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favoredgeneration sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developedand supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea andThailand have been moving towards a more transparent regulatory framework. The Philippines is in theprocess of deregulating its power market, while Indian power utilities continue to grapple with structuralchallenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable,long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the

[17] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

[18] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report,

securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility.

In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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MOODY'S
INVESTORS SERVICE

Attachment I

Moody's, "Regulated electric utilities – California – Customer bill credits after power shutoffs signal weakening political support" (dated October 31, 2019)

MOODY'S
INVESTORS SERVICE

SECTOR COMMENT
31 October 2019

Rate this Research

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Regulated electric utilities – California

Customer bill credits after power shutoffs signal weakening political support

The political backlash arising from Pacific Gas & Electric Company's (PG&E) recent wave of public safety power shutoffs could lead to a less supportive California regulatory environment for the state's investor owned utilities, including Southern California Edison Company (SCE, Baa2 stable) and San Diego Gas & Electric Company (SDG&E, Baa1 positive).

After calls earlier this month from California Governor Gavin Newsom to compensate customers who lost power during PG&E's preemptive power shutoff on 9 October, PG&E agreed this week to provide one-time credits to about 729,000 electric customer accounts that were affected by the outage. Customer bill credits are not common in the utility industry and PG&E's decision to provide one in this case could set a precedent that may be used by state regulators to compensate power outage victims in the future.

PG&E has indicated that it will provide a one-time $100 credit to residential customers who lost power and a $250 credit to affected business customers. About 87% of PG&E's electric customer accounts are residential and the remainder are commercial and industrial businesses. If we assume the same residential-business split for the 729,000 customers affected by the 9 October blackout, we estimate that the one-time customer rebate will total about $87 million, a negligible amount relative to PG&E's 2018 electric operating revenue of $12.7 billion or its operating cash flow of $4.8 billion. However, if customer rebates were to become more common, they would be credit negative for the utility because they would result in a more substantial reduction in revenue and cash flow for the utility over time, depending on the number of customers affected. During the past week, PG&E has initiated additional power shutoffs and will continue to do so in advance of specific weather conditions to reduce the risk of utility equipment causing wildfires.

Other investor-owned utilities in the state have also preemptively shut off power this week. On Wednesday, SCE shut off power to at least 71,000 homes and could shut off power to an additional 304,000 customer accounts in anticipation of strong Santa Ana winds that began affecting Southern California today. SDG&E also shut off power to 26,000 customer accounts, it's largest blackout ever, because of high-fire risk weather conditions. (See "ESG - California: Public safety power shutoffs highlight links between environmental and social risks" for further discussion about heightened social risks arising from the utility power shutoffs.)

Moreover, California State Sen. Scott Wiener recently proposed Senate Bill 378, which would enable residential customers and businesses that have been financially harmed by power outages to recover those costs from utilities. The bill will be taken up in the next legislative session when lawmakers return in January 2020. SB 378 requires utilities to compensate people or businesses harmed by the blackouts; imposes a penalty fee for every hour that power has been shut off multiplied by a certain number of customers affected; prohibits utilities from charging customers for non-fixed costs during a shutoff, and prevents the utility from recouping any losses during a power outage.

In July, legislators passed Assembly Bill 1054 in an effort to help protect the financial health of utilities by mitigating the potential for significant liabilities from wildfire related events. The legislation is a good example of the state taking a leading role in managing wildfire liabilities and an attempt to provide legislative and regulatory support for a growing state wildfire problem (see "Regulated electric utilities – US: FAQ on the credit implications of California's new wildfire law"). Sen. Wiener's draft proposal of SB 378 and any other potential bills under consideration that would penalize utilities for power shutoffs would, if passed, represent a potential reversal of the political support provided by state leaders earlier this year. Although penalties imposed on utilities for customer hardship during power shutoffs would likely pale in comparison to the potential liabilities arising from devastating wildfires, such utility fines or penalties would be an indication of a weaker regulatory and legislative environment for the California utilities.

Moody's related publications

Sector In-Depth

- ESG - California: Public safety power shutoffs highlight links between environmental and social risks, October 2019
- Local government – US: Growing exposure to heat stress mitigated by economic and fiscal strengths, September 2019
- ESG – Global: Governance considerations are a key determinant of credit quality for all issuers, September 2019
- Corporate boards – North America: Gender diversity is correlated with higher ratings, but mandates pose short-term risk, September 2019
- Regulated electric and gas utilities - North America: Free cash flow and capital allocation: external capital needs to decline in 2019, August 2019
- Regulated electric utilities – US: FAQ on the credit implications of California's new wildfire law, August 2019
- Electric and gas – US: Pipeline cybersecurity standards help plug security loophole in utility supply chain, July 2019
- Electric and Gas Utilities - US: California utilities struggle with inverse condemnation exposure, April 2019
- Regulated water utilities - US: M&A expands to cross-sector deals, with mixed credit implications for acquirers, March 2019
- Cross-Sector — Global: Social issues can be material to private issuers' credit quality but are not typically the primary driver, February 2019
- Regulated Utilities and Power - US: PG&E bankruptcy highlights environmental, social and governance risks in California, February 2019
- Cross-sector: Social issues have multiple impacts on government credit quality, November 2018
- Regulated electric and gas utilities - US: Cyber risk is on the rise, but the likelihood of government relief is high, September 2018

Sector Comments

- Regulated electric utilities – US: Proposed California wildfire risk legislation is credit positive but questions remain, July 2019
- Electric utilities – US: Limiting utility liabilities looms large after release of SB 901 Commission draft report, June 2019
- Regulated electric utilities – US: California wildfire strike force report is credit positive, but details are still pending, April 2019

Non-Credit Rating Assessment Framework

- Non-financial companies – Global: Framework to assess carbon transition risk for corporate sectors, September 2019
- Non-financial companies – Global: Corporate governance assessments for publicly traded non-financial companies, July 2019

Cross-Sector Rating Methodology

- General Principles for Assessing Environmental, Social and Governance Risks, January 2019

REPORT NUMBER 1201491

MOODY'S INVESTORS SERVICE

Attachment J

PG&E Response to TURN's Ninth Set of Data Requests (dated February 7, 2020)

PACIFIC GAS AND ELECTRIC COMPANY
Plan of Reorganization OII – 2019
Investigation 19-09-016
Data Response

PG&E Data Request No.:	TURN_009-Q01-Q04		
PG&E File Name:	PlanOfReorganizationOII-2019_DR_TURN_009-Q01-Q04		
Request Date:	February 3, 2020	Requester DR No.:	009
Date Sent:	February 7, 2020	Requesting Party:	The Utility Reform Network
PG&E Witness:	Various	Requester:	Thomas Long

GENERAL STATEMENT AND OBJECTIONS

1. PG&E objects to each request to the extent it seeks information protected from disclosure by the attorney-client privilege, the attorney work-product doctrine, or any other privilege or protection from disclosure. PG&E intends to invoke all such privileges and protections, and any inadvertent disclosure of privileged or protected information shall not give rise to a waiver of any such privilege or protection. PG&E further objects to the data requests to the extent they seek material nonpublic financial information (the use and selective disclosure of which is prohibited by securities laws).

2. PG&E objects to the data requests to the extent that they are overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. PG&E further objects to these requests as unduly burdensome in that TURN seeks a response in four business days, rather than five business days per the procedures in this proceeding.

3. These responses are made without waiving PG&E's rights to raise all issues regarding relevance, materiality, privilege, or admissibility in evidence in any proceeding. PG&E also reserves the right to amend or modify its proposed plan of reorganization filed in this proceeding on January 31, 2020 (PG&E's Plan).[1] PG&E reserves the right, but does not obligate itself, to amend these responses as needed should PG&E's Plan or the scope of these proceedings change.

4. PG&E incorporates each of these General Objections into each of its responses below. Each of PG&E's responses below is provided subject to and without waiver of the foregoing objections and any additional objections made below.

SUBJECT: VARIOUS ISSUES

1 Unless otherwise indicated, capitalized terms herein have the meanings set forth in PG&E's Plan.

QUESTION 1

With respect to the following paragraph in PG&E's January 31, 2020 testimony on page 1-6, lines 5-8, "In addition, PG&E has carefully considered views expressed by California's Governor regarding its prior Plan, and PG&E's accompanying testimony includes a number of additional commitments designed to address the Governor's concerns and to ensure that PG&E's Plan satisfies AB 1054."

> a. Does "additional" mean additional to PG&E's prior Plan? If not, explain what "additional" means in this context.
>
> b. Please identify, by citation to chapter and page in PG&E's January 31, 2020 testimony, each and every additional commitment that is made in the testimony.

ANSWER 1

PG&E objects to this request to the extent that it is burdensome and vague and ambiguous. Subject to its objections, PG&E responds as follows:

> a. "Additional" means new commitments described in the January 31, 2020 testimony but not set forth in the four corners of PG&E's Plan that are designed to address the Governor's concerns and to ensure that PG&E's Plan satisfies AB 1054.
>
> b. See, e.g., pages 4-1; 4-11 to 4-12; 4-19; 4-30; 5-6; 5-6 to 5-8; 5-28 to 5-30; 5-35 to 5-36; and 7-21.

QUESTION 2

Please provide the Willis Towers Watson executive compensation study referenced in PG&E's January 31, 2020 testimony on page 7-4, lines 20-22.

ANSWER 2

See PlanOfReorganizationOII-2019_DR_TURN_009-Q02Atch01

QUESTION 3

Please state PG&E's position regarding each of the following recommendations in TURN's December 13, 2019 testimony in this case, as those recommendations are explained in TURN's testimony:

a. The Commission should require that the Board members agree in writing that safety is PG&E's highest objective and that financial goals such as enhancing shareholder value, are secondary. (TURN Testimony, pp. 12-13)

b. The Commission should require that the Board(s) be composed of at least a majority of members with direct operational experience and meaningful safety experience in the energy industry, as explained in TURN's Testimony on pages 13-14.

c. The Commission should require that there be a tight restriction on the size of the equity and debt holdings of entities with which Board members are affiliated. TURN recommends that, in the aggregate for the members of each Board, their personal holdings and the holdings of entities with which the members are affiliated should not exceed 5% of the outstanding shares of stock or 5% of the value of outstanding debt, as further explained in TURN's Testimony on pages 14-15.

d. The Commission should direct, as a condition of Plan approval, that the Plan proponents agree to propose, in a filing with the CPUC shortly after PG&E's exit from bankruptcy, a Code of Managerial Expectations. This Code should be designed to re-set expectations for senior management to a higher level and to prevent the types of managerial failures that have plagued PG&E in the past decade. This Code should be as specific as possible, including the use of case studies to model both appropriate and inappropriate managerial behavior. The proposal should also include a discussion of the sanctions for failure to satisfy the Code's standards and the circumstances under which different levels of sanctions will be applied. Sanctions should include loss or reduction of incentive compensation and, for serious offenses that warrant termination, reduction or loss of any severance benefits, consistent with contract law requirements. The Commission should allow interested parties to address such proposals in this or another docket of the Commission's choosing, with a goal of reaching a Commission decision on a required Code within one year of PG&E's exit from bankruptcy. (TURN Testimony, pp. 20-25)

e. The Commission should require, as a condition of Plan approval, that the POR or other related documents explicitly acknowledge and accept that the Commission may initiate a CPCN revocation proceeding when, in the Commission's judgment, the safety performance of the post-bankruptcy PG&E is inadequate. TURN's testimony provides guidelines for circumstances that would warrant a CPCN revocation proceeding. (TURN Testimony, pp. 27-31)

Please provide a separate response for each recommendation listed above. Unless the response unequivocally agrees with the TURN recommendation in question, please explain the reason(s) for PG&E's position.

ANSWER 3

PG&E objects to this request on the grounds that it is vague and ambiguous because many of the proposals TURN asks PG&E to comment on are not well defined or explained, and therefore would require PG&E to speculate about what the proposals mean and would entail. Subject to its objections, PG&E responds as follows:

a. PG&E believes proposal (a) above is moot. PG&E's January 31, 2020 testimony unequivocally states in writing: "The Boards view customer and workforce safety as PG&E's first and highest imperative. The Boards firmly believe that safety is job one because safety is the right thing to do, period." (Chapter 4 of PG&E's Testimony at 4-23 (testimony of Ms. Brownell); *see also id.* (observing that "[s]afety also is critical to PG&E's long-term financial stability" because "[s]afety and financial performance go hand in hand at PG&E"); *id.* at 4-2 ("The Boards' first and highest priority is keeping customers and workers safe as PG&E provides reliable, affordable, and clean energy to its customers while returning to financial stability and health."); *id.* at 4-1 (stating that "customer and workforce safety [is] PG&E's first and highest priority"); *id.* at 7-7 (testimony of Mr. Lowe) (stating that "customer and workforce welfare and safety [are] PG&E's highest priorities and the foundations of its future success"); *id.* at 7-9 ("PG&E firmly believes that safety is the most important element of its mission of delivering safe, reliable, affordable, and clean electricity and gas services to its customers."); *id.* (noting that safety is the "most critical element" of PG&E's mission); *id.* at 1-1 (testimony of Mr. Johnson) (noting that "PG&E is in the process of making, and is dedicated to, transformative change to ensure that we prioritize safety and our customers' welfare, and PG&E commits to continue these efforts as it emerges from Chapter 11 under its Plan"); *id.* at 5-1 (testimony of Mr. Vesey) ("PG&E's future success depends on a pervasive, day-to-day, and intense focus on protecting and advancing customer and workforce welfare—including through improvements to safety culture and performance—and improving overall customer experience.").)

b. PG&E agrees with proposal (b) insofar as it recommends that the Boards have members with direct operational experience and meaningful safety experience in the energy industry. PG&E notes that a majority of the current Utility Board members have such experience, as summarized in the testimony of Nora Mead Brownell served on January 31, 2020 and the Compliance Filing attached as Exhibit 1 thereto. PG&E does not agree with proposal (b) insofar as it suggests that there should be an inflexible numeric or percentage-based quota for Board members with such experience. PG&E is concerned that such a quota could impair efforts to assemble the most qualified Boards, taking into account the wide diversity of skills and experience that it is important to have represented on the Boards, and the pool of qualified and available candidates. PG&E is also concerned that such a quota could, given the need to balance a range of skills and backgrounds on the Boards, impair efforts to ensure ongoing consummation of NorthStar Consulting Group's recommendation to "[a]dd Independent Directors to the Board who have experience with safety, *perhaps in another industry such as aviation*." (NorthStar Consulting Group, *Final Report: Assessment of Pacific Gas and Electric Corporation and Pacific Gas and Electric Company's Safety Culture*, at I-12 (May 8, 2017) (emphasis added).)

c. PG&E believes proposal (c) is not sufficiently developed to permit comment at this time. PG&E notes that TURN has not explained in any detail what goals would be served or problems would be remedied by this proposal, how any such goals would be served or how any such problems would be remedied, or how the proposal would be permissible or lawful under PG&E's articles of incorporation and bylaws and governing statutes providing for shareholder election of directors.

d. PG&E believes that proposal (d) is not sufficiently developed to permit comment at this time. PG&E notes that TURN has not, for example, defined what TURN means by "re-set expectations for senior management to a higher level," "types of managerial failures," "as specific as possible," or other concepts that appear to be key to proposal (d). PG&E states that, in general terms, its new Boards have set high expectations for PG&E's new and continuing management, and that holding management accountable for meeting those expectations is a key part of the Boards' job.

e. PG&E does not believe proposal (e) is efficacious. PG&E previously has explained why a periodic CPCN review is unnecessary, would be financially destabilizing, would contravene efforts to improve safety culture and performance, and could have other undesirable effects. PG&E respectfully refers TURN to PG&E's July 19, 2019 filing in the Safety Culture OII (I.15-08-019) for PG&E's position on this topic. To the extent TURN is proposing merely that PG&E's Plan state that the Commission possesses authority to initiate a CPCN review proceeding in appropriate circumstances, PG&E is unsure what would be gained by such a statement. The Commission possesses the authority it possesses; that is a legal matter that necessarily will remain unaffected by anything stated or not stated in PG&E's Plan.

QUESTION 4

Page 3-20, lines 12-14 uses the phrase “constructively implemented” in reference to AB 1054. He uses variants of this phrase in several places in his testimony.

a. Please identify and explain all particular implementation issues under AB 1054 that the witness has in mind when using this phrase (or variants) in his testimony.

b. For each issue identified in response to a) above, please explain what would constitute “constructive” implementation and what would constitute “unconstructive” implementation.

ANSWER 4

PG&E objects to this request to the extent that it is overbroad, unduly burdensome, and vague and ambiguous. Subject to its objections, PG&E responds as follows: With the phrase “constructively implemented,” Mr. Plaster means to convey that there should be a market perception of predictability and fairness with respect to implementation of AB 1054, and that such implementation should support the regulatory compact. There is no precise list of issues and precise outcomes associated with this phrase. It would include the right to recover wildfire costs in rates where the company acted prudently, wildfire certifications being granted appropriately, and the wildfire fund functioning as anticipated without requiring additional cash contributions to replenish the fund except to the extent requisite statutory showings (e.g., costs not being just and reasonable) are made.

Attachment K

PG&E Response to Public Advocates Office Third Set of Data Requests (dated November 15, 2019)

PACIFIC GAS AND ELECTRIC COMPANY
Plan Of Reorganization OII – 2019
Investigation 19-09-016
Data Response

PG&E Data Request No.:	PubAdv_003-Q01-08		
PG&E File Name:	PlanOfReorganizationOII-2019_DR_PubAdv_003-Q01-08		
Request Date:	November 7, 2019	Requester DR No.:	003
Date Sent:	November 15, 2019	Requesting Party:	Public Advocates Office]
PG&E Witness:	Various	Requester:	Christian Lambert

QUESTION 01

The Commitment Letters (ref. Docket #4446) supporting PG&E's Plan of Reorganization state at various points that PG&E's proposed Wildfire Claims Cap of $18.9 billion shall not include "any Wildfire Claim that the CPUC has approved or agreed to approve for recovery or pass through by the Utility..."[1]

a. Please identify the referenced "Wildfire Claim" amounts or estimated amounts that the Plan of Reorganization Commitment Letters envision being passed through or otherwise recovered from ratepayers.

b. Provide a breakdown of the amounts in (a), above, to identify the associated wildfire.

c. If any such "Wildfire Claim" amounts are un-estimated by PG&E at this time, identify the specific wildfire(s), the associated costs of which PG&E does not include in the proposed Wildfire Claims Cap of $18.9B.

d. Explain how PG&E's Plan of Reorganization will remain compliant with the ratepayer neutrality provision of Assembly Bill (AB) 1054 [i.e., Public Utilities Code Section 3292(b)(1)(D)] if any Wildfire Claim(s) or associated costs will be recovered in rates.

e. Please identify the terms of PG&E's Plan of Reorganization (Docket #4563) that provide for the pass-through of any Wildfire Claim(s) or related costs for recovery from ratepayers.

    i. Please explain the apparent discrepancy between PG&E's argument that its Plan "does not require any rate change and does not require customers to pay in rates any costs of payments made to Wildfire Claimants"[2] with the Commitment Letters' reference to "any Wildfire Claim that the CPUC has approved or agreed to approve for recovery or pass through by the Utility."

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1 See Docket #4446-3 at p. 9 of 22; #4446-5 at pp. 15 and 40 of 42; and #4446-6 at pp. 15 and 39 of 41.

2 PG&E Response to OII at p. 4.

ii. Does PG&E intend to seek rate recovery for any Wildfire Claim(s) or related costs subsequent to its exit from bankruptcy? If yes, identify the Wildfire Claim amounts and the corresponding fire. If any such Wildfire Claim amounts are unestimated by PG&E at this time, identify the specific wildfire(s), the associated costs of which PG&E would seek rate recovery.

f. Please identify the terms of PG&E's Plan of Reorganization (Docket #4563) that provide for ratepayer compensation for the pass-through of any Wildfire Claim(s) or related costs for recovery from ratepayers, consistent with AB 1054 [i.e., Public Utilities Code Section 3292(b)(1)(E)].

ANSWER 01

a. PG&E has not identified any Wildfire Claim amounts or estimated amounts that are to be passed through or otherwise recovered from ratepayers, and PG&E has not assumed any such amount. The referenced provisions in the Plan of Reorganization Commitment Letters simply acknowledge that were such recovery to occur, that amount would not count against the cap.[3]

b. See Answer to 1.a.

c. It is not clear what is intended by the phrase "un-estimated by PG&E"; however, PG&E at this time is not contemplating any particular wildfires or associated costs as destined not to be included in the proposed Wildfire Claims Cap of $18.9B.

d. This question is entirely hypothetical, as at this time PG&E's Plan of Reorganization does not call for any Wildfire Claim(s) or associated costs to be recovered in rates. If in the future a Plan were to provide for rate recovery of any Wildfire Claim(s), PG&E would need to demonstrate that other provisions of the Plan would offset such recovery, such that the Plan would be, on average, neutral.

e. The Company's Plan of Reorganization does not contain any term providing for or otherwise addressing the potential pass-through of any costs relating to Wildfire Claims for recovery from ratepayers.

   e.i. There is no discrepancy. See responses to Questions 1.a and e. above.

   e.ii. PG&E currently does not intend to seek net rate recovery subsequent to its exit from bankruptcy of any Wildfire Claims or related costs, up to the amounts set forth in the Plan of Reorganization. For the avoidance of doubt, PG&E may seek rate recovery of such costs in rates, but if it does so, it would offset such rates with other savings such that there would be no net rate impact on customers.

f. PG&E's currently-proposed Plan of Reorganization does not provide for the pass-through of any Wildfire Claim(s) or related costs for recovery from ratepayers, and accordingly there are no such terms to identify.

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3 Capitalized terms in PG&E's responses have the meanings set forth in PG&E's Plan unless otherwise indicated

QUESTION 02

Provide an explanation of how PG&E defines ratepayer neutrality for purposes of its Plan, consistent with AB 1054 [i.e., Public Utilities Code Section 3292(b)(1)(D)]. If PG&E's understanding of ratepayer neutrality address the bill and/or rate impacts of its Plan, include:

a. Any and all supporting analysis or modeling demonstrating the overall bill and/or rate impacts of the PG&E Plan.

b. An explanation of which points (dates) of comparison the PG&E Plan uses to compare whether or not its Plan produces a rate increase (i.e., explain how bills and/or rates upon the Effective Date will be compared to rates and/or bills as of some past date). Identify all pending or ongoing cases, including the cost of capital and general rate cases of PG&E, that PG&E includes in its analysis of such bill and/or rate impacts. Specify the assumptions and any adjustments made for each case.

ANSWER 02

PG&E understands that its Plan is neutral, on average, to ratepayers, because the Plan by its terms does not require ratepayers on average to pay more in rates than they would in the absence of PG&E's reorganization under the terms of PG&E's Plan. Changes in rates that occur as a result of Commission decisions in proceedings such as the cost of capital and general rate cases are not relevant to section 3292(d)(1)(D) because they are not rate changes resulting from the Plan of Reorganization. In light of the current provisions of PG&E's Plan, no modelling or other analysis has been necessary or performed to establish whether the Plan produces an increase in rates. In fact, the PG&E Plan substantially reduces the costs potentially borne by ratepayers, through cost savings to be obtained through the refinancing of debt at lower interest rates under the terms of the PG&E Plan. See also Responses to 1.a. and 1.e. above.

QUESTION 03

Please provide a pro forma balance sheet for the Reorganized Debtors under the PG&E Plan. Provide this balance sheet in an Excel-readable format. Include additional columns that present (a) the corresponding balance sheet items prior to the bankruptcy; (b) any increase to each item per the PG&E Plan; and (c) any decrease to each item per the PG&E Plan.

ANSWER 03

See attached PlanOfReorganizationOII-2019_DR_PubAdv_003-Q01-Q08Atch01CONF, the *pro forma* balance sheet. It includes actual values for 2018 and forecast values for 2019 and 2020. A copy of the material and the confidentiality declaration are being provided concurrently herewith to PAO, and those documents may be provided to other parties upon their execution and delivery of appropriate confidentiality agreements.

PG&E is making this balance sheet available with the strong caution that it relies upon a number of highly uncertain inputs and is therefore subject to material change as PG&E's Chapter 11 proceeding progresses. This balance sheet reflects PG&E's business forecast as of September 2019 and PG&E's filed Plan of Reorganization. It reflects the following assumptions, among others, all of which are highly uncertain:

- Assumes that Wildfire Claims are equal to the amount funded in PG&E's filed Plan of Reorganization, which is subject to change pending the Chapter 11 estimation process or a mediated settlement in the Chapter 11 proceeding.
- Assumes PG&E's capital structure at emergence is $27.35 bn of OpCo debt and $7.0 bn of HoldCo debt, reflecting PG&E's filed Plan of Reorganization which is subject to change.
- Assumes PG&E's ROE is 12% beginning in 2020. Pending a CPUC decision in the Cost of Capital proceeding, PG&E's future ROE is unknown.

Assumes PG&E implements the securitized $2.3 bn of wildfire system hardening costs required by AB 1054 beginning in 2020 (assumes receipt of $800 mm of securitization in 2020). The timeline for implementing that securitization is highly uncertain.

QUESTION 04

The Commitment Letters (ref. Docket #4446) supporting PG&E's Plan of Reorganization state at various points that the Plan's exit financing is conditional upon

> "the weighted average earning rate base of the Debtors for estimated 2021 being no less than 95% of $48 billion (i.e.,$45.6 billion)…"[4]

a. Please detail the assumptions used to arrive at the estimate of $48 billion for 2021, and for the lower estimate of $45.6 billion.

b. Provide a breakdown that shows how forecast and authorized capital additions produce the difference of $48 billion and recorded 2018 weighted average rate base. Provide this breakdown to show the amounts by major regulatory case (e.g., General Rate Case, Gas Transmission and Storage, Transmission Owner, etc.). Label amounts as "authorized," "PG&E forecast," or other (specify) as appropriate.

c. Confirm that the estimated "earning rate base" of $48 billion incorporates the exclusion of fire risk mitigation capital expenditures from equity (i.e., earning) rate base, as required by AB 1054 [i.e., Public Utilities Code Section 8386.3(e)]. If unconfirmed, explain how PG&E's Plan will meet both the equity rate base exclusion required by AB 1054 and the rate base conditions of the Plan's financing Commitment Letters.

d. Please identify the terms of PG&E's Plan of Reorganization (Docket #4563) that provide for the capital additions necessary to reach the minimum estimate of $45.6 billion.

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4 See Docket #4446 at p. 20 of 40; #4446-3 at p. 7 of 22; #4446-5 at p. 40 of 42; and #4446-6 at p. 39 of 41.

ANSWER 04

a. Please see response to question 4.b. below for a detailed breakdown of the $48 bn ratebase forecast in 2021.

   The $45.6 bn estimate is a negotiated figure and does not reflect specific analysis or forecasts. Using 95% of the forecast amount as a term in the Commitment Letters simply reflects that $48 bn is a forecast value and thus includes some inherent uncertainty.

b. See attached PlanOfReorganizationOII-2019_DR_PubAdv_003-Q01-Q08Atch03CONF, a breakdown of PG&E's 2021 ratebase forecast. A copy of the material and the confidentiality declaration are being provided concurrently herewith to PAO, and those documents may be provided to other parties upon their execution and delivery of appropriate confidentiality agreements.

c. PG&E confirms that 2021 ratebase forecast reflects exclusion of fire risk mitigation capital expenditures from earning ratebase. Please see the confidential attachment referred to in response 4.b. for detail on the quantity of capex excluded in each year.

d. PG&E's Plan of Reorganization does not include any terms which relate to or provide for PG&E's capital expenditure forecast.

QUESTION 05

The Commitment Letters (ref. Docket #4446) supporting PG&E's Plan of Reorganization refer to

> "rebates or credits required to be applied to benefit ratepayers as a result of a reduction in the rate base as a result of the sale or disposition of the 77 Beale Street, San Francisco property or any hydroelectric generation assets; provided that the Facility will provide that not more than $750 million of hydroelectric generation assts may be disposed of…"[5]

a. Please detail the assumptions used to arrive at this provision, including an explanation supporting the derivation of $750 million.

b. Please identify the hydroelectric generation assets that "may be disposed of." Explain why each asset was chosen for the list.

c. Please provide the source of the "require[ment]" for these rebates or credits, including identification of the amount and ratemaking treatment of the rebates or credits; identification of the benefits of such sales, and a timeline identifying any bidding process, Commission review, and the addition of the rate credit into rates, in relation to the Effective Date of the Plan.

5 See Docket #4446-5 at p. 27 of 42 and Docket #4446-6 at p. 26 of 41.

d. Please explain if the amount of the “$750 million of hydroelectric generation assets” refers to the current book value, the estimated sale proceeds, or other (specify) valuation of the assets in question. If related to the gains on sale, please explain if the amount is net of any other distributions from the potential sale proceeds, such as taxation or distributions to shareholders. Identify the percentage and amount of each other distribution, with an accompanying explanation of the assumptions supporting each distribution.

ANSWER 05

a. The $750 million figure is simply a negotiated cap on such sales, which potential lenders sought in order to protect their potential credit positions. PG&E did not perform calculations to arrive at this provision figure.

b. PG&E regularly reviews its generation portfolio to ensure that it continues to provide value for PG&E’s customers. In recent years PG&E has identified opportunities to divest of certain small hydroelectric projects where individual project circumstances make them no longer a good fit for the generation portfolio. The primary drivers for selecting the assets on the disposition “list” are: poor economic performance (costs exceed benefits), investment needed to manage risk and implement new regulatory requirements, geographic isolation, and ease of separability from other powerhouses in the portfolio. In some cases PG&E will be able to sell/transfer the specific hydro facilities, and in others the projects may end up being decommissioned. Due to the complexity of the hydro assets, the divestiture process takes several years to complete. The list of assets included in the disposition portfolio, as well as the status of each transaction, has been shared with the Public Advocates Office several times over the last few years, most recently at a meeting on October 3, 2019. See attached PlanOfReorganizationOII-2019_DR_PubAdv_003-Q01-Q08Atch02CONF. A copy of the materials most recently shared with PAO on this topic and the confidentiality declaration are being provided concurrently herewith to PAO, and those documents may be provided to other parties upon their execution and delivery of appropriate confidentiality agreements.

c. The term “requirement” refers to existing accounting and ratemaking procedures for the disposition of utility property. Under those procedures, proceeds from the sale of depreciable utility assets, such as buildings, are credited to the account for accumulated depreciation, which has the effect of reducing the remaining balance of assets in that account and thus reducing the amounts to be collected in future rates. The Commission established a framework for allocating the gain or loss on the sale of utility assets in D.06-05-041, as modified by D.06-12-043. That framework established that the gain or loss on sale associated with depreciable assets be allocated 100% to ratepayers. To the extent there is a gain or loss on sale of the non-depreciable assets, such as land, any gain/loss is allocated between shareholders 33% and ratepayers 67%. That framework does not apply, however, to sales of assets with a price over $50 million, sales with an after-tax gain or loss over $10 million, or extraordinary asset sales. If the Commission finds that one of those circumstances applies, then it will evaluate how to allocate gains or losses without applying the general rule. The Commission does not appear to have dealt with such an exceptional case since issuing D.06-05-041 and D.06-12-043.

The Commission has applied the standard gain/loss on sale rules in its approval of the three small hydro asset sales that it has approved in the last few years. Most recently, the Commission affirmed this treatment in its approval of the Narrows (D.19-10-010) and Deer Creek (D. 19-10-011) hydro projects on October 10, 2019.

The benefits of disposing of PG&E's 77 Beale property would be realized from a possible reduction in office space needed for the current number of employees who occupy PG&E's general office complex, and the corresponding reduction in rate base and reduction in the ongoing operating and maintenance expenses of that office space. The hydroelectric generation assets considered for sale generally relate to projects that are no longer cost-effective for PG&E's customers. The benefits from hydroelectric generation sale would be a reduction in rate base and reduction in ongoing operating and maintenance expenses of those facilities, as well as avoidance of future capital investment requirements.

Each transaction is unique and the stakeholders and timelines are variable. PG&E expects that both the Narrows and Deer Creek transactions will close prior to the Effective Date. PG&E may file applications for approval of 2-4 other transactions prior to the Effective Date, but it is extremely unlikely that any others would close in that timeframe.

d. The reference to "$750 million of hydroelectric generation assets" is meant to reflect estimated sale proceeds.

QUESTION 06

PG&E states that its Plan is conditioned on "satisfactory provisions pertaining to authorized return on equity and regulated capital structure."5 Define "satisfactory" for purposes of PG&E's Plan, using specific values or ranges for the return on equity and the regulated capital structure.

ANSWER 06

PG&E does not have a particular advance definition for what could be "satisfactory." PG&E is requesting an authorized 12% return on equity in its pending Cost of Capital proceeding, and a regulated capital structure of approximately 52% equity (subject to certain specified exclusions from the calculation). Those would be satisfactory provisions for purposes of PG&E's Plan. With respect to any other potential outcomes, PG&E will evaluate those outcomes in light of each other and the surrounding circumstances at the time, to determine if they are satisfactory for purposes of PG&E's Plan.

QUESTION 07

PG&E states that its Plan is conditioned on "satisfactory resolution of claims for monetary fines or penalties for prepetition conduct."6 Define "satisfactory resolution" for purposes of PG&E's Plan, using specific values or ranges for fines or penalties, with a breakdown according to each outstanding proceeding that may give rise to such fines or penalties.

ANSWER 07

PG&E does not have a particular advance definition for what could be a "satisfactory resolution." In light of the paramount importance of fairly compensating Wildfires victims, and the importance of positioning PG&E to emerge from Chapter 11 as a healthy utility with efficient access to the capital markets in order to control costs to ratepayers, PG&E believes that optimal public policy under the circumstances involves no imposition of monetary fines or penalties for prepetition conduct. With respect to any other potential outcome, PG&E will evaluate that outcome in light of the surrounding circumstances at the time, including but not limited to the magnitude of Wildfires Claims being paid under the PG&E Plan, to determine if such resolution is satisfactory for purposes of PG&E's Plan.

QUESTION 08

PG&E states,

> "[t]he Debtors, in their business judgment, may incur debt securities, credit facilities and securitization bonds or facilities at any time on or prior to the Effective Date, allowing the Debtors to avail themselves of attractive market conditions that may arise during the pendency of these cases."

Please provide the details of any such incurrences as they become available, including any eventual indentures.

ANSWER 08

PG&E will provide the details of any such incurrences as they become available, including any eventual indentures.

Attachment L

Moody's, "Credit Opinion: Pacific Gas & Electric Company, Update following rating downgrade" (January 12, 2019)

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
12 January 2019

Update

Rate this Research

RATINGS

Pacific Gas & Electric Company

Domicile	South San Francisco, California, United States
Long Term Rating	Ba3 , Possible Downgrade
Type	LT Issuer Rating
Outlook	Rating(s) Under Review

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Pacific Gas & Electric Company

Update following rating downgrade

Summary

Pacific Gas & Electric Company's (PG&E) credit profile reflects the very challenging political environment as potential liabilities grow, liquidity reserves decline and access to capital is uncertain following severe wildfires in its service territory over the last two years. The company is increasingly reliant on extraordinary intervention by legislators and regulators, which may not occur soon enough or be of sufficient magnitude to address these adverse developments.

Moody's incorporates a view that the potential liability associated with the 2017 and 2018 wildfires is at least $15 billion, and will result in significant pressure on the balance sheet and liquidity. The company's currently modest debt leverage and strong financial metrics are expected to gradually decline over time as additional debt is needed to fund wildfire claims and potential penalties assessed by state regulators. The credit profile also considers the risks associated with additional wildfire liabilities given the likelihood of future wildfires in the utility's service territory and California's unusually strict liability law known as inverse condemnation.

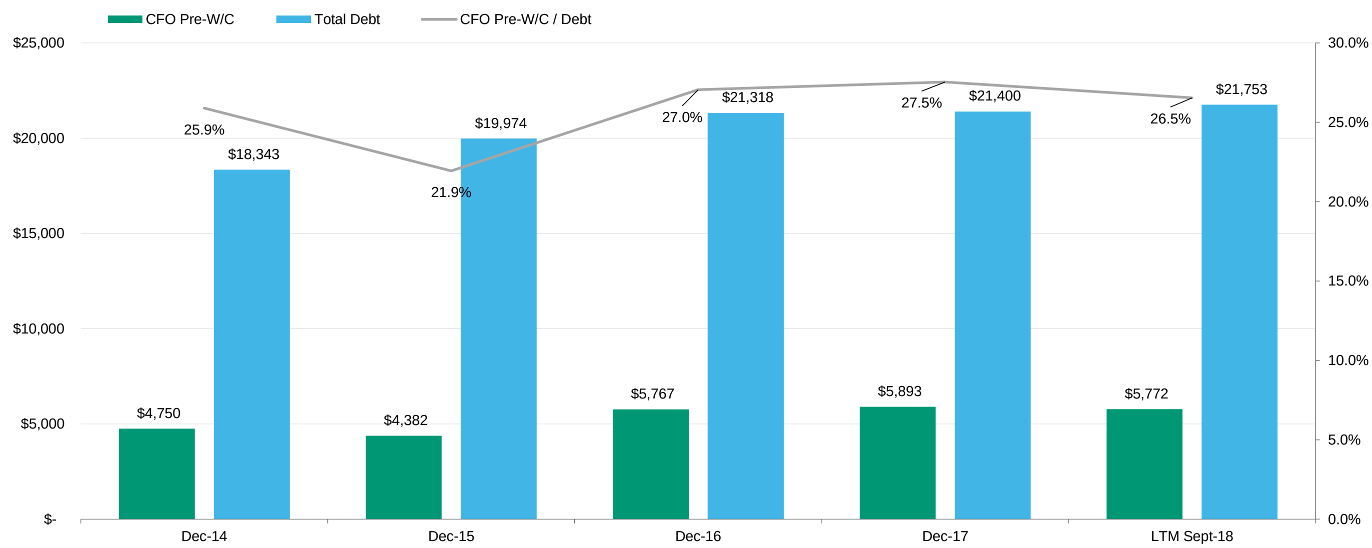
Moody's views the California regulatory environment as more unique compared to other state regulatory jurisdictions. The California Public Utilities Commission (CPUC) had been historically credit supportive, and provided access to extensive recovery mechanisms, including decoupling and a forward test year as well as above average rates of return. These recovery provisions are expected to remain, but the rating now incorporates a more onerous political and legislative environment due to the continued exposure related to potential future wildfire costs under inverse condemnation. The potential for these future risks to materialize is high due to climate change and a growing population in fire-prone areas. These risks are only partially mitigated by the new and untested regulatory cost recovery framework outlined by SB 901. The credit also factors in the state's demanding public policy goals and an elevated level of political risk, especially given the company's history of safety and governance issues.

Recent Developments

On 10 January 2019, Moody's downgraded the ratings of PG&E Corporation (PCG) and PG&E. PG&E's issuer and senior unsecured ratings were downgraded to Ba3 from Baa2 and its short term rating for commercial paper to Not Prime from Prime-2. PCG's issuer and senior unsecured ratings were downgraded to B2 from Baa3, and its short term rating for commercial paper to Not Prime from Prime-3. At the same time, Moody's assigned a Ba3 Corporate Family Rating (CFR), a B1 Probability of Default rating and an SGL-3 Speculative Grade Liquidity Rating. the ratings of PCG and PG&E remain on review for downgrade.

Exhibit 1

Historical CFO Pre-WC, Total Debt and ratio of CFO pre-W/C to Debt ($ in millions)



Source: Moody's Financial Metrics

Credit strengths

» Historically credit supportive regulatory framework with above average returns

» Use of timely cost recovery mechanisms including revenue decoupling

» SB901 includes regulatory framework that appears to mitigate liabilities associated with 2017 and wildfires occurring in 2019 and beyond

» Financial metrics, excluding any potential contingent wildfire or alleged gas safety violations-related liabilities, are currently strong

Credit challenges

» Elevated political and regulatory risk

» Potential material exposure to new, alleged gas system safety violations and the substantial 2018 Camp fire, in addition to previous 2017 wildfire events

» Long-term risk of additional climate change driven liabilities, such as from more intense wildfires, could be significant because of the application of inverse condemnation

» Regulatory application of SB 901 remains uncertain and 2018 fires are not explicitly addressed

» Regulatory and legal overhang from wildfire-related concerns expected to be lengthy

» Uncertainty over structural changes the company is considering

» Demanding state public policy goals

Rating outlook

The review for downgrade will continue to look for signs of legislative and regulatory support for PG&E as the company works through the various investigative, legal and regulatory processes with the California Department of Forestry and Fire Protection (CAL FIRE) and the CPUC. The review for downgrade will also focus on the potentially burgeoning liabilities facing the utility, the criteria and methodology being developed to calculate the financial stress test (CPUC hearings have begun), the likelihood and timing of any securitization financing to finance the potential 2017 wildfire liabilities, as well as uncertainty about whether securitization financing will be allowed to address the potential 2018 wildfire liabilities. The review could result in a multi-notch downgrade of the ratings of both PCG and PG&E.

Factors that could lead to an upgrade

An upgrade of PCG and PG&E's ratings is unlikely while the company resolves 2017 and 2018 wildfire related issues under the application of inverse condemnation. The rating outlook could be stabilized if the 2017 and potential 2018 wildfire costs are substantially less than expected or are resolved in a manner that maintains the companies' credit quality. This assumes that the majority of the maximum cap determined by the financial stress test is financed through the issuance of new parent equity and the remaining costs are covered by securitization debt that will sustain financial metrics.

An upgrade would be predicated on a repeal or material change to inverse condemnation that significantly reduces the utilities' wildfire risk exposure and strengthens our view of the legislative and regulatory environment in California.

Factors that could lead to a downgrade

A downgrade of PCG and PG&E's ratings could occur if cost recovery related to 2017 and potentially 2018 wildfires does not occur in a manner as outlined by SB901, if there are no extraordinary actions taken by legislators and regulators to address these liabilities and maintain the utility's credit quality, if the political and regulatory environment remains challenging or becomes more contentious, if PG&E is found liable for damages associated with the Camp fire, or if there are additional material wildfires. Additionally, a downgrade could occur if liquidity continues to tighten and the company's does not have sufficient access to the capital markets.

Key indicators

Exhibit 2

KEY INDICATORS [1]

Pacific Gas & Electric Company

	Dec-14	Dec-15	Dec-16	Dec-17	LTM Sept-18
CFO Pre-W/C + Interest / Interest	6.6x	5.8x	6.9x	7.0x	6.8x
CFO Pre-W/C / Debt	25.9%	21.9%	27.0%	27.5%	26.5%
CFO Pre-W/C – Dividends / Debt	22.0%	18.3%	22.8%	23.9%	26.6%
Debt / Capitalization	42.6%	43.3%	42.8%	45.8%	46.2%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

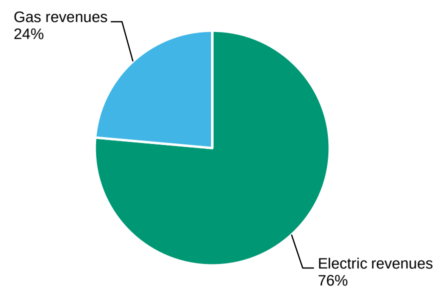
Profile

Headquartered in San Francisco, California, PG&E Corporation (PCG) is a utility holding company that conducts essentially all of its business through Pacific Gas & Electric Company (PG&E), a regulated vertically integrated utility serving northern and central California. For the LTM 30 September 2018, PCG had revenues of about $16.8 billion, total assets were about $70 billion and total debt was approximately $19.4 billion, of which $350 million was at the parent. PG&E serves approximately 5.4 million electric distribution customers and 4.5 million natural gas customers. PG&E is regulated by the California Public Utilities Commission (CPUC) and by the Federal Energy Regulatory Commission (FERC).

Exhibit 3

Revenue by source

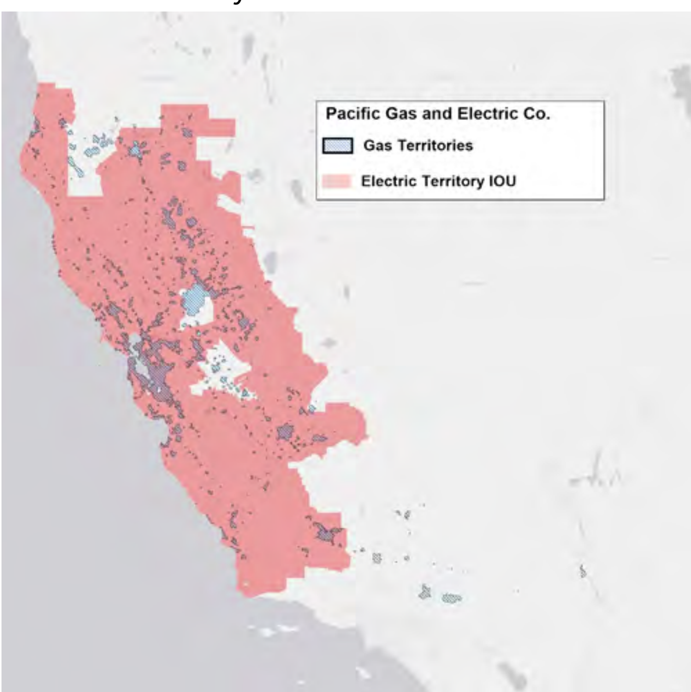
As of LTM 30 September 2018



Source: Company SEC filings

Exhibit 4

PG&E's Service Territory



Source: S&P Global Market Intelligence

Detailed credit considerations

ELEVATED POLITICAL RISK ENVIRONMENT

We view California as a very challenging political environment for PG&E. California utilities tend to receive a higher level of attention and scrutiny from both the media and the public and issues can often become contentious and litigious. PG&E is in a particular vulnerable position, given its history of safety incidents and governance issues over the last several years as well as the aforementioned wildfires.

Over the last two months, since we placed the ratings of both PCG and PG&E on review for downgrade in November 2018, the company has experienced additional negative developments. In December, state legislative leaders publicly aired their concerns about perceived weaknesses in PCG's corporate governance which we believe are influencing the relationship between PG&E and its regulator, the California Public Utility Commission (CPUC). In fact, on 21 December, the CPUC opened a new phase in an existing three-year old investigation into PCG's safety culture. Possible outcomes from the investigation include changes to the Board of Directors and senior management, a corporate restructuring, and possibly reconstituting the ownership structure into a non-profit utility enterprise.

In addition, on 14 December, the CPUC opened another investigation as to whether PG&E violated the state's natural gas safety rules. The CPUC's order followed the recent investigation report by the CPUC Safety and Enforcement Division (SED) staff, which alleges that PG&E falsified records from 2012 to 2017. Financial penalties could result. These alleged violations are a material credit negative for PG&E because, if found to be true, could be a sign of a systemic weakness at PG&E with respect to corporate governance and oversight policies. The new allegations about natural gas safety violations also are arising right after PG&E filed its 2020 general rate case, in which the utility is requesting a revenue increase of about $1.1 billion.

In response to these developments, on 4 January, PCG announced that it is conducting a Board refreshment process, reviewing structural options for the organization, and engaging independent experts to advise it on best practices in wildfire safety. The company indicated that the Board is actively assessing PG&E's operations, finances, management, structure and governance.

Historically, PG&E has been involved in several challenging events that have resulted in financial penalties, some quite material. For instance, PG&E incurred costs exceeding $4 billion related to the 2010 San Bruno pipeline explosion, which included the principal legal claims related to the incident. The ex-parte communication investigations represented yet another significant governance challenge for the company. PG&E and key interested parties, including the cities of San Bruno and San Carlos, and key intervenors have reached a joint-settlement agreement resulting in a total penalty of $97.5 million, which was approved by the CPUC in April 2018. PG&E is also in the process of resolving lawsuits related to the 2015 Butte wildfires. As of 30 September 2018, the company has accrued a charge of $1.1 billion, which exceeds its insurance coverage of $922 million related to those fires. The company has indicated that it is reasonably possible the company may be liable for an additional $200 million of costs related to the Butte fire. The liabilities do not consider any potential punitive damages that PG&E could be liable for. PG&E will need to file with the CPUC for recovery of any costs that exceed its insurance coverage.

APPLICATION OF INVERSE CONDEMNATION EXPOSES UTILITIES TO POTENTIALLY SUBSTANTIAL WILDFIRE LIABILITIES HAS WEAKENED THE REGULATORY ENVIRONMENT

The application of inverse condemnation is a unique risk factor affecting the entire California investor owned utility sector, and has weakened our assessment of the credit supportiveness of the California legislative and regulatory framework. Under inverse condemnation, even if a utility prudently managed its infrastructure at the time of a fire, the utility could be held accountable for damages if its infrastructure was substantially involved in causing the fire, potentially exposing the state's utilities to significant liabilities.

Although inverse condemnation has been a California legal doctrine since at least the 1960s, it has become a larger risk factor in recent years, because damages related to wildfires have exceeded the insurance coverage purchased by utilities. In addition, their ability to secure the appropriate level of insurance coverage may be challenging and more expensive in the future. As a result of the greater exposure, California utilities will need to request cost recovery from customers or likely face a decline in their financial profiles.

As a component of longer term climate change risks, wildfire events are an increasing concern for all of California's utilities, regardless of whether they are investor or publicly owned, including PG&E. Wildfires have become more frequent and damaging due to the effects of climate change, including more severe and prolonged droughts and stronger winds. In addition, California has witnessed a proliferation of real estate developments in fire-prone areas. These changes have resulted in higher wildfire related risks while the insurance market has become tighter and more expensive making it more challenging for utilities to obtain coverage. As a result, despite their increased efforts to mitigate fire risks, California utilities' exposure to wildfires could be significant, totaling multiple billions of dollars. Events over the past few months have led us to conclude that the California regulatory and legislative environments have become much more challenging are not as credit supportive as we historically thought.

Senate Bill (SB) 901 is a net credit positive for PG&E but overall there are both credit strengths and weaknesses in the legislation. The legislation did not repeal or change inverse condemnation, a material credit negative. However, SB901 does offer some constructive tools for the CPUC to utilize going forward to protect the credit quality of investor owned utilities exposed to future wildfire costs. The bill establishes a framework the CPUC will use to conduct its reasonableness review on wildfire-related costs, which appears to offer regulators more flexibility and judgment for utility cost recovery compared to a prudency test used historically. However, it remains to be seen how the framework will actually be put into practice by regulators.

The reasonableness review applies to wildfires that occur after 1 January 2019, which leaves a gap in coverage for any potential fires in 2018, a material credit negative. The reasonableness review includes several key factors including whether the utility disregarded indicators of wildfire risk; failed to operate and maintain its infrastructure in a reasonable manner; findings of government agencies including CAL FIRE; whether the utility was in compliance with regulations, its wildfire mitigation plans, and commission orders including its history of compliance and, whether the costs were caused by a single or multiple violations. Regulators are also expected to consider whether climate conditions exacerbated the extent of damages; costs and expenses beyond the utility's control and other factors regulators determine are necessary to evaluate the reasonableness of costs and expenses. Finally, the bill includes the opportunity for affected utilities to issue securitization bonds to recover costs from ratepayers, however, a financing order is required by regulators.

California had been a strong regulatory framework for utility cost recovery. On 13 July 2017, the CPUC voted to extend PG&E's cost of capital application by two years to 2019 and had subsequently allowed PG&E to delay its next general rate case filing. On 13 Decmeber 2018, PG&E filed its general rate case application for the 2020-2022 period. In the rate filing, PG&E requested a $1.1 billion rate increase in 2020 with increases of $454 million and $486 million in 2021 and 2022, respectively. In its general rate case request, PG&E plans to spend roughly $4.5 billion of capital expenditures per year during the three year period, totaling $13.5 billion. The plan includes about $3 billion in capital investments related to the company's Community Wildfire Safety Program. The company is requesting a final decision by March 2020. Separately, PG&E's cost of capital proceeding is expected to be filed in April 2019.

PG&E is currently authorized a capital structure of 52% equity, 1% preferred and 47% debt and an allowed ROE of 10.25%. In addition, the utility is allowed to utilize several cost recovery provisions including a revenue decoupling mechanism, procurement cost pass-through, and an automatic adjustment mechanism for authorized return on equity. California does not provide automatic recognition of investments between rate cases but it does allow for the use of multiple future test years using attrition rate increases (i.e., scheduled rate increases in between rate cases), which reduces regulatory lag.

2017 WILDFIRE EXPOSURE APPEARS TO BE MITIGATED BY SB901; HOWEVER RECOVERY OF POTENTIAL 2018 WILDFIRE EXPOSURE MORE UNCERTAIN

The 2017 wildfires in northern California could expose PG&E to substantial liabilities because of inverse condemnation. SB901 appears to significantly mitigate PG&E's liability exposure through the use of a stress test whereby the CPUC would consider the utility's financial status in allocating costs and the ability to use securitization bonds to recover costs from ratepayers. Costs allowed for recovery through securitization are those above and beyond the maximum cap determined by the financial stress test whether those costs were determined to be reasonable or not as well as costs deemed reasonable by the CPUC. However, recovery of costs related to the potential liabilities from the November 2018 Camp Fire is more uncertain.

To date, CAL FIRE has released press releases indicating that its investigators have determined that, of the 17 Northern California wildfires that CAL FIRE has investigated, all were caused by PG&E electric power and distribution lines, conductors and/or the failure of power poles. The reports also found evidence that PG&E may have violated state law with regard to 11 of the 17 fires, and these have been referred to local prosecutors, which could ultimately lead to a finding of negligence. Negligence can only be determined in a court of law and could result in additional liabilities including fire suppression costs, personal injury damages, and other damages. The Tubbs fire in Napa County is by far the largest fire as it is expected to account for approximately 60% of the total estimated damages. If the Tubbs investigation by CAL FIRE results in a negative outcome for PG&E, our analysis incorporates a view that the financial stress test would mitigate the potential exposure from the Tubbs fire by determining the maximum exposure to shareholders.

While it is too early to tell what the total damages will be for the 2017 and 2018 wildfires in PG&E's service territory, but we incorporate a view that the liabilities are at least $15 billion. PG&E recorded a pretax charge of $2.5 billion in Q2 2018 for losses associated with 14 fires based on the application of inverse condemnation, the CAL FIRE reports and available reports. The liability reflected the lower end of a range the company could reasonably estimate for losses. PG&E did not believe a loss is probable at the time for the other three fires that CAL FIRE has reported on based on the information available to them. The 2017 Northern California wildfires caused over 245,000 acres burned, 44 fatalities and over 8,500 structures destroyed.

The Camp fire has been reported as the most destructive fire in California history. The 2018 fire burned about 153,000 acres, destroyed over 18,000 structures and caused 88 deaths. At this time, it is too early to determine if PG&E's equipment will be found to be the substantial cause of the Camp fire. However, considering that the recently enacted Senate Bill (SB) 901 has mitigated liabilities associated with the 2017 California wildfires, it does not address recovery for any potential liabilities related to wildfires that occur in 2018. The gap in coverage within SB 901 is a material credit negative, particularly considering the magnitude of the Camp Fire.

As of 30 September 2018, PG&E estimated its the liability related to its 2015 Butte fire to be at least $1.1 billion, which included over 70,000 acres burned, two fatalities and more than 900 structures destroyed. In the third quarter of 2018, the parent and utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from 1 August 2018 through 31 July 2019.

CALIFORNIA UTILITIES FACE ENVIRONMENTAL RISKS AND DEMANDING PUBLIC POLICY GOALS

PG&E has a moderate carbon transition risk within the regulated utility sector. PG&E's moderate positioning reflects the heightened public policy activity in California as well as risks surrounding wildfires in the state, which distinguishes California's utilities from other T&D utilities which generally have a low climate change risk profile. California's policy environment includes aggressive carbon targets and renewable portfolio standard as well as other developments such as community choice aggregators and the growth of rooftop solar.

California places a heavy demand on its utilities to carry out public policy goals. The most important driver is the state's Renewable Portfolio Standard (RPS) that currently requires investor-owned utilities to procure 33% of their total energy sales from renewables by 2020 and 60% by 2030. California legislators have sent a recent bill to the Governor calling for loftier clean energy goals including 100% of the state's energy from carbon-free sources.

In June 2016, PG&E announced a joint proposal with labor and leading environmental organizations that would increase PG&E's investment in energy efficiency and renewables beyond current state mandates while phasing out PG&E's production of nuclear power in California by 2025. As a result, PG&E has committed to a 55 percent renewable energy target by 2031. The high level of intermittent renewable energy could make it challenging for the company to maintain a consistent level of reliability besides also requiring significant capital expenditures in grid upgrades to handle intermittent resources.

From a generation standpoint, less than 10% of PG&E's 2017 electric load was supplied by owned natural gas power plants. About 40% of its electric load was supplied through power purchase agreements, the majority of which are with renewables and hydro facilities. The remaining approximately 50% of its electric load was largely self-generated and consisted mostly of nuclear and hydro power.

PG&E's natural gas distribution business, which accounts for about 25% of consolidated results, is allowed timely recovery of its natural gas commodity purchase costs through a pass through to customers via an effective cost recovery mechanism. However, California's aggressive clean energy policies could eventually cause downward pressure on natural gas volumes in the utility sector. There is also the potential for the growth of electric heat pumps in CA, which would cause declining use by residential customers if decarbonization of home heating becomes a policy objective in the future. These risks are, however, long-term in nature and also partly mitigated because PG&E's revenues are de-coupled from sales volumes. Moody's framework for assessing carbon transition risk in this industry is set out in "Prudent regulation key to mitigating risk, capturing opportunities of decarbonization" (2 Nov 2017).

California's support for clean energy has also resulted in the growth of Community Choice Aggregators (CCA) in PG&E's service territory. CCAs are governmental entities formed by cities or counties that procure their own energy with a much higher share of renewable energy. CCAs are growing rapidly and PG&E projects that CCAs and the Direct Access program will serve a load in 2018 that is equal to approximately 40% of PG&E's total load. The revenue loss on this load is mitigated by a non-bypassable charge (called the Power Charge Indifference Adjustment or PCIA) that is paid to PG&E by the departing load. The PCIA compensates PG&E for the cost of excess purchased power that cannot be recovered through market sales, although currently not in full. PG&E and other investor-owned utilities had filed with the commission requesting a change to the formula that will allow them to fully recover PCIA-eligible PPA and utility-owned generation costs. In October, the CPUC voted to adopt the Alternate Proposed Decision, which makes the PCIA calculation more accurate and equitable by revising the methodology to calculate the PCIA beginning January 1, 2019. This includes revising inputs to the market price benchmarks to improve the accuracy of the PCIA that will be in effect each year, and removing the

10-year limit on cost recovery limit for legacy utility owned generation and certain storage resources. A second phase will be opened in 2019 to address portfolio optimization and other topics.

Intermittent renewables, CCAs, distributed generation, electric cars and storage are all public policy initiatives that combine to place enhanced operational demands on the utility. California already has some of the highest electricity rates in the U.S. and these initiatives will continue to exert upward pressure on retail rates. Much of these rate increases have thus far been tolerable due to the benign natural gas price environment, which has lowered fuel costs. In the absence of further declines in fuel prices, continued high capex at the utility and potential wildfire recovery costs may begin to exert upward pressure on rates and pose a growing challenge. We believe the potential for natural gas prices or wholesale power prices to jump suddenly and remain high on a sustained basis is limited, but such a development would be an immediate credit concern. The impact of gas prices, however, may diminish over time as the share of renewables continues to rise.

FINANCIAL METRICS, CURRENTLY STRONG, EXPECTED TO DECLINE DUE TO POTENTIAL CONTINGENT WILDFIRE-RELATED LIABILITIES AND GAS SAFETY VIOLATION PENALTIES

PCG's financial profile is essentially the same as that of PG&E because of PCG's modest amount of parent debt. PCG and PG&E's financial profiles are currently strong reflecting the companies' limited leverage and robust financial metrics excluding any potential contingent fire-related liabilities.

PCG and PG&E both had ratios of cash flow from operation pre-working capital changes (CFO Pre-W/C) to debt well in excess of 20% over the past few years. For the last twelve months (LTM) 30 September 2018, PCG and PG&E's ratio of CFO Pre-W/C to debt was 26.5%, respectively. When factoring in the eventual resolution of the 2017 and potentially the 2018 northern California wildfires and modest cash flow declines due to the impacts from recent tax reform legislation, we expect PCG and PG&E's financial metrics to gradually decline over time mainly due to an increase in short-term borrowings and securitization debt used to fund wildfire related costs, such that the companies' ratio of CFO pre-W/C to debt declines to the low-teens range.

The companies' currently strong cash flow to debt coverage metrics reflects the effective regulatory cost recovery mechanisms available within California's regulatory framework. While the potential liabilities related to the 2017 wildfires appear to be mitigated by regulatory cost recovery mechanisms available under SB901, the recovery of potential exposure to 2018 wildfire related costs is more uncertain and could be determined by an untested reasonableness review by the CPUC which still leaves open the uncertainty of cost recovery. As such, PCG and PG&E's financial profiles is at risk for further deterioration if the utility is held liable for future wildfire related costs without assurance of cost recovery. In addition, PG&E may be assessed substantial penalties stemming from the aforementioned gas safety violations.

Liquidity analysis

PCG and PG&E's SGL-3 speculative grade liquidity ratings consider relatively stable cash flow generation and Moody's estimate of an aggregate cash balance of roughly $2 billion. We estimate that about $800 million might be consumed by the need to post collateral for payment obligations. PG&E and PCG have fully drawn their respective revolving credit facilities, with aggregate borrowings outstanding of $3 billion and $300 million, respectively. No additional amounts are available and both facilities expire in April 2022. These facilities do not include a material adverse change clause but have a financial covenant limiting the debt to total capitalization ratio to no more than 65%. Both companies were in compliance with this financial covenant as of 30 September 2018 (51% and 50%, at PCG and PG&E, respectively). However, we believe there is a high likelihood of substantial charges being taken for wildfire liabilities, which could materially impact its financial covenant cushion or compliance.

For the LTM 30 September 2018, PG&E's cash flow from operations was $5.4 billion, however, the company's capital expenditures were $6.3 billion, leading to a negative free cash flow over the period. The company elected to suspend its dividend distributions on 20 December 2017, which is saving roughly $1.1 billion in annual cash outflows. To the extent the company's cash balances decline, we believe it has levers to pull to raise additional liquidity, including the sale of some real estate and other assets, a potential accounts receivable financing, or cutting back on capital expenditures to reach a cash flow neutral position.

Both companies' liquidity profiles could be negatively affected by potential wildfire related liabilities. If the company's access to the capital markets is hindered because of the potential detriment related to wildfires, PCG and PG&E's credit quality could be negatively impacted.

Upcoming maturities in the near-to-intermediate term include PG&E's $250 million term loan due in February 2019, as well as the parent's $350 million term loan due April 2020, which also includes an option for a one-year extension.

Structural considerations

Given the preponderance of debt within the corporate family that is held at the utility company, PG&E's over $20 billion of long and short-term senior unsecured debt is rated Ba3 (LGD3), which is in line with the Ba3 Corporate Family Rating. PCG's $650 million of long and short-term senior unsecured debt is rated B2 (LGD5), two notches below the Ba3 CFR. Similarly, PG&E's approximately $250 million of preferred stock is rated B2 (LGD5), also two notches from the Ba3 CFR reflecting its bottom position in the priority of claims.

Rating methodology and scorecard factors

Exhibit 5

Rating Factors

Pacific Gas & Electric Company

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2018		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Baa	Baa	Baa	Baa
b) Consistency and Predictability of Regulation	Ba	Ba	Ba	Ba
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	7.0x	Aa	6x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	27.6%	A	19% - 23%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	24.6%	A	19% - 23%	A
d) Debt / Capitalization (3 Year Avg)	43.1%	A	47% - 52%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Ba3		Ba3

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 9/30/2018(L)
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 6
Cash Flow and Credit Metrics [1]

CF Metrics	Dec-14	Dec-15	Dec-16	Dec-17	LTM Sept-18
As Adjusted					
FFO	**4,816**	**4,722**	**5,871**	**5,915**	**3,606**
+/- Other	(66)	(340)	(104)	(22)	2,166
CFO Pre-WC	**4,750**	**4,382**	**5,767**	**5,893**	**5,772**
+/- ΔWC	(1,153)	(663)	(1,451)	49	(338)
CFO	**3,597**	**3,719**	**4,316**	**5,942**	**5,434**
- Div	721	721	916	789	(6)
- Capex	4,820	5,155	5,690	5,677	6,331
FCF	**(1,944)**	**(2,156)**	**(2,290)**	**(523)**	**(891)**
(CFO Pre-W/C) / Debt	25.9%	21.9%	27.0%	27.5%	26.5%
(CFO Pre-W/C - Dividends) / Debt	22.0%	18.3%	22.8%	23.9%	26.6%
FFO / Debt	26.3%	23.6%	27.5%	27.6%	16.6%
RCF / Debt	22.3%	20.0%	23.2%	24.0%	16.6%
Revenue	17,088	16,833	17,667	17,138	16,773
Cost of Good Sold	6,595	5,823	5,396	5,053	4,570
Interest Expense	841	916	970	976	988
Net Income	1,272	156	1,255	1,585	1,289
Total Assets	60,122	63,313	68,631	68,162	71,474
Total Liabilities	44,157	46,626	50,615	48,785	52,059
Total Equity	15,965	16,687	18,015	19,377	19,415

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Exhibit 7
Peer Comparison Table [1]

	Pacific Gas & Electric Company			Southern California Edison Company			San Diego Gas & Electric Company			Southern California Gas Company		
	Ba3 Rating(s) Under Review			A3 Negative			(P)A2 Stable			A1 Stable		
	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM
(in US millions)	Dec-16	Dec-17	Sept-18	Dec-16	Dec-17	Sept-18	Dec-16	Dec-17	Sept-18	Dec-16	Dec-17	Sept-18
Revenue	17,667	17,138	16,773	11,830	12,254	12,810	4,253	4,476	4,530	3,471	3,785	3,790
CFO Pre-W/C	5,767	5,893	5,772	3,448	4,059	3,634	1,428	1,379	1,366	705	1,192	976
Total Debt	21,318	21,400	21,753	13,297	13,904	14,831	5,269	6,181	6,165	4,082	4,124	4,461
CFO Pre-W/C / Debt	27.0%	27.5%	26.5%	25.9%	29.2%	24.5%	27.1%	22.3%	22.2%	17.3%	28.9%	21.9%
CFO Pre-W/C – Dividends / Debt	22.8%	23.9%	26.6%	20.2%	24.6%	19.6%	23.8%	15.0%	22.2%	17.2%	28.9%	21.9%
Debt / Capitalization	42.8%	45.8%	46.2%	36.5%	41.8%	42.1%	38.4%	46.6%	45.2%	44.1%	45.9%	46.3%

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 8

Category	Moody's Rating
PACIFIC GAS & ELECTRIC COMPANY	
Outlook	Rating(s) Under Review
Issuer Rating	Ba3
Sr Unsec Bank Credit Facility	Ba3/LGD3
Senior Unsecured	Ba3/LGD3
Pref. Stock	B2/LGD5
Commercial Paper	NP
PARENT: PG&E CORPORATION	
Outlook	Rating(s) Under Review
Corporate Family Rating	Ba3[1]
Issuer Rating	B2[1]
Sr Unsec Bank Credit Facility	B2/LGD5[1]
Senior Unsecured Shelf	(P)B2[1]
Subordinate Shelf	(P)B3[1]
Pref. Shelf	(P)Caa1[1]
Commercial Paper	NP
Speculative Grade Liquidity	SGL-3

[1] Placed under review for possible downgrade on January 10 2019

Source: Moody's Investors Service

REPORT NUMBER 1157047

MOODY'S
INVESTORS SERVICE

Attachment M

PG&E Response to EPUC's Fourth Set of Data Requests (dated February 12, 2020)

PACIFIC GAS AND ELECTRIC COMPANY
Plan of Reorganization OII – 2019
Investigation 19-09-016
Data Response

PG&E Data Request No.:	EPUC_004-Q01-Q07		
PG&E File Name:	PlanOfReorganizationOII-2019_DR_EPUC_004-Q01-Q07		
Request Date:	February 5, 2020	Requester DR No.:	4
Date Sent:	February 12, 2020	Requesting Party:	Energy Producers and Users Coalition
PG&E Witness:	Various	Requester:	Evelyn Kahl

Pacific Gas and Electric Company (PG&E) submits the following objections and responses to the fourth set of data requests of the Energy Producers and Users Coalition (EPUC), served on February 5, 2020.

GENERAL STATEMENT AND OBJECTIONS

1. PG&E objects to each request to the extent it seeks information protected from disclosure by the attorney-client privilege, the attorney work-product doctrine, or any other privilege or protection from disclosure. PG&E intends to invoke all such privileges and protections, and any inadvertent disclosure of privileged or protected information shall not give rise to a waiver of any such privilege or protection. PG&E further objects to the data requests to the extent they seek material nonpublic financial information (the use and selective disclosure of which is prohibited by securities laws).

2. PG&E objects to the data requests to the extent that they are overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. PG&E further objects that these requests are unduly burdensome and do not allow sufficient time for response, in that EPUC sought a response in two business days.

3. These responses are made without waiving PG&E's rights to raise all issues regarding relevance, materiality, privilege, or admissibility in evidence in any proceeding. PG&E also reserves the right to amend or modify its proposed plan of reorganization filed on January 31, 2020 (PG&E's Plan).[1] PG&E reserves the right, but does not obligate itself, to amend these responses as needed should the PG&E Plan or the scope of these proceedings change.

4. PG&E incorporates each of these General Objections into each of its responses below. Each of PG&E's responses below is provided subject to and without waiver of the foregoing objections and any additional objections made below.

[1] Unless otherwise indicated, capitalized terms herein have the meanings set forth in PG&E's Plan.

Concerning PG&E's January 31, 2020 Testimony, Volume 1, Chapter 3 addressing PG&E's ability to raise capital post-emergence from bankruptcy:

QUESTION 1

Please provide a detailed and complete description of all efforts that PG&E Utility and the Holding Company plan to make in order to reduce debt used to fund costs associated with wildfire damage claims, and bankruptcy filings. Please describe the period of time over which PG&E anticipates it will attempt to pay off the special debt taken on for these purposes, e.g., "between June 2020 through December 2020."

ANSWER 1

PG&E objects to this request on the grounds that it is overbroad and unduly burdensome, and could potentially encompass all financial-related aspects of the company's operations. PG&E further objects to this request to the extent that it is vague and ambiguous, including in its use of the phrase "special debt." PG&E assumes for purposes of this response that the phrase "special debt" refers to the $6 billion Temporary Utility debt. Subject to its objections, PG&E responds as follows:

PG&E refers EPUC to Chapter 2 of its January 31, 2020 testimony in this proceeding, which describes the $6 billion Temporary Utility debt to be paid by shareholders and PG&E's plans to retire that debt.

QUESTION 2

Please explain whether or not debt taken on to fund wildfire damage claims or bankruptcy costs will be recorded on the balance sheet of the Utility and/or the Holding Company. Please provide a detailed explanation of why the restructured company chooses to record this non-recurring debt on either the Utility balance sheet or the parent balance sheet.

ANSWER 2

PG&E objects to this request to the extent that it is vague and ambiguous, and misleading to the extent that it implies that "non-recurring" debt should not be recorded on a company's balance sheet. Subject to its objections, PG&E responds as follows:

This debt will be recorded on the balance sheets according to generally accepted accounting principles (GAAP). PG&E is in the process of finalizing financial information corresponding to PG&E's Plan, financial results for 2019, and financial projections associated with its updated business plan. PG&E will provide further information as soon as it is reasonably available, which is anticipated to be this week.

QUESTION 3

Concerning pages 3-2 and 3-3 of the January 31, 2020 testimony, please provide a complete copy of all presentations made to Moody's and to Standard & Poor's concerning the post-exit from bankruptcy plan of PG&E Utility and the Holding Company concerning business risk, financial risk, ability to issue secured debt, and the proposed structure and affordability to customers through the use of securitization bonds.

ANSWER 3

PG&E objects to this request on the grounds that it is vague and ambiguous as framed. Subject to its objections, PG&E responds as follows:

PG&E has not yet made presentations to Moody's or Standard & Poor's that reflect PG&E's Plan. PG&E is in the process of finalizing financial projections associated with its updated business plan and will provide updated projections as soon as they are reasonably available, which is anticipated to be this week. Those updated projections will serve as the basis for future presentations to credit rating agencies.

QUESTION 4

Concerning pages 3-7 and 3-8 of the January 31, 2020 testimony, please provide the development of the credit metrics using Moody's methodology for PG&E's post-bankruptcy exit and those produced for Southern California Edison and San Diego Gas & Electric.

Please also provide the Moody's benchmarks which can be used to judge the strength or weaknesses of credit metric projections for PG&E.

ANSWER 4

PG&E objects to this request to the extent that it is vague and ambiguous. PG&E further objects to this request to the extent that it seeks material nonpublic financial information (the use and selective disclosure of which is prohibited by securities laws), material that is in the process of being updated, or material protected from disclosure under the attorney work product doctrine or other applicable privileges or protections from disclosure. Subject to its objections, PG&E responds as follows:

PG&E is in the process of finalizing financial projections associated with its updated business plan and will provide updated projections as soon as they are reasonably available, which is anticipated to be this week. Production of preliminary materials at this stage would be potentially misleading, would be an early selective disclosure of material information, and would be unduly burdensome, irrelevant and imprudent in light of the imminent finalization of company projections.

With respect to documents reflecting Moody's benchmarks, PG&E refers EPUC to the documents provided in response to Question 1 in TURN's eighth set of data requests.

Concerning PG&E's January 31, 2020 Testimony, Volume 1:

QUESTION 5

With respect to Chapter 5, "Utility Safety and Governance," please provide the five-year projected capital expenditure budget for PG&E Utility electric operations and gas operations, and note the components of the five-year capital expenditures which are made in order to remain in compliance with state safety and operating excellence standards, and independent oversight of safety and risk measures. For all capital programs, please note whether or not PG&E has a timeline commitment for implementing the capital expenditures program to improve safety and responsiveness of their infrastructure to protect the public.

Please include an excel spreadsheet with native formulas intact.

ANSWER 5

PG&E objects to this request on the grounds that it is overbroad, unduly burdensome, and vague and ambiguous. Subject to its objections, PG&E responds as follows:

PG&E is in the process of finalizing financial information corresponding to PG&E's Plan, financial results for 2019, and financial projections associated with its updated business plan. PG&E will provide responsive information as soon as it is reasonably available, which is anticipated to be this week.

QUESTION 6

Concerning Chapter 10, page 10-3, PG&E asserts that as a result of AB 1054, its plan for post-emergence exit from bankruptcy and participation in the wildfire fund will result in rate impacts on customers being neutral, on average, to the ratepayers of the electrical corporation. Please provide a complete identification of the rates by rate tariff currently in effect which are not impacted by wildfire damage claims and/or bankruptcy costs, that will be used to determine rate neutrality under the Company's post-emergence from bankruptcy plan.

ANSWER 6

PG&E objects to this request on the grounds that it is overbroad, vague and ambiguous, and beyond the scope of this proceeding to the extent it purports to include post-emergence rate impacts beyond those resulting from PG&E's Plan. Subject to its objections, PG&E responds as follows:

AB 1054 requires that the reorganization plan and other documents resolving the insolvency proceeding are neutral, on average, to ratepayers. Therefore, PG&E's analysis has appropriately focused on the rate impacts resulting from PG&E's Plan, and the baseline is rates in the normal course of ratemaking proceedings, independent of PG&E's Plan. PG&E's Plan does not by its terms provide for any rate recovery from ratepayers, and in fact the anticipated Cost of Capital update following PG&E's emergence from bankruptcy will reflect a net savings for ratepayers associated with the significant interest cost savings created by PG&E's Plan. Accordingly, PG&E has determined that its Plan does not require ratepayers to pay more in rates than they would pay in the absence of PG&E's reorganization under the terms of PG&E's Plan. Given the nature of PG&E's Plan, this determination does not require further analysis of the rates that ratepayers would pay in the absence of PG&E's reorganization under the terms of PG&E's Plan. With respect to the interest cost savings created by PG&E's Plan, PG&E refers EPUC to PlanOfReorganizationOII-2019_DR_CLECA_01-Q02_Chapter 2 debt savings calc.xlsx, provided in response to CLECA's first set of data requests. PG&E will provide an estimate of its updated cost of debt on emergence from bankruptcy pursuant to PG&E's Plan, with reference to estimated revenue requirement debt financing-related savings for 2021.

QUESTION 7

Please state whether or not there are any wildfire damage costs or bankruptcy costs included in PG&E's currently effective rates to retail customers. Please identify all components of such costs, and explain why they are included in the existing rate structure.

ANSWER 7

PG&E objects to this request to the extent that it is overbroad and vague and ambiguous, including in its use of the terms "wildfire damage costs" and "bankruptcy costs." Subject to its objections, PG&E responds as follows:

To the extent "wildfire damage costs" refers to Fire Claims as defined in PG&E's Plan, currently effective customer rates do not include Fire Claims costs. PG&E is willing to meet and confer with EPUC regarding any additional information sought by this request.

Attachment N

PG&E Response to TURN's Seventh Set of Data Requests (dated February 7, 2019)

PACIFIC GAS AND ELECTRIC COMPANY
Plan of Reorganization OII – 2019
Investigation 19-09-016
Data Response

PG&E Data Request No.:	TURN_007-Q01-Q08		
PG&E File Name:	PlanOfReorganizationOII-2019_DR_TURN_007-Q01-Q08		
Request Date:	February 3, 2020	Requester DR No.:	007
Date Sent:	February 7, 2020	Requesting Party:	The Utility Reform Network
PG&E Witness:	Various	Requester:	Thomas Long

<u>GENERAL STATEMENT AND OBJECTIONS</u>

1. PG&E objects to each request to the extent it seeks information protected from disclosure by the attorney-client privilege, the attorney work-product doctrine, or any other privilege or protection from disclosure. PG&E intends to invoke all such privileges and protections, and any inadvertent disclosure of privileged or protected information shall not give rise to a waiver of any such privilege or protection. PG&E further objects to the data requests to the extent they seek material nonpublic financial information (the use and selective disclosure of which is prohibited by securities laws).

2. PG&E objects to the data requests to the extent that they are overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. PG&E further objects to these requests as unduly burdensome in that TURN seeks a response in four business days, rather than five business days per the procedures in this proceeding.

3. These responses are made without waiving PG&E's rights to raise all issues regarding relevance, materiality, privilege, or admissibility in evidence in any proceeding. PG&E also reserves the right to amend or modify its proposed plan of reorganization filed in this proceeding on January 31, 2020 (PG&E's Plan).[1] PG&E reserves the right, but does not obligate itself, to amend these responses as needed should PG&E's Plan or the scope of these proceedings change.

4. PG&E incorporates each of these General Objections into each of its responses below. Each of PG&E's responses below is provided subject to and without waiver of the foregoing objections and any additional objections made below.

SUBJECT: RATE NEUTRALITY

[1] Unless otherwise indicated, capitalized terms herein have the meanings set forth in PG&E's Plan.

QUESTION 1

Please state whether PG&E's proposed implementation of AB 1054's "neutral, on average" requirement includes each of the following commitments:

a. PG&E will not seek rate recovery at any time after the emergence from bankruptcy of any costs paid to resolve liability claims resulting from the 2017 and 2018 wildfires.

b. PG&E will not seek rate recovery at any time after the emergence from bankruptcy of any costs that PG&E may pay to resolve liability claims resulting from 2019 wildfires.

c. PG&E will not seek rate recovery at any time after the emergence from bankruptcy of any costs paid to professionals (attorneys, financial consultants, etc.) related to the Utility's or Corporation's bankruptcy, including bankruptcy-related costs incurred prior to the filing of the bankruptcy petitions.

d. PG&E will not seek rate recovery at any time after the emergence from bankruptcy of any financing-related fees or costs (including but not limited to hedging costs) related to the Utility's or Corporation's bankruptcy, including bankruptcy-related fees or costs incurred prior to the filing of the bankruptcy petitions (including but not limited to debtor-in-possession financing).

Please provide a separate answer for each of the above items a. through d. If the answer is anything other than an unequivocal affirmative that the stated commitment is included in PG&E's implementation of the requirement, please provide a detailed explanation of: PG&E's position regarding the stated commitment; PG&E's intentions related to seeking rate recovery of the costs in question; and all reasons for PG&E's position.

ANSWER 1

PG&E objects to this request to the extent that it is vague, overbroad, unduly burdensome, and seeks information beyond the scope of this proceeding. Subject to its objections, PG&E responds as follows:

a. PG&E does not believe such a commitment is necessary to comply with AB 1054's "neutral, on average" requirement because just and reasonable costs paid to resolve liability claims resulting from the 2017 and 2018 wildfires could be recovered in rates in the normal course, independent of PG&E's Plan. With respect to PG&E's Plan, PG&E has not made a determination as to whether it would seek to recover such costs following emergence.

b. PG&E does not believe such a commitment is necessary to comply with AB 1054's "neutral, on average" requirement because just and reasonable costs paid to resolve liability claims resulting from 2019 wildfires could be recovered in rates in the normal course, independent of PG&E's Plan.

c. PG&E does not believe such a commitment is necessary to comply with AB 1054's "neutral, on average" requirement, to the extent the total amount of bankruptcy-related costs PG&E seeks to recover is less than or equal to the interest cost savings. PG&E has not made a determination as to whether or to what extent it would seek to recover the costs paid to professionals related to the Chapter 11 Cases.

d. PG&E does not believe such a commitment is necessary to comply with AB 1054's "neutral, on average" requirement, to the extent the total amount of bankruptcy-related costs PG&E seeks to recover is less than or equal to the interest cost savings. PG&E seeks to recover certain financing-related fees and costs, including Noteholder RSA fees, hedging costs, Utility bridge fees, and other related costs. PG&E proposes to implement this cost recovery via an advice letter updating PG&E's authorized cost of debt within 30 days of the Effective Date of PG&E's Plan, which will effect a net savings for customers.

QUESTION 2

Please state whether PG&E's proposed implementation of AB 1054's "neutral, on average" requirement includes each of the following commitments:

a. For ratemaking purposes, PG&E will record below-the-line or otherwise not include in base costs used for forecasting purposes any costs paid to resolve liability claims resulting the 2017 and 2018 wildfires.

b. For ratemaking purposes, PG&E will record below-the-line or otherwise not include in base costs used for forecasting purposes any costs that PG&E may pay to resolve liability claims resulting from 2019 wildfires.

c. For ratemaking purposes, PG&E will record below-the-line or otherwise not include in base costs used for forecasting purposes any costs paid to professionals (attorneys, financial consultants, etc.) related to the Utility's or Corporation's bankruptcy, including bankruptcy-related costs incurred prior to the filing of the bankruptcy petitions.

d. For ratemaking purposes, PG&E will record below-the-line or otherwise not include in base costs used for forecasting purposes any financing-related fees or costs (including but not limited to hedging costs) related to the Utility's or Corporation's bankruptcy, including bankruptcy-related fees or costs incurred prior to the filing of the bankruptcy petitions (including but not limited to debtor-in-possession financing).

Please provide a separate answer for each of the above items a. through d. If the answer is anything other than an unequivocal affirmative that the stated commitment is included in PG&E's implementation of the requirement, please provide a detailed explanation of: PG&E's position regarding the stated commitment; PG&E's intentions related to ratemaking treatment of the costs in question; and all reasons for PG&E's

position.

ANSWER 2

PG&E refers TURN to its objections and responses to Question 1 above

QUESTION 3

With respect to the sentence in PG&E's January 31, 2020 testimony on page 10-3, lines 17-21 that states, "Likewise, changes in rates that occur as a result of other Commission decisions after PG&E's emergence from bankruptcy, and independent of the Plan, including prudence review, are not relevant to Section 3292(d)(1)(D) because they are not rate changes resulting from the Plan.":

a. Please explain in detail what PG&E means by "prudence review" in this context. Please also identify each such "prudence review" (whether pending or upcoming) that PG&E has in mind in this context.

b. Please explain in detail what PG&E means by "independent of the Plan" in this context.

c. Please describe any and all circumstances by which a post-emergence prudence review related to a *pre*-emergence PG&E-caused wildfire event could lead to an increase in rates.

d. Please describe any and all circumstances by which a post-emergence prudence review related to a *post*-emergence PG&E-caused wildfire event could lead to an increase in rates.

e. Please describe any and all circumstances by which a post-emergence prudence review related to professional costs and fees, or financing-related costs and fees could lead to an increase in rates.

ANSWER 3

PG&E objects to this request on the grounds that it is overbroad, unduly burdensome, and vague and ambiguous. Subject to its objections, PG&E responds as follows: "[P]rudence review" means the review of costs for reasonableness performed by the Commission in ratemaking proceedings pursuant to Public Utilities Code section 451. In this context, "prudence review" means any such review that might occur in the future following PG&E's emergence from bankruptcy. "[I]ndependent of the Plan" means rate changes that could occur independent of the reorganization plan and other documents resolving the bankruptcy proceeding. There are any number of circumstances under which the Commission could engage in a post-emergence prudence review of costs related to pre- or post-emergence wildfire events, or of professional costs and fees or financing-related costs. To the extent the Commission determines that costs were prudently incurred, it may authorize the recovery of those costs in rates.

QUESTION 4

The document titled “PG&E Corporation, Evercore ISI Utility Conference” and dated January 9-10, 2020, is found at the following link:

> http://s1.q4cdn.com/880135780/files/doc_presentations/2020/Evercore-ISIPresentation_FINAL_010720.pdf

Page 3 of the Appendix to that document contains the following text as the third bullet under the heading “PG&E Pre-Emergence Wildfire Liabilities: “May seek payment for claims after funding initial contribution”

> a. Please explain what was meant by this bullet.
>
> b. Please explain any and all circumstances under which PG&E, after emergence from bankruptcy, would reserve the opportunity to seek payment from ratepayers for wildfire claims it has paid.

ANSWER 4

PG&E objects to this request to the extent it is overbroad, unduly burdensome, and vague and ambiguous. Subject to its objections, PG&E responds as follows:

> a. PG&E was indicating in this bullet that, if the Utility is eligible to participate in the Wildfire Fund created under AB 1054, it may seek reimbursement from the Wildfire Fund for eligible amounts related to “covered wildfires,” i.e., Utility equipment-caused wildfires that ignited on or after July 12, 2019.
>
> b. Decision 18-06-029 authorized PG&E to establish and record in a Wildfire Expense Memorandum Account (WEMA), among other things, “payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expense paid by PG&E . . ..” The WEMA thus reserves the opportunity to seek cost recovery. PG&E further responds that this question is entirely hypothetical and speculative. PG&E has not made a determination that it will seek to recover wildfire claims costs recorded in the WEMA, nor has it defined the circumstances upon which it would make such a determination. PG&E further notes that in inquiring about “all circumstances” regarding potential payments, post-emergence, for unspecified wildfire claims, the request is speculative and beyond the scope of this proceeding. PG&E further refers TURN to its response to Question 1 above.

QUESTION 5

With respect to the sentence in PG&E’s January 31, 2020 testimony on page 10-2, lines 7-12 that includes the statement that “ . . . PG&E will refinance a portion of its prepetition debt, at lower interest rates, and the Plan therefore will yield approximately $1 billion in savings associated with lower interest expenses on long term debt . . .”:

a. Does the reference to $1 billion refer to *annual* savings?

b. Is PG&E saying that this reduced cost will translate into rate reductions? If so, explain in detail how rate reductions would happen.

c. Please provide all workpapers associated with the calculation of the $1 billion in savings, including all relevant assumptions

ANSWER 5

a. No.

b. Yes. Following emergence from bankruptcy, PG&E intends to update its cost of debt for Cost of Capital purposes to incorporate the costs of its exit financing and lower debt costs resulting from PG&E's Plan. PG&E anticipates the Commission would review and approve in principle the adjustments to the cost of debt as part of this proceeding, including the interest rate savings created by the Plan and offsets consisting of certain bankruptcy-related costs PG&E seeks to recover. Given the total of the bankruptcy-related costs PG&E seeks to recover is significantly less than the interest cost savings created by PG&E's Plan, the net result is a savings for ratepayers. Within 30 days of the Effective Date of PG&E's Plan, PG&E proposes to submit an advice letter to update its cost of debt for Cost of Capital purposes, which would be lower than the cost of debt currently authorized and therefore translate into rate reductions.

c. PG&E refers TURN to PlanOfReorganizationOII-2019_DR_CLECA_01-Q02_Chapter 2 debt savings calc.xlsx, provided in response to CLECA's first set of data requests.

QUESTION 6

With respect to the sentence in PG&E's January 31, 2020 testimony on page 10-3, lines 14-17 that states, "Moreover, changes in rates that occur as a result of Commission decisions in proceedings such as cost of capital … are not relevant to Section 3292(d)(a)(D) because they are not rate changes resulting from the Plan."

a. Does PG&E dispute that its bankruptcy may have an effect on its cost of capital going forward? If the answer is anything other than an unqualified negative, please explain in detail the basis for PG&E believing that its cost of capital going forward would not be affected by its bankruptcy.

b. Please describe the nexus there would need to be between changes in rates that occur from Commission decisions and PG&E's Plan for PG&E to deem the rate changes as "changes resulting from the Plan."

ANSWER 6

PG&E objects to this request to the extent that it is overbroad and vague and ambiguous. Subject to its objections, PG&E responds as follows:

> a. As set forth in PG&E's response to Question 5.b. above, PG&E proposes to update its cost of debt for Cost of Capital purposes following its emergence from bankruptcy. Mr. Kenney simply means to convey that Cost of Capital and General Rate Case proceedings proceed in the normal course independent of PG&E's bankruptcy proceeding.
>
> b. If the changes in rates reflect costs the Utility would not have incurred independent of PG&E's Plan and are of a type the Utility would not be entitled to recover in the normal course, they would be "rate changes resulting from the Plan" that would be evaluated pursuant to Section 3292(d)(1)(D).

QUESTION 7

PG&E's January 31, 2020 testimony on page 10-3, lines 6-8, states that, "The Plan of Reorganization is neutral, on average, to ratepayers, if the Plan by its terms does not require ratepayers to pay more in rates than they would in the absence of PG&E's reorganization under the terms of PG&E's Plan." Please provide a narrative that explains in detail how PG&E determines the rates that ratepayers would pay "in the absence of PG&E's reorganization under the terms of PG&E's Plan."

ANSWER 7

PG&E objects to this request as overbroad, unduly burdensome, and vague and ambiguous. Subject to its objections, PG&E responds as follows: AB 1054 requires that the reorganization plan and other documents resolving the insolvency proceeding are neutral, on average, to ratepayers. Therefore, PG&E's analysis has appropriately focused on the rate impacts resulting from PG&E's Plan. PG&E's Plan does not by its terms provide for any rate recovery from ratepayers, and in fact the anticipated Cost of Capital update following PG&E's emergence from bankruptcy will reflect a net savings for ratepayers associated with the significant interest cost savings created by PG&E's Plan. Accordingly, PG&E has determined that its Plan does not require ratepayers to pay more in rates than they would pay in the absence of PG&E's reorganization under the terms of PG&E's Plan. Given the nature of PG&E's Plan, this determination does not require a determination of the rates that ratepayers would pay in the absence of PG&E's reorganization under the terms of PG&E's Plan. PG&E further refers TURN to its response to Question 1 above.

QUESTION 8

PG&E's January 31, 2020 testimony on page 10-2, lines 4-7, includes the phrase, "...relative to the rates that would have been in effect absent PG&E's reorganization under the PG&E Plan." Please provide a narrative that explains in detail how PG&E determines the rates that "would have been in effect absent PG&E's reorganization under the terms of PG&E's Plan."

ANSWER 8

See objections and response to Question 7 above.

Attachment O

PG&E Response to CLECA's First Set of Data Requests, Question 2, Attachment 1 (dated February 4, 2020)

High Coupon Senior Note Exchange Savings

Pacific Gas and Electric Company
Senior Notes (Long-Term)

<u>Bond Series</u>	**Amount**	**Coupon**
High Coupon		
6.35% due 2038	$400,000,000	6.350%
6.25% due 2039	$550,000,000	6.250%
6.05% due 2034	$3,000,000,000	6.050%
5.80% due 2037	$950,000,000	5.800%
5.40% due 2040	$800,000,000	5.400%
5.125% due 2043	$500,000,000	5.125%
Total	**$6,200,000,000**	
Weighted Average Coupon	**5.89%**	
Exchanged Bonds		
$3.1B 10-year	$3,100,000,000	4.550%
$3.1B 30-year	$3,100,000,000	4.950%
Total	**$6,200,000,000**	
Weighted Average Coupon	**4.75%**	
<u>Savings Calculation</u>		
Principal Amount Exchanged	$6,200,000,000	
Pre-Exchange Weighted Average Coupon	5.89%	
Post-Exchange Weighted Average Coupon	4.75%	
Annual Interest Savings	$70,700,000	
Duration of Savings (Years)	20	
Total Nominal Interest Savings	$1,414,000,000	
2020 Present Value of Interest Savings, Discounted at 4.75%	**$942,811,069**	

Attachment P

Interest rate savings calculations

Alternative assumptions for PG&E's interest rate savings calculation

PG&E's Calculation

PG&E's Response to CLECA's First Set of Data Requests, Question 1, Attachment 1, February 4, 2020

High Coupon Senior Note Exchange Savings

Pacific Gas and Electric Company

Senior Notes (Long-Term)

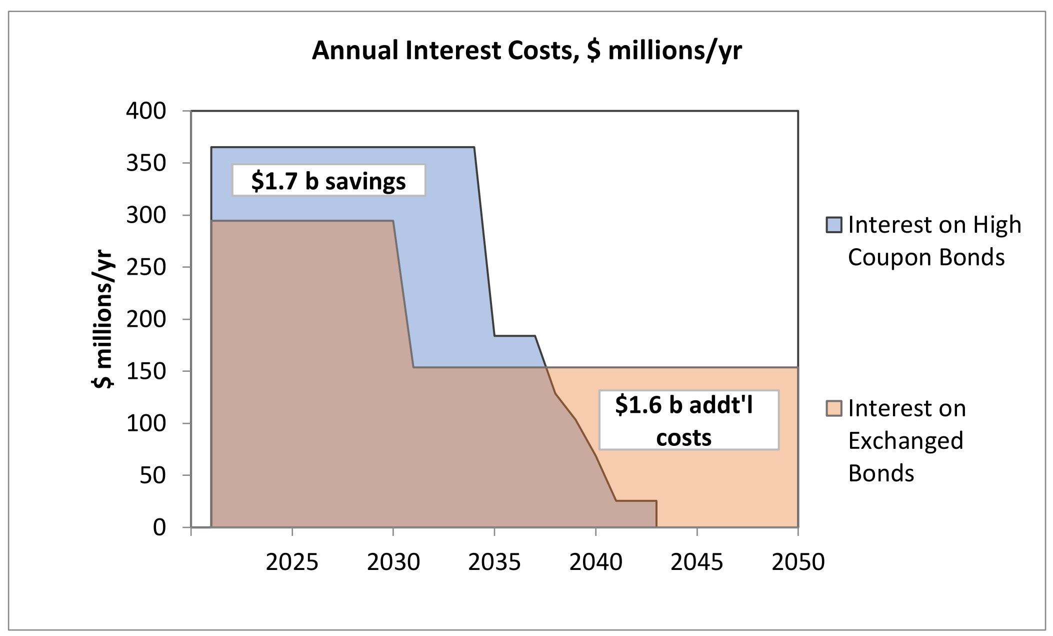
Bond Series	Amount	Coupon	Term Remaining
High Coupon Bonds			
6.35% due 2038	$400,000,000	6.350%	18
6.25% due 2039	$550,000,000	6.250%	19
6.05% due 2034	$3,000,000,000	6.050%	14
5.80% due 2037	$950,000,000	5.800%	17
5.40% due 2040	$800,000,000	5.400%	20
5.125% due 2043	$500,000,000	5.125%	23
Total	**$6,200,000,000**		
Weighted Average Coupon	**5.89%**		**16.66**
Exchanged Bonds			
$3.1B 10-year	$3,100,000,000	4.550%	
$3.1B 30-year	$3,100,000,000	4.950%	
Total	**$6,200,000,000**		
Weighted Average Coupon	**4.75%**		
Savings Calculation			
Principal Amount Exchanged	$6,200,000,000		
Pre-Exchange Weighted Average Coupon	5.89%		
Post-Exchange Weighted Average Coupon	4.75%		
Annual Interest Savings	$70,700,000		
Duration of Savings (Years)	20		
Total Nominal Interest Savings	$1,414,000,000		
2020 Present Value of Interest Savings, Discounted at 4.75%	**$942,811,069**		

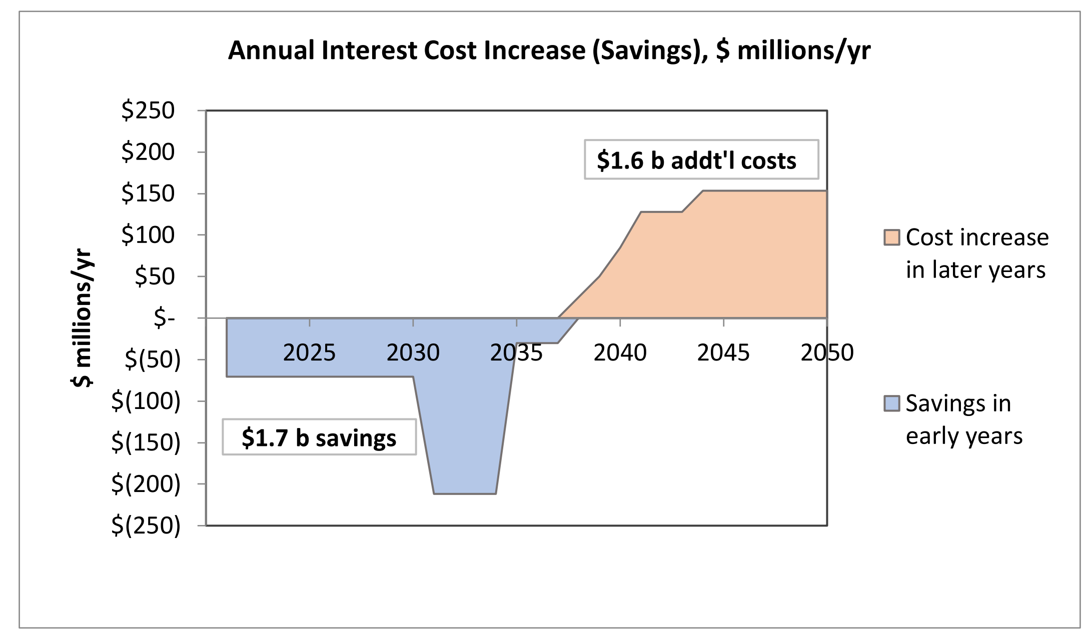
at alternative discount rates, and duration equal to wtd avg years to maturity, old bonds:

new coupon	4.75%	**$839,526,837**	-11%
weighted average years to maturity	16.66		
old coupon	5.89%	**$781,211,614**	-17%
weighted average years to maturity	16.66		
currently authorized return on rate base (D.19-12-056)	7.81%	**$697,154,296**	-26%
weighted average years to maturity	16.66		
currently authorized return on equity	10.25%	**$610,835,281**	-35%
weighted average years to maturity	16.66		
currently authorized return on equity	10.25%	**$652,436,592**	-31%
weighted average years to maturity	20.00		

High Coupon Bonds and Exchanged Bonds, Interest Cost Comparison

$ in millions			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Bonds exchanged on 1-1-2021			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Bond Series	Principal Amount	Interest Rate																
Interest on High Coupon Bonds																		
6.35% due 2038	$400	6.350%	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25
6.25% due 2039	$550	6.250%	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34
6.05% due 2034	$3,000	6.050%	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182		
5.80% due 2037	$950	5.800%	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55
5.40% due 2040	$800	5.400%	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43
5.125% due 2043	$500	5.125%	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26
Total	$6,200		$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$184	$184
Interest on Exchanged Bonds																		
$3.1B 10-year	$3,100	4.550%	$141	$141	$141	$141	$141	$141	$141	$141	$141	$141						
$3.1B 30-year	$3,100	4.950%	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153
Total	$6,200		$295	$295	$295	$295	$295	$295	$295	$295	$295	$295	$153	$153	$153	$153	$153	$153
Increase (Savings)			($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($212)	($212)	($212)	($212)	($30)	($30)
Savings in early years	$1.7 b savings		($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($212)	($212)	($212)	($212)	($30)	($30)
Cost increase in later years	$1.6 b addt'l costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Nominal total, 30 years ($ millions)	($27)																	
		@																
Discounted total, 30 years ($ millions)	($559)	4.75%																
	($566)	5.00%																
	($583)	6.00%																
	($588)	7.00%																
	($583)	8.00%																
	($572)	9.00%																
	($557)	10.00%																
	($539)	11.00%																
	($520)	12.00%																
	($500)	13.00%																
	($480)	14.00%																
	($460)	15.00%																
	($440)	16.00%																





ATTACHMENT P. INTEREST RATE SAVINGS CALCULATIONS CCSF-Meal Testir

High Coupon Bonds and Exchanged Bonds, Interest Cost Comparison

$ in millions			17	18	19	20	21	22	23	24	25	26	27	28	29	30
Bonds exchanged on 1-1-2021			2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Bond Series	Principal Amount	Interest Rate														
Interest on High Coupon Bonds																
6.35% due 2038	$400	6.350%	$25	$25												
6.25% due 2039	$550	6.250%	$34	$34	$34											
6.05% due 2034	$3,000	6.050%														
5.80% due 2037	$950	5.800%	$55													
5.40% due 2040	$800	5.400%	$43	$43	$43	$43										
5.125% due 2043	$500	5.125%	$26	$26	$26	$26	$26	$26	$26							
Total	$6,200		$184	$129	$103	$69	$26	$26	$26	$0	$0	$0	$0	$0	$0	$0
Interest on Exchanged Bonds																
$3.1B 10-year	$3,100	4.550%														
$3.1B 30-year	$3,100	4.950%	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153
Total	$6,200		$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153
Increase (Savings)			($30)	$25	$50	$85	$128	$128	$128	$153	$153	$153	$153	$153	$153	$153
Savings in early years	$1.7 b savings		($30)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost increase in later years	$1.6 b addt'l costs		$0	$25	$50	$85	$128	$128	$128	$153	$153	$153	$153	$153	$153	$153
Nominal total, 30 years ($ millions)	($27)															
		@														
Discounted total, 30 years ($ millions)	($559)	4.75%														
	($566)	5.00%														
	($583)	6.00%														
	($588)	7.00%														
	($583)	8.00%														
	($572)	9.00%														
	($557)	10.00%														
	($539)	11.00%														
	($520)	12.00%														
	($500)	13.00%														
	($480)	14.00%														
	($460)	15.00%														
	($440)	16.00%														

Attachment Q

PG&E Response to TURN's Nineteenth Set of Data Requests (dated February 19, 2020)

PACIFIC GAS AND ELECTRIC COMPANY
Plan of Reorganization OII – 2019
Investigation 19-09-016
Data Response

PG&E Data Request No.:	TURN_019-Q01		
PG&E File Name:	PlanOfReorganizationOII-2019_DR_TURN_019-Q01		
Request Date:	February 13, 2020	Requester DR No.:	019
Date Sent:	February 19, 2020	Requesting Party:	The Utility Reform Network
PG&E Witness:	Various	Requester:	Tom Long

Pacific Gas and Electric Company ("PG&E") submits the following objections and responses to the nineteenth set of data requests of The Utility Reform Network ("TURN"), served on February 13, 2020.

GENERAL OBJECTIONS

1. PG&E objects to each request to the extent it seeks information protected from disclosure by the attorney-client privilege, the attorney work-product doctrine, mediation and settlement protections, or any other privilege or protection from disclosure. PG&E intends to invoke all such privileges and protections, and any inadvertent disclosure of privileged or protected information shall not give rise to a waiver of any such privilege or protection. PG&E further objects to the data requests to the extent they seek material nonpublic financial information (the use and selective disclosure of which is prohibited by securities laws).

2. PG&E objects to the data requests to the extent that they are overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. PG&E further objects to these requests as unduly burdensome in that TURN seeks a response in two business days, rather than five business days per the procedures in this proceeding.

3. These responses are made without waiving PG&E's rights to raise all issues regarding relevance, materiality, privilege, or admissibility in evidence in any proceeding. PG&E also reserves the right to amend or modify its proposed plan of reorganization filed in this proceeding on January 31, 2020 (PG&E's Plan).[1] PG&E reserves the right, but does not obligate itself, to amend these responses as needed should the PG&E Plan or the scope of these proceedings change.

4. PG&E incorporates each of these General Objections into each of its responses below. Each of PG&E's responses below is provided subject to and without waiver of the foregoing objections and any additional objections made below.

[1] Unless otherwise indicated, capitalized terms herein have the meanings set forth in PG&E's Plan.

QUESTION 1

In the “Chapter 2 debt savings calc” spreadsheet PG&E provided as part of its response to CLECA Data Request 1, Question 2, the utility used a 4.75% discount rate to determine the 2020 present value of interest savings.

a) Please explain the basis for choosing the 4.75% discount rate for purposes of PG&E’s calculation of present value of interest savings.

b) Is the $942.8 million 2020 present value figure in this table intended to represent the present value to PG&E’s customers of the interest rate savings? If PG&E’s response is anything other than an unqualified affirmative, please explain what the 2020 present value figure is intended to represent.

c) Does PG&E believe that a 4.75% discount rate is a reasonable discount rate to use to reflect the time-value of money to PG&E’s customers? Please explain the basis for the answer.

d) Has PG&E used a 4.75% discount rate in the past for purposes of reflecting the time-value of money to PG&E’s customers when calculating the present value of costs or savings over a period of time? If so, please identify each time PG&E has so used this figure in the period from 2010-2019. If PG&E believes it would be unduly burdensome to provide all such examples, please provide the most recent five times PG&E has so used this figure in the period from 2010-2019.

e) Has PG&E used its authorized rate of return in the past for purposes of reflecting the time-value of money to PG&E’s customers when calculating the present value of costs or savings over a period of time? If so, please identify each time PG&E has so used this figure in the period from 2010-2019. If PG&E believes it would be unduly burdensome to provide all such examples, please provide the most recent five times PG&E has so used this figure in the period from 2010-2019.

ANSWER 1

PG&E objects to this request to the extent that it is overbroad, unduly burdensome, and vague and ambiguous. PG&E further objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, the attorney work-product doctrine, mediation and settlement protections, or any other privilege or protection from disclosure. Subject to its objections, PG&E responds as follows:

a. The discount rate of 4.75% is the same as the weighted cost of the new debt because that represents the risk adjusted cost of capital for new debt capital. *See, e.g.*, Brealey and Myers “Principles of Corporate Finance”, pp. 47-48, Fifth Edition.

b. The $942.8 million estimate is from the perspective of PG&E because this represents the risk adjusted cost of secured debt capital for PG&E.

c. No. When estimating changes in revenue requirements to PG&E's customers, a reasonable discount rate is PG&E's Commission-adopted return on rate base.

d. PG&E is not aware of any past instances in which it has used a debt discount rate to value changes in the revenue requirement.

e. Generally PG&E uses the authorized costs of debt, equity, and capital structure to calculate a discount rate for purposes of valuing changes in the revenue requirement to customers. The Commission has often used authorized return on rate base as a discount rate to evaluate cost-effectiveness. *E.g.*, D.09-05-037 and D.05-12-040.

Attachment R

Statement of Governor Gavin Newsom Regarding Debtors' Motion Pursuant to 11 U.S.C. §§ 363(b) and 105(a) and Fed. R. Bankr. P. 6004 and 9019 for Entry of an Order (I) Authorizing the Debtors and TCC to Enter into Restructuring Support Agreement with the TCC, Consenting Fire Claimant Professionals, and Shareholder Proponents, and (II) Granting Related Relief (Docket #5138 of the U.S. Bankruptcy Court, District of Northern California, Case 19-30088) (December 16, 2019)

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UNITED STATES BANKRUPTCY COURT

NORTHERN DISTRICT OF CALIFORNIA

SAN FRANCISCO DIVISION

In re: PG&E CORPORATION, -and- PACIFIC GAS & ELECTRIC COMPANY, Debtors.	Case No. 19-30088 (DM) Chapter 11 Lead Case (Jointly Administered) **STATEMENT OF GOVERNOR GAVIN NEWSOM REGARDING DEBTORS' MOTION PURSUANT TO 11 U.S.C. §§ 363(B) AND 105(A) AND FED. R. BANKR. P. 6004 AND 9019 FOR ENTRY OF AN ORDER (I) AUTHORIZING THE DEBTORS AND TCC TO ENTER INTO RESTRUCTURING SUPPORT AGREEMENT WITH THE TCC, CONSENTING FIRE CLAIMANT PROFESSIONALS, AND SHAREHOLDER PROPONENTS, AND (II) GRANTING RELATED RELIEF** **[Docket No. 5038]**
☐ Affects PG&E Corporation ☐ Affects Pacific Gas & Electric Company ☒ Affects both Debtors **All papers shall be filed in the Lead Case, No. 19-30088 (DM)*	Date: December 17, 2019 Time: 10:00 a.m. (Pacific Time) Place: United States Bankruptcy Court Courtroom 17, 16th Floor San Francisco, CA 94102

Governor Gavin Newsom, by and through his counsel, O'Melveny & Myers LLP, respectfully submits this statement (the "**Statement**") regarding *Debtors' Motion Pursuant to 11 U.S.C. §§ 363(b) and 105(a) and Fed. R. Bankr. P. 6004 and 9019 for Entry of an Order (I) Authorizing the Debtors and TCC to Enter into Restructuring Support Agreement with the TCC, Consenting Fire Claimant Professionals, and Shareholder Proponents, and (II) Granting Related Relief* [Docket No. 5038] (the "**TCC RSA Motion**").[1] Governor Newsom files this Statement in his official capacity as Governor of the State of California, but not on behalf of any agency, department, unit or entity of the State of California.[2] In support of this Statement, Governor Newsom respectfully states as follows:

1. Catastrophic wildfires fueled by climate change, decades of mismanagement by PG&E, and a challenging regulatory environment destabilized the investor-owned utility sector and contributed to the filing of these Chapter 11 Cases in January. In Assembly Bill 1054 (Holden, Chapter 79, Statutes of 2019) ("**AB 1054**"), the state stepped in to address those issues and assure Californians access to safe, reliable, and affordable power. AB 1054 provided the Debtors with the tools to resolve the Chapter 11 Cases, but <u>only</u> if the reorganized company could meet California's goals. AB 1054 is clear that the Debtors can benefit from the wildfire fund only if they also meet the obligations to the people of California that come with the right to operate within the state.

2. The wildfire fund established in AB 1054 is critical to the Debtors having a path to a feasible plan. Any resolution of these cases requires not only confirmation of a plan by the Bankruptcy Court, but also approval by the California Public Utilities Commission. To that end, AB 1054 requires real, durable, and transformational changes to the governance and operation of the utility, and a flexible capital structure that allows for billions of dollars in safety investments and grid upgrades. These reforms are not optional, but instead are the core of the compact set forth in AB 1054.

---

[1] Capitalized terms used but not defined herein have the meaning given to such terms in the TCC RSA Motion.

[2] The Attorney General has appeared in these proceedings on behalf of certain agencies and departments of the State of California. The Governor does not take a position in this pleading on any issues raised in any filing by the Attorney General related to the TCC RSA Motion.

3. On December 13, 2019, Governor Newsom informed the Debtors that the Amended Plan and related restructuring transactions provided therein do not, in his judgment, comply with AB 1054. The Amended Plan does not result in a reorganized entity positioned to meet the compact of providing safe, reliable, and affordable service to its customers. A copy of the December 13, 2019 letter is attached hereto as Exhibit A.

4. These concerns are not new. Throughout the fall, the Governor, through his advisors and staff, raised concerns that the Debtors' proposed plan of reorganization did not meet the requirements of AB 1054.[3] Yet the Debtors have continued to push forward—first with the motion to approve the restructuring support agreement entered into with the Consenting Subrogation Claimholders (the "**Subro RSA**") [Docket No. 3992], and now with the TCC RSA Motion.

5. Progress toward fair treatment of victims is good. And, in principle, settlements between the Debtors and other creditors move these chapter 11 cases toward timely resolution. Unfortunately, the Tort Claimants RSA contains provisions limiting competition and precluding the TCC and Consenting Fire Claimant Professionals from supporting any other competing plan of reorganization—even one that provides identical treatment of the fire victims' claims. That type of "progress" is more about creating an illusion of momentum than it is about advancing the Chapter 11 Cases. Any feasible plan of reorganization must start with a plan anchored in providing safe, reliable, and affordable power to Californians as required by AB 1054.

6. These Chapter 11 Cases are unique. Without AB 1054, the Debtors have no path to a feasible plan. Further, it is unclear whether the Debtors have sufficient value under the Amended Plan to pay claims in full, make required payments to participate in the wildfire fund, and exit bankruptcy with the necessary fiscal capacity to meet the requirements of AB 1054. As a result, the Debtors must meet their fiduciary obligations, allow all potential plan proponents to benefit from the various restructuring support agreements proposed in these Chapter 11 Cases, and focus on ensuring that the plan that is ultimately presented to this Bankruptcy Court for confirmation complies with AB 1054.

[3] To be clear, the Alternative Plan also does not meet AB 1054.

7. Therefore, to the extent the proposed settlement proceeds, the Bankruptcy Court should require amendments that allow the TCC and Consenting Fire Claim Professionals to support any alternative restructuring, or deem the Fire Victim Claims unimpaired, provided those claims receive the value set forth in the Tort Claimants RSA.

Dated: December 16, 2019

O'MELVENY & MYERS LLP

By: */s/ Jacob T. Beiswenger*

JACOB T. BEISWENGER

By: */s/ Nancy A. Mitchell*

NANCY A. MITCHELL (*pro hac vice*)
PETER FRIEDMAN (*pro hac vice*)
MATTHEW HINKER (*pro hac vice*)

Attorneys for Governor Gavin Newsom

EXHIBIT A

OFFICE OF THE GOVERNOR

December 13, 2019

William D. Johnson
Chief Executive Officer
PG&E Corporation
77 Beale Street
San Francisco, CA 94177

RE: Draft Amended Plan of Reorganization for PG&E Corporation ("Corp") and Pacific Gas and Electric Company (the "Utility" and, collectively with Corp, "PG&E") dated as of December 6, 2019 (the "Amended Plan")

Dear Mr. Johnson:

Since the day PG&E decided to file for bankruptcy protection, I have been clear about the state's objectives. Californians must have access to safe, reliable, and affordable service. Victims and employees must be treated fairly. And California must continue to make forward progress on our climate change goals. These objectives were codified into law in Assembly Bill 1054 (Holden, Chapter 79, Statutes of 2019) and must be satisfied as part of any emergence from bankruptcy.

To facilitate an expeditious resolution of the chapter 11 cases that achieves the state's objectives, my office has undertaken a review of the Amended Plan and the materials submitted in support of such plan to determine whether, in my sole judgment, the Amended Plan and the restructuring transactions contemplated therein comply with AB 1054. I appreciate the efforts of the management team to provide my office information to assist in that review.

I have determined that the Amended Plan and the restructuring transactions contemplated therein do not comply with AB 1054. In my judgment, the Amended Plan and the restructuring transactions do not result in a reorganized company positioned to provide safe, reliable, and affordable service to its customers, as required by AB 1054.

PG&E's chapter 11 cases punctuate more than two decades of mismanagement, misconduct, and failed efforts to improve its safety culture. PG&E caused the devastating San Bruno gas pipeline explosion, which killed 8 people, caused 58 injuries, and destroyed approximately 38 homes. PG&E has caused multiple catastrophic wildfires in the last three years, including the Camp Fire, which we know killed 85 people, destroyed the town of Paradise and resulted in billions of dollars in economic losses to the region.

PG&E's recent management of the public safety power shutoffs did not restore public confidence. Instead, PG&E caused extreme uncertainty and harm for Californians who rely on power for their health care and for their livelihoods. For too long, PG&E has been mismanaged, failed to make adequate investments in fire safety and fire prevention, and neglected critical infrastructure. PG&E has simply violated the public trust.

It is against this backdrop that compliance with AB 1054 must be measured. To access the state's wildfire fund, AB 1054 requires:

- PG&E to resolve its insolvency proceeding by June 30, 2020;

- The bankruptcy court to determine that the plan of reorganization fairly satisfies pre-petition wildfire claims;

- The California Public Utilities Commission (the "CPUC") to determine that the reorganization plan and other documents are consistent with the state's climate goals and neutral, on average, to ratepayers; and

- The CPUC to determine that the plan of reorganization, other plan documents, and the resulting governance structure be acceptable to the CPUC taking into account PG&E's safety history, criminal probation, recent financial condition, and other relevant factors in order for the reorganized company to access the wildfire fund.

The CPUC's review of the plan of reorganization is not a rubber stamp – it is a critical component of AB 1054.

To be approved under AB 1054, any plan of reorganization must position the emerging new entity for transformation. Such plan should include stringent governance and management requirements, enforcement mechanisms, and a capital structure that allows the company to make critical safety investments. In addition to the feedback set forth below, my team will provide your advisors with additional information to further clarify my views on specific features of the plan.

Governance and Management Requirements

The resolution of this bankruptcy must yield a radically restructured and transformed utility that is responsible and accountable. To that end, my office previously informed you that any acceptable plan under AB 1054 must provide for major changes in governance and incorporate enforcement mechanisms. PG&E has failed to address most of the issues we previously raised on governance.

The governance and enforcement mechanisms that I believe are necessary include the following:

1. Changes that will result in a more qualified and independent board of directors that understands its obligation to achieve the goals of AB 1054. A transformed company should be governed by a board of directors selected based on a pre-determined set of qualifications, include members with extensive safety experience, and be comprised of a majority of Californians. To facilitate transformation, the board that will lead the reorganized company should be acceptable to me and approved by the CPUC and identified in the Amended Plan. I do not expect that the post-confirmation board of directors will include the current directors.

2. Strict, clearly defined operational and safety metrics to which the reorganized company will be held accountable.

3. An escalating enforcement process that provides for greater oversight of the reorganized company if it fails to meet the defined operational and safety metrics. Because of this company's history, the license to operate should be conditioned on it agreeing to this process. This should also include a streamlined process for transferring the license and the operating assets to the state or a third-party when circumstances warrant.

4. Escalating enforcement should include governance changes that protect California in the event that the reorganized company fails to meet the operational and safety metrics or commits other bad acts including a subsequent bankruptcy filing.

The Amended Plan does not incorporate any mechanisms to address these issues. Thus, I believe the Amended Plan falls woefully short of the requirements of AB 1054.

The Amended Plan must provide, as a non-waivable condition, that the confirmation order is entered by June 30, 2020 and the effective date occur by August 29, 2020. In the event either of these dates are not met, the Bankruptcy Court should appoint a chapter 11 trustee acceptable to the CPUC to manage the debtors and dispose of their assets and/or operations.

Capital Structure

To achieve safe and reliable service and make critical safety and infrastructure investments, the emerging company's capital structure must be stable, flexible, and position the company to attract long-term capital. Based on the financial information provided by PG&E, the reorganized company would not compare favorably to its peers on critical financial metrics. The Amended Plan also leaves the company with limited ability to withstand future financial and operational headwinds.

These issues arise, in part, because the Amended Plan contemplates using a combination of holdco debt, secured debt, securitization, and monetization of the net operating losses in order to make plan distributions – leaving the reorganized entity with limited tools to finance itself when it needs to access capital to make billions of dollars in safety investments. I am also concerned that the Amended Plan relies on expensive and short-term bridge financing. All of this contributes to a reorganized company that, in my judgment, will not be positioned to provide safe, reliable, and affordable electric service.

Without providing an exhaustive list of other issues, the Amended Plan must meet the AB 1054 requirements to treat victims fairly, including providing for the assumption of any pre-petition settlement agreements related to Fire Claims including the Butte Fire settlement. The Amended Plan should also provide that all environmental obligations and related agreements, all obligations and agreements related to the Diablo Canyon project, and all state tax obligations be assumed by the reorganized entity and be unimpaired.

The state remains focused on meeting the needs of Californians including fair treatment of victims – not on which Wall Street financial interests fund an exit from bankruptcy.

PG&E's current plan is not feasible without access to the wildfire fund established under AB 1054. PG&E's board of directors and management have a responsibility to immediately develop a feasible plan. Anything else is irresponsible, a breach of fiduciary duties, and a clear violation of the public trust.

Sincerely,

Gavin Newsom
Governor of California

Attachment S

I.15-08-019, Assigned Commissioner's Scoping Memo and Ruling (December 21, 2018)

MP6/eg3 12/21/2018

FILED
12/21/18
03:51 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	Investigation 15-08-019

ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

Summary

This Scoping Memo and Ruling (Ruling) sets forth the scope to be addressed and the schedule for the next phase of this proceeding, consistent with the Order Instituting Investigation and the prior Scoping Memo in this proceeding. This Ruling builds on this Commission's Decision (D.) 18-11-050 adopting the recommendations of the NorthStar Report and directing Pacific Gas and Electric Company (PG&E) to implement the recommendations as adopted in the decision.

1. Principles

Continuous, safe, and reliable gas and electric service at just and reasonable rates must be provided to Northern California in order to protect human life and sustain prosperity. The Commission's examination of PG&E's

safety culture accordingly continues in this proceeding. The Commission will examine PG&E's and PG&E Corporation's (PG&E Corp.) current corporate governance, structure, and operations to determine if the utility is positioned to provide safe electrical and gas service, and will review alternatives to the current management and operational structures of providing electric and gas service in Northern California.

As the Commission evaluates proposed alternatives, it will consider a range of factors, including:

- the safety and reliability of utility service;
- the operational integrity and technical unity of components within PG&E's gas and electric transmission and distribution systems;
- the stability and adequacy of the utility workforce;
- the utility's relationships with and role in local communities;
- the ability of the state to implement its energy policies, including the need to reduce greenhouse gas (GHG) emissions and local criteria pollutants in both the utility sector and the economy as a whole;
- the ability of the utility to meet financial challenges posed by large catastrophic events such as earthquakes and wildfires;
- the utility's ability to raise capital and purchase gas, electricity, equipment and services; and
- the cost of utility service.

Careful consideration is also necessary to determine whether there is a viable transition process from the status quo to any preferred alternative. If there is not a clear path forward to implement an alternative (including consideration of legal, financial, and technical grid issues), then the alternative will not be considered a viable option in this proceeding.

The future of PG&E may also be impacted by other actors beyond the Commission. The Legislature, the court appointed Federal Monitor, the various courts considering claims against PG&E, the Federal Energy Regulatory Commission, and the communities served by PG&E all have a role in determining PG&E's future. As a publicly traded company, PG&E must also respond to the financial markets, and to the requirements of the vendors and other parties with which it conducts business.

The Commission has not drawn any conclusions about the outcome of this proceeding and recognizes these other actors may be the origin of proposals for consideration. The Commission undertakes this next phase of this proceeding in a thoughtful and deliberate manner, consistent with the importance of the issues being addressed.

2. Background

PG&E has had serious safety problems with both its gas and electric operations for many years. The following examples illustrate both the types of safety incidents PG&E has experienced and the remedial consequences imposed by this Commission and several courts.

On September 9, 2010, a PG&E natural gas transmission pipeline ruptured in San Bruno. The event is well detailed in a Commission decision:

> At 6:11 p.m. on September 9, 2010, Segment 180 of Line 132, a 30-inch diameter natural gas transmission pipeline owned and operated by PG&E, ruptured in the Crestmoor neighborhood of San Bruno, California. Gas escaping from the rupture

> ignited. There was an explosion of such tremendous force that a crater approximately 72 feet long by 26 feet wide was created. A 28-foot long section of pipe weighing about 3,000 pounds was blown approximately 100 feet from the crater. The conflagration continued for over an hour and a half, releasing 47.6 million cubic feet of flammable natural gas before the flow was stopped. It required the response of 600 firefighting (including emergency medical service) personnel and 325 law enforcement personnel.
>
> The resulting deaths, injuries, and damage to property were especially severe […].
>
> The Crestmoor neighborhood was effectively wiped off the map. An entire community was displaced.[1]

PG&E faced historically significant administrative penalties and fines and criminal punishment as a result of the San Bruno explosion. This Commission imposed a fine and other penalties on PG&E totaling $1.6 billion.[2] PG&E was also found guilty by a federal jury of federal criminal conduct, specifically multiple willful violations of the Natural Gas Pipeline Safety Act of 1968 and of obstructing an agency proceeding.[3] As part of PG&E's sentence in the federal criminal proceeding, it was required to submit to a federal monitor for compliance and ethics.[4] In November 2018, Judge William Alsup, who was

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[1] D.15-04-023 at 3-4.

[2] D.15-04-024 at 2.

[3] Case No. CR-14-00175-THE; *see also* Press Release, Department of Justice, U.S. Attorney's Office, Northern District of California, dated August 9, 2016, available at: https://www.justice.gov/usao-ndca/pr/pge-found-guilty-obstruction-agency-proceeding-and-multiple-violations-natural-gas.

[4] Case No. CR-14-00175-THE, Order dated January 26, 2017. In February 2017, Mark Filip was selected as the Compliance and Ethics Monitor of PG&E for a period of five years.

assigned the PG&E federal criminal manner, directed PG&E to respond by December 31, 2018, to questions regarding the Camp Fire, which occurred in November 2018.

On June 19, 2012, a PG&E subcontractor was killed during demolition of PG&E's decommissioned Kern Power Plant. As part of a settlement of the subsequent Commission Order Instituting Investigation (OII), PG&E was required to implement, on a company-wide basis, a Corrective Action Plan that included a Contractor Safety Program and an Enterprise Causal Evaluation Standard, and pay penalties totaling $5,569,313.[5]

On August 18, 2016, the Commission imposed penalties on PG&E of $25,626,000 in response to six incidents from 2010 through 2014 that called into question the safety of PG&E's natural gas distribution system.[6] In response to the Commission's OII in that proceeding, "PG&E also set forth its efforts to enhance gas distribution system recordkeeping accuracy, accessibility, and controls, as well as operational safety improvements."[7]

On August 27, 2015, the istant OII was opened by the Commission, to examine PG&E's and PG&E Corp.'s safety culture. This Commission was, and remains, concerned that the safety problems being experienced by PG&E were not just one-off situations or bad luck, but indicated a deeper and more systemic

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[5] These penalties consist of $3,269,313 in ratemaking offsets that benefit customers and $2,300,000 in fines payable to the state's General Fund. (D.15-07-014 at 2.)

[6] D.16-08-020 at 2-4. An additional penalty of $10.8 million was imposed for the Carmel incident. (*Id*. at 10, 51.)

[7] *Id*. at 4.

problem. The fact that imposing penalties on PG&E (the Commission's standard tool for addressing safety problems) did not seem to change the situation reinforced this concern.

As the Commission stated: "[t]his investigation will…determine whether PG&E's organizational culture and governance are related to PG&E's safety incidents and performance record, and if so, to what extent; and if so, how can or should the Commission order or encourage PG&E to develop, implement, and update as necessary a safety culture of the highest order."[8] In D.18-11-050, the Commission adopted the findings of the consultant to the Safety and Enforcement Division, the Northstar Consulting Group. The report concluded that "[w]hile PG&E is committed to safety and efforts have been made to reduce incidents and increase the organizational focus on safety, these efforts have been somewhat reactionary – driven by immediate needs and an understandable sense of urgency, rather than a comprehensive enterprise-wide approach to addressing safety."[9] The failure of PG&E to develop a comprehensive enterprise -wide approach to address safety, eight years after the 2010 San Bruno pipeline explosion, is of vital concern to this Commission.

The Butte Fire, which began on September 9, 2015, burned approximately 70,000 acres of land and destroyed 921 structures, and left two civilians dead.[10]

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[8] Investigation 15-08-019, OII at 15.

[9] Northstar Report at I-1.

[10] Cal Fire Report, last modified October 15, 2015, available at http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=1221.

Footnote continued on next page

The Commission's Safety and Enforcement Division (SED) issued PG&E a citation for $8 million for violation of the CPUC's General Order 95, Rule 31.1, for failing to maintain its 12 kilovolt (kV) overhead conductors safely and properly.[11] SED also cited PG&E $300,000 for failure to timely report to the CPUC that PG&E's facilities may have been linked to the ignition of the Butte Fire and for failing to maintain the minimum required clearance between a 12 kV conductor and a tree.[12]

In the fall of both 2017 and 2018, historically large wildfires burned in PG&E's service territory. The scale of these fires set new records on almost every metric which exists to measure wildfires. Because the Commission's investigations into these fires are ongoing, the specific causes of the fires, potential enforcement actions, and PG&E's prudency related to the fires will not be addressed in this proceeding. However, the Commission will consider the fact that PG&E's service territory includes fire prone land according to the Commission's fire threat maps,[13] which is a critical safety challenge for PG&E.

On December 14, 2018, the Commission opened an OII proceeding to consider penalties and ordered immediate action against PG&E for what

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11 Citation Issued Pursuant to D.16-09-055. Available here: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/E1704001E2015091601Citation20170425.pdf.

12 Citation Issued Pursuant to D.16-09-055. Available here: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/E1704002E20150916_01Citation20170425.pdf.

13 D.17-01-009, revised by D.17-06-024.

Footnote continued on next page

Commission staff says are systemic violations of rules to prevent damage to natural gas pipelines during excavation activities.[14] The Commission directed PG&E to take immediate corrective measures and to attest under penalty of perjury that it is conducting natural gas pipeline locate and mark efforts and programs in a safe manner consistent with all applicable laws. The Commission has not prejudged the outcome of that proceeding; however, the fact that these allegations have been made are noted to provide context for the type of challenges we expect PG&E to address by adopting and maintaining a safety culture.

This Commission is tasked with regulating PG&E's safe operation of its natural gas pipeline and electricity infrastructure. Given PG&E's record and the dangers inherent in PG&E's service territory, the Commission must evaluate whether there is a better way to serve Northern California with safe and reliable electric and gas service at just and reasonable rates. This ruling identifies the scope of issues considered in the next phase of this proceeding.

3. Scope of Issues

The safe operation of PG&E's gas and electric systems and the threat of personal harm to PG&E employees and members of the public are of critical concern to the Commission and California. To address that concern and mitigate future risk, the next phase of this proceeding will consider a broad range of alternatives to current management and operational structures for providing electric and natural gas in Northern California. Accordingly, the following list of

[14] I.18-12-007.

proposals is illustrative rather than exclusive and is intended to show the range of possible alternatives under consideration. This list does not limit the Commission's potential actions or directives. The outcome of this investigation may include recommendations to other entities that have a role in ensuring safe electrical and gas service in Northern California, if a desired outcome requires action by someone other than this Commission. Parties may present other options than the ones listed below. The Commission may revise the scope of alternatives to be considered after receiving comments from parties.

This is not a punitive exercise. Indeed, the keystone question is, compared to PG&E and PG&E Corp. as presently constituted, would any of the following proposals provide Northern Californians safer gas and electric service at just and reasonable rates?

Corporate Governance – Board of Directors

- Should PG&E and PG&E Corp. be subject to a utility-specific business judgment rule (BJR) to require the Board of Directors to account for safety beyond the current fiduciary duties?[15] If so, should such a utility-specific business judgment rule apply to corporate officers as well?
- Should the PG&E Board of Directors regularly file with the Commission a report of how the Board met its duties under the BJR to account for safety? Should this include a summary of the oversight exercised by the Board including information reviewed, when deliberations occurred, and the depth of the review? Should the report include the Board review of the corporate officers' leadership as it pertains to safety? Should compensation to the Board

[15] *See, e.g*. California Corporations Code § 309 and *Gaillard v. Natomas Co.*, 208 Cal. App. 3d 1250 (1989).

Members be dependent on a Commission finding that the Board members discharged their safety duties appropriately?

- Should PG&E form an independent nominating committee to identify and select candidates for the Board of Directors?
- Should PG&E identify specific criteria for potential Board of Directors members? For example, should PG&E have one or more Board of Directors members be experts in organizational safety, gas safety, and/or electrical safety? If so, should the appointment of safety experts be made subject to Commission or Governor approval?
- Should PG&E form an audit committee constituted of independent directors possessing financial and safety competence, as defined by the Commission, to evaluate the Board of Directors' discharge of their duties and make recommendations for qualifications of future members of PG&E's Board of Directors?
- The Securities and Exchange Commission requires publicly traded companies to file an 8-K Form when a material event occurs. Generally, an event is material if there is a substantial likelihood that a reasonable investor would consider the information important in making an investment decision. Should PG&E file an analogous safety report with the Commission when PG&E makes a significant decision regarding capital expenditures pertaining to safety, a change in management as it pertains to safety, or any other decision that may impact safety?
- Should PG&E file a public annual report of all Directors and Officers insurance policies obtained by PG&E and identify the risk PG&E identified to obtain the insurance? If PG&E amends its Directors and Officers insurance, should it notify the Commission of the risk identified and the terms of the amended policy?

- Should part or all of the existing Board of Directors resign and be replaced by directors with a stronger background and focus on safety?

Corporate Management – Officers and Senior Leadership

- Should PG&E retain new corporate management in all or in part?
- Should the questions posed above for Corporate Governance be similarly considered for corporate management?
- Should compensation for non-officer executives be modified? Does the current incentive structure properly incent PG&E decision-makers?[16]

Corporate Structure

- Should PG&E's gas and electric distribution and transmission divisions be separated into separate companies? If so, should the separate companies be controlled by a holding company? Should the holding company be a regulated utility?
- Should PG&E's corporate structure be reorganized with regional subsidiaries based on regional distinctions? For example, PG&E could be divided into multiple smaller utilities operating under a single parent company. If so, should such a reorganization apply to both gas and electric services? Do the physical characteristics of the gas and electric systems lend themselves to the same regional structure, or do the physical characteristics of the respective systems lend themselves to different regional structures?

[16] Senate Bill 901 (Dodd) prohibits an electrical or gas corporation from recovering any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of the corporation, from ratepayers.

- Should the Commission revoke holding company authorization, so PG&E is exclusively a regulated utility? Should all affiliates and subsidiaries be spun off or incorporated into the regulated utility?
- Should the Commission form a standing working group with the union leadership of PG&E to identify the safety concerns of PG&E staff?

Publicly Owned Utility, Cooperative, Community Choice Aggregation or other Models

- Should some or all of PG&E be reconstituted as a publicly owned utility or utilities?
- Should PG&E be a "wires-only company" that only provides electric distribution and transmission services with other entities providing generation services? If so, what entities should provide generation services?

Return On Equity

- Should the Commission condition PG&E's return on equity on safety performance?
- What are the safety considerations for the utility if its financial status is downgraded by the investment community?

Other Proposals

- What other measures should be taken to ensure PG&E satisfies its obligation to provide safe service?

4. Comments

Parties should make preliminary comments on the desirability of these alternatives with discussion of how each proposal impacts the following considerations:

- the safety and reliability of utility service;

- the operational integrity and technical unity of components within PG&E's gas and electric transmission and distribution systems;
- the stability and adequacy of the utility workforce;
- the utility's relationships with and role in local communities;
- the ability of the state to implement its energy policies, including the need to reduce GHG emissions and local criteria pollutants in both the utility sector and the economy as a whole;
- the ability of the utility to meet financial challenges posed by large catastrophic events such as earthquakes and wildfires;
- the utility's ability to raise capital and purchase gas, electricity, equipment and services; and
- the cost of utility service.

In addition, the parties shall make initial observations on the legal, technical, and financial feasibility of these proposals and include observations on the feasibility of transitioning from the current utility structure to proposed alternatives. Parties may also offer additional proposals with consideration given to the same factors and feasibility concerns. Parties may also comment on scope and process recommendations.

For ease of reference, parties' comments shall follow the same format provided in this ruling. Specifically, parties shall comment on proposals in the following sequence: Corporate Governance, Corporate Management, Corporate Structure, Public Utility or Cooperative, Return on Equity, and Other Proposals. Opening comments are limited to 40 pages. Reply comments are limited to 20 pages.

To better inform this proceeding, on or before January 16, 2019, PG&E is also directed to file a summary of:

- PG&E's and PG&E Corp.'s corporate structures, including organizational charts for the respective Board of Directors, executives, and other senior leadership as of September 1, 2010, and as of December 31, 2018. The summary should also explain the different lines of business of PG&E and PG&E Corp.
- The senior positions in PG&E and PG&E Corp. responsible for management of safety, and how the different roles interact.

After review of comments filed by parties, the Commission will identify the best process to consider proposals and identify concerns that require additional filings from parties.

5. Schedule

The next step for this Commission is to obtain input on the various possible approaches to address the underlying issue of PG&E's safety culture. The Commission needs to have more information and analysis from a range of perspectives before it can consider implementation of any particular approach, or even select any approach to consider in more detail. Accordingly, the schedule set forth below is limited to the filing and service of party comments on the issues identified above.

The following schedule is adopted:

PG&E and PG&E Corp. Background Filing	January 16, 2019
Concurrent Opening Comments filed and served	January 30, 2019
Concurrent Reply Comments filed and served	February 13, 2019

This schedule may be modified by the assigned Commissioner or Administrative Law Judge (ALJ) as necessary. Once comments are received, the assigned Commissioner and ALJ will determine the next procedural steps to take.

6. Presiding Officer

In the interest of judicial efficiency, ALJ Peter V. Allen is designated as the Presiding Officer in this phase of the proceeding.

7. Public Category of Proceeding/*Ex Parte* Restrictions

As stated in the original scoping memo issued on May 8, 2017, this proceeding is categorized as ratesetting. With the change in presiding officer, the voluntary *ex parte* prohibition previously imposed by the assigned Commissioner is lifted, and will not apply to this phase of the proceeding. The Commission's rules regarding *ex parte* communications in ratesetting proceedings remain in place. Accordingly, *ex parte* communications are restricted and must be reported pursuant to Article 8 of the Commission's Rules of Practice and Procedure.

8. Advisor

Any person interested in participating in this proceeding who is unfamiliar with the Commission's procedures or has questions about the electronic filing procedures is encouraged to obtain more information at http://consumers.cpuc.ca.gov/pao/ or contact the Commission's Public Advisor at 866-849-8390 or 415-703-2074 or 866-836-7825 (TYY), or send an e-mail to public.advisor@cpuc.ca.gov.

IT IS RULED that:

1. The scope of this proceeding is described above.

2. The schedule of this proceeding is as set forth above.

3. Administrative Law Judge Peter V. Allen is designated as the presiding officer for this phase of the proceeding.

4. Page limitations for opening and reply comments are as set forth above.

Dated December 21, 2018, at San Francisco, California.

/s/ MICHAEL PICKER

Michael Picker
Assigned Commissioner

Attachment T

Meal Reply Testimony Workpaper

Utility / PG&E Corp Sources & Uses, 1/31/20 PG&E Testimony, Table 2-1			
Sources		**Uses**	
<u>Equity Capital</u>		DIP Facility	$ 2,000
Proceeds from Equity Issuance	$ 9,000	Trade Payable & Other Claims	2,300
Equity to Fire Victims Trust	6,750	Pre-Petition PG&E Corp. Debt	650
Total Equity Capital	**15,750**	Pre-Petition Utility Debt	21,530
<u>New Utility Debt</u>		Accrued Interest	1,270
Refinancing of Pollution Control Bonds	100	Fire Claims	24,150
Noteholder RSA Debt	11,850	Wildfire Fund Contributions	5,000
Additional Debt Issued by Utility	5,825	Cash	750
Temporary Utility Debt	6,000		
Total New Utility Debt	**23,775**		
New PG&E Corporation Debt	4,750		
Reinstated Utility Notes	9,575		
Insurance Proceeds	2,200		
Cash	1,600		
Total PG&E Sources	**$ 57,650**	**Total PG&E Uses**	**$ 57,650**

Memo:

An additional $1.35 billion in deferred payments to the Fire Victim Trust not included in the above sources & uses

ATTACHMENT B. LEVERAGE DETAIL CCSF-Meal Testimony 02-21-20

Debt Relative to Rate Base
($ millions)

PG&E Opening Testimony 1-31-20, Table 2-1 and as noted	10-K 12/31/2016	10-Q 9/30/2017	10-K 12/31/2017	10-K 12/31/2018	Pre-Emergence Amount	Emergence Adjustment	Post-Emergence (5) Incl. Temp Debt	Post-Emergence (5) Excl. Temp Debt	
Pacific Gas & Electric Company ("Utility")									
Pre-Petition Utility Debt [1] [2]	$ 18,088	$ 17,839	$ 18,647	$ 21,344	20,668	(20,668)	-	-	
Pollution Control Bonds[3]	incl	incl	incl	incl	862	(762)	100	100	
Reinstated Utility Senior Secured Notes [1]	-	-	-	-	-	9,575	9,575	9,575	
Noteholder RSA Debt [1]	-	-	-	-	-	11,850	11,850	11,850	
DIP Facility[1]					2,000	(2,000)	-	-	
Incremental Debt at Utility[1]					-	**5,825**	5,825	5,825	
Temporary Utility Debt[1]					-	**6,000**	6,000	-	
Total Utility Debt	**$ 18,088**	**$ 17,839**	**$ 18,647**	**$ 21,344**	**$ 23,530**	**$ 9,820**	**$ 33,350**	**$ 27,350**	
PG&E Corporation ("HoldCo")									
Senior Unsecured Credit Facility[1] [2]	348	349	482	650	650	$ (650)	$ -	$ -	
New HoldCo Debt[1]						**4,750**	4,750	4,750	
Total HoldCo Debt	**$ 348**	**$ 349**	**$ 482**	**$ 650**	**$ 650**	**$ 4,100**	**$ 4,750**	**$ 4,750**	
Total HoldCo & Utility Debt	**$ 18,436**	**$ 18,188**	**$ 19,129**	**$ 21,994**	**$ 24,180**	**$ 13,920**	**$ 38,100**	**$ 32,100**	
Utility Rate Base - annual average [4]	**$ 32,400**	**$ 34,400**	**$ 34,400**	**$ 36,800**	**$ 36,800**	**$ -**	**$ 45,000**	**$ 45,000**	2020 forecast
							$ 48,000	$ 48,000	2021 forecast
Leverage Metrics:									
Holdco Debt as a % of Total Debt	2%	2%	3%	3%	3%		12%	15%	
Utility Debt / Utility Rate Base [4]	**56%**	**52%**	**54%**	**58%**	64%		**74%**	**61%**	using 2020 rate base forecast
Average 2016-2018, exludes 9/31/17		56%							
							69%	57%	using 2021 rate base forecast (assumes no debt added to support rate base growth, 20-21)
Utility Debt + Hold Co Debt / Utility Rate Base [4] [5]	**57%**	**53%**	**56%**	**60%**	66%		**85%**	**71%**	using 2020 rate base forecast
Average 2016-2018, exludes 9/31/17		57%							
							79%	67%	using 2021 rate base forecast (assumes no debt added to support rate base growth, 20-21)

Footnotes
1) PG&E Opening Testimony, January 31, 2019, Table 2.1. Utility pre-petition debt = $22.18 billion of total pre-petition debt, less PCB, less debt at PG&E Corp.
2) 2016, 2017, 2018 amounts from PG&E 10-K and 10-Q.
3) Pollution Control Bonds: outstanding balance at 12-31-18, PG&E form 10-K for 2018, page 127.
4) From PG&E earnings presentations (see Rate Base tab for detail). For period-to-period leverage comparisons, Utility Rate Base is used as a proxy for Total Capital.
5) Post-emergence debt levels assume no draws on short-term credit facilities (leverage metrics would be higher to the extent the short-term credit facilities are drawn upon).

Historical and Projected Rate Base and Annual Capital Expenditures
($ millions)

$ in billions	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Notes
Weighted Average Rate Base											
Date/Source of Forecast:											
2014-Q4 Earnings Presentation	28.2	31.0	33.6								
2015 Barclay's Presentation (dashed portion is linear extrapola	28.2	29.5	33.1	35.0	37.3	39.8					
avg annual $ increase for linear extrapolation 2.3		1.3	3.6	1.9	2.3	2.5					
						39.8	42.1	44.4	46.7	49.0	linear extrapolation
2015-Q4 Earnings Presentation			32.6	34.3	36.3	38.5					
2016-Q4 Earnings Presentation			32.4	34.4	37.0	39.0					"Continue to Upgrade Our System" graphic
2017-Q2 Earnings Presentation				34.4							
2017-Q3 Earnings Presentation (prior to Oct 17 wine country fires)			32.4	34.4	37.0	39.0					same "Continue to Upgrade Our System" graphic
2018-Q1 Earnings Presentation				34.4	36.8	40.0					2017-Q4 first tax cuts and jobs act impact graphic
2018-Q2 Earnings Presentation					36.6	40.3	45.0	48.0	51.0	54.0	first cap ex graphic showing wildfire mitigation plan cap ex forecast ($900 million WMP, $200 MM other GRC and separately funded)
2018-Q4 Earnings Presentation (2/28/2019)					36.6	40.5	45.0	48.0	51.0	54.0	detail on wildfire spending, "7.8B program spend through 2023"
2019-Q1 Earnings Presentation (5/2/19)					36.8	40.5	45.0	48.0	51.0	54.0	detail on wildfire spending, "8.2B program spend through 2023"
2019-Q2 Earnings Presentation					36.8	40.5	45.0	48.0	51.0	54.0	Footnote, slide 9: PG&E is in the process of preparing a five-year financial forecast, including projected capital expenditure assumptions, in connection with the Chapter 11 proceedings. While PG&E is currently evaluating capital expenditure assumptions, amounts may materially increase from the current forecast.
Post Bankruptcy Filing 1/29/19: 2018-Q4 (2/28/2019), 2019-Q2 (8/9/19), 2019-Q3 (11/7/19) Earnings Prese					36.8	40.3	45.0	48.0	51.0	54.0	
2020-Jan9-10 Evercore ISI Utility Conference											Includes 2019-Q3 slides

2014Q4
http://s1.q4cdn.com/880135780/files/doc_presentations/2014/Earnings-Presentation-Q4-2014-Master.pdf

2015 September 8 BarclaysConference
http://investor.pgecorp.com/news-events/events-and-presentations/event-details/2015/2015-Barclays-Energy-and-Power-Conference/default.aspx

2015Q4
http://s1.q4cdn.com/880135780/files/doc_financials/2015/Q4/Earnings-Presentation-Q4-2015-FINAL.pdf

2016Q4 March 2017 Business Update
http://s1.q4cdn.com/880135780/files/doc_downloads/2018/July-2017-Business-Update.pdf

2017Q2 July 2017 Business Update
http://s1.q4cdn.com/880135780/files/doc_downloads/2018/July-2017-Business-Update.pdf

2017Q3 Nov 2017 Business Update
http://s1.q4cdn.com/880135780/files/doc_downloads/2018/November-2017-Business-Update.pdf

2017Q4 (post first major fire), and overlaps 2018Q1
http://s1.q4cdn.com/880135780/files/doc_financials/2017/Q4/Fourth-Quarter-2017-Earnings-Presentation.pdf

2018Q2 July 2018 Business Update
http://s1.q4cdn.com/880135780/files/doc_presentations/2018/July-2018-Business-Update.pdf

2018Nov5 Business Update
http://s1.q4cdn.com/880135780/files/doc_presentations/2018/Business-Update-Presentation-Q3-2018.pdf

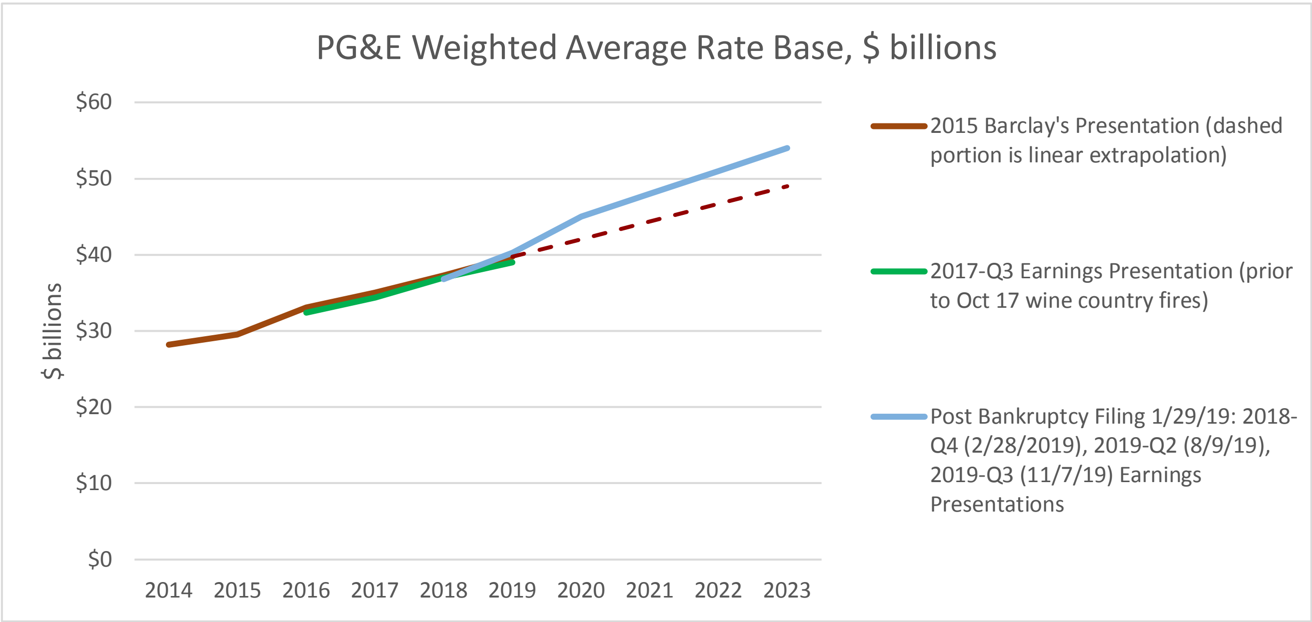
2018Q4
http://s1.q4cdn.com/880135780/files/doc_financials/2018/q4/Presentation-and-Complete-Earnings-Exhibits.pdf

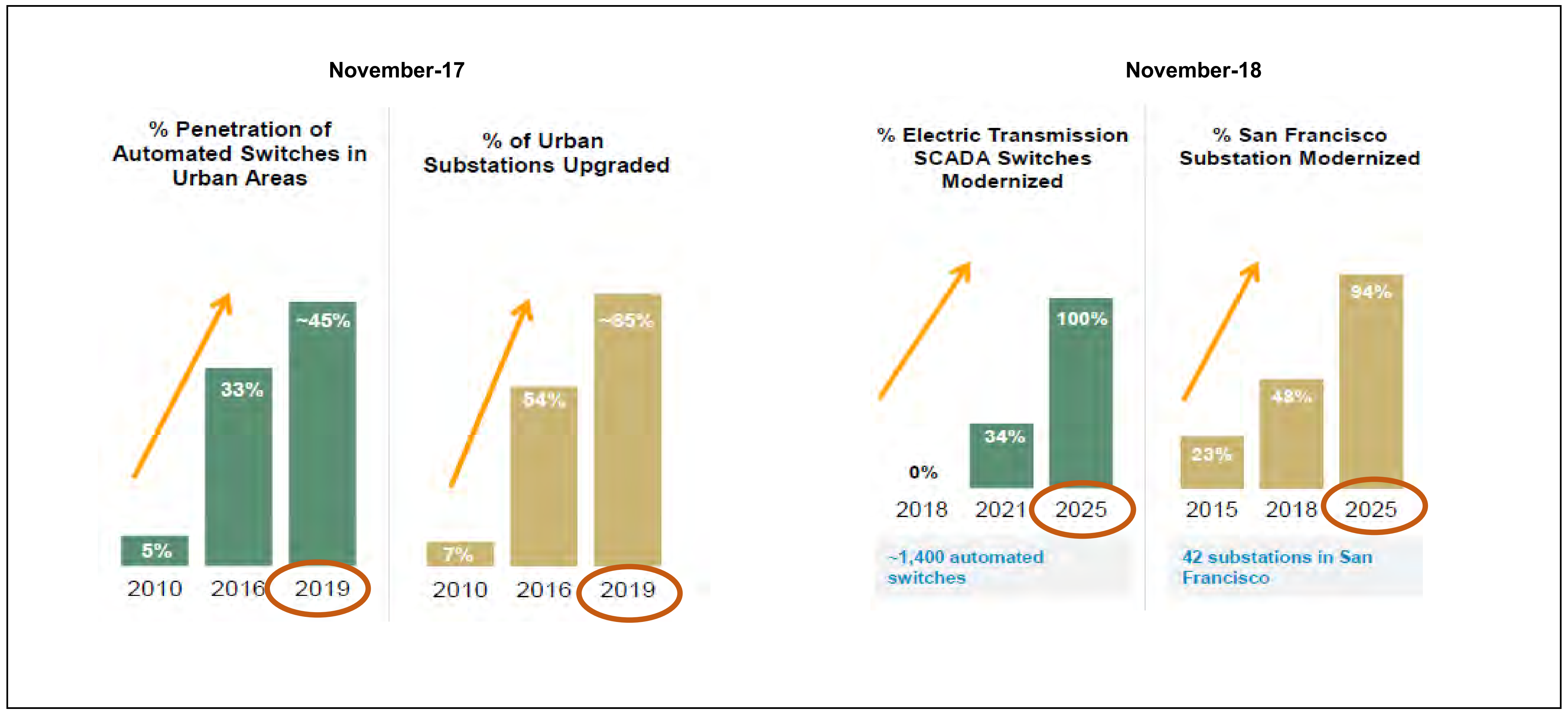
2019Q1 (presented post bankruptcy filing, May 2, 2019)
http://s1.q4cdn.com/880135780/files/doc_financials/2019/q1/Earnings-Presentation-Q1-2019_Final.pdf

2019Q2
http://s1.q4cdn.com/880135780/files/doc_financials/2019/q2/Earnings-Presentation-Q2-2019_FINAL.pdf

2019Q3
http://s1.q4cdn.com/880135780/files/doc_financials/2019/q3/update/Q319-Earnings-Presentation_FINAL.pdf

Jan 2020 Update (Evercore ISI Utility Conference)
http://s1.q4cdn.com/880135780/files/doc_presentations/2020/Evercore-ISI-Presentation_FINAL_010720.pdf


PG&E Weighted Average Rate Base, $ billions
$60
$50
$40
$30
$20
$10
$0
$ billions
2014 2015 2016 2017 2018 2019 2020 2021 2022 2023
2015 Barclay's Presentation (dashed portion is linear extrapolation)
2017-Q3 Earnings Presentation (prior to Oct 17 wine country fires)
Post Bankruptcy Filing 1/29/19: 2018-Q4 (2/28/2019), 2019-Q2 (8/9/19), 2019-Q3 (11/7/19) Earnings Presentations


November-17
% Penetration of Automated Switches in Urban Areas
5%
33%
~45%
2010 2016 2019
% of Urban Substations Upgraded
7%
54%
~85%
2010 2016 2019
November-18
% Electric Transmission SCADA Switches Modernized
0%
34%
100%
2018 2021 2025
~1,400 automated switches
% San Francisco Substation Modernized
23%
48%
94%
2015 2018 2025
42 substations in San Francisco

Alternative assumptions for PG&E's interest rate savings calculation

PG&E's Calculation

PG&E's Response to CLECA's First Set of Data Requests, Question 1, Attachment 1, February 4, 2020

High Coupon Senior Note Exchange Savings

Pacific Gas and Electric Company

Senior Notes (Long-Term)

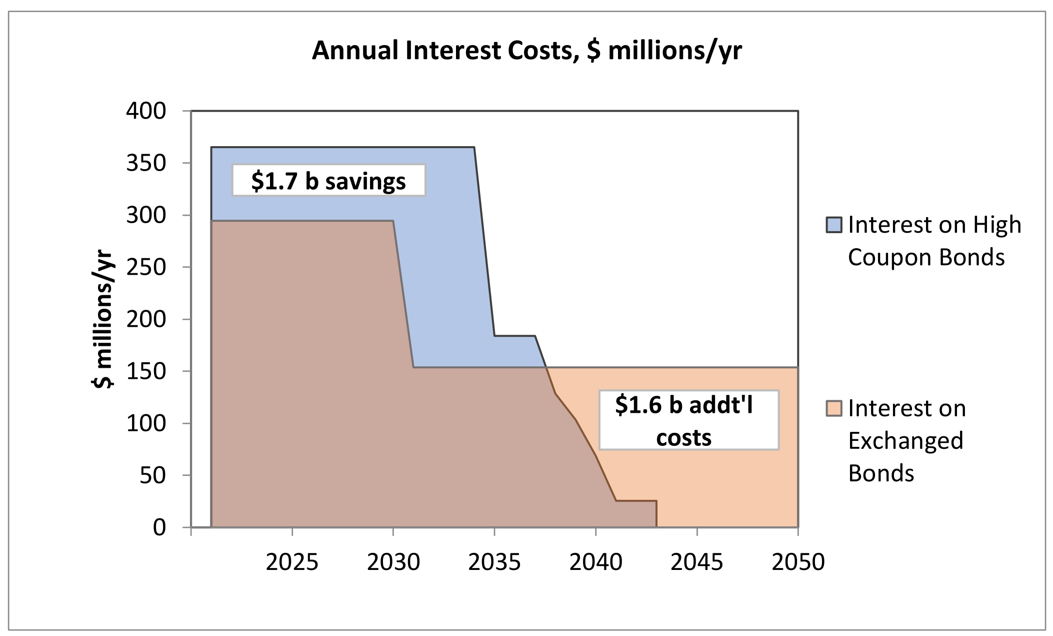
Bond Series	**Amount**	**Coupon**	**Term Remaining**
High Coupon Bonds			
6.35% due 2038	$400,000,000	6.350%	18
6.25% due 2039	$550,000,000	6.250%	19
6.05% due 2034	$3,000,000,000	6.050%	14
5.80% due 2037	$950,000,000	5.800%	17
5.40% due 2040	$800,000,000	5.400%	20
5.125% due 2043	$500,000,000	5.125%	23
Total	**$6,200,000,000**		
Weighted Average Coupon	**5.89%**		**16.66**
Exchanged Bonds			
$3.1B 10-year	$3,100,000,000	4.550%	
$3.1B 30-year	$3,100,000,000	4.950%	
Total	**$6,200,000,000**		
Weighted Average Coupon	**4.75%**		
Savings Calculation			
Principal Amount Exchanged	$6,200,000,000		
Pre-Exchange Weighted Average Coupon	5.89%		
Post-Exchange Weighted Average Coupon	4.75%		
Annual Interest Savings	$70,700,000		
Duration of Savings (Years)	20		
Total Nominal Interest Savings	$1,414,000,000		
2020 Present Value of Interest Savings, Discounted at 4.75%	**$942,811,069**		

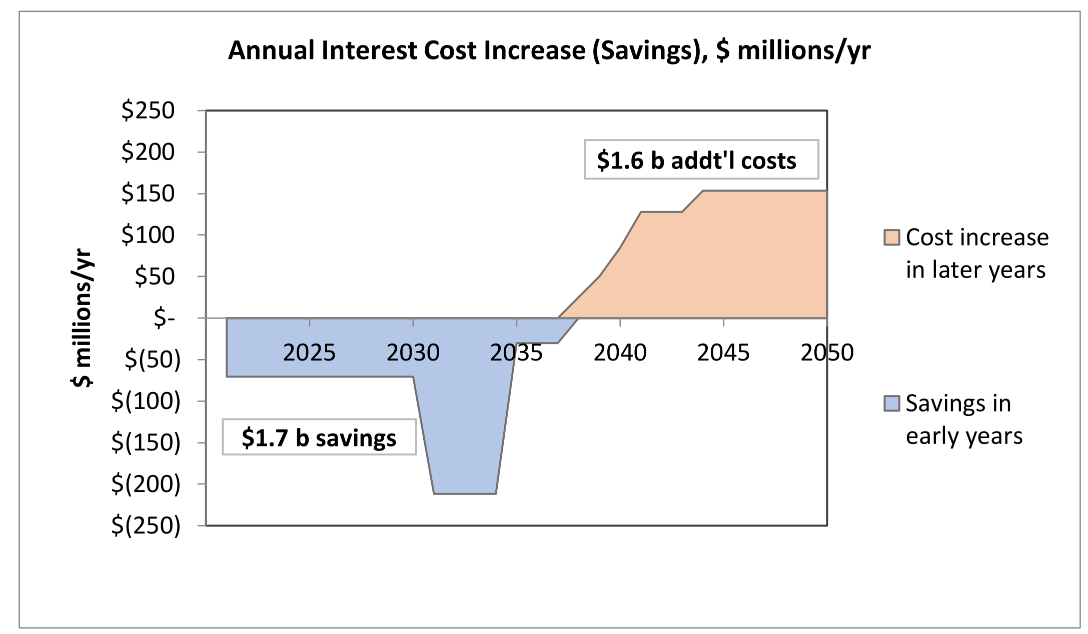
at alternative discount rates, and duration equal to wtd avg years to maturity, old bonds:

new coupon	4.75%	**$839,526,837**	-11%
weighted average years to maturity	16.66		
old coupon	5.89%	**$781,211,614**	-17%
weighted average years to maturity	16.66		
currently authorized return on rate base (D.19-12-056)	7.81%	**$697,154,296**	-26%
weighted average years to maturity	16.66		
currently authorized return on equity	10.25%	**$610,835,281**	-35%
weighted average years to maturity	16.66		
currently authorized return on equity	10.25%	**$652,436,592**	-31%
weighted average years to maturity	20.00		

High Coupon Bonds and Exchanged Bonds, Interest Cost Comparison

$ in millions			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Bonds exchanged on 1-1-2021			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Bond Series	Principal Amount	Interest Rate																
Interest on High Coupon Bonds																		
6.35% due 2038	$400	6.350%	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25
6.25% due 2039	$550	6.250%	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34	$34
6.05% due 2034	$3,000	6.050%	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182		
5.80% due 2037	$950	5.800%	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55	$55
5.40% due 2040	$800	5.400%	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43	$43
5.125% due 2043	$500	5.125%	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26
Total	$6,200		$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$365	$184	$184
Interest on Exchanged Bonds																		
$3.1B 10-year	$3,100	4.550%	$141	$141	$141	$141	$141	$141	$141	$141	$141	$141						
$3.1B 30-year	$3,100	4.950%	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153
Total	$6,200		$295	$295	$295	$295	$295	$295	$295	$295	$295	$295	$153	$153	$153	$153	$153	$153
Increase (Savings)			($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($212)	($212)	($212)	($212)	($30)	($30)
Savings in early years	$1.7 b savings		($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($71)	($212)	($212)	($212)	($212)	($30)	($30)
Cost increase in later years	$1.6 b addt'l costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Nominal total, 30 years ($ millions)	($27)																	
		@																
Discounted total, 30 years ($ millions)	($559)	4.75%																
	($566)	5.00%																
	($583)	6.00%																
	($588)	7.00%																
	($583)	8.00%																
	($572)	9.00%																
	($557)	10.00%																
	($539)	11.00%																
	($520)	12.00%																
	($500)	13.00%																
	($480)	14.00%																
	($460)	15.00%																
	($440)	16.00%																





High Coupon Bonds and Exchanged Bonds, Interest Cost Comparison

$ in millions			17	18	19	20	21	22	23	24	25	26	27	28	29	30
Bonds exchanged on 1-1-2021			2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Bond Series	Principal Amount	Interest Rate														
Interest on High Coupon Bonds																
6.35% due 2038	$400	6.350%	$25	$25												
6.25% due 2039	$550	6.250%	$34	$34	$34											
6.05% due 2034	$3,000	6.050%														
5.80% due 2037	$950	5.800%	$55													
5.40% due 2040	$800	5.400%	$43	$43	$43	$43										
5.125% due 2043	$500	5.125%	$26	$26	$26	$26	$26	$26	$26							
Total	$6,200		$184	$129	$103	$69	$26	$26	$26	$0	$0	$0	$0	$0	$0	$0
Interest on Exchanged Bonds																
$3.1B 10-year	$3,100	4.550%														
$3.1B 30-year	$3,100	4.950%	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153
Total	$6,200		$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153	$153
Increase (Savings)			($30)	$25	$50	$85	$128	$128	$128	$153	$153	$153	$153	$153	$153	$153
Savings in early years	$1.7 b savings		($30)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost increase in later years	$1.6 b addt'l costs		$0	$25	$50	$85	$128	$128	$128	$153	$153	$153	$153	$153	$153	$153
Nominal total, 30 years ($ millions)	($27)															
		@														
Discounted total, 30 years ($ millions)	($559)	4.75%														
	($566)	5.00%														
	($583)	6.00%														
	($588)	7.00%														
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