PACIFIC GAS AND ELECTRIC COMPANY

COMMENTS ON CPUC WORKING CONCEPTS IN TRANSMISSION FINANCING AND OWNERSHIP CONCEPT PAPER

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Introduction

Pacific Gas and Electric Company ("PG&E") respectfully submits these comments in response to the *Working Concepts in Transmission Financing and Ownership* Concept Paper (the "Concept Paper") issued by the California Public Utilities Commission ("CPUC" or "Commission") on March 11, 2026. PG&E appreciates the Commission's leadership in exploring approaches to support the development of needed transmission infrastructure while promoting affordability for customers. In the following sections, PG&E provides general policy comments, followed by a response to each of the questions posed in the Concept Paper.

Policy Overview

PG&E actively seeks to minimize transmission costs while continuing to provide safe and reliable service. PG&E's Simple, Affordable Model is designed to responsibly invest in a safe and reliable system while minimizing customer bill impacts by reducing operating and maintenance expenses, increasing beneficial electric load to serve new demand, lowering financing costs, and achieving other areas of savings. To provide an electric transmission-specific example, prioritizing projects that interconnect large load has the potential to reduce overall rates while building out the transmission system. Current analyses indicate that, under the right conditions, serving an additional 1 GW of new demand could reduce existing customers' monthly electric bills by 1 percent or more.[1]

PG&E supports the targeted use of public financing tools, including Department of Energy ("DOE")–style loans, in situations whereby public financing tools: (1) enable transmission projects that are unlikely to proceed absent such support; and (2) demonstrably reduce total project costs without shifting costs to other customers. In 2025, Senate Bill ("SB") 254 already took a step in this direction with the creation of the California Transmission Infrastructure Accelerator to, amongst other goals, facilitate

[1] PG&E (2026), "Rate Reducing Load Growth: Unlocking an Affordable & Sustainable Future," available at: https://autl.assembly.ca.gov/system/files/2026-01/pg-e-au-e-hearing-01.28.26-rate-reducing-load-growth-short-story-final.pdf

public financing for California Independent System Operator ("CAISO")-approved transmission projects.

PG&E recommends that the Concept Paper place the narrow issue of alternative transmission financing and ownership into the broader context of a holistic, system-wide approach to affordability. There are several areas where the Commission and legislature can support affordability objectives, including permitting, siting, and environmental review reforms that reduce development timelines and financing costs without compromising environmental or community protections.

PG&E appreciates the Commission's shared interest in ensuring that transmission policies align with California's affordability goals and deliver demonstrable value to customers. Because no single Transmission Owner controls the entire transmission bill, achieving systemwide affordability outcomes requires coordinated action across Transmission Owners and the institutions that govern planning and cost recovery. PG&E looks forward to continuing to partner with the Commission and other stakeholders on these issues.

Transmission Ownership Structures

Q1: Are there publicly available studies that provide insights on overall cost savings for ratepayers attributable to the various ownership models?

Across the academic and policy literature, there is no clear consensus that either investor owned utilities ("IOUs") or publicly owned utilities ("POUs") consistently deliver more efficient or lower cost electric service. The two ownership models operate under materially different regulatory frameworks, governance structures, and risk profiles, and they often face distinct climate, environmental, and operational challenges.[2] These differences complicate direct comparisons and limit the ability to draw generalized conclusions. Most studies instead conclude that no single ownership model is universally the lowest cost. Actual cost outcomes depend on factors including operational efficiency, administrative costs, tax treatment, risk allocation, cost of capital, and governance quality. Strong governance can enable either model to operate cost-effectively, while weak governance—particularly in public systems—can erode structural advantages and, in some cases, result in higher costs than those incurred by well-governed IOUs.

Research highlighting potential POU cost advantages generally focus on access to low-cost, tax-exempt public debt. However, multiple analyses—most notably a 2025

[2] Pritzker Environmental Law and Policy Brief (2025), available at: https://law.ucla.edu/sites/default/files/PDFs/Publications/Emmett%20Institute/PritzkerPaper.pdf

Brattle report[3] and Pritzker Environmental Law and Policy briefs—emphasize several important caveats to these advantages, particularly for transmission:

- *Risk shifts from shareholders to customers*
  IOUs charge customers for shareholder returns, but shareholders also absorb financial and operational risk, for example when a utility is found imprudent and costs are disallowed or penalties are imposed. In POUs, customers bear the full risk of investment decisions, budget overruns, and system failures. Wildfire and infrastructure-related liabilities fall entirely on the public, even if a POU acts imprudently. Lower tax payments may reduce rates but also reduce state tax revenue. And during periods of economic recession, customers would bear the brunt of POU revenue losses.

  The City of Hercules' now-defunct Hercules Municipal Utility ("HMU") illustrates that access to public debt and municipal financing does not necessarily yield better outcomes for customers. Over time, HMU accumulated significant losses and many customers had higher rates than they would have had as PG&E customers.[4] To address the resulting financial strain and outstanding bond obligations, the City of Hercules pursued a public sale of HMU assets (ultimately to PG&E) with proceeds used to retire the municipal utility's bonds,[5] underscoring that stranded-cost and execution risk in a POU model is ultimately borne by the public.

- *Operational readiness and scalability*
  In evaluating public-ownership or public-financing models, it is important to consider not only financing costs but also the full operational and financial implications embedded in revenue requirements. POUs may face challenges meeting rapidly growing system needs, achieving IOU-level economies of scale, or maintaining comparable engineering, maintenance, and system-operations capabilities, which can result in higher operations and maintenance ("O&M") costs and longer project timelines.

  In practice, public-authority models may require contracting with experienced third-party operators to ensure safe and reliable operation, potentially including incentive or performance-based fees to compensate for operating risk and align

[3] Brattle (2025), "Electric Utility Municipalization: Key Statistics and Risk Considerations," available at: https://www.brattle.com/wp-content/uploads/2025/02/Electric-Utility-Municipalization-Key-Statistics-and-Risk-Considerations.pdf
[4] City of Hercules (2014), Staff Report to the City Council dated February 11, 2014, available at: https://hercules.granicus.com/MetaViewer.php?view_id=5&meta_id=52660
[5] City of Hercules (2014), Staff Report to the City Council dated March 4, 2014, available at: https://hercules.granicus.com/MetaViewer.php?view_id=5&clip_id=571&meta_id=53305

performance outcomes. These incremental operating and governance costs, together with statutory caps, voter-approval requirements, and credit-rating constraints can materially offset the benefits of lower cost borrowing.[6]

Academic literature reinforces these patterns. A 2025 UCLA Law study, *The Cost & Carbon of Competing Utility Models*, comparing the Los Angeles Department of Water and Power ("LADWP") (i.e., a POU) and Southern California Edison ("SCE") (i.e., an IOU) found that overall residential rates and system costs have largely converged, but structural cost differences remain.[7] While public ownership avoids shareholder returns and some taxes, the study concludes that public ownership does not inherently guarantee lower costs. Instead, performance differences between LADWP and SCE were driven primarily by governance quality, scale, financing conditions, and political oversight—not ownership type. The study further observes that poorly designed or overly constrained public governance can negate structural advantages and, in some cases, result in higher costs than under regulated IOU models.

Public ownership could reduce costs under the right conditions, but the evidence shows this depends greatly on governance effectiveness, system scale, and financing structure. Ownership alone is not a reliable predictor of lower costs or superior performance.

Q2: Are there public sources that provide evidence of savings related to competitively bid projects versus projects that default to incumbent investor-owned utilities?

Several publicly available studies have examined whether competitive transmission solicitation processes have produced cost savings relative to projects developed by incumbent investor-owned utilities. While some early analyses suggested that competitive bidding could yield potential customer benefits, the record of completed projects does not provide clear or consistent evidence that competition has, in practice, delivered demonstrated cost savings.

[6] Brattle (2025), "Electric Utility Municipalization: Key Statistics and Risk Considerations," available at: https://www.brattle.com/wp-content/uploads/2025/02/Electric-Utility-Municipalization-Key-Statistics-and-Risk-Considerations.pdf
Ibid. And the CPUC Concept Paper

[7] UCLA School of Law (2025), "The Cost & Carbon of Competing Utility Models," available at: https://law.ucla.edu/sites/default/files/PDFs/Publications/Emmett%20Institute/Costs%26Carbon%20FINAL.pdf

For example, a 2019 report by the Brattle Group asserted that competitive transmission solicitations may offer savings for customers.[8] However, those conclusions were largely prospective and based on a limited evidentiary record at a time when few competitive transmission projects authorized under Federal Energy Regulatory Commission ("FERC") Order No. 1000 (issued in 2011) had reached completion. As a result, the report relied on projected outcomes rather than demonstrated cost performance and did not establish that competitive bidding had actually produced lower costs in the United States compared to projects developed by incumbent transmission owners.

More recent studies that evaluate actual project experience and costs raise serious questions about whether the purported benefits of competition have materialized. A 2019 report by Concentric Energy Advisors found that incumbent transmission owners generally delivered projects within a relatively narrow range of initial cost estimates and concluded that there was no credible basis to assume that expanding competitive solicitations would result in meaningful additional savings for customers.[9] Concentric's subsequent analyses in 2022 and 2024 further reinforced these conclusions.[10, 11] Those studies found that competitive solicitations under Order No. 1000 have not demonstrated consistent cost savings, have contributed to material schedule delays, and in some cases have resulted in cost escalation despite the presence of bid-stage cost caps. Concentric's 2024 update, which reviewed additional projects and more advanced stages of development for previously studied projects, concluded that the benefits of competitive solicitation processes remain unsupported by the totality of the evidence. The analysis also highlighted that cost cap mechanisms often include numerous exclusions that limit customer protections and that transparency limitations make it difficult to assess how cost caps are applied in practice.

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[8] Brattle (2019), "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," available at: https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf

[9] Concentric Energy Advisors (2019), "Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations," available at: https://ceadvisors.com/wp-content/uploads/2024/10/CEA_Order1000report_final.pdf

[10] Concentric Energy Advisors (2022), "Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits," available at: https://ceadvisors.com/wp-content/uploads/2024/10/Competitive-Transmission-Experience-To-Date-Shows-Order-No.-1000-Solicitations-Fail-to-Show-Benefits.pdf

[11] Concentric Energy Advisors (2024), "An Updated Examination of FERC Order No. 1000 Projects: Expanded Review Shows That Benefits of Competition Remain Elusive," available at: https://ceadvisors.com/wp-content/uploads/2024/10/An-Updated-Examination-of-FERC-Order-1000-Projects.pdf

Other publicly available sources echo these concerns. A 2025 whitepaper published by Developers Advocating Transmission Advancements ("DATA") cites recent examples indicating that competitive solicitations can result in illusory cost containment, inefficient project scoping, litigation, and delayed delivery of customer benefits rather than superior outcomes.[12] The Delaney–Colorado River ("DCR") Transmission Project (also known as Ten West Link) provides a particularly salient California example. The CAISO selected DCR Transmission as the project sponsor through a competitive solicitation conducted pursuant to FERC Order No. 1000, and the project was advanced on the premise that a binding cost cap would protect customers while delivering economic benefits. However, in its filing at FERC, DCR Transmission sought recovery based on project costs of approximately $553 million, compared to a binding cost cap of approximately $259 million—more than double the capped amount. Although the matter remains under active litigation as of early 2026, the DCR Transmission proceeding illustrates how competitive solicitations can produce illusory cost containment and place at risk the very customer protections that competitive transmission is often claimed to provide.

Taken together, these public sources do not establish that competitively bid transmission projects have reliably produced cost savings relative to projects assigned to incumbent investor-owned utilities. Accordingly, the Commission and state policymakers should view claims of savings from competitive transmission with caution and should not assume that competitive bidding, standing alone, is a proven mechanism for reducing customer costs.

Potential Options for Achieving Transmission Cost Savings

Q3: Are there publicly available case studies of a government entity financing and building electric infrastructure at lower cost compared to a private entity? Are there publicly available data about the scope of the project and its costs?

While public and government financing structures can reduce nominal financing costs relative to IOU financing, financing cost alone do not capture the full economic and risk profile of transmission projects. Case studies from the public power sector demonstrate that access to lower-cost public debt and the absence of shareholder return on equity can reduce revenue requirements. At the same time, public financing models may introduce additional costs and risks that are less apparent in headline comparisons. These include increased ratepayer exposure to construction and

[12] Developers Advocating Transmission Advancements (2025), "Recent Experience with Competitive
Transmission Projects and Solicitations," available at: https://www.modernizethegrid.com/wp-content/uploads/2025/02/DATA-Whitepaper-2024_2-5-25_vF_edit.pdf

completion risk, reduced flexibility associated with long-term fixed payment obligations, governance and execution risks, administrative costs, and potential implications for future rate stability. Accordingly, a meaningful comparison of public and private transmission financing should consider full lifecycle costs and risk allocation, including factors that are not easily quantified.

As an example, The Bonneville Power Administration ("BPA") uses third-party financing under its Lease Purchase Program to acquire major transmission assets without drawing on its limited U.S. Treasury borrowing authority. Under this structure, a special-purpose public entity finances construction by issuing public debt, while BPA enters into a long-term, capitalized lease with fixed payments sufficient to fully cover debt service. Those lease payments are pledged as the sole security for the bonds. The model is intended to provide utility-style, intergenerational cost recovery, achieve financing costs lower than equity-based alternatives, and preserve BPA's balance-sheet capacity for future needs.[13]

Although public authorities such as BPA may benefit from lower financing costs, they also assume greater ratepayer obligation risk. BPA's lease payments are fixed, long-term "hell-or-high-water" obligations that must be paid regardless of project completion or performance and are recovered directly through rates. Under BPA's lease model, with these unconditional payment obligations, ratepayers remain responsible for lease payments even if the project experiences cost overruns, delays, or design deficiencies. By contrast, under the IOU model, cost recovery is subject to prudence review and regulatory approval, and certain risks—such costs found to be imprudent—are borne by shareholders and not customers.

A prominent example of the risks of government-driven energy infrastructure is the Muskrat Falls hydroelectric project in the province of Newfoundland and Labrador, Canada.[14] The project was approved in 2012 with an initial estimated cost of $7.4 billion, and the final cost incurred upon completion in 2023 was about $13 billion, an approximately 76% cost overrun. A subsequent investigation by the Minister of Natural Resources for the Province of Newfoundland and Labrador found that significant cost overrun was due to optimistic assumptions, weak oversight, and the absence of

[13] BPA Green-Certified Revenue Bonds Support Clean Energy Infrastructure, Lower Interest Costs (2024), available at: https://www.publicpower.org/periodical/article/bpa-green-certified-revenue-bonds-support-clean-energy-infrastructure-lower-interest-costs

[14] The Canadian Press (2023), "Muskrat Falls hydroelectric project in N.L. considered commissioned: CEO," available at: https://kitchener.citynews.ca/2023/04/12/muskrat-falls-hydroelectric-project-in-n-l-considered-commissioned-ceo/

independent regulatory review.[15] Under public-authority financing structures, such overruns are borne directly by ratepayers through fixed payment obligations.

Q4: Are there publicly available case studies of a government entity financing an infrastructure project with the participation of private equity or other private sector financing, with public data?

Public–private financing mechanisms are playing an increasingly important role in accelerating clean energy deployment and modernizing the electric grid. Two prominent approaches are federal de-risking through the U.S. DOE's Office of Energy Dominance ("OED") and state-level green bank co-financing models. The OED lowers the cost of capital for large-scale infrastructure projects, as illustrated by a late-2025 transaction in which the DOE guaranteed a $1.6 billion term loan at a preferred interest rate to AEP Transmission, a subsidiary of American Electric Power.[16] That financing supports upgrades to approximately 5,000 miles of transmission infrastructure across five states and is expected to save customers an estimated $275 million in financing costs over the life of the loan, while enabling more efficient responses to growing electricity demand.

At the state level, green banks use public capital to attract and de-risk private investment in clean energy markets. The New York Green Bank ("NYGB") is a leading example. As a state-sponsored public finance entity, NYGB has committed more than $2.5 billion to projects supporting sustainable infrastructure, including solar generation, energy storage, and broader decarbonization initiatives.[17]

California has also historically used similar public-financing tools. For example, tax-exempt bonds issued through entities such as the California Pollution Control Financing Authority ("CPCFA") and the California Infrastructure and Economic Development Bank ("CA I-Bank") were used to finance major generation assets, including Diablo Canyon Power Plant and the Geysers geothermal power station. While these public-financing structures provided access to lower-cost, tax-exempt financing,

[15] Commission of Inquiry Respecting the Muskrat Falls Project (2020), "Muskrat Falls: A Misguided Project," available at: Volume-1-Executive-Summary-Key-Findings-and-Recommendations.pdf

[16] Department of Energy (2025), "Energy Department Closes Loan Guarantee to Strengthen U.S. Grid Reliability," available at: https://www.energy.gov/articles/energy-department-closes-loan-guarantee-strengthen-us-grid-reliability

[17] New York Green Bank (2025), "Impact Report for the fiscal year ended March 31, 2025," available at: https://greenbank.ny.gov/-/media/Project/Greenbank/Files/NYGB-Impact-Report.pdf

the resulting debt obligations remained with PG&E, and the Company retained full responsibility for project delivery, operations, and cost recovery through rates.

Taken together, these federal and state financing models demonstrate how targeted use of lower cost public capital can leverage private investment to accelerate grid modernization and clean energy deployment.

Q5: At what scale have certain financing solutions been used? What are the constraints, opportunities, risks, and/or tradeoffs of scaling up other kinds of financing?

Public and government-backed financing has reached a meaningful—but still limited—scale, with most activity occurring through federal credit programs rather than state-led public financing. The scale of financing solutions needed is significant when viewed against projected transmission investment needs. The CAISO estimates that meeting anticipated load growth through 2045—driven in part by electrification and large-scale offshore wind development—will require $45–63 billion in new transmission investment over the next two decades.[18] To date, public financing has been demonstrated primarily at the $1–5 billion per-project scale and $10–20 billion at the portfolio level, but it has not yet expanded to the magnitude implied by regional and national transmission requirements.[19]

Recent examples of financing solutions include a $26.5 billion loan package closed in early 2026 by the U.S. DOE's Office of Energy Dominance Financing ("DOE EDF"), supporting generation and transmission investments in Georgia and Alabama, and $22.9 billion in conditional loan commitments announced in January 2025 across eight utilities in twelve states, including multiple transmission and grid-modernization projects. PG&E has also received approval for up to $15 billion in DOE loan support for transmission-level investments. Following the change in administration, PG&E has worked with the DOE and the loan remains in place, although these funds have not yet been drawn.[20]

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[18] California Independent System Operator (2024), "2024 20-Year Transmission Outlook," available at: https://www.caiso.com/documents/2024-20-year-transmission-outlook-jul-31-2024.pdf

[19] US Government Accountability Office (2025), "DOE Loan Programs: Actions Needed to Address Authority and Improve Application Reviews, available at: https://www.gao.gov/products/gao-25-106631

[20] Beyond DOE loan programs, the 2021 Infrastructure and Investment Jobs Act expanded DOE's grantmaking capabilities, including setting aside $10.5 billion for the DOE's Grid Resilience and Innovation Partnerships ("GRIP") Program, which provides another pathway for utilities to access federal funds to support customer affordability. In August 2024, PG&E in partnership with the State of California and other partners, was selected for a ~$600 million

DOE loan programs can play an important catalytic role; however, structural constraints may limit the ability of public or alternative financing to scale further. Specifically, DOE loan programs can reduce financing costs but their statutory authority is time-limited, with significant portions expiring between 2026 and 2028. This creates uncertainty for long-lead-time transmission projects that must navigate siting, permitting, California Environmental Quality Act ("CEQA") review, and wildfire-related risks before reaching financial close. In addition, federal credit programs are subject to statutory requirements to demonstrate a reasonable prospect of repayment and cannot absorb open-ended market, regulatory, or liability risks, including wildfire exposure or prolonged uncertainty around cost recovery. As a result, public financing cannot substitute for durable regulatory cost-recovery frameworks or function as an unlimited backstop for large-scale transmission investment.

Public or alternative financing also does not alter the underlying regulatory framework governing transmission development. Projects remain subject to state- and federally-approved siting, cost allocation, and/or cost-recovery requirements, and continue to face development and construction risks. While financing authority may be federal, these core regulatory decisions remain with states and the Commission, which can constrain the scalability of alternative financing approaches.

Furthermore, scaling public or alternative financing introduces additional risks and tradeoffs. Greater reliance on public financing increases federal or state balance-sheet exposure to construction, regulatory, and demand risks, even where loans are ultimately repaid. Heavy dependence on public credit could also crowd out private capital or weaken incentives for efficient project selection if not carefully governed. Moreover, transmission investment must compete with other federal and state priorities—including resilience, wildfire mitigation, housing, and transportation—placing practical limits on how far public financing can realistically expand.

Overall, however, public and hybrid financing can provide targeted benefits when used alongside traditional utility investment. Federal credit programs can offer lower-cost, long-tenor debt, reducing interest expense and near-term revenue requirements when paired with established regulatory cost recovery. Recent DOE approvals also demonstrate that such financing can be deployed at the portfolio level across multiple projects and jurisdictions, supporting more coordinated, system-level transmission upgrades. While these approaches do not eliminate underlying

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GRIP grant – California Harnessing Advanced Reliable Grid Enhancing Technologies for Transmission ("CHARGE 2T") – to strengthen and modernize the transmission system, and currently PG&E and its grant partners are awaiting further instructions from the DOE to finalize the grant award. The grant award, unlike a loan, is not required to be repaid to the federal government.

development or regulatory risks, they can complement private capital by lowering borrowing costs and supporting broader transmission deployment within existing regulatory frameworks.

Q6: How does tax liability for government entities differ from that of investor-owned utilities?

Tax liability differs significantly between government entities and IOUs, with important implications for ratepayers and public revenues. While public financing models may benefit from tax-exempt status, those savings do not exist in a vacuum. Any reduction in taxes paid by IOUs would result in a corresponding loss of revenue to state and local governments, which ultimately must be made up through other means.

For example, in 2025 PG&E paid substantial taxes and fees beyond state and federal income taxes, including more than $537 million in property taxes and over $138 million in franchise fees to cities and counties across northern and central California. These payments directly support essential public services. If infrastructure ownership were shifted away from IOUs, governments would need to identify alternative revenue sources to replace these lost funds, potentially offsetting or diminishing any perceived financial benefits of public ownership for ratepayers.

Q7: Are there publicly available examples of electric infrastructure project costs reduced because of any of: permitting exemptions or streamlining, meeting/beating timelines, or incentive/penalty structures for the project lead?

Permitting remains a significant potential source of delay for electric infrastructure projects in California, and delays can materially increase project costs for publicly or privately funded projects alike. PG&E recognizes this challenge and welcomes opportunities to work collaboratively with state agencies, county and local governments, and other stakeholders to improve coordination and reduce permitting-related obstacles. Clear alignment and prioritization across all levels of government—particularly with respect to the urgency and importance of electric infrastructure—has the potential to reduce costs by helping projects stay on schedule.

Q8: How does exposure to liability and other risk affect public utilities' willingness to own transmission?

Shifting ownership from private investors to public agencies would transfer significant risks to government entities, increasing the potential liabilities for which they would be responsible. These risks extend well beyond financing and include wildfire liability, operational safety, long-term maintenance obligations, construction quality,

acquisition of rights-of-way, supply chain and materials availability, and the inherent uncertainty of long-term cost forecasting. Notably, wildfire exposure has already contributed to credit rating downgrades for multiple public agencies,[21] underscoring how these risks can erode the anticipated benefits of public financing and potentially increase costs to taxpayers and ratepayers alike.

Considerations for Implementation

Q9: Please comment on feasibility of either of these models [Public-Private Partnership Build-Operate-Transfer or Lease-Type] for California. Please specify barriers and the structural elements that would have to exist for the model to develop transmission at lower costs.

The feasibility of any public–private partnership ("PPP") model, whether build-own-transfer ("BOT") structures or long-term lease arrangements, must consider the following barriers and structural elements:

- *Alignment with the current legal or regulatory structure*

Transmission assets are capital-intensive, long-lived, and subject to extensive regulation, with revenues dependent on FERC-approved rates and state-level siting and permitting approvals. As a result, PPP models must be closely integrated with regulated cost-recovery mechanisms to achieve bankability. Experience across California infrastructure sectors further suggests that PPP authority and deployment tend to be episodic and statute-specific rather than broadly available, limiting scalability absent new legislative authorization and regulatory alignment.*22*

- *Wildfire risk management*

Wildfire liability presents a material and distinguishing constraint for PPP transmission models in California, and its allocation cannot be meaningfully altered through financing structure alone. Under California law, electrical corporations are subject to inverse condemnation for wildfire damages caused by utility equipment, regardless of fault, with cost recovery governed through prudency review and the statutory framework established by Assembly Bill ("AB") 1054. AB 1054, together

[21] RRA, State Regulatory Evaluations — Energy (March 2026), placed California on its watch list, citing ongoing uncertainty surrounding wildfire funding. Similarly, S&P Global Ratings, Research Update on Los Angeles Department of Water and Power (April 14, 2025), revised LADWP's outlook to negative, citing wildfire litigation and potential liabilities related to the Palisades Fire, credit contagion risk associated with power system exposures, and accelerating capital spending.

[22] California Transportation Commission, Public-Private Partnerships (P3), available at: https://catc.ca.gov/programs/public-private-partnerships

with SB 254, created the California Wildfire Fund (“the Fund”) as a financial backstop for participating IOUs, contingent on safety certification, approved wildfire-mitigation plans, and required shareholder and ratepayer contributions.

Access to the Fund, however, is limited to covered wildfires and participating utilities. As a result, private developers, public entities, or special-purpose entities involved in PPP arrangements generally lack independent access to the Fund and cannot efficiently assume wildfire liability without materially increasing financing costs or requiring indemnification from a public entity. Absent statutory expansion of the Fund eligibility or explicit indemnification mechanisms, efforts to shift wildfire liability to private PPP partners would undermine project bankability and erode any potential cost savings. Accordingly, PPP transmission models in California must be structured on the premise that wildfire liability remains a public-sector risk, with corresponding implications for cost and risk borne by the sponsoring public entity.

- *Total present value of costs for customers (not just lower nominal financing rates)*

While PPPs may lower nominal borrowing costs through access to public or tax advantaged debt, financing costs represent only one small component of total project cost and do not mitigate the primary drivers of cost escalation in large transmission projects, including permitting uncertainty, siting and environmental constraints, supply chain volatility, labor availability, and scope changes.

Moreover, in the context of transmission infrastructure, construction and completion risk cannot be fully transferred to private partners, and cost overruns are frequently addressed through contract renegotiation or embedded in long term lease or availability payment obligations borne by customers. As a result, PPP structures often change the timing or mechanism of cost recovery rather than eliminating underlying costs or risks. Financing benefits alone may be insufficient to offset the higher initial costs and extended development timelines associated with PPP transmission models, resulting in higher total present value costs for customers despite lower nominal financing rates.

- *The time and resources to create a project-specific entity*

Significant time and institutional effort is often required to establish project-specific entities and governance structures, which can have direct cost implications. Unlike traditional utility development, PPP arrangements typically require the creation or designation of a special-purpose entity, the negotiation of bespoke contractual frameworks, and alignment between public-sector authority and private financing and construction responsibilities.

This upfront structuring phase must address ownership and transfer or lease terms, risk allocation, regulatory treatment, and long-term cost recovery, often necessitating enabling legislation, Commission approvals, and coordination with FERC and CAISO processes.

These requirements can extend development timelines relative to conventional utility projects, increasing pre-construction carrying costs, exposing projects to inflation and interest-rate risk, and delaying realization of any financing benefits associated with lower-cost capital. In the absence of standardized PPP authorities or templates, entity-formation and transaction costs tend to be largely fixed and front-loaded, reducing the potential for economies of scale and eroding net savings for smaller or time-sensitive transmission projects. As a result, modest financing advantages under a PPP structure may be outweighed by higher upfront costs and timing-related inefficiencies.

Incorrect Statement related to Cost of Capital

PG&E recommends removing the misleading statement in the Concept Paper that "debt is usually lower cost than equity, so higher financial leverage reduces all-in cost of capital (as long as the cash flows are predictable)."[23] While debt is typically cheaper than equity, increasing leverage also increases financial risk. As leverage rises, equity holders—who are residual—bear greater risk, and therefore require a higher return. At the same time, higher leverage increases fixed cash-flow obligations, which can also drive up the cost of debt.

The Concept Paper itself also acknowledges this dynamic, noting that:

> "The use of a high proportion of debt in the capital structure may introduce more risk to cashflow and may increase the probability of default. As a result, to compensate equity holders for the increase in potential volatility to cash flow, a higher return may be required."[24]

However, the Concept Paper fails to recognize implications for the overall weighted cost of capital. Once higher component costs of both debt and equity are reflected, the weighted cost of capital would not decline; instead, it would either increase or, more commonly within a reasonable range of capital structures, remain largely unchanged. This outcome reflects the fundamental relationship between risk and return and is consistent with both theoretical and empirical research showing that, for a

[23] CPUC (March 11, 2026), "Working Concepts in Transmission Financing and Ownership," page 12, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/electric-costs/electric-transmission-rates-and-related-ferc/ab3264-concept-paper-cpuc-20260311.pdf

[24] Ibid, page. 3.

given business and risk profile, the weighted cost of capital is generally stable across a wide range of leverage levels.[25, 26]

Importantly, the IOUs' authorized capital structures reflect a balanced level of leverage that supports reasonable credit ratings, efficient access to capital markets, financial resilience under stress, and appropriate ratepayer protections. Materially increasing leverage would risk credit deterioration and higher financing costs, ultimately increasing—not reducing—long-term customer costs. Consistent with this, in the 2026 Cost of Capital decision, the Commission authorized the capital structure, finding that "maintaining the existing common equity authorization of 52.00% is reasonably sufficient for PG&E to maintain a reasonable credit rating and attract capital while ensuring adequate consideration of ratepayers."[27]

Conclusion

PG&E appreciates the opportunity to provide input on the Commission's examination of alternative transmission financing and ownership approaches. As reflected in PG&E's comments, DOE-style loans directly reduce the cost of transmission projects funded through the program compared to traditional utility borrowing. But broadly speaking, available evidence does not support the conclusion that any single ownership or financing model consistently delivers lower, risk-adjusted costs over the life of a project, and broad assumptions regarding public ownership may obscure material tradeoffs related to scalability and implementation risk.

As California advances substantial transmission investment to support reliability, load growth, and decarbonization, policies should prioritize timely delivery, clear alignment of risk with those best positioned to manage the risk, and frameworks that preserve regulatory clarity and customer protections. Specifically, the transmission investments identified through the CAISO Transmission Planning Process and PG&E's recent large load interconnection studies are critical to advancing California's economic, climate, and safety objectives. Any recommendations emerging from the Commission's efforts should avoid frameworks that could delay or disrupt the timely development of these investments.

PG&E looks forward to continued engagement and collaboration on the topic of Transmission Financing and Ownership.

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[25] A.25-03-010, PG&E, *2026 Cost of Capital Rebuttal Testimony*, Chapter 2 (Return on Equity) and Chapter 3 (Credit Quality and Capital Structure).
[26] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, June 1958, Vol. 48, No. 3, at 261-297.
[27] CPUC D.25-12-043