# California State Assembly

## UTILITIES AND ENERGY

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Wednesday, March 26, 2025
1:30 pm -- State Capitol, Room 437

## OVERSIGHT HEARING

***Energy Affordability:***
***Strategies to Reduce California's Transmission Costs***

California has led the national and global transition to decarbonize the electricity sector with ambitious goals. Established in 2002, the California's Renewables Portfolio Standard (RPS)[1] program, sets increasing targets for the percentage of renewable energy[2] that retail electricity providers must procure. Since then, the Legislature has modified, increased, and accelerated the RPS numerous times. Notably, SB 100 (De León, Chapter 312, Statutes of 2018), also known as the "100% Clean Energy Act of 2018," established a landmark policy that renewable and zero-carbon resources supply 100% of retail sales and electricity procured to serve all state agencies by 2045 (the 100% Clean Energy Policy).[3] This policy has been updated under SB 1020 (Laird, Chapter 361, Statutes of 2022), and among other requirements, established interim targets to meet the sector-wide 100% goal.

Similarly, the updated 2022 Scoping Plan released by California Air Resources Board (CARB) in December 2022, calls for capping at 38 million metric tons of carbon dioxide equivalent (MMTCO2e) in 2030 and 30 MMTCO2e in 2035 in the electricity sector.[4] These sector-wide targets establish the planning goal that informs all subsequent electricity procurement and transmission planning. Meeting these ambitious targets over the next two decades while ensuring the electric grid remains safe, resilient, reliable, affordable, and accessible to all Californians is an arduous challenge. It demands proactive, coordinated, and strategic planning; and innovative

[1] SB 1078 (Sher, Chapter 516, Statutes of 2002) established the Renewable Portfolio Standard (RPS) Program with the initial requirement that 20% of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2015 with SB 350 (De León, Chapter 547, Statutes of 2015) which mandated a 50% RPS by 2030. SB 350 includes interim annual RPS targets with three-year compliance periods and requires 65% of RPS procurement to be derived from long-term contracts of 10 or more years.
[2] Renewable energy sources that meet the eligibility criteria include biomass, geothermal, solar, wind, and others.
[3] Public Utilities Code §454.53
[4] Pg.75; CARB, "DRAFT 2022 Scoping Plan Update," May 10, 2022

thinking from a diverse coalition of stakeholders, such as the executive branch, utilities, community choice aggregators, developers, and transmission owners.

The SB 100 report noted that in order to meet state clean energy and climate goals, California will need to roughly triple its current electricity capacity.[5] Specifically, the report projects that the state will need to add approximately 6 gigawatts (GW) of new renewable capacity annually, nearly double the historical average.[6] A study conducted by the Clean Air Task Force and the Environmental Defense Fund concluded that, at a minimum, transmission capacity must double by 2045 to accommodate new renewables and ensure grid reliability.[7] As such, the associated costs with this anticipated massive build out are immense. Furthermore, the current transmission development process is often convoluted and plagued by delays, taking over a decade from initial planning to project completion.

In its 2023–24 transmission planning cycle, the California Independent System Operator (CAISO) found the need for 26 transmission projects that are estimated to cost $6.1 billion.[8] Currently, transmission costs—primarily borne by utility ratepayers— are projected to rise by $45 to $60 billion—an increase that further exacerbates California's high electric rates.[9] The escalating costs impose a significant burden on many households and particularly, disproportionately impact low-income families who often pay a larger share of their incomes on utility bills at the expense of other essential needs. This underscores the critical need to explore alternative financing models for transmission infrastructure without further burdening ratepayers.

This hearing supports the Committee's ongoing efforts to address energy affordability by following the 2024 and 2025 hearings on "Affordability Concerns in the Electric Sector: Current Cost Drivers and Future Implications" and "Energy Affordability: Utility Wildfire Expenditures."[10]

***Findings:***

- *Transmission costs in California, paid by utility ratepayers, are projected to surge by $45 to $60 billion over the next two decades, exacerbating California's already high energy rates. As such, it is imperative for the state to explore alternative financing strategies to mitigate ratepayer costs.*

- *Rates have already increased roughly 50% over the past three years for customers served by investor-owned utilities raising concerns about affordability and the role of the state in helping develop cost-effective energy infrastructure*.

[5] Pg. 10, CEC, CPUC, & CARB; "Achieving 100% Clean Electricity in California," *2021 SB 100 Joint Agency Report Summary: An Initial Assessment,* March 2021.
[6] CARB, "California releases report charting path to 100 percent clean electricity."
https://ww2.arb.ca.gov/news/california-releases-report-charting-path-100-percent-clean-electricity
[7] Lucid Catalyst, Clean Air Task Force, and the Environmental Defense Fund, "California's Clean Energy Transition: Understanding Today's Challenges to Reach Tomorrow's Goals," presentation January 18, 2022.
[8] California ISO, "2023-2024 Transmission Plan". Board Approved on May 23-20234
[9] Pg. 5; CAISO; "CAISO YEAR TRANSMISSION OUTLOOK", July 31, 2024
[10] See the Committee's website for more information on these and other prior hearings here: (https://autl.assembly.ca.gov/bill-hearings/informationaloversight-hearingshttps://autl.assembly.ca.gov/bill-hearings/informationaloversight-hearings).

- *Each stage of the transmission development process entails challenges that introduce delays.[11] These delays invariably increase project costs that are ultimately borne by ratepayers.*

- *Transmission development continues to be impacted by supply chain issues, such as the availability of transformers. Delays in global manufacturing and shortages of raw materials have disrupted project timelines, hindering critical upgrades and new transmission build out. This ongoing disruption poses a serious challenge to California's efforts to enhance grid reliability and support the growing demand for clean energy.*

- *The growing transmission build out has already – and will continue to – impact electric customer bills. As of July 2024, the statewide Transmission Access Charge – the FERC-approved rate for transmission project costs – stood at $ 11.60/MWh. However, the TAC is projected to rise by 350% by 2045 as the grid accommodates new clean energy resources.[12]*

- *Public-private financing for transmission projects could save ratepayers up to $ 3 billion, annually or approximately $123 billion over 40 years.*

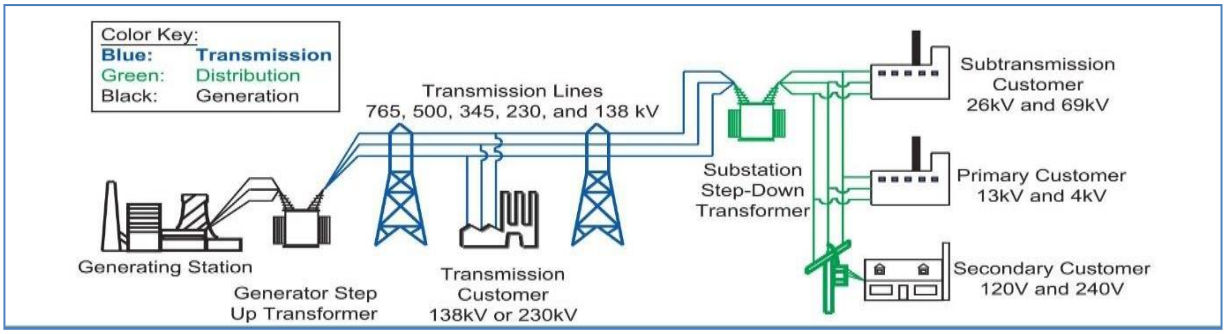
***The Backbone of California's Electricity & Infrastructure Planning.*** Planning for electricity procurement and associated infrastructure is an intricate, dynamic, and multi-layered process that involves a diverse array of entities such as load-serving entities (LSEs), regulatory and oversight bodies, generation and transmission owners, and joint power authorities. For this hearing, the focus of this planning will chiefly involve— the California Air Resources Board (CARB), California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Independent System Operator (CAISO). Their planning efforts are centered on the necessary procurement needed to meet our clean energy goals and the development of a robust transmission system needed to accommodate the new load growth. While these entities operate within distinct jurisdictions, their responsibilities are inherently interdependent. As such, coordinating their roles, timelines, and approvals becomes a complicated task. *See further details about this planning framework in the Appendix.*

***What is Transmission?*** Transmission lines are connected to substations that "step-down" the power to a lower-voltage so that it can be delivered to customers through distribution lines, although some large industrial customers receive their electricity at transmission or sub-transmission voltage. As shown in Figure 1, infrastructure operating at higher voltages comprise the transmission grid (in blue), while those at lower voltages comprise the distribution grid (in green). The distinction in voltage level between the transmission and distribution grid differs

[11] A delayed project is defined as a CAISO-approved project when it exceeds the original estimated in-service date in the CAISO Transmission Plan.
[12] Public Advocates Office; "Public Advocates Office"; Transmission Data Dashboard (as of October 2024). Accessed March 21, 2025.

across the utilities and is set at the discretion of the utility. Nevertheless, the transmission system carries the electric energy at relatively high voltage usually above 69 kilovolts (kV).[13]

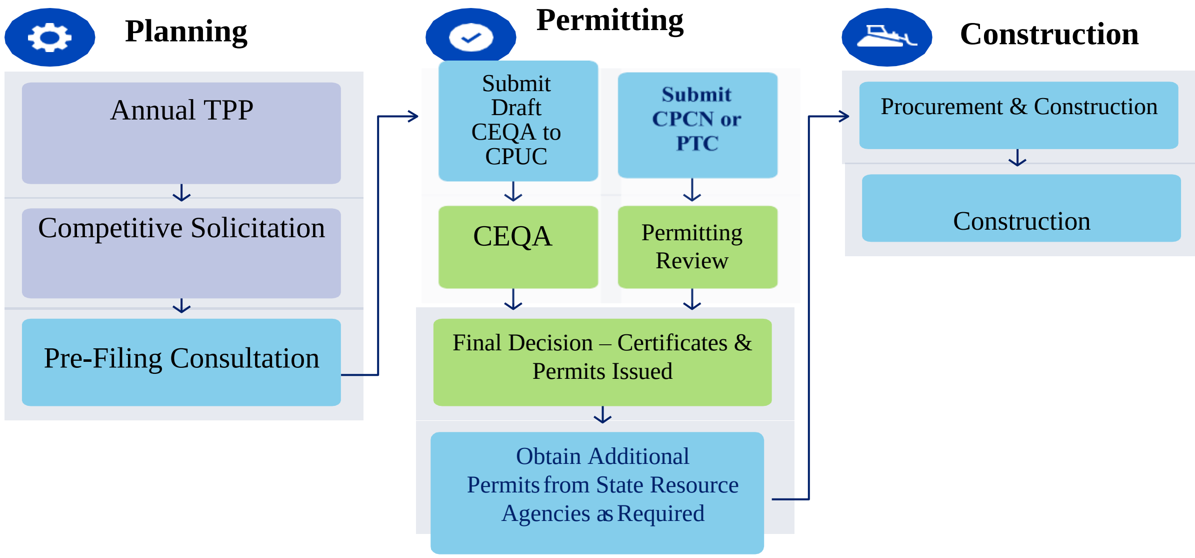
***Figure 1**:* Diagram of the standard North American electric grid.[14] All the poles and wires we see along the highway and in front of houses are called the electrical transmission and distribution system. (Sometimes called the "electrical grid")




If electricity was like cars on the road, the transmission system would be the highways and freeways, while the distribution system would be the surface streets. Transmission lines may be owned and operated by investor-owned utilities, publicly-owned utilities, or even independent third-party transmission owners that competitively bid for transmission projects. As the transmission system is the connecting point between generation resources (supply) and consumers (demand), planning for transmission construction—both new and upgrading old—requires an understanding of both future generation resource needs (capacity and location) and consumer demand changes. Therefore, transmission planning requires a robust planning process that considers all aspects of electricity supply and demand.

The California Public Utilities Commission (CPUC) typically estimates that major transmission projects require five to six years to move from initial concept and planning to full construction—under ideal conditions.[15] However, in reality, these timelines are often extended, with many projects taking ten years or more to complete due to various delays in the transmission development process. ***Figure 2:*** Provides an overview of the key phases of the transmission development process from concepts in CAISO's Transmission Planning Process (TPP) to actual construction of the transmission project.[16] The various aspects of Figure 2 are discussed below.

[13] Though this is not a hard-and-fast rule, some utilities designate circuits >60kV "transmission." >69kV is NERC's definition, as provided by the U.S. Energy Information Administration glossary of terms. https://www.eia.gov/tools/glossary/index.php?id=T
[14] National Park Service website, "Electrical Power Transmission and Distribution," access on May 5, 2023; https://www.nps.gov/subjects/renewableenergy/transmission.htm
[15] California Public Utilities Commission (CPUC), "General Information on Permitting Electric Transmission Projects at the CPUC", June 2009.




***Transmission Planning Phase: CAISO Annual TPP process.*** The transmission planning process (TPP), occurs annually and begins with CAISO identifying potential system limitations as well as transmission projects in need of upgrades or new transmission infrastructure to chiefly meet reliability, state policy goals, and economic or other needs[17] for the state.[18] CAISO first obtains demand forecast of electricity, consumption, and peak and hourly electricity demand from the CEC's integrated energy policy report (IEPR).[19] Corresponding to this action, the CPUC's Integrated Resource Process (IRP)[20] then works to identify the optimal mix of system-wide resources capable of meeting climate planning targets for the electric sector.[21] CAISO then receives the IRP results as inputs into its TPP. The transmission plan is updated annually, and culminates in a CAISO Board of Governors approved transmission plan that identifies the

[17] Maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects. Pg 3. CAISO; "2017-2018 TRANSMISSION PLAN." March 22, 2018

[18] See Slide 2, "CAISO Presentation: The CAISO assesses transmission needs annually with intensive coordination with California state agencies;" Assembly Committee on Utilities and Energy. May 18, 2023

[19] The CEC uses these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety. To carry out these assessments, "the Commission may require submission of demand forecasts, resource plans, market assessments, and related outlooks from electric, natural gas utilities, transportation fuel and technology suppliers, and other market participants." The CEC is also required to publish a strategic plan for California's transmission grid and include it in the IEPR.

[20] Called for under SB 350 (De León, Chapter 547, Statutes of 2015). The legislation establishes targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030.

[21] Via the Reference System Plan (RSP) and Preferred System Plan (PSP). The CPUC creates the Reference System Plan (RSP) to meet the electric sector target informed by the California Air Resources Board Climate Change Scoping Plan. The CPUC uses this RSP to establish filing requirements for the load-serving entities. The second year considers the procurement each load-serving entity proposes to meet these GHG targets. As each load-serving entity has its own local constraints to consider, each files its own plan. The CPUC reviews, modifies, and aggregates these individual load-serving entities' plans into a preferred system plan (PSP). Based on the approved PSP, the CPUC considers authorizing load-serving entities to procure resources within the next 1-3 years to meet GHG planning targets.

needed transmission solutions[22] and authorizes cost recovery through CAISO transmission rates, subject to the Federal Energy Regulatory Commission (FERC). However, it has been reported that FERC provides minimal oversight regarding the reasonableness of costs submitted for inclusion in transmission operators' revenue requirements.[23] According to the Public Advocates Office, this trend is likely to worsen as CAISO continues to approve more policy-driven transmission projects to access the resources needed to meet California's clean energy and climate goals.[24]

***Permitting Phase: CPUC Reviews Transmission Projects***. Utilities seeking to construct new transmission facilities are generally required to obtain a permit from the CPUC for certain infrastructure projects, pursuant to Public Utilities Code §1001.

The CPUC reviews permit applications under two concurrent processes:

i) An environmental review of applicable projects pursuant to California Environmental Quality Act (CEQA)[25] and CPUC environmental rules. However, some projects may trigger a federal National Environmental Policy Act (NEPA; the federal equivalent of CEQA) review if they cross federal land or use federal funds.

ii) The review of project needs and costs as outlined in Public Utilities Code §1001 and General Order (GO) 131-E also known as a Certificate of Public Convenience and Necessity (CPCN) or a Permit to Construct (PTC). The size of a project determines what permit will be required:

- Projects below 50 kV are considered distribution projects, rather than transmission projects, and in general do not require CPUC approval.

- Projects between 50 kV and 200 kV require a PTC, which consists primarily of an environmental review pursuant to CEQA. The CPUC process generally does not require a detailed analysis of the need for or economics of these projects.

  *To note, more than 100 transmission projects are currently under development or construction across the three major investor-owned utilities—*

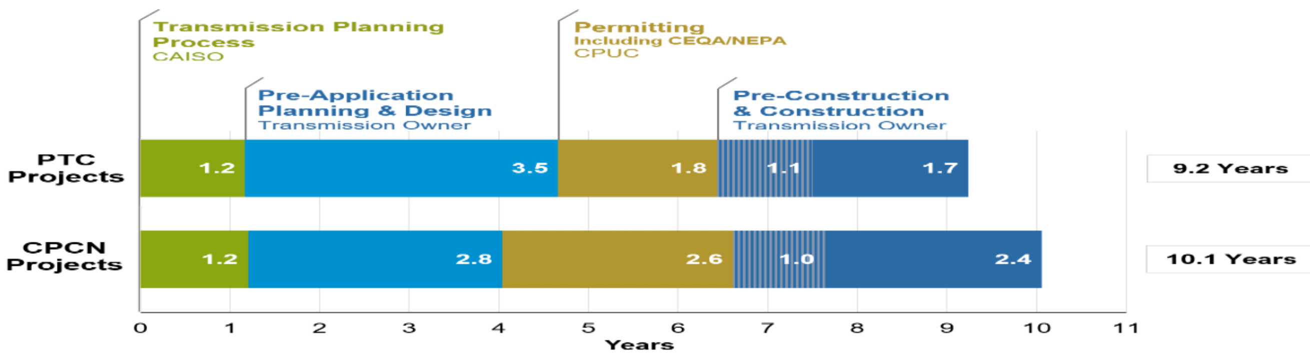
[22] As well as identifying non-transmission solutions that will be pursued in other venues as an alternative to building additional transmission facilities.
[23] Pg. 49; Joskow, Paul. Competition for Electric Transmission Projects in the U.S.: FERC Order 1000. March 2019. Available at https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf.
[24] The CAISO dramatically increased the number and scale of policy-driven transmission projects it approves, going from zero policy-driven projects between 2014 and 2021, to 6 projects at $1.5 billion in 2022, to a proposed 22 projects at $7.5 billion in 2023. (The CAISO's annual transmission plans are available at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.)
[25] CEQA was enacted in 1970 and requires public agencies to evaluate the environmental impacts of development projects before approving plans, policies, or development projects. A proposal will only trigger CEQA review if it involves the exercise of discretionary powers by the CPUC and results in a direct, or reasonably foreseeable indirect, physical change in the environment. A proposal will only trigger CEQA review if it involves the exercise of discretionary powers by the CPUC and results in a direct, or reasonably foreseeable indirect, physical change in the environment.

*PG&E, SDG&E, and Southern California Edison. The majority of these projects are under the 200 kV threshold.*[26]

- Projects over 200 kV require a CPCN and are consistently subject to complete CEQA review, including an EIR. The CPCN process analyzes the need and the economics of the project, as well as the environmental impacts of the project.

**Figure 3**: Represents 54 transmission projects that were analyzed by the Public Advocates Office and permitted by the CPUC between 2002 and 2024.[27]CPUC permitting represents about 25% of the average project development timeline, while transmission owners are responsible for approximately 65% of the average project development timeline.

**Figure 3**: Development Timeline: Concept to Construction




***Developer Submits Draft CEQA to CPUC.*** New reforms pursuant to GO 131-E currently allow transmission project applicants to submit their own draft versions of CEQA documents along with their transmission project applications. Prior to this modification, CPUC staff would study project impacts and also create draft environmental reports that were similar to the transmission applicants —leading to duplicative work. According to data provided by the CPUC to this committee, from 2012 to 2023, of a total of 664 projects that required CPUC review: 608 projects were exempt from CEQA.[28] This shows that over 90% of IOU projects over the last decade were exempt from CEQA, not even counting the thousands of projects < 50 kV that do not require any review from the CPUC.

Throughout the environmental and permitting review processes, the CPUC also solicits and responds to stakeholder and public feedback.

***Construction & Procurement Phase: Supply Chain and Workforce Challenges.*** California's power transmission infrastructure is currently grappling with significant supply chain challenges that hinder the state's clean energy transition. The global supply chain disruptions, including the

[26] Public Advocates Office; "Competitive Solicitation in Transmission Line Development Lowers Ratepayer Costs and Decreases Delays" June 9, 2023.
[27] Public Advocates Office; "Public Advocates Office"; Transmission Data Dashboard (as of October 2024). Accessed March 21, 2025.
[28] From a data request to the CPUC by this committee on March 29, 2023

COVID-19 Pandemic and political instability, have led to increased costs and delays in acquiring raw materials like steel and aluminum as well as essential components such as transformers and conductors, impeding the timely expansion and modernization of the grid.[29] The U.S. power system comprises over 80,000 transformer types, many of which are outdated, susceptible to failures, and non-standardized, thus complicating replacement efforts. These shortages, coupled with extended lead times for manufacturing and delivery, hinder timely infrastructure upgrades and expansions, further exacerbating supply chain challenges.[30] Concurrently, rising electricity demand is intensifying pressure on the grid. The rapid adoption of electric vehicles and building electrification is projected to escalate electricity demand by up to 76% by 2045[31]. The proliferation of AI technologies and the expansion of data centers is driving up consumption with projections indicating that by 2027, AI data centers could require an additional 68 gigawatts (GW) globally, nearly doubling 2022 levels and approaching California's total power capacity of 86 GW. [32] This demand surge further strains the limited supply chain for transformers, conductors, and critical materials needed in construction of new transmission lines and substations required to support these data centers.[33]

California's major investor-owned utilities—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—are confronting significant transmission challenges exacerbated by supply chain constraints. According to the National Association of Electrical Manufacturers, "delivery of a new transformer ordered today could take up to three years." To address these challenges, California should consider strategic planning and investments to bolster its transmission infrastructure supplies.

The domestic transformer manufacturing industry faces labor shortages due in part to the demands of training, working conditions, and some of the manufacturing facilities being in rural areas that offer a limited regional labor pool. Domestic manufacturers indicated that a lack of workers is one of the largest impediments to expanding capacity.[34] PG&E, serving a vast and diverse territory, has experienced notable delays in connecting new projects to the grid, particularly in areas such as San Francisco. These delays are attributed to staffing shortages and the need for substantial upgrades to distribution lines, some of which are at capacity. Addressing these issues is expected to require significant time and financial investment.[35] The rapid integration of advanced technologies, such as smart grids and renewable energy sources, requires a workforce proficient in these new systems. However, there may be a gap between the existing

[29] International Energy Agency, https://www.iea.org/news/rising-component-prices-and-supply-chain-pressures-are-hindering-the-development-of-transmission-grid-infrastructure
[30] Trabish H. (2025), Transformer Supply Bottleneck Threatens Power System Stability as Load Grows
[31] Hohbein R., Aczel M. (2024), Key Challenges for California's Energy Future, California Council on Science & Technology, https://ccst.us/reports/key-challenges-for-californias-energy-future-2/
[32] Pilz K et al, (2025), AI's Power Requirements Under Exponential Growth, https://www.rand.org/pubs/research_reports/RRA3572-1.html
[33] Walton R. (2025) Hitachi Energy Commits $250M to Address Transformer Shortage, https://www.utilitydive.com/news/hitachi-energy-commits-250-million-transformer-shortage/742010/
[34] Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the U.S. Grid, (2024) The National Infrastructure Advisory Council.
https://www.utilitydive.com/news/electric-transformer-shortage-nrel-niac/738947/
[35] Venteicher W. (2023), Need Power in California? Get in Line. Politico, https://www.politico.com/news/2023/04/21/california-energy-electricity-power-00093187

skill sets of utility workers and the competencies required to manage and operate modernized grids.[36] The perception of the industry as traditional and less dynamic compared to other technology-driven sectors may hamper recruitment efforts. While these changes may make it difficult for utilities to secure the necessary workforce to support transmission projects, many in the labor community assert an adequate workforce stands ready and available. Close communication between the utilities and the labor community will be critical in ensuring the workforce needs are met as the entire energy sector undergoes rapid expansion and modernization.

***Who Pays for All this Development? The Transmission Access Charge.*** Electricity rates are primarily influenced by the cost of delivering reliable service to customers. Generally, an IOU's cost of service is measured by its "revenue requirement". The revenue requirement is the sum of a utility's costs and typically includes operating costs, capital costs, a return of capital invested, and taxes.[37] The collective revenue requirements of all participating transmission owners within the CAISO region determine the Transmission Access Charge (TAC) rate, which is subsequently charged to electric customers.

TACs are directly correlated with electricity consumption: customers incur higher TAC costs as their energy usage increases over a billing cycle. For instance, residents in California's hotter regions typically depend more heavily on air conditioning, resulting in higher electricity consumption and, hence, elevated TAC expenses.

Statewide electric demand is anticipated to rise substantially in the coming decades with California's ongoing electrification efforts. While these shifts support the state's clean energy objectives, they will also contribute to higher TAC obligations for ratepayers. Specifically, as of July 2024, the TAC rate stood at $ 11.60/MWh. However, TAC is projected to rise by 350% by 2045 as the grid accommodates new clean energy resources.[38]

***Alternative Financing Models for Transmission Infrastructure.*** As electricity rates continue to rise, the need for innovative and cost-effective solutions to finance transmission infrastructure is becoming paramount. Presently, infrastructure services – including electricity, transportation, and telecommunications – may be paid for through a variety of institutional funding models involving public entities, private companies, or a combination of both.

The estimated cost of the 2024 20-Year Outlook infrastructure is between $39 and $54 billion for engineering and construction costs only.[39] If financing and development costs are included, this number increases to up to $216 billion over 40 years under an IOU financing and development scenario, as shown in Figure 4 below.

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[36] Addis B. (2024) Emerging Power and Utilities Workforce Challenges and How to Overcome Them, https://www.mossadams.com/articles/2024/09/power-and-utilities-workforce-challenges

[37] P.g 12; "Improving Transmission Financing in California: Alternative Models and Policy Strategies to Increase Affordability"; October 2024

[38] Public Advocates Office; "Public Advocates Office"; Transmission Data Dashboard (as of October 2024). Accessed March 21, 2025.

[39] Note that Figure 2 excludes interregional transmission for out-of-state wind that is already being developed. These costs will be paid by the line subscribers. It additionally does not include costs for upgrades to existing utility transmission facilities that are likely not eligible for competitive solicitation.

**Figure 4**: Ilustrates potential cost savings by these alternative funding models.[40] The left hand axis shows the annual cost savings while the right hand axis shows the cost savings over the 40-year life time of a typical infrastructure project. While investor-owned utility cost would be up to $5.4 billion annually, the cost per year for the P3-Concession model (discussed below) would be about $4 billion (25% in annual savings), $2.5 billion per year for the wholly public funding model (54% cost saving) and as low as $2.3 billion per year for the P3-Lease model (57% cost savings). These savings are even more pronounced if looked at from the right hand axis, the typical lifetime of a power transmission infrastructure project.

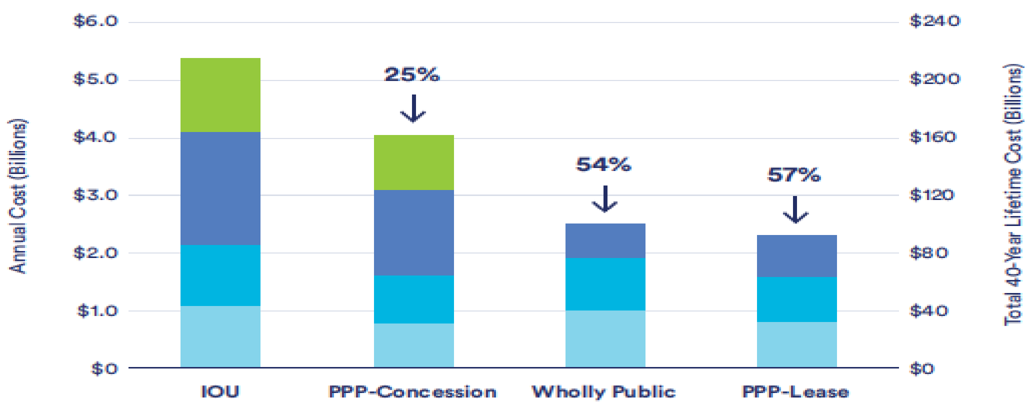


**Figure 4 Key:** Green for taxes; Navy Blue for return on rate base, Blue for depreciation expenses; and Sky Blue for operating expenses.

***Wholly Public.*** Government entities may assume full responsibility for the planning, financing, construction, and operation of electrical transmission projects, and retain ultimate ownership of the project. This approach contrasts with traditional IOUs or private entity models. By leveraging public funding mechanisms, the wholly public model aims to reduce costs, enhance efficiency, and align infrastructure development with public policy objectives, such as integrating renewable energy sources and ensuring equitable access to reliable electricity.

Key Components and Some Benefits:

- Public Ownership and Financing: Government agencies or publicly-owned utilities assume full ownership of transmission assets. Financing is secured through public means, such as bonds or state funds, which often carry lower interest rates compared to private financing, thereby reducing the overall cost of capital for infrastructure projects. These projects also usually enjoy low or no federal taxes, as well as the elimination of the private corporations' rate of return.

- Integrated Planning and Development**:** Public entities coordinate the planning and development of transmission projects, ensuring alignment with state energy policies and

[40] P.g 5; Clean Air Force & Net-Zero California Report, " Wired for Savings: Evaluating the Impact of Alternative Transmission Financing and Development Models on California Ratepayers"

community needs. This integrated approach facilitates the incorporation of renewable energy sources and supports statewide goals for carbon reduction.

- Cost Savings and Ratepayer Benefits**:** By eliminating the profit margins required by private investors and utilizing low-cost public financing, the wholly public model can result in significant cost savings. Cost savings estimates amount to approximately $ 2.9 billion (54%) in annual savings, or $116 billion over the 40-year lifetime of an asset as illustrated in Figure 4.[41]

Potential Challenges:

- Capital Requirements: Large-scale transmission projects require substantial capital investment, which may strain public budgets or necessitate increased public borrowing.

- Operational Expertise**:** Managing transmission infrastructure requires specialized knowledge. Public entities may need to acquire the necessary expertise to operate and maintain these systems effectively, or contract for the work with added expense and reduced efficiency.

- Risk Management: Public entities assume full responsibility for project risks, including construction delays, cost overruns, and operational challenges; as well as asset risks such as wildfire liability.

***Case Studies in California*.** Rather than create a wholly new state agency, California could instead expand the capabilities and legal authorities of existing agencies such as:

- The California Infrastructure and Economic Development Bank (IBank).
- The California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA).
- Department of Water Resources (DWR).

***California Infrastructure and Economic Development Bank (IBank)*.** Established in 1994, IBank is a state-run financial institution that provides funding to finance public infrastructure and private development.[42] One of IBank's primary functions is offering traditional infrastructure loans for projects like street repairs and water treatment plants. These infrastructure loans are currently only available to state and local government entities, not private developers.[43] They may also offer credit enhancements, which are strategies to improve the creditworthiness of a financial instrument or borrower, thereby reducing perceived risk and facilitating access to capital at more favorable terms.

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[41] Clean Air Force & Net-Zero California Report, " Wired for Savings: Evaluating the Impact of Alternative Transmission Financing and Development  Models on California Ratepayers"

[42]California Infrastructure and Economic Development Bank, About IBank, available at: https://www.ibank.ca.gov/about/about-ibank/ (accessed March 21, 2024).

[43] California Infrastructure and Economic Development Bank, Infrastructure Loans, available at: https://www.ibank.ca.gov/loans/infrastructure-loans/ (accessed March 21, 2025).

The Climate Catalyst Revolving Loan Fund at IBank prioritizes, "projects that advance the state's climate goals."[44] Notably, IBank's Climate Catalyst Fund already has specific legal authority to finance transmission under specified conditions. The operative statute provides that IBank shall establish a separate "Clean Energy Transmission Financing Account" within the Fund.[45]

***California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA).*** Established in 1980, CAEATFA promotes energy efficiency, renewable energy, and advanced transportation technologies through financing and incentives for qualifying projects. To that end, CAEATFA has broad authority to issue bonds, notes, and other obligations.[46] CAEATFA would likely require a statutory amendment in order to finance transmission regardless of whether it uses bonds or loans. The CAEATFA's definition of "project" does not include transmission infrastructure. As a result, CAEATFA cannot currently fund "projects" that only constitute transmission lines. Under its present regulations, CAEATFA only actually finances residential and commercial clean energy upgrades.[47]

***Department of Water Resources (DWR).*** Established in 1956, DWR manages California's water resources, systems, and infrastructure**.** Since the 2000-2001 energy crisis, DWR has had the authority to purchase power on behalf of California's retail customers. AB 1373 (E. Garcia, Chapter 367 Statutes of 2023) authorizes the Department of Water Resources (DWR) to serve as a central procurement entity to procure diverse clean energy resources in order to help the state meet its clean energy and reliability goals. This function could be deployed to provide centralized, more efficient, and integrated planning across the state.

***Public-Private Partnerships (P3).*** P3 refers to long-term (typically 25 or more years) performance-based contracts with public-sector entities in which the private sector takes or shares responsibility and risk for the design-build-finance-operate-maintain (DBFOM) elements of a public infrastructure project.[48] In 1989, California was one of the first states to pass P3 legislation, and two of the nation's first P3 highway projects were built in Southern California under that legislation.[49] According to the Public Advocates Office, which has encouraged the state to explore P3 arrangements to finance transmission in addition to purely public financing

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[44] California Infrastructure and Economic Development Bank, Criteria, Priorities, and Guidelines for the Selection of Projects for IBank Financing under the Climate Catalyst Revolving Loan Fund Program (Jan. 2022), available at: https://ibank.ca.gov/wp-content/ uploads/2022/08/Criteria-Priorities-and-Guidelines-for-IBanks-Climate-Catalyst-Revolving-Loan-Fund.pdf (accessed March 21, 2025).

[45] Gov. Code § 63048.93, subd. (c)(2).

[46] Pub. Res. Code § 26011, subd. (c).

[47] Because transmission does not fall within the meaning of "advanced transportation technologies," transmission could only theoretically fit within CAEAFTA's statute as an "alternative source."

[48]Bay Area Council Economic Institute, *Public-Private Partnerships in California How Governments Can Innovate, Attract Investment, and Improve Infrastructure Performance* 1 (Aug. 2018), available at: http:// www.bayareaeconomy.org/files/pdf/P3inCaliforniaWeb. pdf (accessed March 21, 2025).

[49] Id; Alan T. Marks et. al, California Public Private Partnership Developments, Milbank (March 23, 2009), available at: https://www.milbank.com/a/ web/606/032309_California_Public_Private_Partner¬ship_Developments.pdf (discussing AB 680 (1989)); Assem. Bill 680 (1989-90 Reg. Sess.) available at: https://ppp.worldbank.org/public-private-partnership/ sites/ppp.worldbank.org/files/ppp_testdumb/docu¬ments/California0Toll0Road0Law.pdf).

approaches, P3 "would likely result in intermediate ratepayer savings between the bookends of pure public and pure private investment options."[50]

As an example, the Hydrogen Fuel Cell Partnership (H2FCP), a nonprofit public benefit corporation, is a "collaborative of auto manufacturers, energy companies, fuel cell technology companies, and government agencies" that work to promote hydrogen fuel cells.[51] Among other public agencies, the Governor's Office, CARB, and the CEC are members of the H2FCP, which evolved out of 1999's California Fuel Cell Partnership.[52] If a transmission-P3 were similarly arranged as a nonprofit corporation or as an informal association of state agencies and private entities, then it is possible that, like the H2FCP, it would not require any enabling legislation, so long as the state agencies would act within their existing authorities.[53]

Two types of P3 are the concession-type and the lease-type. The concession-type involves contracts where the government-owned asset is designed, built, operated, and financed by a private company over the life of the asset, and then ultimately returned to the government at the end of the concession agreement. This path may offer improved efficiency by taking advantage of skilled expertise and innovation in private sector but not deliver the same financing cost savings. The private partner would recoup its investment and return on that investment through user fees, tolls, or service charges, the period of which dictates the duration of the concession. This model presents an opportunity for reduction in public investment and some tax savings as the state of California would avoid upfront capital costs. Cost savings estimates amount to approximately $1.3 billion (25%) in annual savings, or $54 billion over 40-year lifetime of an asset.[54]

A lease-type P3 occurs when a government entity finances the transmission asset but hires a private-sector partner for operations, maintenance, and management. A key advantage of the lease-type P3 over the concession-type P3 is that the latter relies on private sector financing and the return on equity and commercial debt that comes with that. A lease-type P3 has the advantage of using lower cost public debt, exemption from certain taxes, and the retention of private sector efficiency in operating and maintaining the transmission line. The contracts with the private sector can also shield the public entity from operational risks and allow for better control of costs.[55] Cost savings estimates amount to approximately $3 billion (57%) in annual savings, or $123 billion over 40-year lifetime of an asset.[56]

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[50] The Public Advocates Office, Public investment infrastructure is a promising option to support California's energy transition and reduce ratepayer costs 4(May 16, 2023), available at: https://www.publicadvocates. cpuc.ca.gov/-/media/cal-advocates-website/filesreports/230516-caladvocates-public-investment-in-infrastructure.pdf (accessed March 21, 2025).
[51] Hydrogen Fuel Partnership, https://h2fcp.org/ Accessed March 10, 2025
[52] Ibid
[53] See Hydrogen Fuel Cell Partnership, About Us.
[54] Clean Air Force & Net-Zero California Report, " Wired for Savings: Evaluating the Impact of Alternative Transmission Financing and Development Models on California Ratepayers"
[55] Improving transmission financing in California, October 2024.
[56] Clean Air Force & Net-Zero California Report, " Wired for Savings: Evaluating the Impact of Alternative Transmission Financing and Development Models on California Ratepayers"

***Conclusion.*** California requires a monumental scale-up of transmission capacity, to accommodate a rapidly growing portfolio of renewable resources. However, the development of transmission infrastructure remains a complex undertaking —a process often characterized by significant delays which inflate project costs. These rising costs are reflected in utility bills, placing a strain on ratepayers across the state. Consequently, the projected cost for future transmission development necessitates a more creative approach to funding this infrastructure. Nonetheless, the state should consider all options and be mindful of the tradeoffs in determining solutions to rising energy bills.

## Appendix

- The Scoping Plan–CARB– Occurs every 5 years:
  The California Global Warming Solutions Act of 2006 created a comprehensive, multi-year program to reduce GHG emissions in California. The Act required CARB to develop a Scoping Plan that describes the approach California will take to reduce GHGs to achieve the goal of reducing emissions to 1990 levels by 2020; this goal has since been updated to be a reduction of 40 percent below 1990 levels by 2030.[57] A subsequent report is expected to be released in 2025.

- SB 100 Report– Multi-Agency– Occurs every 4 years:
  The SB 100 report is a multi-agency report that serves as a foundation that evaluates the challenges and opportunities in implementing the 100% Clean Energy Policy. The first report was released in March 2021 by CARB, the CEC, and the CPUC.

- IEPR –CEC – Occurs every 2 years:
  The CEC prepares an Integrated Energy Policy Report (IEPR) as a data-driven forecast of all aspects of energy industry supply, production, transportation, delivery, distribution, demand, and pricing. The CEC is then required to use these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety. The CEC is also required to publish a strategic plan for California's transmission grid and weave it into the broader IEPR framework. [58]The CEC adopts an IEPR every two years with updates every other year.

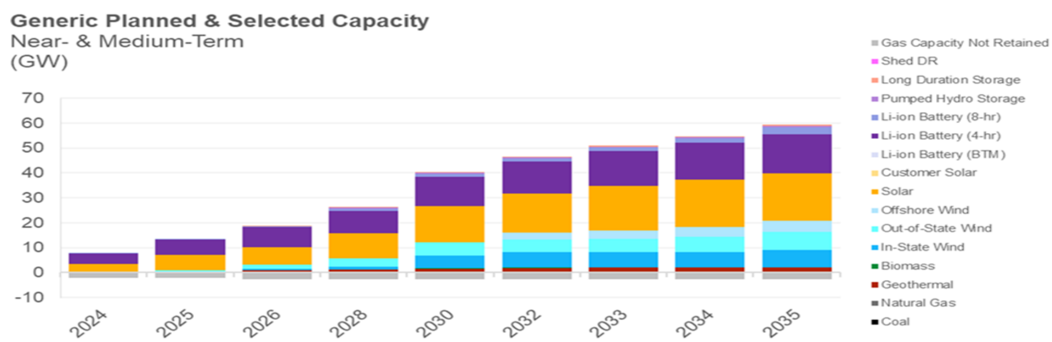
- The IRP–CPUC-Occurs every 2 years:
  SB 350 (De León, Chapter 547, Statutes of 2015) mandates the CPUC to adopt a process for each regulated Load Serving Entities—electrical corporations, community choice aggregators, and electric service providers) — to file an Integrated Resource Plan (IRP). The goal is to reduce the cost of achieving GHG emission reductions by looking broadly at system needs, rather than at individual LSEs or resource types. The IRP process begins with the CPUC developing a Reference System Plan (RSP), which estimates (LSEs) should procure to meet clean energy and climate goals cost-effectively.

  The CPUC then allows these individual LSEs to file their individual procurement plans, after which the CPUC reviews and approves those plans based on their consistency with collective system needs under the Preferred System Plan (PSP). This Preferred System Plan is often the basis for a number of additional planning processes, including the SB 100 report, Transmission Planning Process (TPP) by the CAISO, and subsequent LSEs' IRP plans. Current statute, within the IRP framework, also allows the CPUC to order the resource procurement, outside of individual LSEs' IRPs, in order to meet decarbonization goals.

[57] SB 32, Pavley, Chapter 249, Statutes of 2016
[58] California Public Resources Code Section 25324

In February 2024, the California Public Utilities Commission (CPUC) adopted a decision within its Integrated Resource Planning (IRP) process to align the state's electric sector with an ambitious greenhouse gas (GHG) reduction target of 25 million metric tons (MMT) by 2035.[59] This target represents the most aggressive target within the range identified by the California Air Resources Board (CARB) and reflects the state's commitment to decarbonize the power sector. To meet this target, the CPUC has determined that 56GW of new clean energy resources will be needed by 2035 as illustrated in Figure 1. This includes 19 gigawatts (GW) of new solar capacity and 15 GW of 4-hour battery storage—meaning doubling the state's solar capacity and tripling its battery storage compared to current levels, necessitating substantial investments in transmission infrastructure.

**Figure 1: Planned and Selected Resource Capacity (MW) for 25 MMT Core Case**




An additional component of the IRP process is the sensitivity analysis**,** which additionally requires CPUC to assess emerging and evolving technologies that may lack ample pricing data or availability to be incorporated as primary resources. These analyses provide insights into their potential role, feasibility, and impacts within the broader energy portfolio.

- The TPP–Annually, CAISO conducts its Transmission Planning Process (TPP) to evaluate system constraints and identify necessary transmission upgrades or new infrastructure to enhance grid reliability and efficiency. The TPP is guided by the CPUC's Integrated Resource Planning (IRP) process**,** which determines the optimal resource mix to achieve the state's greenhouse gas (GHG) reduction targets for the electric sector.

- The CAISO Transmission Outlook – In May 2022, the California Independent System Operator (CAISO) worked collaboratively with the CPUC and CEC and developed CAISO Transmission Outlook that identifies long-term transmission infrastructure necessary to meet California's clean energy and reliability goals cost-effectively.

[59] Proposed Decision 24-02-047 issued 2/15/2024 in IRP Proceeding, Rulemaking 20-05-003