Comments on the Draft "Green Book"

THE THEORY AND EVOLUTION OF COMMUNITY CHOICE IN CALIFORNIA

11 JUNE 2018

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Table of Contents

Tables and Figures

Introduction

While the Commission's draft "*Green Book*" under the "*California Customer Choice Project*" contains a wealth of information and probing questions of a structural nature, what is lacking is an understanding of how Community Choice Energy agencies (CCEs) have been designed to operate, the ways in which they are evolving in terms of operational sophistication and inter-agency coordination (joint action), the reasons why, and how these new public power agencies could best enhance California's energy sector.

This is a notable omission given the extraordinary acceleration of the CCE industry, though somewhat understandable considering how diverse and dynamic the CCE industry has become.

Unfortunately, it has caused the Commission to situate and portray Community Choice as a mode of "Customer Choice" along with retail Direct Access and Distributed Energy Resources. This is a false tautology that precludes an accurate understanding of how California's energy sector is structured at present, much less an informed discussion of how it should be optimally re-organized going forward.

A more accurate view of Community Choice, far from being comparable to retail Direct Access or other modes of "customer choice" under the Commissions broad regulatory purview, is that it represents a structural transference in the powers long-vested in the Investor Owned Utilities (IOUs) and in the Commission itself — and that this level of market transformation warrants much closer examination.

CCE from this perspective represents a re-balancing of decision-making authority, institutional capacity and technical expertise, empowering local governments by devolving these functions to a more democratic level of governance, and consequently diminishing the statutory and de-facto autonomy of the State regulator and private utility monopolies. CCEs, in other words, are a fusion of technical expertise and political agency expressly designed to accelerate meaningful structural change within California's energy sector.

In this deeper structural sense, CCE does not inhabit a pre-defined "market" in which individual customers make limited decisions ("customer choice"). Rather, CCEs become the mediating agency between retail customers in their jurisdictions and various upstream segments of the energy value chain — in terms of long-term planning, market operations, retail products and services, regulatory engagement and legislative advocacy. These new public power agencies thus inherently combine attributes of the Commission (in terms of public oversight of planning, customer protections, etc.) and the IOUs (retail rate setting, NEM and FIT tariffs, RPS procurement, etc.) with their own municipal authorities, policy directives and substantial networks of civic and private institutions.

From this vantage point, it is easy to comprehend how CCEs directly shape the "market" in which customers consequently become aware of and make choices. For example, certain CCEs offer higher NEM rates than the IOUs, which shape the market economics of rooftop solar photovoltaic contracting decisions by customers in their territory. Similarly, CCEs have begun to offer large commercial and industrial customers more customized rate structures and products — and there is nothing stopping a CCE from de-facto "re-opening" Direct Access in their own territory in a planned fashion by allowing sophisticated customers to choose their own supplier (subject to creditworthiness and business process alignments with the CCE agency). Lastly, there is nothing stopping CCEs from leveraging their technical expertise to take customers "off grid", their legislative advocacy to remove over-the-fence restrictions on commercial microgrid developments, or their institutional capacities, local networks and inherent municipal authorities to (1) accelerate microgrid developments in new developments or (2) guide the formation of new municipal utilities to develop microgrids (and even establish separate balancing areas). This contrasts sharply with the Commission's narrow proclamation that:

> *"…customer choice* ***does not*** *include the choice of poles and wires distributing electricity…. the role of the IOU is changing but remains essential."*

In summary, the Commission's draft "*Green Book*" describes the authorities of CCEs somewhat accurately but does not examine the actual structure of CCEs as public power agencies — and the manner in which CCE is repeatedly portrayed (e.g. as an option for customers to "choose" comparable with retail Direct Access and Distributed Energy technologies) actually obscures the real-world context necessary for stakeholders to comprehend the deeper and more valuable functions of Community Choice.

Critically, it is actually within these deeper functions that the real debate should be taking place. At that level of discussion, it will become apparent that:

1. Many of the concerns expressed by the Commission are being addressed internally within the CCE industry through its own innovation in business models and inter-governmental collaboration.
2. The Commission's primary goal should be to remove regulatory barriers that currently prevent the application of Information Technology to integrate Distributed Energy and optimize planning and operations within the energy sector;
3. The immediate barriers to progress are arguably issues of data access and business process alignment between the CCEs and IOUs — much of which the Commission could easily resolve in the near-term.

Consequently, the purpose of these comments is to provide the Commission with:

1. A theoretical framework of industrial organization through which to more accurately analyze the energy industry (i.e. the structural evolution of the electricity industry and its extension into the transportation and natural gas industries), with a particular focus on Distributed Energy Resources (DER) and the powerful role of CCE within this deeper context;
2. An overview of the emerging "CCE 2.0 and 3.0" maturity models that are respectively aligning and accelerating the operational and governmental evolution of CCE agencies in California — **and in so doing, changing the parameters of and/or mitigating the various risks with which the Commission is concerned** — along with key barriers and issues that the Commission should resolve in the near-term so as not to jeopardize this evolution.
3. An overview "primer" of energy risk management practices necessary to understand key aspects and impacts of the "CCE 2.0" business model;
4. An explication of how and why CCE 1.0 and 2.0 business models have been structured differently in relation to the aforementioned key dynamics, and the relative strengths and weaknesses in each approach.

5. An update and outlook on the "CCE 3.0" joint-action initiatives taking place within the industry.

Lastly, the Appendix contains a detailed narrative description of the various functions that typically comprise a CCE's business model. It is intended to be broadly representative (not prescriptive or reflective of any one agency) and included primarily to ensure the Commission understands just how transparent and technically-sophisticated CCEs are becoming in California.

These comments are not intended to be exhaustive by any means; rather, it is intended to provide useful conceptual models, high-level situational awareness and an over-the-horizon outlook for the Commission and stakeholders involved in the "*California Customer Choice Project*" to better understand how Community Choice has and continues to evolve — and in so doing, helps elevate the debate to a level commensurate with California's ambitious goals.

Samuel Golding
President of Community Choice Partners, Inc.

Industrial Organization & Economic Theory: Science of Choice vs Contract

The text below draws heavily upon the industrial organization and economic theories of the Professors Ronald Coase and Oliver E. Williamson[1] — both recipients of the Nobel Prize who worked closely together at various points in their academic careers.

As further context, the political theory that inspired Community Choice originated with Paul Fenn in the 1990s, then a student at the University of Chicago. It was there that Professor Ronald Coase suggested to Mr. Fenn that it could be applied most readily to the power industry, as it was about to undergo a market restructuring in various states. Mr. Fenn subsequently co-authored and passed the nation's first Community Choice law in Massachusetts. He later did the same in California and contributed substantially to the development of the initial regulations in California. (I later became acquainted with Mr. Fenn as the Managing Director of his firm Local Power for a number of years.)

What follows is intended to provide more intellectual clarity into how the Commission and stakeholders within the "*California Customer Choice Project*" analyze the energy sector and the opportunities for reformation therein — with particular attention paid to the integration of Distributed Energy and role of Community Choice.

> *"…mutuality of advantage from voluntary exchange is… the most fundamental of all understandings in economics." — James Buchanan, 2001*
>
> *"A predictive theory of economic organization will recognize how and why transactions differ in their adaptive needs, whence the use of the market to supply some transactions and recourse to hierarchy for others." — Oliver E. Williamson, 2002*
>
> *"Politics is a structure of complex exchange among individuals, a structure within which persons seek to secure collectively their own privately defined objectives that cannot be efficiently secured through simple market exchanges." —James Buchanan, 1987*

Economic phenomena are often analyzed through the science of choice, a neoclassical framework that focuses primarily on how consumers behave and how firms seek to profit by maximizing their productive function. At first blush, this is the primary lens through which the Commission has viewed Community Choice in the context of California's energy sector.

This framework is actually quite narrow and ill-suited to analyzing the complexities of resource allocation and economic optimization within the energy sector; the limitations of this simple "market exchange" perspective appear to have caused the Commission to repeatedly conflate Community Choice with Customer Choice. In fact, the two are at diametric ends of an intellectual spectrum; to the extent that Community Choice was designed in response to and intended to overcome the structural superficiality of Customer Choice.

It is critical that the Commission fully comprehend this distinction, because Community Choice actually represents an extremely powerful and novel mode of economic organization that — if executed properly

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[1] For deeper reference to the concepts summarized herein, I recommend "*Contract, Governance and Transaction Cost Economics" (2017)* and "*The Theory of the Firm as Governance Structure: From Choice to Contract" (2002)* by Professor Oliver E. Williamson — available online: [http://kisi.deu.edu.tr/sedef.akgungor/Williamson.pdf]

— can support and accelerate California's efforts to decarbonize its economy. Alternatively, California risks profound opportunity costs if accurate assessments of feasible alternatives are instead sacrificed in a constrained process which prioritizes immediate political objectives (of a factional nature, ipso facto).

The power industry is a highly specialized exchange economy within which "customer choice" transactions are heavily mediated by multiple dimensions of regulatory fiat; it is thus more deeply and accurately understood from a science of contract perspective. This is the proper theoretical framework through which to more accurately understand the energy industry, the nature of the changes occurring within California, and the emerging potential of Community Choice.

This perspective is all the more critical considering that California's efforts to decarbonize its economy necessitate expanding the electricity industry into the transportation and natural gas economic systems by electrifying vehicles and end-uses (appliances, industrial processes, etc.). Doing so entails a profound transformation in how Distributed Energy Resources are integrated into, valued and monetized across a complex value chain that is regulated and controlled by different institutions, and in how individual customers, networks of local institutions, municipal authorities, and the private sector are leveraged to accelerate and manage this effort. Community Choice as it is evolving in California is uniquely positioned to play an enabling role on all of these fronts.

At its core, contract theory resolves how the attributes of the various transactions required within any economic system, and how those transactions are best satisfied, consequently determine the optimal models of governance (internally within both public and private entities) as well as the effective parameters of market functions. It also recognizes that all complex contracts are unavoidably incomplete and that this (1) represents a source of fundamental uncertainty, (2) creates the risk of strategic opportunism (gaming, etc.) and (3) requires adaptive behavior across various structural dimensions to manage — which is a determining factor in how the economic system should be organized overall. This is a particularly useful insight when applied to the power sector.

In other words, the types of transactions are the "why" that necessitates the "how" of the resulting structure of any economic regime. Consequently, a holistic analysis of an economic system as complex as the energy industry should:

1. Define the various transactions required (or desired) by the economic system, and the differing attributes therein — in particular, applying systems theory to analyze the transactions required to integrate Distributed Energy Resources in a holistic fashion across all components of the value chain;

2. Apply organization theory to analyze the extant and optimal division of roles (clusters of transactions) between the public and private orders (e.g. markets, hybrids, firms and bureaus);

3. Draw upon the theory of the firm, contract as a framework, and the logic of transaction cost economizing within each order to analyze why and how different types of transactions are best accomplished through either (1) hierarchical (administrative) means of control versus (2) market mechanisms and price signals — paying particularly close attention to the level of adaptive behavior required to manage increasingly complex transactions therein;

4. Apply game theory to analyze strategic behavior that impacts how transactions are operationalized owing to information asymmetries, bounded rationality, fragility of motive,

conflicts of interest, and opportunism of various other kinds across and within all of the public and private organizations participating in the economic system.

Transactions and Dependencies within the Power Sector

As structural context in considering California's power sector:

1. Transactions within the electricity industry exhibit a high degree of asset specificity, in that they require upfront investments in transaction-specific assets, with unique physical attributes and site-specificity, that must be managed by specialized human assets (expertise);
2. The resulting commodity is not cheaply or widely stored; and
3. The manner by which various asset attributes are valued and monetized by transactions are:
    a. Both highly differentiated and <u>temporally divergent</u> across the different classes of market participants;
    b. Mediated by highly complex rules (defined by a variety of parties within different forums) that evolve dynamically;
    c. Widely variable in terms of frequency and potential for disturbances (i.e. the consequences owing to errors in the contracting process); and
    d. Often not fully compensated (for Distributed Energy Resources in particular) under extant market rules, planning regimes and regulations.

Transactions of this nature render parties on both sides vulnerable to bilateral dependencies, in that:

1. Suppliers often face a loss of productive value in deploying their specialized assets to the "best" buyer (or most often, to multiple "best" buyers of differentiated product attributes from the same asset); while
2. Buyers transact within a constrained ecosystem of suppliers.

Given these unique structural attributes and resulting dynamics of the electricity industry:

1. Simple market exchanges have historically been unable to deliver credible contracting across all transaction types; and
2. A primary hazard of the bilateral dependencies between buyers and sellers is that this create strategic advantages to vertical integration (unified organization within a value chain).

Consequently, the electricity sector requires an *a priori,* value-preserving governance structure to provide order to the transactions that subsequently occur within both markets and hierarchies.

As a matter of economic efficiency, the Commission should be focused on ensuring that transactions are carried out in markets to the greatest extent possible while ensuring the financial and physical stability of the economic system. This is the "right question" to ask — and it opens up a valuable discussion of the role of Community Choice in California.

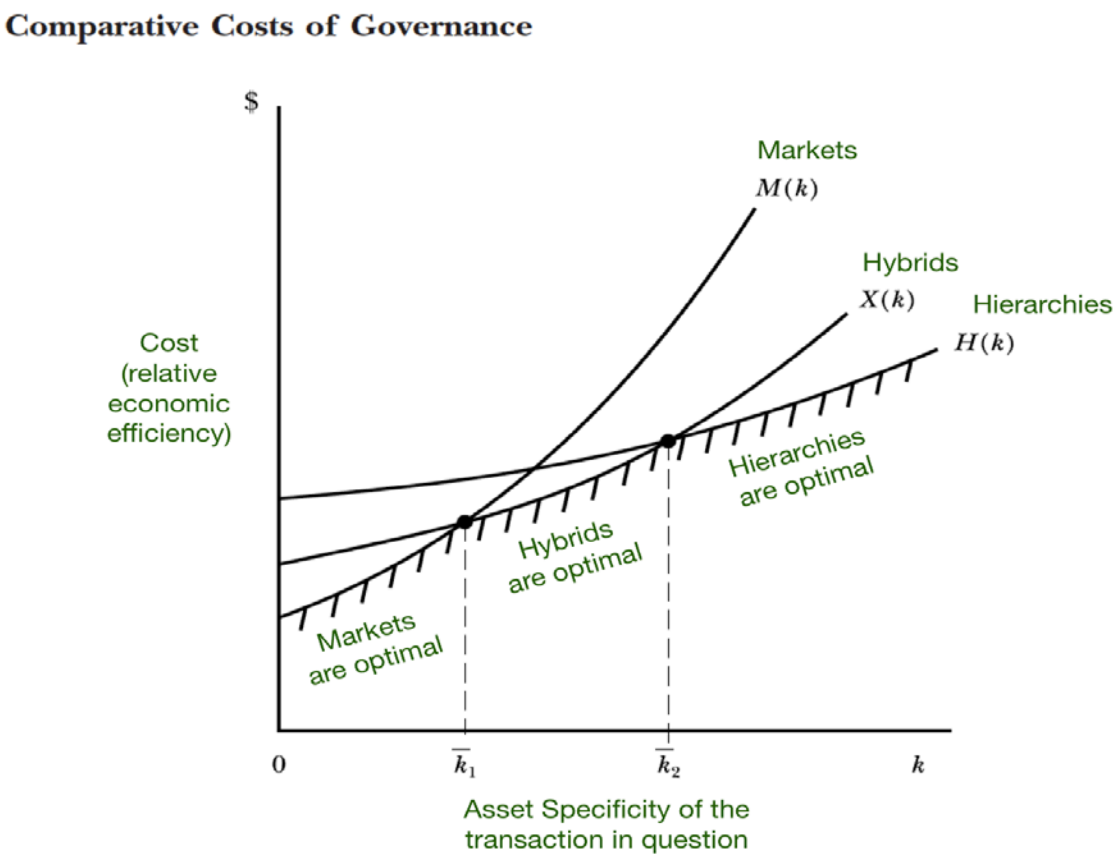
Markets, Hierarchies and Hybrids

Organizing economic activity through markets, hierarchies or a hybrid of the two imposes differential costs (in terms of economic efficiency) as a function of asset specificity — because the need for "out of market" cooperative adaptation increases in relation to the complexity of transactions. Broadly speaking:

1. Markets function efficiently in inverse relation to the complexity of a transaction, and beyond a certain point, will fail to provide liquidity or counterparties for complex transactions.
2. Transactions that exceed a certain level of complexity must therefore be satisfied "out of the market" i.e. through increasingly hierarchical modes of economic organization.
3. Consequently, high levels of asset specificity, and a corresponding need for adaptive behavior in transactions, will favor hierarchy over markets.
4. Economic efficiency degrades under such regimes, as bureaucratic costs accrue from needing to manage complex transactions and the incentive intensity of markets is replaced by administrative controls.

The graph below, with my explanatory notations colored green, is sourced from a leading academic in this field (Professor Oliver E. Williamson of UC Berkeley, joint recipient of the 2009 Nobel Memorial Prize in Economic Sciences):

Figure 1: Comparative Costs of Governance under Markets, Hierarchies and Hybrids



Source: Oliver E. Williamson, with explanatory notations added in green

Each mode of governance differs in terms of how transactions are managed with regard to costs and competencies, with key dynamics depicted graphically below:

Figure 2: Comparative Dynamics under Markets, Hierarchies and Hybrids

	Incentive Intensity	Command & Control (at the interface)	Contract Law Regime
Markets	Strong	Weak	Strong (legal rules)
Hierarchies	Weak	Strong	Weak (forbearance law)
Hybrids	Variable	Variable	Variable

Source: Community Choice Partners, Inc., with reference to Oliver E. Williamson

California's Current Structure

Much of the economic activity within California's power sector is governed through a combination of hybrids and hierarchies. While a comprehensive analysis is beyond the scope of these comments, in brief:

1. Regulatory institutions such as the California Public Utilities Commission, California Energy Commission and California Independent System Operator (CPUC, CEC and CAISO) are hierarchical bureaus which define the rules by which transactions are governed within the electricity industry (to varying degrees of economic efficiency);
2. Investor Owned Utilities, as State regulated monopolies, are hybrid firms that perform much of the required transactions internally through hierarchical administrative controls and engage "markets" transactions to varying degrees;
3. Historically within this construct:
    a. Energy supplies are transacted by the IOUs:
        i. Primarily through solicitations for long-term contracts, hierarchical evaluations of portfolio cost impacts, and bilateral negotiations with developers;
        ii. Secondarily through a variety of hybrid modes such as direct bilateral negotiations and brokering houses;
        iii. Thirdly through the CAISO wholesale markets for residual supplies and balancing.
    b. Capacity (resource adequacy) is transacted by the IOUs:
        i. Primarily through a hierarchical process of target setting (with the CEC and CPUC) and a hybrid mode of bilateral negotiations for short-term supplies;
        ii. Secondarily through a hierarchical process of target setting (with the CPUC and CAISO), and a hybrid mode of long-term solicitations, hierarchical evaluations, and bilateral negotiations with developers.
    c. Distribution grid investments are transacted through an internal hierarchical process, though the Commission is attempting to evolve this process into a hybrid mode and then

market mode that engages Distributed Energy developers (through the IDER and DRP proceedings).

d. Transmission investments are transacted through a hierarchical planning process, a hybrid mode of solicitation and hierarchical evaluations.

DER & Systems Thinking: Evolution of Hierarchical Controls to Hybrid Modes and Market Mechanisms

California has created a large ecosystem of Distributed Energy firms under a truly complex array of supportive policies, wholesale energy market rules, capacity procurement mandates, public fund subsidies (rebates) and corresponding programmatic activity.

This "market" ecosystem of DER firms is heavily mediated through the aforementioned mechanisms; apart from the CAISO's efforts to integrate DER into wholesale markets, the modes of governance that define current DER transactions are hierarchies and hybrids that tend towards hierarchy.

Consequently, DER firms under this framework must navigate a vast array of mechanisms in an attempt to monetize the various specific attributes of their assets. From a transaction cost economizing viewpoint, this is far from ideal; it constrains market activity and increases economic costs.

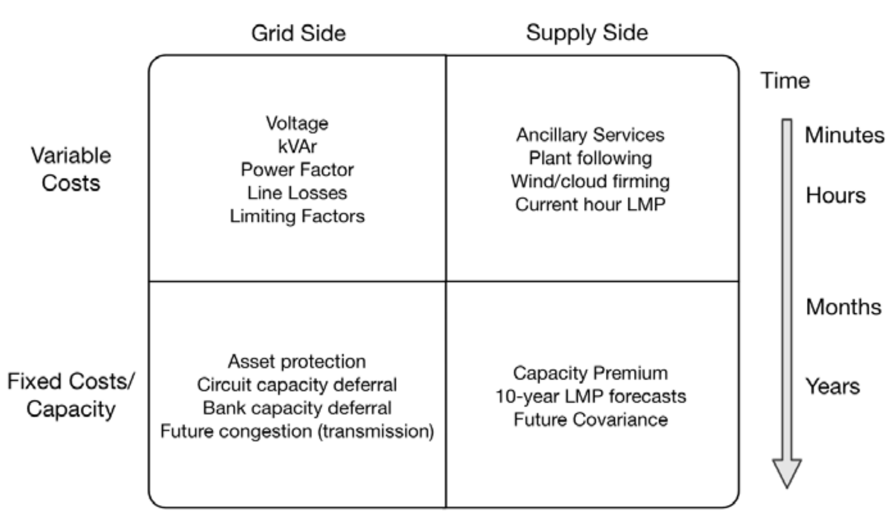
The primary technical barrier in creating market mechanisms that credibly contract for DER in a manner that matches asset specificity with the costs and benefits created across the power industry value chain has long hinged on:

1. The availability of data and accurate methodologies;
2. The software and computation infrastructure required to construct functional markets.

What has changed is that we now have the data, methodologies, computation capacity and software required to target, value and integrate Distributed Energy Resources into the planning processes and operations of the distribution grid, transmission grid and wholesale markets.

Below is a simple representation of the different components that comprise an "all in" marginal cost calculation for accurately valuing DER deployments in specific geographic locations (i.e. circuits within utility distribution grids):

Figure 3: Dimensions of "All In" Marginal Costs



Source: Integral Analytics (2016)

Computations such as these are actually being used internally to varying degrees by certain utilities already, including Pacific Gas and Electric and Southern California Edison.

In other words, the question of how DER is integrated into planning and operational processes, and how quickly and efficiently markets are created to do so, is now one of execution.

The Role of Hierarchies in Enabling DER Market Transactions

The CAISO has been integrating and refining DER into wholesale electricity market rules for a number of years, and the CPUC has been doing so on a related front in terms of long-term contracting for resource adequacy (capacity) via IOU solicitations. More recently:

1. Rule 21 revisions mandated the use of Smart Inverters and a (somewhat undefined) requirement that the IOUs communicate and control these devices for integration into distribution grid operations;
2. Through the IDER and DRP proceedings, the Commission has imposed hierarchical controls to define valuation methodologies, business processes and data access requirements with the goal of evolving the governance of DER integration towards hybrid and eventually market modes of transacting.

Coordinating the valuation and operational control of DER within this evolving framework is a challenge. In brief however, there is a near-term opportunity to collapse the transactional complexity that has evolved across the various hybrid and hierarchical domains of the power sector into a more streamlined market mechanism — with geographically-specific price formation along the lines of the above (see Figure "Dimensions of "All In" Marginal Costs").

To this end, I offer this simple conceptual model for consideration by the Commission:

All too often, hierarchical regulatory institutions in the power sector draw a dividing line at an economically inefficient point in this simple model. The Commission has in fact done so repeatedly for Community Choice agencies and more recently, within the DRP proceeding, by drawing the dividing line too far to the left.

Within the DRP (R.14-08-013), the Commission's recent decision directed all three IOUs to:

1. Standardize DER forecasting results, distribution grid topology maps and related data types;
2. Establish a single online portal with both downloadable datasets and API (Application Programming Interface) access; and
3. Annually publish updated maps and data types to allow for DER to offset planned distribution gird investments at specific locations.

The Commission also ordered that this process be both constructed with substantial stakeholder engagement and subsequently overseen on a regular, ongoing basis by a stakeholder committee.

As an example of the data types that the IOUs plan to release under this initiative:

Figure 4: IOU Circuit-Level Planning Data for DER under the DRP

III. CIRCUIT-LEVEL PLANNING ASSUMPTIONS

As an attachment to SCE's 2018 GNA, SCE will provide the forecasted net load, and forecasted DER nameplate capacity by technology type while complying with existing CPUC rules governing confidential customer information.[2] The example provided is for illustrative purposes only, and does not represent actual grid needs.

Facility	2018 Growth (MW)					2019 Growth (MW)				
	Base Demand	PV	EE	EV	LMDR	Base Demand	PV	EE	EV	LMDR
Circuit 12 kV	3.000	0.000	-1.000	1.000	0.000	2.000	0.000	-1.000	1.000	0.000

2020 Growth (MW)					2021 Growth (MW)					2022 Growth (MW)				
Base Demand	PV	EE	EV	LMDR	Base Demand	PV	EE	EV	LMDR	Base Demand	PV	EE	EV	LMDR
0.09	0.00	0.00	0.02	0.00	0.09	0.00	-0.02	-0.02	0.00	0.20	0.00	-0.02	0.04	0.00

Source: SCE Advice Letter 3787-E

Note that these forecasts are proposed to be provided at the distribution circuit level, and are based on an internal forecast that is sufficiently temporally granular to capture load impacts at different points in time. (SCE's Advice Letter 3787-E further notes that more sophisticated forecasting is being developed in this regard and will be relied upon in 2019.)

The Commission's expressly stated purpose under this initiative is to remove barriers to wider market participation by DER firms — primarily through the release of certain planning data and the creation of a hybrid solicitation mechanism overseen by the IOUs and other stakeholders. While the Commission's progress is laudable, several questions spring to mind:

1. If the analytics exist to create "all in" marginal cost price signals, why has this not been deployed?
   a. DER firms will continue to have to navigate other hybrid mechanisms to monetize the attributes of their assets, which poses transactional cost inefficiencies and leads to undervaluation/ underutilization.
2. If the IOUs have developed or contracted for sophisticated DER analytics and forecasting tools, why has the Commission only required that only data outputs be released in a limited fashion?
   a. For example, the Commission could both enhance oversight over the use and refinement of such tools and also align planning assumptions of CCEs and IOUs far more closely if CCEs were given access the underlying analytics and primary data sources.
3. More specifically, if the analytics exist to analyze customer-specific data and evaluate optimal configurations of DER assets, why has the Commission not created a process under which this targeting intelligence could be leveraged to accelerate DER deployments?
   a. As it stands, IOUs will release limited "hot spots" on the distribution grid that warrant DER investments, and then leave it up to the market of DER firms (which lack customer data) to identify customers, configure DER proposals, and solicit customer participation.

b. Compared to a more automated, data-driven targeting process, this imposes severe transaction cost inefficiencies.

In short, the DRP has created a hybrid mechanism of DER procurement that fails to fully capture the market price signals that are technically possible, to leverage utility-held data to streamline DER targeting and customer acquisition, and to coordinate DER planning assumptions to the full degree warranted by the acceleration of CCE load departure.

Referring back to the simple conceptual model (data → analytics → targeting and price signals), the Commission has drawn the line far to the left. To a certain extent, this type of inefficiency occurs because the regulator lacks the resources to deeply understand the opportunities latent within the power sector — and thus opportunities to enhance the overarching market design remain hidden.

This insight brings us to the critical role of hybrid entities — and the opportunity of Community Choice versus the IOUs in this key regard — that the Commission should pay close attention to.

The Role of Hybrid Entities in Enabling DER Market Transactions

"We're all along for the ride in terms of how and when the utilities want to reform their business models."

- CTO of a Distributed Energy firm, speaking privately after a CPUC "Thought Leader" panel

Hybrids are by definition entities that balance the need for hierarchical controls with market mechanisms to satisfy transactional requirements. The key question is whether they do so in the most economically-efficient manner possible — and the Commission should be evaluating the role of the IOUs and CCEs from this perspective.

Underlying the design inefficiency that the DRP has created is the reality that:

1. Targeting DER from a holistic (systems theory) planning perspective requires co-optimizing wholesale market price forecasts, capacity planning, transmission planning, distribution grid planning and retail usage and account data.
2. Performing such a complex analysis requires access to data (including confidential data for every customer in the area) and substantial resources to perform the analytics.
3. Subsequently operationalizing DER transactions in the manner required to best monetize all attributes of these assets requires:
    a. Acting as a mediating entity which streamlines DER asset valuation and integration into the hybrid and hierarchical forms of valuation, incentive administration and planning assumptions across various regulatory proceedings and procurement mechanisms; and
    b. Offering the flexibility in retail rate structures and billing procedures, operational data connections to DER systems and related business process evolutions required to integrate DER into retail products and services.

These are significant market barriers which DER firms are not structurally positioned to overcome; however, both the IOUs and CCEs are:

- IOUs have the data, analytics and resources to do so — but owing to business model and strategic conflicts are unwilling at this time to perform the mediating function that would otherwise accelerate and streamline the DER market.

- CCEs have — or will soon possess — much of the data, analytics and resources required to perform this mediating function, and do not have the same business model and strategic conflicts that the IOUs do.

CCEs as Hybrid Entities

Within this framework, CCEs are a hybrid form of governance that possess adaptive attributes allowing transactions to be accomplished through both hierarchical and market modes — and are demonstrating increasing sophistication in regard to DER integration. Notable characteristics and activities in this regard include:

- CCEs are public sector "bureaus" in that they transact as a nonprofit in accordance with policy objectives set by elected officials, but also "firms" in that CCEs are exposed to competitive pressures and consequently, incentive intensity that serves as a check against hierarchical costs (bureaucratic inefficiencies of various kinds that blunt progress).
- As they have evolved in California, CCEs have:
    - Achieved economies of scale through multi-jurisdictional governance structures (Joint Powers Agencies, or JPAs);
    - Accessed increasingly sophisticated operational expertise through strategic contracting,
    - Hired expert staff to exert effective public oversight — if not direct control — over strategic operational and planning functions; and
    - Engaged in procurement, programs, rate design and regulatory and legislative initiatives to accelerate renewables and Distributed Energy Resources (DERs).
- The nature of opt-out customer aggregation avoids numerous transactional costs implicit in individual customer choice, and the resulting customer base of a CCE is relatively stable and geographically concentrated; this is the structural foundation upon which CCEs are able to negotiate long-term contracts to construct new generation assets.
- CCEs, as new public power agencies, have the responsibilities of a Load Serving Entity (LSE) but also the geographic scale, public policy goals and inherent authorities of municipalities.
    - Certain CCEs have been coordinating changes in municipal land use, building code and transportation planning to support DERs and vehicle electrification (including public transit i.e. buses).
- CCEs functions as a mediating agency between retail customers and wholesale markets, and increasingly between retail customers and other components on the energy value chain. Recent examples include:
    - Targeted electric vehicle deployments informed by distribution grid analytics;
    - Deployment of Virtual Power Plant capabilities, and the subsequent integration of various DER assets (demand response, electric vehicle managed charging, etc.) into DRAM capacity auctions as well as CCE portfolio optimization and CAISO market operations;
    - Joint solicitation of DERs by CCEs and IOUs to offset peaker plants and transmission upgrades;
    - Construction of microgrids jointly controlled by CCEs and IOUs, and the tariffs required to jointly operate DER assets.

- Development of customized rate schedules that offer more flexibility than IOU rates, including exposure to CAISO wholesale market prices.
- Below is a somewhat-dated chart surveying the various DER initiatives of CCEs:

Figure 5: Select CCE Distributed Energy Initiatives (Q4 2017)

	Launched 2010	2014	2015	2016	2016	2017
	MCE Clean Energy	Sonoma Clean Power	Lancaster Choice Energy	CleanPowerSF	Peninsula Clean Energy	Redwood Coast Energy Authority
	PG&E	PG&E	SCE	PG&E	PG&E	PG&E
Active Integration of Distributed Energy into Power Operations						
Demand Response	In Development	✔			In Development	In Development
Electric Vehicle Load Shifting	✔	✔	✔			In Development
Customer Load Shifting	✔	✔				In Development
Aggregated Energy Storage		In Development				In Development
Administration of Distributed Energy Programs						
Residential Energy Efficiency (EE)	✔	✔	In Development			✔
Low-Income & Multifamily EE	✔					✔
Commercial Energy Efficiency	In Development					✔
Fuel Switching Gas to Electric	✔	✔				
Electric Bus Program			✔			
Local Infrastructure Development						
Microgrid Development						✔
Local Utility-Scale Renewables		✔	✔			✔
EV Charging Stations	✔	✔				✔
Energy Efficiency Financing	✔	In Development		In Development		✔
Electric Vehicle Incentives	✔	✔	✔			
Low Income Solar Incentives	✔					
Solar Net Energy Metering (NEM)	✔	✔	✔	✔	✔	✔
Renewable Feed-In Tariff (FIT)	✔	✔		In Development	In Development	In Development
Customer Rate Options						
Opt-Up Renewable Tariffs	✔	✔	✔	✔	✔	✔
Balanced Payment Plan		In Development	✔	In Development		
Electric Vehicle Rate	✔	✔		✔		✔
Battery Storage Rate	✔					
Intra-Agency Coordination for Planning and Programs						
Transportation Electrification		✔				✔
Water & Energy		✔		✔		
Building Codes & Fees		✔	✔	✔		
Land Use						
T&D Grid Modeling for Local & Distributed Energy Development						
		Electric Vehicles				Localization Study
Partnership with Utility on Distributed Resources						
						Microgrid Grant

Source: CalCCA & Community Choice Partners

In summary, CCEs represents a new balance of power in terms of governmental regulation, applied innovation, market access for new technologies and practices, and technically-informed, proactive engagement with the regulators and legislature to remove barriers to DER integration in numerous regards.

The Political Nature of Community Choice

Community Choice Energy agencies by design are intended to be a technically-informed agent of democratic change within California's energy sector. Prior to more deeply examining the power agency functions of CCEs, it is therefore instructive to more deeply examine the political nature of what "Community Choice" comprises in practice.

To begin with, the city and county governments that form CCEs are inherently localists and realists, interested in practical applications and structural reforms that can address the vast range of diverse challenges for which municipalities are responsible for managing. This level of practical politics is almost always non-partisan, solution-oriented and focused on measurable results, with regular engagement of civic, academic and private interests and a pragmatic level of discourse. To achieve their goals, municipalities are naturally conditioned to be flexible in their use of both civic models of hierarchy and participation, as well as market models of development and finance.

One has to look no further than, for example, the City of San Jose's Climate Action Plan and General Plan to witness the extraordinary institutional knowledge, attention to detail and multi-disciplinary perspective with which municipalities are addressing complex challenges like decarbonization.

Because CCEs are governed by boards of elected officials, often under a Joint Powers Authority imbued with the powers of its city and county government members, the Commission has acknowledged the near-term benefit that Community Choice agencies represent in broadening the energy planning regime to encompass (and align) local municipal authorities (e.g. land use, building codes, transportation planning, disaster preparedness, urban planning, etc.) with statewide decarbonization efforts.

However, to focus only on the local government aspect of Community Choice misses a much deeper and more powerful reality — *because Community Choice agencies as they have evolved in California are typically composed of horizontal, multisectoral networks of local institutions.*

These networks include mediating institutions such as Councils of Governments, business associations, community development organizations, labor unions, philanthropies, social and environmental justice nonprofits, school districts, universities and anchor research institutions, local banks, and various other community organizations.

It is a rare CCE for which this does not hold true, and it certainly includes all of the larger multi-jurisdictional Joint Powers Agencies. The reason is two-fold:

1. Municipalities inherently and routinely engage with and draw their political resiliency from these institutions as a matter of course — to the extent that one cannot analyze the political constituency and dynamics of municipal governments without reference to these civic and private actors;
2. Many CCEs were formed through multi-year exploratory efforts that were directly supported by or otherwise substantially engaged with these various local institutions.

Indeed, many Community Choice agencies have subsequently established community committees as a component of their formal governance structure:

1. Sonoma Clean Power
2. Redwood Coast Energy Authority
3. East Bay Community Energy
4. Silicon Valley Clean Energy
5. Peninsula Clean Energy
6. Valley Clean Energy

7. Monterey Bay Community Power (committee under formation)
8. Clean Power Alliance of Southern California (committee under formation)

These agencies, as well as the CCEs which lack formal community committees, also maintain substantial engagement on an ad-hoc basis with their communities. Board and committee meetings are noticed and open to the public, and in aggregate, the Community Choice industry hosts or participate in hundreds of public workshops and events every year.

As political institutions, CCEs are therefore power agencies that are inherently representative of the diversity of their constituencies, aware of local challenges and opportunities, open to new ideas, and consequently multi-disciplinary, democratic and nimble in their approach to problem solving.

This network function of Community Choice is still emerging, as institutional capacity, awareness and effective engagement does take time to develop. But what it is creating is politically extraordinary: technically-informed, strategic and collaborative action that is aligned with public purpose and leverages a truly vast array of civic and private expertise.

A corollary impact of this network function, as it is being applied to the governance of Community Choice agencies, is that it acts as a powerful, countervailing force against short-term opportunism. Any individuals, be they local politicians, agency staff or representatives of a community group, or factions therein can and will be motivated by private gain from time to time (personal prestige, profit, political gain, etc.); however, large groups of institutions will strive to achieve long-terms solutions for the betterment of their community.

Community Choice in California is thus a powerful combination of direct and participatory democracy — a source of legitimacy and strength which no other institution in the power sector can claim to match.

The political constitution of CCEs, in summary, has much to do with their potential to accelerate meaningful change within the California energy industry.

Concluding Remarks

The Commission has yet not proposed a framework sufficient to elevate the level of discourse to the point at which sensible decisions regarding how best to organize the energy industry could possibly be evaluated and agreed upon by stakeholders to the process.

The science of contract theory, and related theories comprising industrial organization theory as applied to the design of an economic system:

1. Provides a firm theoretical justification for why the science of choice is an inadequate lens through which to analyze the changes occurring in California's energy industry, much less the multi-dimensional nature of Community Choice within that context;
2. Allows a richer microeconomic discussion of industrial organization, including:
    a. How to expand the electricity industry most effectively into the transportation and natural gas economic systems;
    b. How to best integrate and accelerate Distributed Energy within these systems; and
    c. Perhaps most importantly, how best to understand the risks and advantages of Community Choice within this broader context.

Notably, CCEs can play a powerful and unique mediating function in terms of DER integration and are fast evolving to the level of sophistication and coordination in planning and operations required to do so. The Commission should accelerate this function by:

1. Expanding data access and resolving business process mis-alignments between CCEs and IOUs;
2. Understanding CCEs in a deeper fashion and more central role in this regard going forward.

Theory remains nothing without effective implementation in practice — so with this theoretical framework established, the remainder of these comments are intended to provide the Commission with the situational awareness to understand how CCEs are evolving in terms of their operational capabilities and coordination in planning, as well as more detailed suggestions in regard to barriers that the Commission must fix in the near-term.

Commission Concerns and Mitigations: CCE 2.0 & 3.0 Maturity Models

The rapid evolution of CCEs in California can be broadly understood under "CCE 2.0" and "CCE 3.0" maturity models. (Note that the attributes of these models are broadly representative of best practices that have emerged from within the CCE industry, and not strictly prescriptive.) As summarized below, the former refers to specific business model characteristics and practices of individual CCE agencies, and the latter refers to governmental joint-action across multiple CCE agencies:

Figure 6: CCE 2.0 & 3.0 Maturity Models

CCE 2.0: BUSINESS MODEL

1. Portfolio Management Services
2. Virtual Power Plant Services
3. In-house Enterprise Data Pipeline
4. Other hallmarks:
   - CEO with industry experience
   - Experienced staff in key positions (energy risk management, data analytics, etc.)
   - Comprehensive Risk Policy
   - Dedicated Risk Committee
   - Flexibility & at-risk service contracts

CCE 3.0: JOINT-ACTION

- Individual agencies working together
- Sharing resources, staff, jointly contracting for services and power, etc.
- Assist new CCE initiatives & avoid re-inventing the wheel
- In future: establishing a separate Joint Powers Authority (*"JPA of CCEs"*) to provide advanced services at-scale (low cost)

Source: Community Choice Partners, Inc.

Understanding how the CCE industry is evolving is critical in the context of planning how best to plan reforms to California's energy sector — because the CCE 2.0 and 3.0 maturity models are actually designed to mitigate various structural risks going into this market transformation.

For example, common concerns expressed over the acceleration of Community Choice in California include:

1. CCEs employ a variety of approaches to energy risk management, which may fail to meet acceptable, industry-standard practices and thus heighten Provider of Last Resort (POLR) and creditworthiness concerns — the latter lead to the recent revision of the CCE Bond calculation methodology.
2. CCEs do not coordinate in a sufficient fashion to ensure that power planning exercises are conducted in a regional manner, which is necessary to optimize investment decisions and meet the State's carbon reduction goals in a least-cost fashion — this has heightened the debate in the Integrated Resources Planning (IRP) proceeding over the legal "grey area" of CPUC oversight over CCE IRPs;
3. Lack of coordination between IOUs and CCEs on retail rate setting and distributed resources will fragment the Commission's ability to optimize the acceleration of DER throughout the state (regardless of CCE intentions).

These reasons often underpin the various regulatory threats that CCEs routinely deal with — which provides a compelling case study in the limitations of hierarchical modes of governance.

Meanwhile, CCEs have been proving their flexibility as hybrid entities that are more adept at managing or entirely mitigating these concerns through meaningful structural change:

1) The CCE 2.0 Business Model is designed to mitigate concerns over the competence of CCEs in terms of energy risk management and also to equip agencies with the foundational set of operational characteristics necessary to (1) deploy increasingly customized retail rate schedules and products and (2) begin integrating DER more deeply into planning and operations.

2) The CCE 3.0 Joint-Action Model is intended to (roughly in order of timing):

    a) Enhance institutional capacity by coordinating the responsibilities of key staff across individual CCE agencies to achieve a more comprehensive view of factors that impact energy risk management;

    b) Overcome individual CCE creditworthiness concerns by pooling risk in joint solicitations;

    c) Achieve greater economies of scale in the contracting for or in-house provision of key services;

    d) Assist new municipalities exploring CCE by providing expert forecasting and implementation services by a trusted public counterparty at relatively low-cost;

    e) Harmonize CCE planning assumptions;

    f) Lead to the establishment of a centralized "JPE of CCEs" agency to perform administrative functions, under which member CCEs retain control of their finances, rate-setting, procurement choices, local programs and local staff (as appropriate).

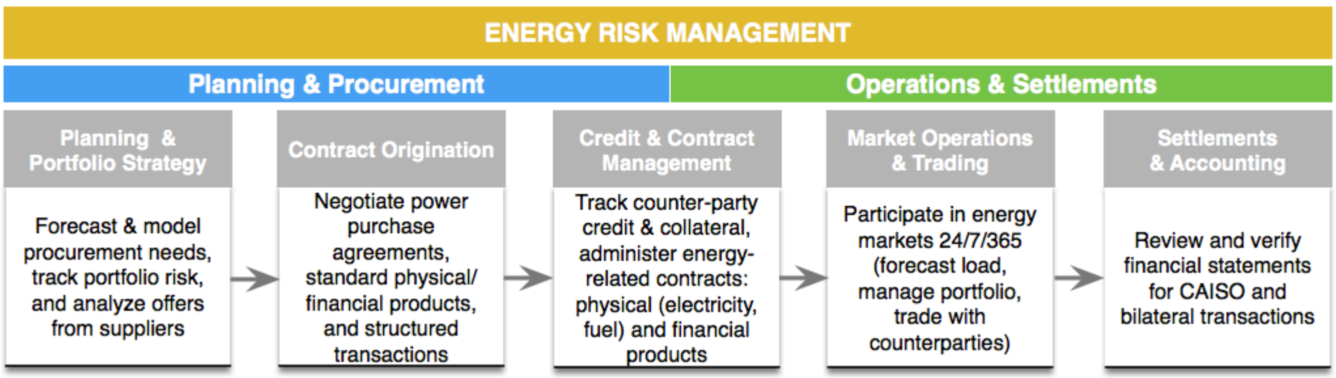
Much of the Commission's concerns should consequently be mitigated by the continuing evolution and internal leadership of the CCE industry in California.

Most of the remainder of these comments focus on the key dynamics, contextual history, conceptual models and near-term outlook that the Commission will find useful in understanding this evolution.

Energy Risk Management: A Structural Primer for Understanding CCE 2.0

To understand the significance of the CCE 2.0 and 3.0 maturity models, it is first necessary to develop an understanding of energy risk management. This is the core business of CCEs and comprises between 80% and 90% of costs for the existing aggregators in California. This practice spans planning and portfolio analysis, contract origination and management, short-term load forecasting, scheduling and balancing of operations, and financial settlements — as shown in the figure below:

Figure 7: Departmental Functions within Energy Risk Management



Source: Community Choice Partners

Commodity risk management within a competitive market is a complex practice. Supplying power to any aggregation of customers requires a diverse portfolio of energy products of various types and term lengths to be contracted for and actively managed as market conditions change over time.

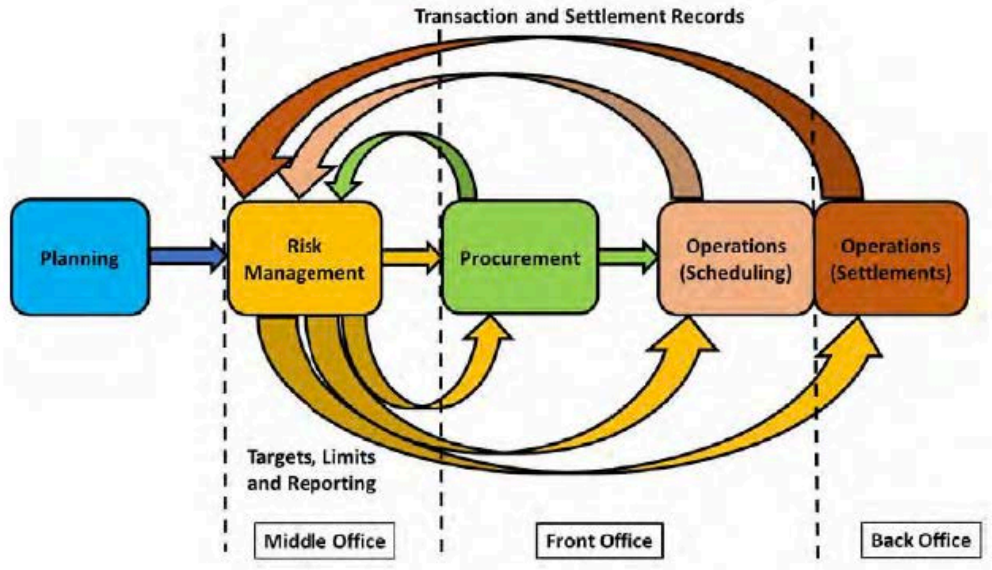
A "diversified portfolio" of energy products includes not just physical electricity products (energy, capacity, renewable certificates, emission reduction credits, ancillary services), but also physical fuel products (primarily natural gas, transportation and storage) and financial or insurance products (transmission congestion revenue rights, call/put options, multi-party spreads, etc.)

Significant expert analysis and market experience is required to assess how much of the portfolio should be contracted for in advance (hedged) versus exposed to market prices, and which products to purchase, in what volumes, when and from which counterparties in the market.

Subsequently, the portfolio has to be actively managed. Risk exposures may change in relationship to market price movements, the creditworthiness of counterparties, etc., and decisions taken whether to buy or sell certain products. During operations (the trading day on the market when contracts are settled), a number of contingencies can occur that also require intelligent decision making — including deviations between forecasted load and what customers actually use moment-to-moment, unplanned power plant outages, and market price volatility. Afterwards all of the data and financial obligations must be tracked, audited and settled in accordance with contracts and market rules.

To organize these decisions and processes, the commodity risk management industry distinguishes between "back, middle and front office" departments and responsibilities:

Figure 8: Front, Middle and Back Office Functions in Energy Risk Management



Source: "Advanced Energy Risk Management Services for South Bay Clean Power: Questions and Answers with Five Portfolio Managers"

Within the commodity risk management discipline, the "**front office**" is the department that interfaces and transacts directly with buyers and sellers and the electricity market, while the "**back office**" collects all the data necessary to track and audit the financial settlements that occur after the trading day. The "**middle office**" conducts sophisticated forecasting and analytics to guide strategic decisions in the front office, continuously monitors sources of risk, and also provides independent (departmentally separate) management oversight of both front and back office transactions to ensure compliance with adopted risk management policies and transaction limits.

Underpinning the back, middle and front office operations is the governance of the enterprise. What is acceptable in terms of financial risk, and the specific ways that risk is managed in practice across the front, middle and back office (wherein the middle office is responsible for monitoring and compliance) is formally adopted in an **Energy Risk Management Policy** and accompanying Policies and operational Procedures; this trifecta is referred to as the "3Ps" of Energy Risk Management.

These documents are highly detailed, and specify the sources of financial risk, credit policies, the methodologies to be employed in assessing and reporting risk, the management oversight procedures that must be followed, the responsibilities of all staff and contractors involved, the transaction and trading authority delegated to specific parties therein (by product type, term length, volume and/or financial commitment), and what to do in the event that transaction limits or other rules are violated.

Front Office Procurement and Market Operations & Back Office Settlements

Power operations require an entity to be certified with the CAISO (the California Independent System Operator that oversees electricity market operations) as a "**Scheduling Coordinator**" to be able to submit short-term load forecasts, schedule power contracts, and receive data for settlements (invoice processing) while maintaining financial security requirements.

Transacting in the electricity markets require participants to post collateral, in amounts that vary according to the CAISO grid operator's estimate of each participant's financial exposure. The CAISO may revise these estimates as positions and market conditions change, and also make "margin calls" that draw upon this collateral and require additional capital to be posted as warranted.

Most energy products that a CCE transacts are physical electricity products contracted bilaterally in advance ("hedged"), and then scheduled in the electricity markets; the CCE then sells excess power or purchases any additional electricity required directly from the electricity markets. In this manner, the inevitable deviations between a CCE's expected load and the actual usage of customers moment to moment is a source of "imbalance" risk for the agency — with the magnitude of the financial risk determined by both the size of the CCE's market exposure and market price volatility (the price level of the market at the moment when electricity is purchased or sold). The ability of a CCE to maintain competitive rates over time as compared to the incumbent utility in part depends upon how expertly it manages its portfolio and sources of financial risk.

An energy portfolio that is diversified (in terms of various contract lengths, product types, and range of counterparties) affords more flexibility, lower cost and opportunity to manage risk — but doing so requires a comparatively sophisticated operation. This **front office** department — not just the Scheduling Coordinator function (required to financially and operationally engage in the power markets in any capacity) but also the ability to actively manage diversified power portfolio by trading in the market and bilaterally with third-parties —requires substantial staff expertise and infrastructure, with trading desks and secure databases housed in "control centers" that are operated on a continuous basis (24/7).

Procuring energy products for a diversified portfolio requires various enabling agreements to be executed in advance with a range of counterparties that offer "physical" electricity and fuel products as well as financial and insurance products. These counterparties may be fuel suppliers, power plant operators, financial and insurance institutions, financial-only electricity market participants, wholesale suppliers and Energy Service Providers (ESPs) which maintain their own diversified portfolios.

Certain products are standardized and highly liquid (such as on- or off-peak block power purchases) while other "originated" products require customization and competitive negotiation with a range of suppliers. The front office procures these various energy products within transaction limits and guidance set by the middle office analytics; credit-worthiness of counterparties must also be considered, as counterparty default or non-performance is a source of financial risk. All contracts executed (electricity, fuel, financial and insurance products) must be compiled in a database and managed in accordance with contract terms.

Depending on the contract, it may be bought, sold or exercised in advance of or during the trading day; the front office may buy or sell physical and financial products and exercise financial options as warranted by market conditions and risk management procedures.

The **back office** subsequently collects all the data necessary to track and audit the financial settlements that have accrued — both through the electricity markets directly (after the trading day for physical power products and certain financial products) and bilaterally outside of the electricity markets (which may be fuel, financial and insurance products).

Bilateral contracts outside of the electricity markets must be accounted for, settled or contested in accordance with contract terms. For daily transactions in the market directly, the CAISO grid operator informs market participants of their payment obligations and credits, which are re-calculated over time as more accurate data is received and analyzed (any changes in this regard are called "resettlements", which take place over a matter of months). To verify the accuracy of the grid operator's calculations, the back office has access to the underlying data and will often conduct "shadow settlement" calculations to duplicate the results; any discrepancies may be contested by market participants and clarified with the grid operator.

Long-Term Planning and Middle Office: Forecasting, Modeling and Risk Management

The "**middle office**" forecasting analytics and oversight procedures that underpin Energy Risk Management are highly sophisticated, given that the forecasting must capture a wide degree of uncertainty across multiple, inter-related dimensions:

1. Volatility of electricity market, natural gas prices and seasonal hydroelectric generation output;
2. The inherent unpredictability of the underlying factors that impact price formation (such as weather that drives hourly patterns of electricity usage, varying by location across the power grid);
3. The constantly-evolving nature of the power sector in terms of its:
    a. Physical characteristics and fleet composition (e.g. the dramatic acceleration of variable renewables and distributed energy, and acceleration of energy storage);
    b. Regulated market rules (e.g. the expansion of the CAISO Energy Imbalance Market to encompass other Western US balancing areas, etc.);
    c. The liquidity and range of products available to purchase (e.g. the new "super peak" block CAISO market power product, traditional on- and off-peak block power products, and the range of customized products available for negotiation).

Longer-term forecasting usually relies upon **"fundamental" or "production cost" models**: software platforms that actually simulate the power grid and market prices based on mathematical rules and complex planning datasets. These models capture changes to the power grid, composition of the wholesale fleet of power plants, patterns of load consumption, etc. and are able to predict a range of outcomes based on variable factors such as hydroelectric generation, seasonal weather patterns, natural gas price trends, distributed energy scenarios and new procurement mandates or changes in market rules that could impact how the entire system functions.

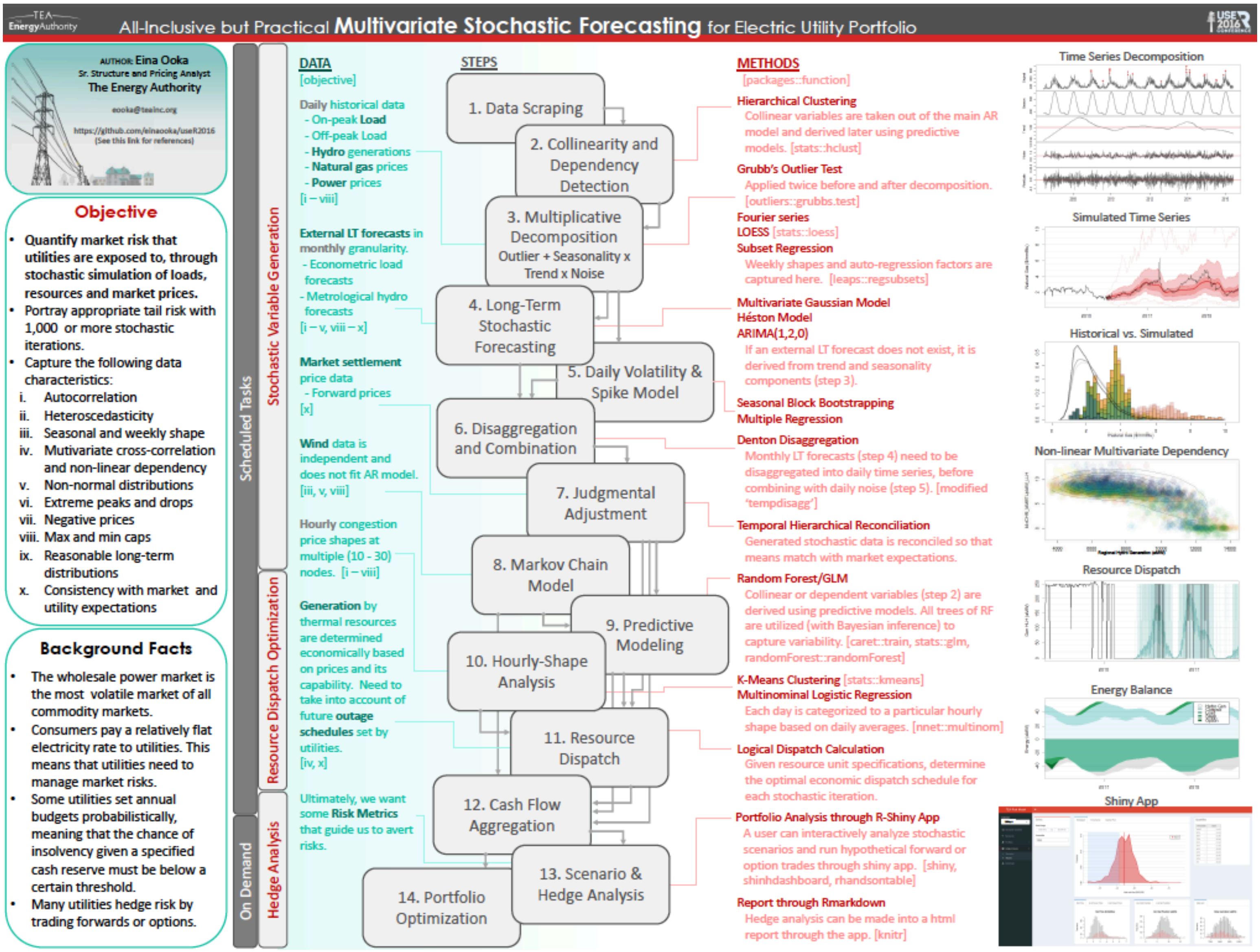
Fundamental models are often relied upon for Integrated Resource Planning and valuing long-term Power Purchase Agreements, as the models are able to simulate broad changes in the power sector. However, fundamental models do not capture the strategic behavior of market participants (e.g. bidding strategies), and so are inaccurate for the purposes of risk management over shorter timeframes.

Consequently, for the short- and medium- term forecasting used to inform portfolio strategies and risk management, the industry relies more heavily upon "**technical" models**: statistical techniques developed by the broader financial risk management industry and adapted for the energy sector. These models rely upon historical, observed data to implicitly capture the strategic behavior of other market participants.

To do so, a range of techniques may be blended together, for example machine learning (artificial intelligence), econometric and stochastic algorithms, etc. All techniques have strengths and weaknesses that require expert judgment and constant attention to manage. There is therefore no "perfect forecast" methodology that is universally employed.

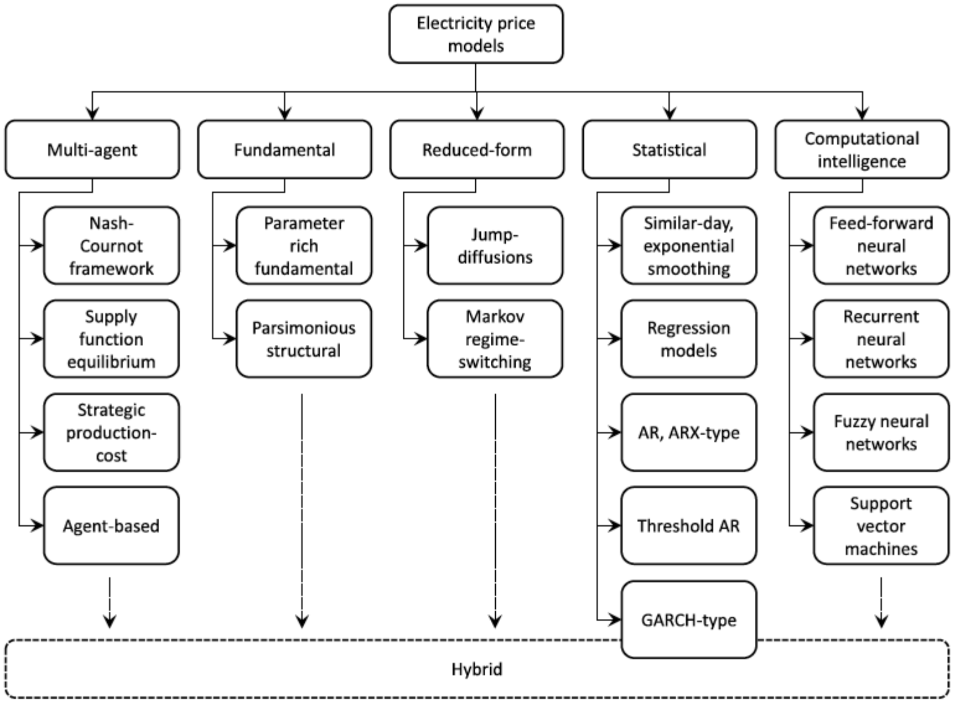
To illustrate this diversity and complexity, the two graphs below depict (1) models created by a Portfolio Manager that is currently serving California CCE 2.0 agencies and (2) an academic literature review of different modeling techniques employed in the power sector:

Figure 9: Example of Technical Analytics for Energy Risk Management



Source: The Energy Authority (TEA)

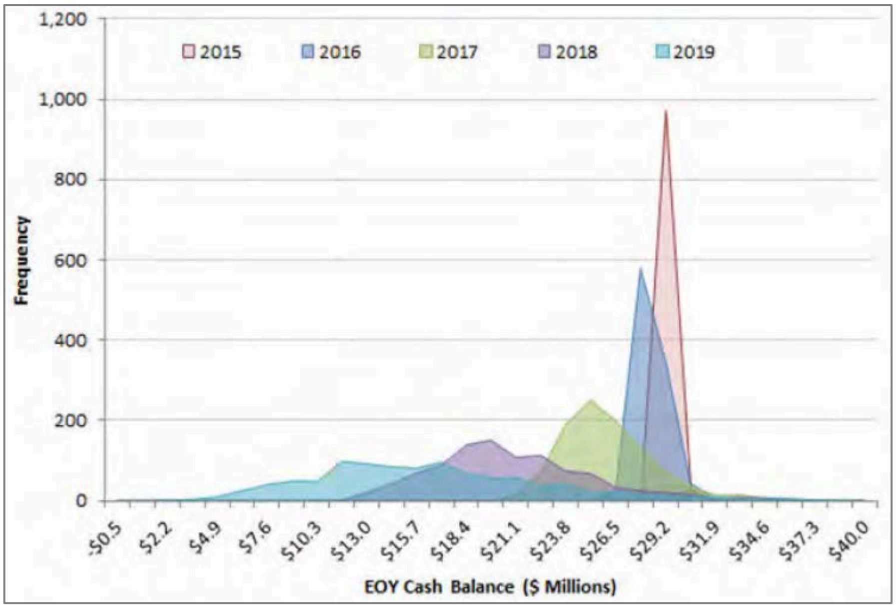
Figure 10: Electricity Price Forecasting Methodologies



Source: Rafael Weron, "Electricity price forecasting: A review of the state-of-the-art with a look into the future", 2014, International Journal of Forecasting.

Because of the inherent uncertainty being modeled, these simulations do not result in a single "deterministic" output or recommendation, but rather a more nuanced, "stochastic" range of probabilities that reflect potential outcomes and the financial impacts of any decision taken. The ability of the models to predict such a range of outcomes is generally tighter over the near-term, with broader ranges of outcomes over time:

Figure 11: Example of Probabilistic Forecasting of Cash Flow



Source: The Energy Authority (TEA) from "Advanced Energy Risk Management Services for South Bay Clean Power: Questions and Answers with Five Portfolio Managers"

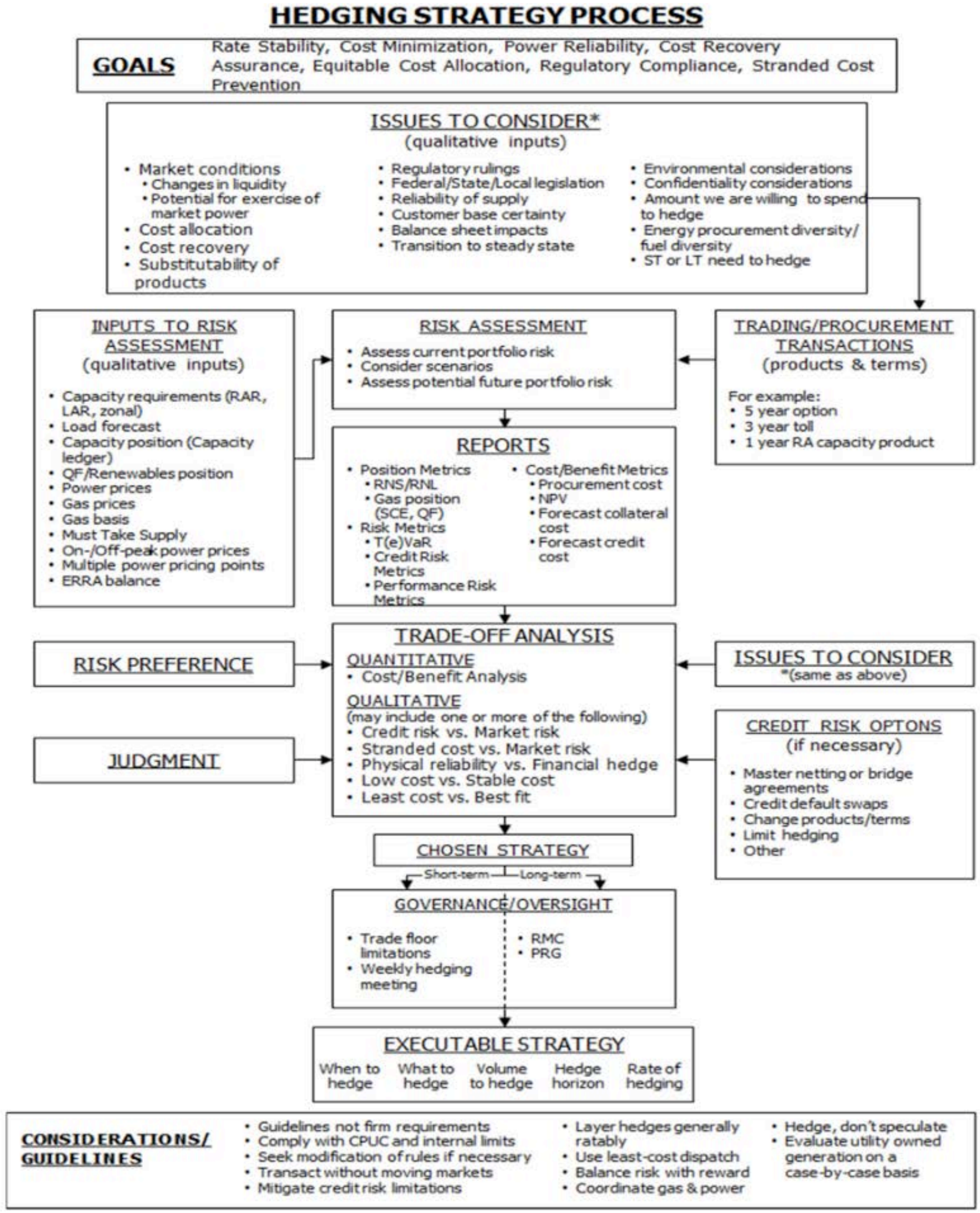
The accuracy of these complex analytics depends upon the quality and extent of the underlying data employed, as well as expert judgement regarding the data sources and various qualitative factors that could impact the calculations.

Effective Energy Risk Management consequently relies on a significant body of expertise, database infrastructure, and calculation methodology that is explicitly organized and strictly managed in accordance with adopted policies and oversight procedures.

For example, Southern California Edison's portfolio management and hedging strategy process is shown in the graphic below. It demonstrates a highly data-driven and yet interdisciplinary and qualitative approach to assessing and managing energy portfolio risk:

(refer to the next page)

Figure 12: Conceptual Schema of Southern California Edison's Hedging Process



Source: SCE ERRA Review of Operations filing

CCE 1.0 & 2.0 Business Model Options: Energy Risk Management

Organizationally, the ultimate efficacy of the Energy Risk Management (ERM) department is not purely an analytical exercise — it is also a practical exercise, in that mistakes by the Front Office or Back Office are a source of risk that must be actively monitored. Consequently, it is extremely important that the Energy Risk Management Policy, procedures and practices are well thought out, and that the front, middle and back office departments are fully integrated in terms of data management, analytics and business processes (including oversight procedures).

Within the Community Choice industry, much of the debate over how best to structure Energy Risk Management for new CCEs revolves around:

- Whether Energy Risk Management activities should be made explicit and transparent for CCEs, or outsourced to Energy Service Providers (ESPs, or "power marketers"); and
- The extent to which consultants versus more operationally-experienced companies and public power entities should be relied upon to provide services within this context.

There are broadly three operational models for CCEs to choose from when structuring ERM:

1. CCE 1.0: the CCE relies upon a consultant for power planning and procurement, who subsequently brokers a "full requirements" power contract from an ESP. Over time, the CCE may execute power purchase agreements for specific renewable projects to diversify this part of its power portfolio.
2. CCE 2.0 (integrated): the CCE relies upon a Portfolio Manager service company for planning, procurement, contract management, active market operations and financial settlements. The Portfolio Manager acts as an "agent" of the public power agency, purchasing and actively managing market exposure and power contracts from multiple counterparties in a fully diversified power portfolio tailored to the CCE.
3. CCE 2.0 (hybrid): a "hybrid" version that is often somewhere between the two models above, under which the CCE relies upon a consultant for power planning and procurement, but contracts for power from multiple ESPs and manages market interactions and financial settlements by separately contracting with a Scheduling Coordinator (which is typically a Portfolio Manager with a constrained scope of work).

The sections below summarize these models, and also compare their relative benefits and risks.

CCE 1.0 — Consultant and Power Marketer Model

Most CCEs prior to 2017 have contracted for almost all power required to launch from an Energy Service Provider (ESP or "power marketer") under a "full requirements" contract that includes Schedule Coordination (the functional interface with the CAISO market) and a fixed price for a certain quantity of power. Under this "CCE 1.0" model, CCEs have relied upon consultants to conduct forecasting and to broker the full requirement power contract. Over time, these CCEs often source power from one or more renewable developers and other suppliers.

Under that model, CCEs are essentially outsourcing the complexity of portfolio management to a for-profit company. The ESP commits to the fixed price and quantity of electricity, and internally conducts portfolio management activities to satisfy their contractual requirements while making a profit. In return, the CCEs receive a fixed price for a set quantity of power, and are only directly financially exposed to purchasing or selling power on the market for deviations between their forecasted and actual customer load.

Disadvantages of this model include:

1. A lack of institutional insight into the "front line" of commodity risk management modeling techniques and operational practices;
2. Separation and limitation of the CCE's Energy Risk Management departmental functions (back, middle and front offices);
3. An inability to engage in trading for risk management purposes during market operations;
4. A relatively inflexible approach to Energy Risk Management overall (in that the CCE's portfolio is fixed for a period of time, typically one to three years) — which may expose the CCE to market and regulatory risks that were not fully understood when power was contracted for in advance.
5. The CCE is reliant upon the consultant's expertise in conducting planning and procurement exercises (potentially supplemented by internal staff or third-party vendors and software over time).
6. The CCE assumes the responsibility to implement and integrate more expansive Energy Risk Management functions (which may conceivably evolve over a period of years to more closely approximate the full range of capabilities previously described in the first section of this memo).

CCE 2.0 (Integrated) Model — Relying on a Portfolio Manager for Energy Risk Management

Over the course of 2017, numerous CCEs have chosen instead to adopt the "Portfolio Manager" or "CCE 2.0 (integrated)" model. Under this model, the CCE contracts for all of the aforementioned Energy Risk Management (ERM) functions to be provided in a transparent fashion by a service provider operating "as an agent" of the government agency. These contractors possess all of the capabilities that ESPs do in regard to Energy Risk Management — but offer those capabilities as a service to CCEs (instead utilizing those capabilities in-house to manage power portfolios to sell at a profit to CCEs). Several municipal utilities and public power joint-action agencies are providing these services for CCEs currently:

Figure 13: CCE 2.0 Agencies & Public Power Portfolio Managers

Source: Community Choice Partners

Advantages of this model include:

1. A tightly-integrated front, middle and back office — providing a high degree of assurance that a new CCE operates along established industry best-practices;

2. A comprehensive Energy Risk Management policy adopted by the CCE's Board, along with the accompanying procedures and practices to ensure the Portfolio Manager is conforming to the policy;
3. The establishment of a Risk Management Committee, and full transparency in documenting all aspects of Energy Risk Management;
4. The practical ability to contract for and actively manage a diversified portfolio of not just electricity products, but also potentially fuel, financial and insurance products at launch;
5. Active risk management in market operations (balance of month transactions, and day-ahead and real-time trading);
6. In general, the broad assurance that a variety of proven, industry-standard modeling, software, expertise and management/oversight procedures are being employed to protect the CCE's interests.

Additionally:

- CCEs that have employed this model are also planning to transition certain responsibilities to staff over time, with the active support of the Portfolio Manager (whose clients often need this flexibility and training support — particularly for public power clients).
- CCEs that employ the Portfolio Manager model may also choose to contract with one or more Energy Service Providers (ESPs) for power supplies. In other words, from a risk management perspective, the CCE still retains the ability to offshore operational and financial risk to ESPs for some or all of the power supply — but the CCE gains the ability to contract for a broader range of energy products as well (including directly with power plants, fuel suppliers and financial/ insurance counterparties).

Disadvantages of the CCE 2.0 model include:

1. A more in-depth RFP design, bid evaluation and contract negotiation up-front during the CCE's formation;
2. More proactive engagement/ time commitment from staff, committees and the Board on matters related to Energy Risk Management and strategic decisions (which requires more resources, but is arguably not a disadvantage in terms of local control and oversight of risk management).

CCE 2.0 (Hybrid) Model — Consultant, Scheduling Coordinator and Power Marketer(s)

After the first CCE contracted for the CCE 2.0 (integrated) model — the Redwood Coast Energy Authority in 2016 — a number of CCE initiatives have also employed a CCE 2.0 "hybrid" strategy.

Under this model, the consultants who were relied upon to conduct feasibility studies are still subsequently contracted to provide planning and procurement to launch the CCE, while the CCE simultaneously contracts with a Scheduling Coordinator. The Scheduling Coordinator is often a Portfolio Manager with a scope of work that is contractually limited, and excludes most Energy Risk Management functions (i.e. the functions retained by the consultants). CCEs that have employed this model have subsequently contracted for power from one or more ESPs at launch.

Advantages of the CCE 2.0 (hybrid) model, as compared to the CCE 1.0 model, include:

1. The ability to contract with more than one ESP for power at launch (a measure of portfolio diversification);
2. More transparency into power market operations;

3. Support for active trading for risk management purposes during market operations (balance of month transactions, and day-ahead and real-time trading).
4. CCEs that employ this model are also more likely to develop more comprehensive Energy Risk Management Policies for the Board of the agency to adopt, and will find it organizationally less difficult to evolve and integrate their Energy Risk Management departmental functions over time to more closely approximate the CCE 2.0 (integrated) model and the full range of capabilities required.

Potential disadvantages of this model, as compared to the CCE 2.0 (integrated) model, and mitigating strategies include:

1. The CCE's Energy Risk Management functions are not tightly integrated at launch (i.e. the back, middle and front office are still bifurcated across multiple contractors, staff and consultants) — which poses various process inefficiencies and limitations, as well as challenges in risk management oversight (middle office functions).
2. The CCE may be comparatively limited in its choice of counterparties and products when constructing its initial portfolio, which limits diversification and may result in higher power costs or risk profiles.
3. The CCE's strategic decisions in planning and procurement may be reliant upon the quality of the consultants employed (which do not possess the depth of expertise, software and data that Portfolio Managers do).

Experienced management serves to mitigate or significantly lower the risks pertaining to power procurement strategy (and back, middle, front office integration) inherent in the CCE 2.0 (hybrid) model.

Over the course of 2017, it is worth noting that many new CCE agencies — and all agencies which have pursued the CCE 2.0 (hybrid) model implementation pathway — have hired Executive Directors with substantial public power and energy risk management expertise. For example:

Figure 14: Select CCE CEO's with Public Power Experience

SILICON VALLEY CLEAN ENERGY

Girish Balachandran
Chief Executive Officer

28 years of experience.

Former General Manager of Riverside Public Utilities & Alameda Municipal Power

Monterey Bay Community Power

Tom Habashi
Chief Executive Officer

30 years of experience.

Former General Manager of Roseville Electric Utility

CITY OF SAN JOSE
CAPITAL OF SILICON VALLEY

Lori Mitchell
Director of Community Energy

20 years of experience.

Former Manager of Procurement for the San Francisco Public Utilities Commission (SFPUC)

Regulatory Risk & the Debate over CCE 2.0 Integrated vs. Hybrid Models

The debate within the CCE industry between CCE 2.0 (integrated) and the CCE 2.0 (hybrid) model centers around an issue of timing and operational risk: namely, whether new public power agencies are best-served by relying upon Portfolio Managers for the full range of Energy Risk Management services at launch, or whether these functions can be contracted for separately and competently integrated by newly-formed CCEs during the period leading up to launch and early stage operations:

- The CCE 2.0 (hybrid) model assumes that newly-formed CCEs can competently bifurcate Energy Risk Management back, middle and front office functions, assess the technical capabilities and business strategies of multiple vendors for different scopes of work, and manage the overall integration of these contractors and functions on a relatively rapid time line.
- The CCE 2.0 (integrated) model assumes that, given the inherent complexity and magnitude of risk at-stake, the most expeditious and effective Energy Risk Management practices for newly-formed CCEs should be implemented by an experienced Portfolio Manager — and then the CCE will be able to use the resulting holistic, transparent Energy Risk Management framework to delegate certain responsibilities to alternative vendors or to in-house staff, over time and in a methodical fashion.

It should be noted that many public power utilities often rely upon a hybrid model of one kind or another. For example, both NCPA and TEA (the Northern California Power Agency and The Energy Authority, which are Portfolio Managers providing CCEs with services) are jointly-owned by municipal utilities, and their members may provide certain Energy Risk Management functions in-house. However, these municipal utilities all possess a long track record of performance and in-house expertise, and manage the integration of their in-house functions with Portfolio Managers and external vendors in an expert and methodical fashion. **The staff expertise and institutional capacity of any individual CCE is therefore a determining factor impacting the risks and benefits of implementing either the CCE 2.0 integrated or hybrid model — there is consequently no "one size fits all" best practice.**

Two additional concerns detailed in the following sections — the significant and complex regulatory risks that CCEs in California face, and the increasing necessity to deploy Distributed Energy services — highlight further advantages of the CCE 2.0 (integrated) model.

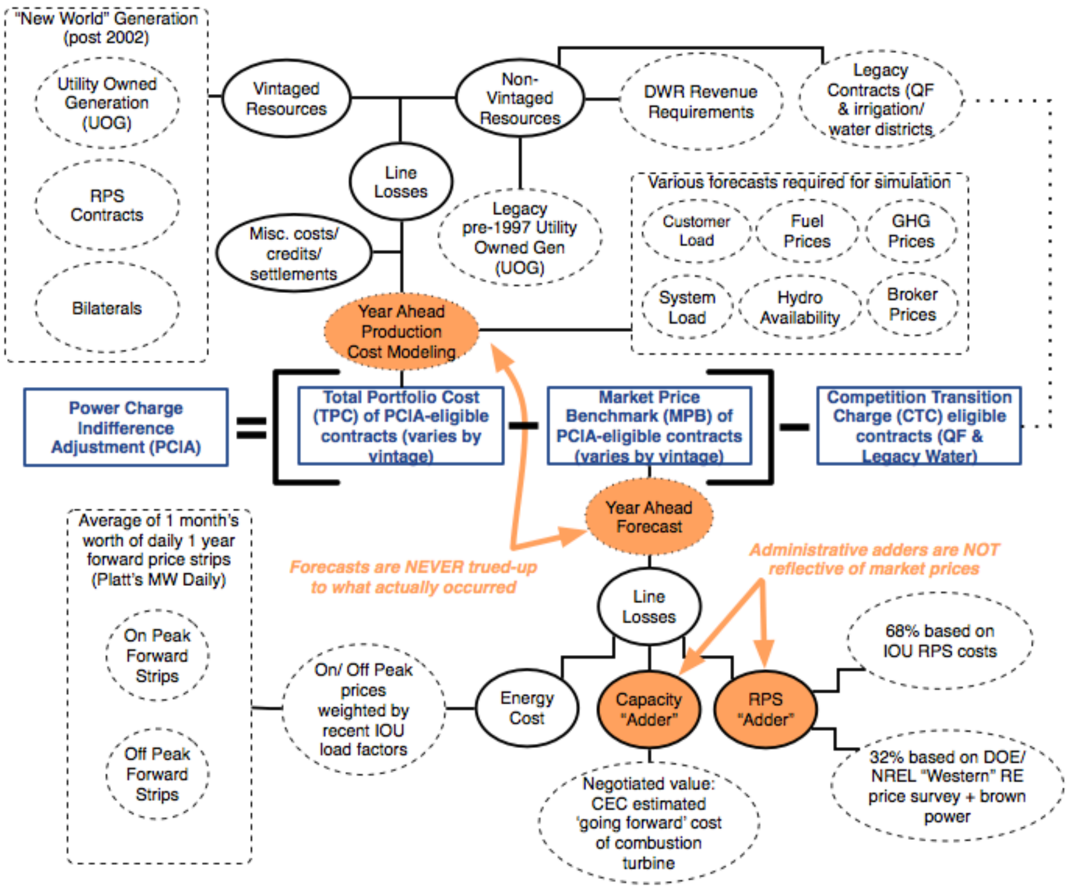
Regulatory Risks and CCE 2.0 Energy Risk Management

The debate over how best to evolve CCE Energy Risk Management capabilities has been heightened by concerns that the Power Charge Indifference Adjustment (PCIA) mechanism will be reformed by the CPUC this year.

This may significantly decrease net margins for CCEs (likely beginning in 2019), by increasing the charges assessed to CCE customers to recover above-market power costs from contracts that the utilities had previously entered into.

The graphical representation below shows the current PCIA calculation along with the data and modeling employed, and highlights the primary sources of inaccuracy under debate:

Figure 15: Conceptual Schema of Power Charge Indifference Adjustment (PCIA) Methodology



Source: Community Choice Partners

There are also a number of other regulatory-induced changes occurring in 2019 and 2020 that will be technically challenging for CCEs to manage — all of which represent potential cost-shifts. These include:

1. The implementation of default Time of Use (TOU) rates for the residential sector, which changes the timing and magnitude of revenue inflows for CCEs.
    a. Note that the uniformity of retail rates across customers of the same class has been maintained through an implicit cross-subsidization that obscures the locational cost of electricity.
    b. This retail cross-subsidization, or socialization of costs, has been carried over in certain key respects to the design of the wholesale market structure as well — which is a longer discussion beyond the scope of these comments.
2. The potential change in how wholesale load patterns are estimated for settlements in the CAISO power market in PG&E's territory:
    a. Currently, most CCEs in PG&E's territory do not actually use all of their own customers' hourly electricity usage for wholesale settlements. The load profiles for large customers are based on actual hourly usage; but for residential and most commercial customers, CCEs have not been able to furnish smart meter data that is sufficiently accurate to submit to the CAISO grid operator. Consequently, most CCEs *estimate* these customers' hourly usage by applying

utility territory-wide class average usage profiles to the CCE's customers' monthly total usage. (In other words, a residential customer in Marin is assumed to have the same hourly usage pattern as a customer in Davis.)

b. Given the more temperate climate of most CCEs in PG&E's territory (i.e. on the coast and Bay Area), this is likely a significant source of cost shift from CCEs to bundled customers.

c. Leading CCEs are beginning to overcome this challenge: both Monterey Bay Community Power and East Bay Community Energy are forecasting and settling electricity purchases on the basis of smart meter data for all customers. If this practice becomes widespread (as is expected) all CCE's wholesale settlements (and portfolio risk exposures) will change dramatically.

These changes impact many aspects of Energy Risk Management for CCEs. Within the context of these complex risks:

1. CCE 1.0 agencies run the risk of locking in power prices and positions for multi-year periods that could cause financial losses for the agency and its customers during periods of regulatory and market changes.
   a. The principal risks are that CCE 1.0 agencies' rate-setting and revenue projections will be increasingly inaccurate, power will be purchased to cover the wrong times, key risks may be priced inaccurately, and the agencies could increasingly fail to properly hedge their positions in the market.
2. CCE 2.0 agencies are better equipped to anticipate these sorts of systemic changes, and to implement a more flexible, tailored approach to portfolio management as a risk mitigation strategy.

A Cautionary Tale: the Illinois CCE 1.0 Industry

A similar situation occurred in the Illinois CCE market several years ago, where municipalities universally employed a consultant and Power Marketer model similar to California's "CCE 1.0" model (though even more simplified).

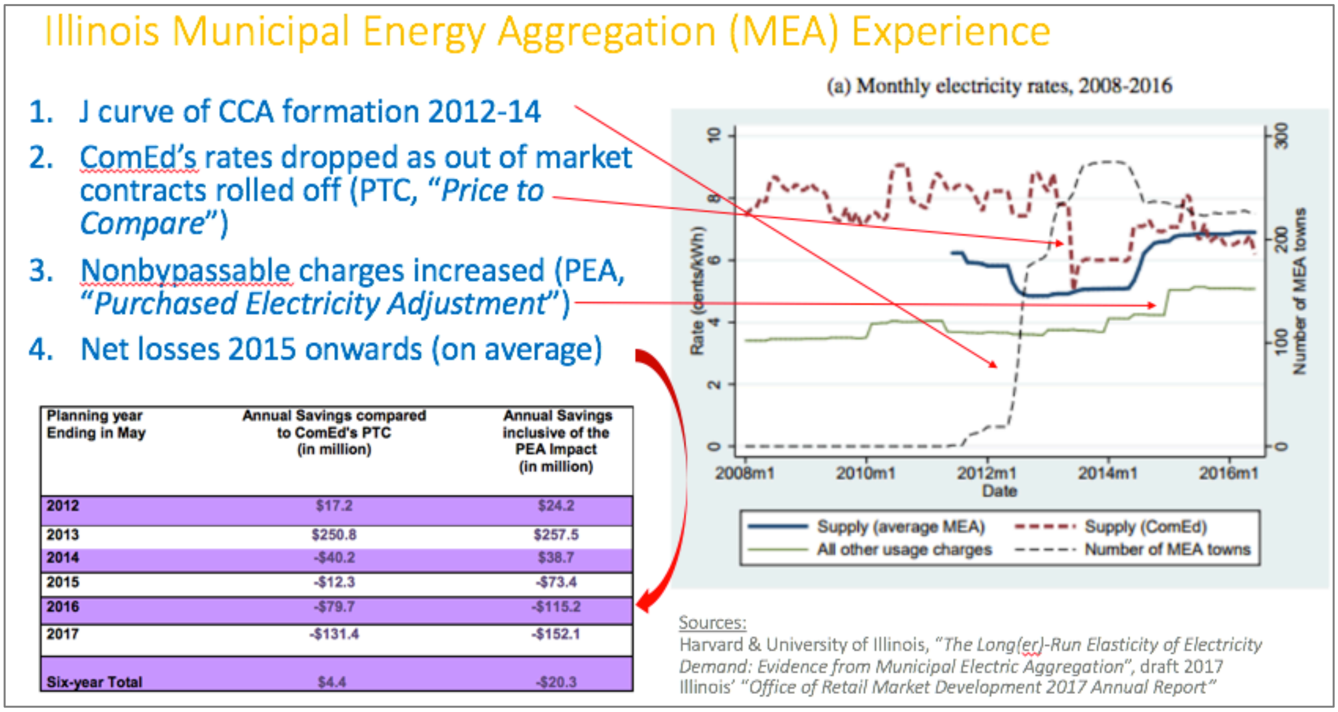
In brief, what happened was that a small number of CCEs achieved costs savings early on, which fueled the rapid expansion of additional CCEs — just before the utility's rates dropped. This drop occurred because the utility had entered into multi-year contracts just before the "Fracking Revolution" lowered natural gas and power market prices; those contracts expired shortly after many CCEs formed.

This was anticipated and widely-understood by many experts in the power market. However, the municipalities forming CCEs were reliant upon consultants and ESPs for procurement advice. This posed a financial conflict of interest (and a classic Principal-Agent Dilemma in terms of Game Theory), as the consultants and ESPs would be paid for management fees and power supply regardless of whether the CCEs were beating the utility's rates.

Consequently, many municipalities were not informed of this risk and advised to form CCEs, and a large number were subsequently unable to deliver on promised cost savings (compared to the utility's rates. After their supply contracts expired the municipalities then suspended CCE operations and returned customers to the utility. The City of Chicago is perhaps the most well-known example in this regard.

The graphic below depicts these dynamics, with explanatory notations:

Figure 16: Illinois CCE 1.0 Market Failings



Planning year Ending in May	Annual Savings compared to ComEd's PTC (in million)	Annual Savings inclusive of the PEA Impact (in million)
2012	$17.2	$24.2
2013	$250.8	$257.5
2014	-$40.2	$38.7
2015	-$12.3	-$73.4
2016	-$79.7	-$115.2
2017	-$131.4	-$152.1
Six-year Total	$4.4	-$20.3

Source: Community Choice Partners

Drawing upon the lessons-learned in Illinois, and in advance of similar structural changes anticipated in California (due to the PCIA reformation and other regulatory risks), the "CCE 2.0" model was explicitly created as the quickest way to:

1. **Equip California CCEs with the sophistication, unbiased advice and transparency necessary to ensure that the impact of these sorts of complex regulatory and market changes are accurately forecasted (to the greatest extent possible); and**
2. **To practically manage this uncertainty through a flexible approach to procurement and "utility-grade" power market operations.**

The Commission should be aware that these more advanced energy risk management capabilities have become widely deployed within the California CCE industry over the last ~2 years.

CCE 2.0: the Challenge and Opportunity of Distributed Energy Resources

While Distributed Energy is often discussed as a policy goal for CCEs, it also poses distinct challenges and opportunities in the context of a CCE's commodity risk management obligations as a load-serving entity. The CCE 2.0 business model, in contracting for Portfolio Management, expert staff and Distributed Energy services, is designed to help manage these challenges while unlocking opportunities for CCEs.

Distributed Energy & Impacts on Energy Risk Management

A CCE's primary business model is to buy wholesale power and sell it to customers. At launch, agencies take significant debt, which is then paid off over time while the CCE manages wholesale market risk and collects revenues. A CCE's ability to predict and manage the sources of risk in its power portfolio (and to set rates and predict revenues) is dependent on the ability to first predict customer load patterns. A growing challenge is that Distributed Energy is changing when, how and how much electricity is used by customers.

This dynamic is both unpredictable and accelerating, and in California it is negatively impacting both the accuracy of load forecasting for individual CCEs and the ability of the power market to forecast load patterns system-wide. Market price formation is now driven by net load patterns: dispatching power plants to meet the load remaining after subtracting out variable renewable generation and the impact of distributed energy.

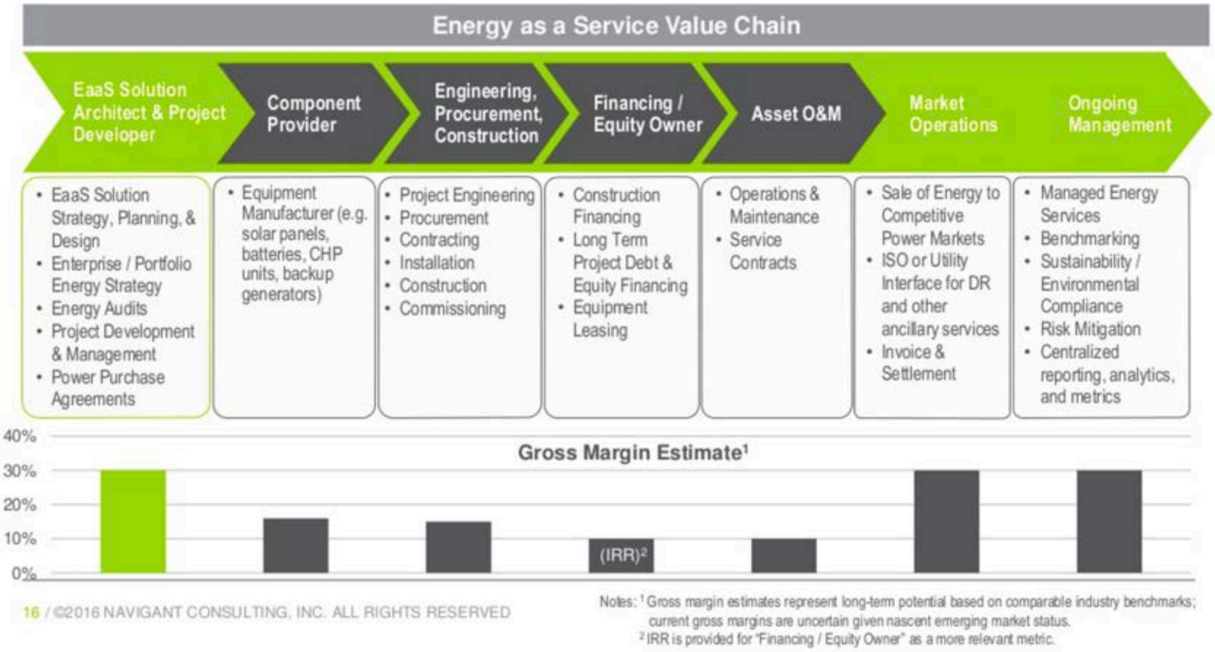
The CCE 2.0 model incorporates a diverse set of services necessary to support Distributed Energy — *and to use these capabilities and new data sources to refine the predictive analytics used for Energy Risk Management*. In turn, the CCE will be able to both 1) better forecast Distributed Energy impacts and resources within its own customer base and 2) will also be able to actively rely upon Distributed Energy in a more controlled and targeted fashion — combined, these capabilities will increasingly lower sources of financial risk in the agency's wholesale portfolio and position management planning and operations. In this manner, CCE 2.0 can be viewed as a business model strategy that lowers operational and forecasting risks, while simultaneously developing a competitive advantage.

Energy as a Service Business Model (or "Platform Optimizer") & "Virtual Power Plant" Capabilities

The overarching business strategy here is for the CCE's core business model to evolve from only selling kilowatt-hours to providing "Energy as a Service" to its customers. In doing so, the CCE would be able to act as a "Platform Optimizer" that creates new value by interfacing Distributed Energy with the wholesale electricity market and within its own energy portfolio (actively balancing supply and demand), offering a variety of services and flexible rate structures to its customers that more accurately allocate costs and benefits, and integrating DER into capacity and distribution grid planning, etc..

In the Distributed Energy value-chain graphic below, these functions correspond primarily to the "Market Operations" and "Ongoing Management" links — though CCEs can also facilitate the "EaaS Solution Architect & Project Developer" link as well (for example by using customer data for targeting purposes, and proactive customer engagement to generate sales leads for project developers):

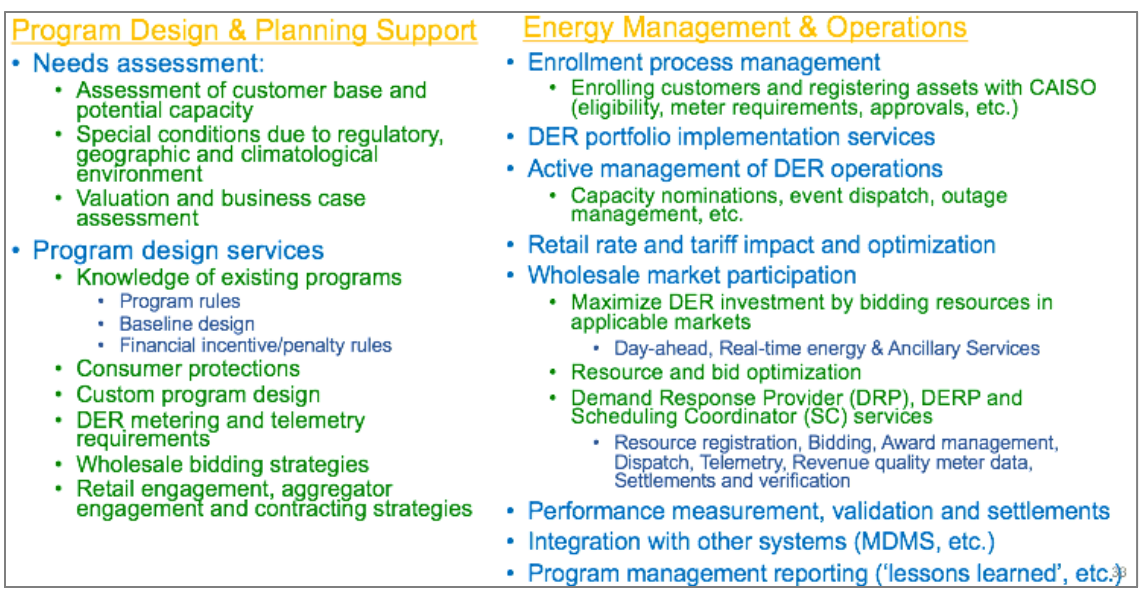
Figure 17: Value Chain of "Platform Optimizer" or "Energy as a Service" Business Model



Source: Navigant Consulting, 2017

To be able to practically perform these tasks in practice, a CCE must contract with a Portfolio Manager for full Energy Risk Management services, and then additionally contract for more specialized services from a Distributed Energy Scheduling Coordinator (a company that is able to create "Virtual Power Plants" out of aggregations of Distributed Energy assets and customers). The latter set of services is summarized as:

Figure 18: 3rd Party Virtual Power Plant Functionalities in CCE Operations and Planning



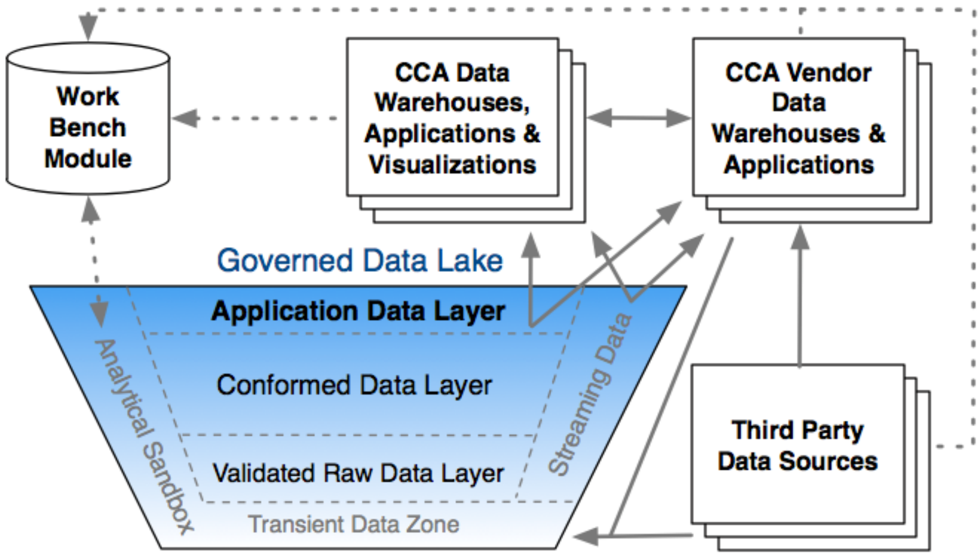
Source: Community Choice Partners

Data Management & Customer Engagement Functions to Support Distributed Energy

Beyond energy risk management capabilities, CCEs are also beginning to advance on deploying:

- An extremely flexible and transparent database design that it controls, because the CCE is going to need to handle a variety of new, diverse sources of data and interactions with third parties, as well as a much greater level of customized data handling and analytical procedures to meet its day to day business process requirements (such as DER targeting analytics). In order to facilitate these integrations and to ensure scalability and flexibility, CCEs will require that a Governed Data Lake and Data Warehouses be implemented to co-exist alongside and integrate with third-party contractor data warehouses. A conceptual schema of this structure is below:

Figure 19: Conceptual Schema of CCE Enterprise Data Pipeline



- More automated and database-driven rate-setting and revenue forecasting capabilities (for example, to offer real-time pricing and marginal cost-based price signals), and more granular tracking of the costs and benefits of Distributed Resources for settlements and billing purposes.
- Proactive customer engagement and Customer Relationship Management (CRM) platforms (i.e. instead of simply fielding customer inquiries, the CCE should anticipate taking an active engagement approach to target and enroll customers for DER programs and rate structures using outbound calling services, customer portals and other targeted marketing strategies).
- Enhanced key account management to establish close "Energy Manager" relationships with larger commercial and industrial customers, and offer customized rates, wholesale market products and collateral obligations, and Distributed Energy services — while keeping overhead and transactional costs low. This requires more sophisticated software platforms, to facilitate customer engagement and to integrate into the CCE's energy portfolio management activities at a low transactional cost.

CCE 2.0 "Agency Development" or "Change Management" Techniques

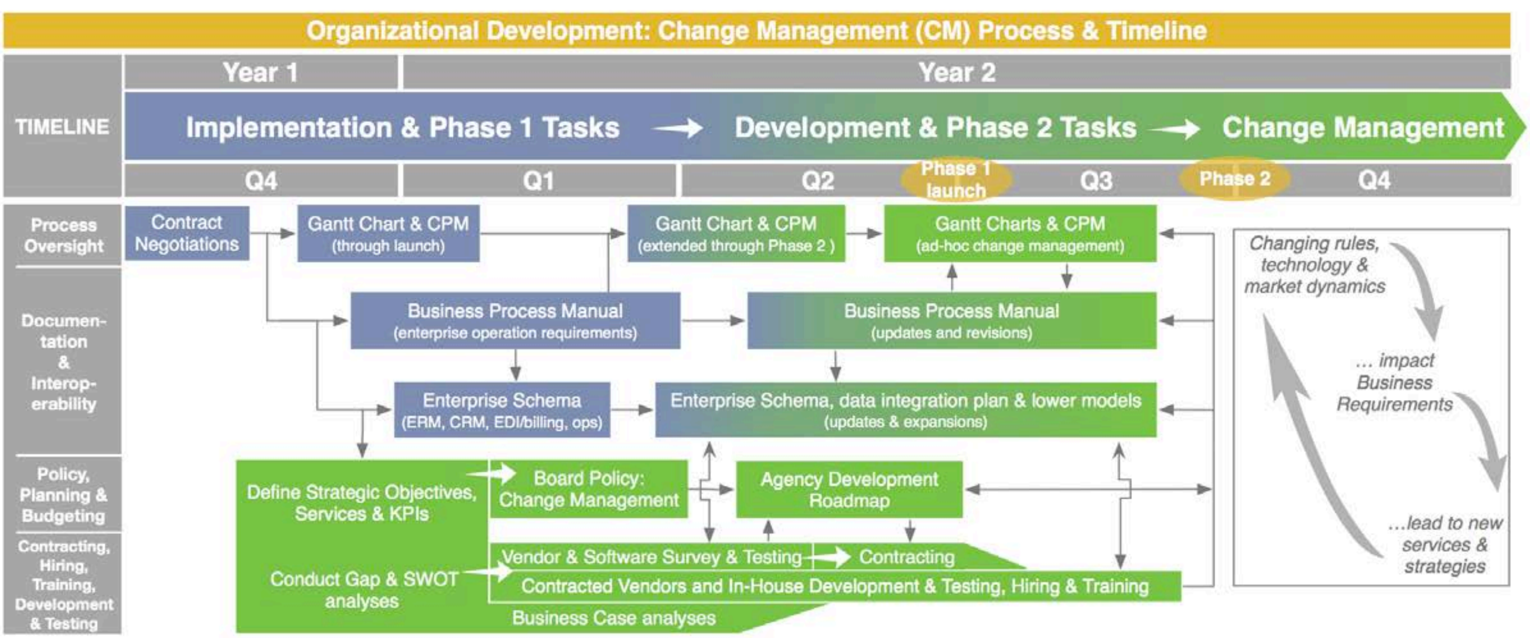
It is important to understand that while the "CCE 2.0" model described here provides CCEs with a strong foundation upon which to evolve, there is no fully "off the shelf" set of services uniquely tailored to the dynamic, complex challenges and opportunities CCEs are facing in California.

Consequently, it is critical for CCEs to contract for services in a well-structured and fully-transparent fashion — because this is a precondition for CCEs to be able to integrate the services of different vendors and to evolve their in-house staffing and capabilities over time. It is also important to implement formal processes that allow the agency to (1) document its current capabilities and business processes and (2) systematically analyze and evolve its capabilities over time, in a methodical and strategic fashion.

Various management techniques CCEs apply in this regard may evolve to include adopting a formal "Change Management" or "Agency Development" Policy, establishing a corresponding committee that regularly convenes and supports staff initiatives in this regard, drafting a Business Process Manual and Agency Development Roadmap, defining Key Performance Indicators (KPIs) and strategic priorities, conducting Gap and SWOT analyses, surveying and testing vendors' capabilities and/or analytical platforms, conducting business case analyses, utilizing Gantt Charts (critical path methodology) to manage ongoing changes, and updating conceptual or practical diagrams of the agency's underlying technology platforms, analytical and business process requirements (an "enterprise schema").

Together, these techniques can be combined to launch and evolve an agency over time; as a graphical illustration of this process:

Figure 20: Conceptual Schema of CCE "Change Management" Techniques



Source: Community Choice Partners, Inc.

Many CCEs have implemented a selection of the above change management techniques internally to guide their evolution as power agencies (though none have yet adopted a formal Board policy to guide the process).

CCE 3.0: Governmental Joint-Action between Multiple CCE Agencies

Joint-action across CCEs is growing rapidly, through discussions held within the CalCCA trade association and also between certain CCE agencies. As a concise summary of activity to-date:

Figure 21: Examples of CCE Joint-Action Activity to-date

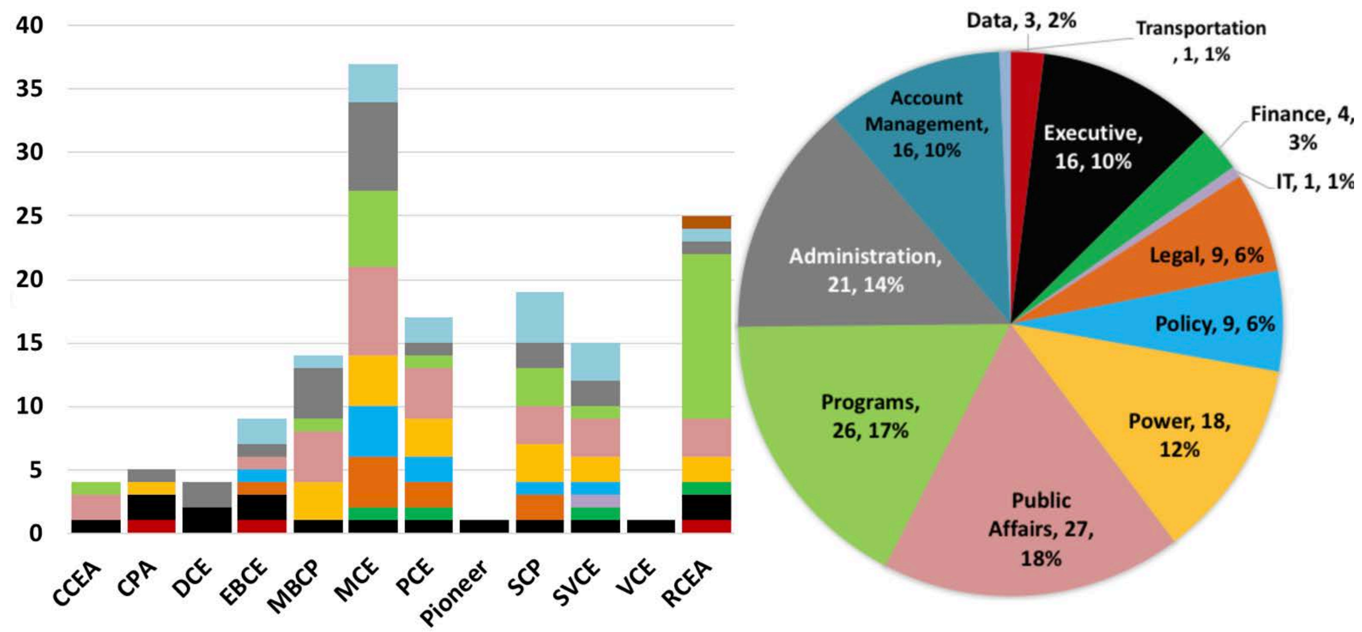
Source: Community Choice Partners, Inc.

To expand on the points in the above graphic:

1. CCE policy staff coordinate with one another through CalCCA to track and engage on matters before the Commission and Legislature;
2. CCE procurement staff have a weekly conference call to discuss market dynamics and to share best practices;
3. Established CCE agencies have begun to share analytical tools and templates with newer agencies, and to make key staff available to tackle specific challenges jointly;
4. Municipalities seeking to explore and implement CCE have begun to request services from operational CCE agencies (competing against offers from teams of consultants);
5. Silicon Valley Clean Energy and Monterey Bay Community Power are jointly soliciting "carbon free energy with storage" and close to executing contracts at-present.

To a large extent, these activities are being fueled by the rapid expansion of expert staff and experienced CEOs that have entered the CCE industry over the last year; the graph below depicts the number of staff by CCE and department; there are ~150 staff in total, and this figure is expected to grow rapidly (perhaps by 2x) over the next year:

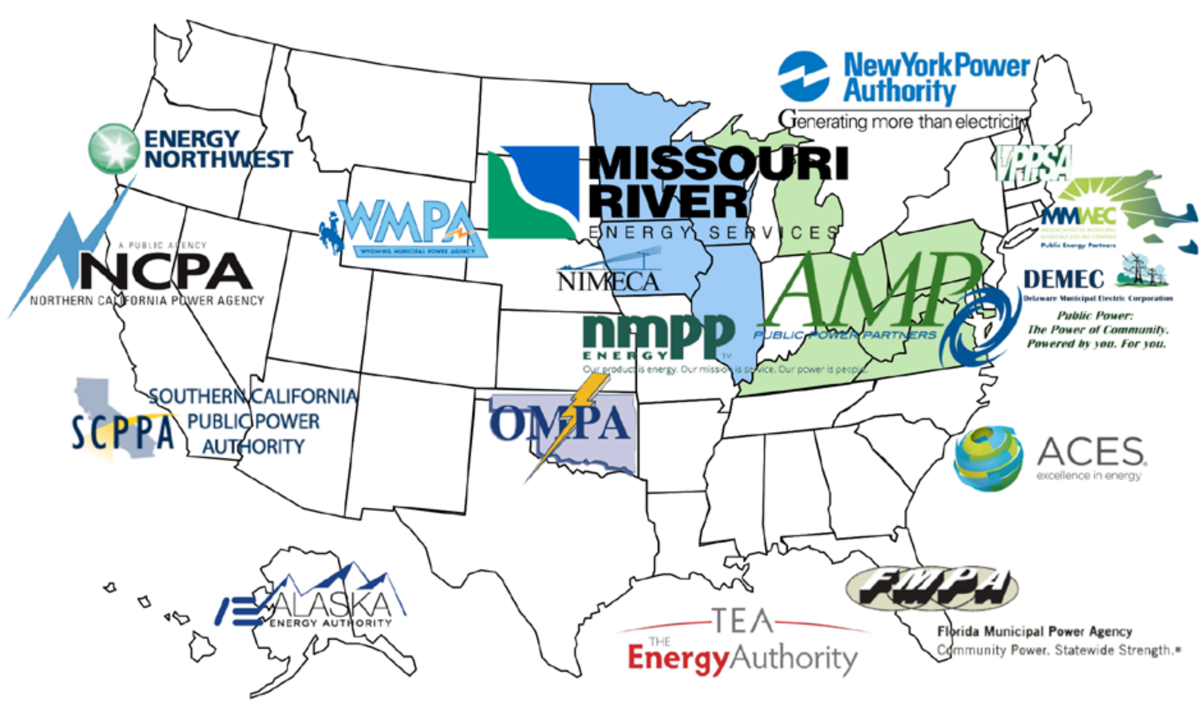
Figure 22: CCE Agency Staffing Levels by Department and Agency (Q2 2018)



Source: Community Choice Partners

Many of the new CCE CEOs that are driving this evolution have substantial experience in the public power sector. The broader public power industry has established over 60 such joint-action agencies like California's NCPA and SCPPA (centralized agencies governed by multiple municipal utilities). Below is a map showing some of the largest public power JPAs:

Figure 23: Map of Public Power Joint-Action Agencies



Source: Community Choice Partners

In summary:

1. Joint-action activities are developing rapidly across CCEs to lower costs, share best practices, standardize and enhance services, pool procurement and enhance creditworthiness;
2. CCEs recognize the broad, multi-dimensional nature of energy risk management, and that they are far greater than the sum of their parts if they work together in this regard (i.e. they are able to track and manage sources of risk more effectively through joint-action, as opposed to operating each agency in isolation from one another);
3. CCE CEOs have already held discussions within CalCCA to establish a "JPE of CCEs" that further enhances the sophistication and coordination of CCE agencies.

This is an extraordinary structural evolution in CCE; the Commission should engage to better understand the ways in which CCE agencies are overcoming various institutional capacity challenges and market issues through the use of joint-action, and to track the emergence and evolution of the "JPA of CCEs".

CCE Industry Growth & Structural Issues the Commission Must Resolve

While the Commission has publicly expressed concerns in various regards as to the acceleration of Community Choice, it has largely ignored the various data access, data quality, and business process mis-alignments between CCEs and IOUs — when fixing these would actually avoid substantial challenges during this period of market transformation and accelerate the evolution of CCEs.

These changes are now warranted, both due to the size of the CCE industry and because the evolution of CCE capabilities in planning and operations will be jeopardized by inaction on the Commission's part.

Data and Business Process Issues that the Commission Should Fix

As illustrative examples of the current data access, data quality and business process issues between CCEs and IOUs:

1. Many of the actual business processes and data access tariffs for CCEs have remained largely unchanged since their origin in the late 1990s and early 2000s;
    a. Current tariffs simply do not reflect the reality that load-serving entities in California must capture Distributed Energy and wholesale market and portfolio risk dynamics with a comparable level of diligence in forecasting.
    b. Consequently, data access is increasingly insufficient to support accurate — much less optimal — CCE forecasting and planning exercises, and also leads to misalignments in CCE and IOU forecasting assumptions.
2. The informal process by which data access and business process requirements are updated has failed to keep pace with the rate of technological progress, or to fully engage with CCEs and municipalities investigating CCE to reflect their collective insights and requests.
    a. Limited changes are consequently resigned to individual negotiations between CCEs and the three IOUs, and this process often leads to unsatisfactory results.
3. In terms of operational data access and coordination:
    a. No CCE agency has access to real-time load information that could be used to refine market operations (while the IOUs do);
    b. Only CCEs in PG&E's territory have access to customer AMI usage data under an operational business process (via Green Button "batch processing" that pushes all customer AMI data to the CCE);
        i. However, this use of this data is constrained as it is received the day <u>after</u> the market trading day.
    c. Little thought has been given to how CCEs and IOUs coordinate data sharing for DERs.
4. Access to historic customer AMI data for CCEs, <u>which load forecasting and power procurement is based upon</u>, varies across all three IOU territories;
    a. The data provided is not "billing quality" and must be analyzed and fixed by each individual CCE.
    b. The number off historic years of data available varies by IOU;

- i. **SCE for example furnishes only 2 years of data, which is insufficient to support industry-standard practices in load forecasting.**

5. Access to customer account data in general also varies widely across all 3 IOU territories:
    a. PG&E furnishes the most expansive sets of data, while SCE's tariff is <u>highly</u> constrained;
    b. This hinders the development of standardized practices and analytics in the CCE industry, or even the sharing of best practices in this regard, which could otherwise more rapidly enhance predictive analytics across all CCE territories simultaneously.
    c. No IOU maintains a data dictionary for the datasets available to CCEs (and often, IOU staff do not understand the data types and fields).
6. Business process requirements for CCEs across all three IOUs are different, opaque and present serious problems on occasion:
    a. Only SCE maintains a formal business process manual for how the IOU and CCEs interact in these regards.
        i. It is titled the "CCE Handbook"— and while valuable, this documentation is incomplete in various regards and no longer available online (though it is available upon request).
    b. There are a notable number of CCE customer accounts that have not received generation service bills for over a year — because of IOU business process issues.

As the CCE industry continues to rapidly expand, this systemic lack of data access and business process issues — and the inefficiencies, opportunity costs and balkanization of forecasting and planning assumptions it creates for operational CCEs — will grow commensurately.

There are numerous deficiencies at this level that could be easily resolved, but there is no overarching process in which to systematically and transparency do so.

To this end, the Commission should consider the merits of implementing a formal process to:

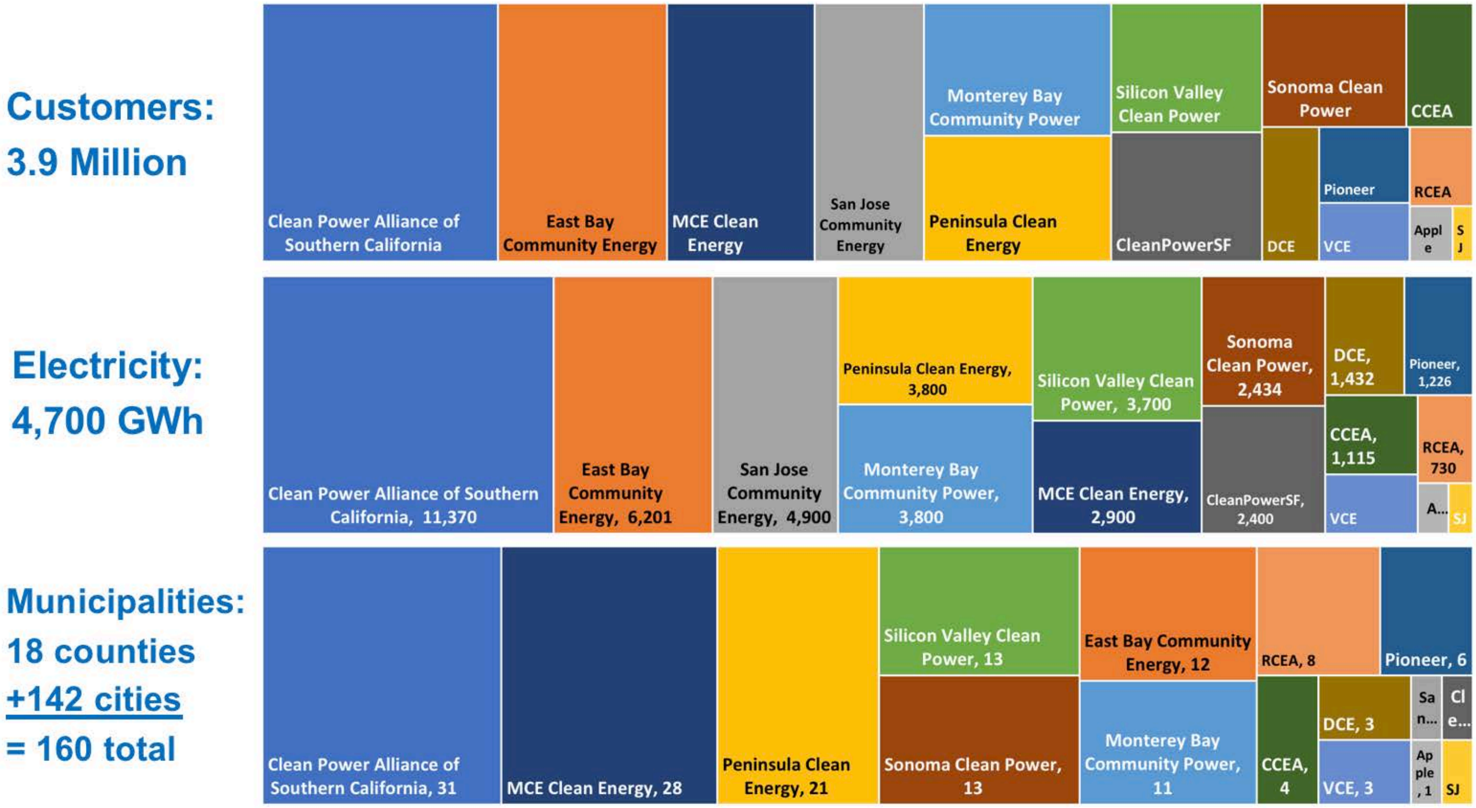
1. Expand, standardize and maintain data access across all three IOU territories in a fashion that is comparable to the approach recently adopted under the Distribution Resources Plan proceeding (i.e. API access facilitating access to a wide range of data);
2. Examine and resolve business process mis-alignments between CCEs and IOUs;
3. Ensure that CCEs and CCE initiatives are universally and proactively engaged in this process in a transparent, open and ongoing fashion; and
4. Prioritize expanding access to Distributed Energy Resource data, forecasting and business intelligence analytics currently held by the IOUs that could be used to enhance CCE predictive analytics and Distributed Energy program design exercises.

The Scale and Institutional Capacity of CCEs Warrant the Expedited Resolution of these Issues

It is self-evident that the CCE industry is now sufficiently large to warrant the above process. CCE formation and expansion has dramatically accelerated in California over the course of the last ~2 years; there are now 16 agencies currently operating or set to launch soon.

As the graph and map below depict, CCEs now employ ~150 staff (and growing), and will soon serve a vast territory within California:

Figure 24: Comparison of Customers, Load & Municipalities of CCE Agencies (2019 Forecast)



Source: Community Choice Partners

Figure 25: Map of CCE Agency Territories

Source: the Local Energy Aggregation Network

Appendix: Representative CCE 2.0 Business Model Functions

This appendix provides a narrative, non-technical summary of a CCE 2.0 agency's functional capabilities and activities comprising management and operations.

Note that these functions are meant to be representative and are not prescriptive, as the CCE industry is both diverse and constantly evolving. The main purpose is to provide the Commission with deeper insight into how sophisticated Community Choice agencies in California have become.

For the purposes of this section, we broadly define "operations" as continuous or near-continuous activities, the delay of which at any given moment could cause significant difficulties for the CCE. Examples of operational functions include power market operations and active portfolio management, data and billing communications with the IOU, and customer call centers. "Management" comprises all remaining functions that are not as time-sensitive.

Various other functions are categorized under different subheadings; the organization of these functions in practice will vary based upon the staff hired, contractors selected to provide services, and how those systems and processes are best integrated.

Management Functions

The management functions outlined below comprise the ongoing activities of the CCE after launch. These functions are less time-sensitive than operational activities, and they generally provide the oversight, analytics, intelligence and strategic decisions that determine the evolution and success of the program over time.

Governance

Policy Development

Develop and update Board policies e.g.: General Organizational Policies, Board Operating Procedures, Conflict of Interest, Records Retention, Financial Management, Accounting and Procurement, Information Technology Security, Delegation of Authority to General Manager for Regulatory and Legislative Matters, Customer-Related Policies, Customer Confidentiality, Prohibition of Untrue Statements, Terms and Conditions of CCE Service, Delinquent CCE Accounts & Collections, Social Media, Enterprise Risk Management (ERM), Financial Reserves Policy, Human Resources, Employee Handbook, Salary Policy, Performance Evaluation Policy & Procedures, Injury Prevention Plan.

Enterprise Risk Management is the most complex, potentially comprised of several inter-related policies and encompassing:

1. Financial risks: counterparty (credit, bankruptcy, default), commodity (price risk, short/long position, non-delivery, short-term trading), transmission price/position (including congestion), retail customer non-payment, rate structure risk, reserve margin inadequacy, operational performance, model error, legal risks, volumetric and loss of customers, natural disasters.
2. Reliability risks: generation, transmission and distribution outages, supply shortfall, natural disasters.
3. Regulatory risks: compliance (filing penalties), dispute resolution (environmental, customer service, labor, etc.), market change rules, regulatory requirement changes.

ERM policies vary in their scope, and typically focus on energy portfolio risk (and transaction authorities, limits and oversight provisions therein), revenue and regulatory risks.

Board and Committee Relations

Provide regular reports and updates to the Board, Community Advisory Committee and any other committees in public and closed sessions, interact with members to formulate and refine strategic initiatives, and coordinate with various management and operational functions to update relevant CCE-related policies.

Administration and Oversight

Human Resources

Oversee employment practices in compliance with labor laws and adopted policies, administer employee benefits, manage relations and performance issues, maintain continuing education and training programs, and plan for, solicit, hire and provide for the training of employees as the CCE grows.

Note that as a startup agency, the CCE will expand key and support staff positions significantly over the initial years of operations to assume control over increasing aspects of both management and operations.

Internal Process Controls & Compliance

Business Process Controls

Ensure operating procedures and practices meet current and planned business process and continuity assurance requirements set by policy, and that decision-making in management and operations is based on the best available information sourced across various functions.

Data Management Process Controls

Ensure that the significant volumes of data collected by the CCE from various sources is maintained in a fashion that meets the extant and planned business process requirements of the program, facilitates data interchange between the CCE and operational counterparties, and complies with law and regulation governing security and privacy (particularly for customer data).

Note that this function is particularly complex and critical, as the effective handling and subsequent analysis of large volumes of data is what provides the foundation for effective decision making and operational capabilities of the CCE. Additionally, there is ongoing development in data exchange protocols for distributed resources, which the CCE should anticipate and integrate as necessary to support related management and operation functions.

Compliance Process Controls

Ensure internal processes comply with evolving policies, rules and regulations, manage compliance reporting obligations and filings, and investigate and resolve non-compliance events.

Information Technology

Provide and maintain the information technology infrastructure required for reliable and secure provision of service, in accordance with applicable frameworks and industry practices (e.g. Critical Infrastructure protection, CIP) and managed by a Security Information and Event Management (SIEM) system to harden cybersecurity across all network levels.

Facilities and Security
Provide and provision adequate office space, and arrange for physical security.

Accounting & Finance

Budget and Financial Planning
Prepare annual budgets for City Council approval, working across functions as necessary and satisfying the revenue requirements and financial policies of the program.

Accounting and Controls
Maintain accounting records and processes to provide accurate and timely financial information to management and for routine financial statements and in preparation of audits (in accordance with accounting standards and adopted policies), assist in budgeting exercises and monitor expenditures for budget compliance, process payroll, monitor compliance with the fiscal provisions of vendor contracts, file annual returns and manage treasury functions.

Capital Projects
Plan for and implement the process of applying for a credit rating, and subsequently to prepare the issuance of revenue bonds to support capital project finance. Thereafter, to maintain bond indenture compliance and to satisfy investor and participant information requests.

External Affairs: Public Relations, Marketing and Outreach

Provide and disseminate multi-lingual print and digital marketing materials for the CCE, update the program's website and social media content, evolve the CCE's brand strategy as required, communicate with members of the press, conduct opinion surveys, represent the CCE at public events, and to communicate CCE initiatives as needed to customers and communities through a variety of channels (direct mail, email and paid/earned targeted social media, newsletters, radio and online ads, retail merchandising, in-store displays, etc.).

These functions require sensitivities to customer demographics, and incorporate customer feedback to refine and advance branding and campaign strategies as well as to implement new functionality and features of operational Customer Care services. Note that campaigns may rely on additional consultants, marketing vendors and contract labor.

Customer Care: Key Account Relationship Management & Self Optimizing Customer Functions

Establish and maintain relationships with key accounts, and work with other management functions to offer customized services and rate structures.

Provide automated platforms that allow key accounts to self-select customized retail rate and products in a streamlined fashion. This requires integration with various forecasting, portfolio management and retail billing functions.

As context: in any CCE territory, there will be a number of very large, sophisticated commercial and industrial customers which will employ energy managers who are tasked with monitoring and minimizing or stabilizing energy costs. These customers should be assigned an account manager by the CCE, and may request specialized rate structures, such as real-time pricing or customized hedging, and/or installation of Distributed Energy Resources that could be supported by or integrated with the

CCE's activities (which are more readily provided through software solutions that automate such customizations).

Legislative and Regulatory Affairs

Monitoring, Analytics, Advice and Representation

Monitor the numerous legislative initiatives and regulatory proceedings (FERC, CAISO and CPUC, primarily) which could impact the CCE's obligations and authorities, analyze the impact of proposed changes (particularly to the CCE's procurement costs and processes), and educate and coordinate amongst different departments to synthesize legal advice and strategies, represent the CCE in these forums (including expert testimony) and maintain compliance.

Note that this function will be provided by multiple contractors and staff, as the subject matter and required expertise is necessarily broad. For example, there may be over sixty regulatory proceedings to be monitored, dozens of related in-depth workshops and meetings, and numerous filings and testimonies required over the course of a year. IT solutions should support this function (there are appropriate SaaS platforms for legal firms and more customized energy-specific platforms available).

Lobbying Activities

Identify and facilitate communications with key legislators and staff involved in proposed laws that could impact the CCE's obligations and authorities.

Compliance Reporting

Prepare and submit compliance filings to meet obligations required by regulatory mandates, e.g.:

CARB	Annual Report: Power Source Disclosure Program
	GHG Source Registration
	Mandatory Reporting of Greenhouse Gas Emissions (MRR)
	Renewable Portfolio Standard Adjustment
CAISO	CRR - Allocation - Tier 1 Nomination
	CRR - Allocation - Tier 2 Nomination
	CRR - Allocation - Historical Load
	CRR - Allocation - Load Forecast
	Flexible Capacity Filing
	Month Ahead Resource Adequacy Plan (T-45)
	Annual Supply Plan
	CRR - Allocation - Priority Nomination Tier
	CRR - Allocation - Tier 3
	CRR - Allocation - Tier Long Term
	CRR - Allocation - Tier 1 Nomination
	CRR - Allocation - Tier 2 Nomination
	CRR - Auction

	CRR - ETC Usage Template
	CRR - OBAALSEs Source Declaration
	LSE Officer Certification
CEC	Annual Power Content Label
	CEC-1386 Wind Power Purchases and Verification form CEC-1384.
	Biennial Storage Compliance Advice Filing
	Integrated Energy Policy Report - Resource Plan
	Integrated Energy Policy Report - Demand Forecast (Form 7.2)
	Quarterly Fuel and Energy Report
	RA Historic Data Request
	WREGIS e-Tag Summary Report Attestation Form
	Year-Ahead Load Forecast - Initial
	Year Ahead Load Forecast - Final
CPUC	Annual RPS compliance report
	GHG Emissions Performance Standard
	Joint Reliability Plan - Data Request
	Month Ahead (T-45) Resource Adequacy Filing (MARA)
	RA Price Data Request
	Year Ahead Resource Adequacy (YARA) - System
	Year Ahead Resource Adequacy (YARA) - Local RA
EIA	Form EIA-826
	Form EIS-861

This is supported by various portfolio analytics and CRM query functions that provide data in the appropriate format to support the preparation of filings.

Internal Reporting

- Load forecasting reports of daily day-ahead accuracy statistics including overall mean absolute percent error (MAPE), overall root mean squared error (RMSE), and peak MAPE.
- Energy portfolio performance including energy, transmission rights, hedges, AS revenues to obligation costs, DA/RT price comparison, mark-to market report, LMP trend and forward curve report, purchase and sales report, and customized executive support metrics (dashboards, red flags, event-driven analyses, option strike optimizations, etc.)
- Customer call center inbound, outbound and DER enrollment metrics including but not limited to call volumes, average response time, various quality assurance metrics and a disposition of the nature of customer inquiries.

Strategic Energy Initiatives and Operational Excellence

Advise on emerging technologies, markets, products and corresponding procurement strategies.

In particular, stay abreast of the rapidly-evolving landscape of distributed energy technologies, business models, financing strategies and programs as well as related developments in regulations, market rules, and funding or financing sources and mechanisms. (This function requires close integration with Legislative and Regulatory affairs.)

Evaluate new customer-facing products and services in terms of policy alignment, customer value and financial viability, and coordinate with various departments to continuously integrate distributed energy into the CCE's energy management (planning, procurement, contract management and operations), customer care, data management and regulatory engagement functions in a systematic fashion.

Analytics and Program Design

Modeling

Note that many of the below subsets of modeling exercises must be harmonized to varying degrees to support planning and operations, and this poses a nontrivial, critical and ongoing integration exercise "behind the scenes" for any power enterprise.

Construction of Forward Curves

Forward curves are a foundational element to any valuation, risk assessment, or planning exercise — and regardless of source (i.e. from a vendor or in-house modeling) are constructed based on a number of assumptions of what impacts market price formation e.g.: natural gas prices, demand growth, thermal fleet changes (power plant retirements and capacity expansions), the penetration and location of variable renewable generation, carbon pricing and regimes, changes in market rules (including market expansion), and technological innovation that

Targeting of Distributed Energy Resources

Analyze customer data and other data to identify specific customers that present distinct opportunities for Distributed Energy Resources. Note that this is an evolving area that both utilities and CCEs in California have implemented to varying degrees.

Distributed Energy Resource EM&V (Evaluation, Measurement & Verification) and Forecasting

Collect and analyze the hourly or sub-hourly impact of energy efficiency and distributed energy resource installations based on project attribute data and GreenButton smart meter usage data (on an automated basis) for integration into forecasting, planning and procurement functions.

Note that this is an evolving area of capabilities that several utilities and CCEs are piloting in California through the implementation of OpenEE Meter (an open-source technology), which may allow pay-for-performance DER programs and eventually the forward procurement of shaped blocks of energy provided by DER.

Load Forecasting

Prepare a variety of short- to long-term forecasts of electricity usage patterns using customized algorithms (e.g. nonlinear regression, neural networks, etc., time series filters, trend models) inputting historic customer usage data, historic weather station data, and examining various potential future scenarios to identify key areas of variability or uncertainty (weather, economy, customer growth, demand elasticity, DER and enabling technologies).

This supports a variety of subsequent planning and operational activities (price forecasting, revenue forecasting, fundamental modeling, IRP, day ahead and real-time load scheduling, active risk management, et cetera).

Revenue Forecasting

Utilize a rate engine, with inputs harmonized with the stochastic input and scenario assumptions used in price and load forecasting exercises, to simulate expected utility service fees, revenue inflows to and customer payments from the CCE (under extant and future rate and tariff schedules), and provide comparisons to extant and forecasted utility rate schedules. This includes scenarios and potentially dynamic modeling of DER and customer behavioral impacts.

This function supports rate-setting and budgeting exercises.

Price Forecasting

Prepare a variety of short- to medium-term forecasts of electricity and natural gas market prices (including forward curve development) using technical models and customized algorithms, examining various potential future scenarios and identifying key areas of variability or uncertainty.

This supports a variety of subsequent operational activities (power trading, short/medium term PPA valuation, et cetera).

Fundamental Modeling & Analysis

Use "fundamental" models for short-to-long term planning and PPA valuation. Requires production cost dispatch models (e.g. Ventyx PROMOD, PLEXOS, GridView DAYZER, GE MAPS, ABB GridView, Aurora XMP, etc.) that simulate the structure of the physical electricity grid (including transmission lines, substations and existing and planned generation assets), capture wholesale market rules, and develop various forecasts required as model inputs in order to forecast (deterministically and stochastically i.e. statistically risk-adjusted) the performance of the CCE's portfolio of assets and contracts across a variety of future scenarios.

Simulations capture the California market and the broader Western Electricity Coordinating Council (WECC) region to capture import and export dynamics. Power flows, supply, demand, market prices, climactic conditions, new generation and distributed resource development, CCE costs and potential market rule changes are considered in a holistic manner to assess the financial impact of different scenarios across the planning horizon (typically, up to twenty years).

Note that this function would develop similar forecasts based on available data for IOU's portfolio, to inform regulatory engagements, strategic planning and portfolio strategy impacted by non-bypassable charges and/or the allocation of IOU portfolio resources as offsets to the CCE procurement requirements (e.g. PCIA and CAM).

Note that software varies in capabilities (for example, GridView and PLEXOS support co-optimization for ancillary services in addition to energy dispatch) and treatment of DER in particular, as well as and frequency of updates — both of model structure and input datasets. For further reference, see Navigant's "Survey of Models and Tools for Stationary Energy Storage Industry" (2014).[2]

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[2] http://energystorage.org/system/files/resources/survey_of_modeling_capabilities_and_needs_for_the_stationary_energy_storage_industry_-_final_may_2014.pdf

Transmission Modeling (congestion)

Assess basis risk across the portfolio of contracts (i.e. the price spread of transmission congestion, between the contracted delivery points for power and where load is settled), utilizing technical (statistical, historical) analytics and power flow/ production cost models (note not all support this function, or vary in their extent and frequency of input updates); evaluate pre-existing financial hedge rights (CAISO CRR, congestion revenue rights) and portfolio optimization opportunities, support congestion/virtual bidding strategies (as applicable), support allocation/auction bid strategies (given portfolio characteristics), and support long-term PPA valuation (analyze physical transmission constraints and CRR financial optimizations).

DER Program Design

Distributed Energy program design is complex, and broadly requires a different approach depending on whether the resources under consideration are 1) "dispatchable" i.e. may be aggregated and controlled actively as a "virtual power plant" within the CCE's active energy portfolio, or 2) are passive resources that may not be remotely controlled, but do have to be monitored or estimated for incorporation into planning and regulatory engagement functions.

Dispatchable DER

These are technologies such as demand response, energy storage, electric vehicle managed charging, smart inverter functionality on photovoltaic systems, combined heat and power smart inverter and/or "peak boosting" and a variety of end-use technologies and practices that fall under building or industrial automation.

1) Needs assessment:
    a) Assessment of customer base and potential capacity
    b) Special conditions due to regulatory, geographic and climatological environment
2) Valuation and business case assessment
3) Program design services
    a) Knowledge of existing programs
        i) Program rules
        ii) Baseline design
        iii) Financial incentive/penalty rules
    b) Custom program design
    c) Metering and telemetry requirements for DER
    d) Wholesale bidding strategies
    e) Retail engagement, aggregator engagement and contracting strategies

Note that certain technologies are active but determined by onsite customer considerations (i.e. peak demand retail rate management), in which case only excess capacity beyond these use cases is available for the CCE.

Non-Dispatchable DER

These are technologies such as rooftop solar and energy efficiency, which may be broadly supported by the CCE through a combination of 1) overcoming market and non-market barriers for project developers and customers (i.e. customer aggregation and group buying supported by targeting analytics, direct install programs utilizing pre-approved contractors and contract structures, etc.) and 2) funding support, either by applying to administer funds from the CPUC (for energy efficiency), streamlining awareness of and access to existing rebate and financing options (i.e. single point of customer contact program design), and a variety of other program design options.

Portfolio Strategy, Planning & Contracting

Portfolio Development & Valuation

Support the development of competitive procurement strategies (bilateral contracts, competitive solicitations, open season, etc.) that meet regulatory and local policy goals (risk management, etc.) over the medium- to long-term. This function depends on the variety of supporting tools developed and maintained to support the valuation of different physical (electricity, fuel) and financial/insurance products and offers.

Portfolio Reporting

Prepare reports and forecasts for internal use on a regular basis (e.g. daily, monthly, annual) on the CCE's expenses, risk and cost drivers, and open positions for different power products to be filled by origination and long-term procurement activities.

Power Contracting

Origination

Meet seasonal to medium-term portfolio hedging objectives via competitive solicitations and bilateral transactions for required physical and financial products. Negotiate power purchase agreements (PPAs), DR/DER, peaking/tolling and other structured transactions in compliance with the CCE's internal risk policies and procedures.

Products are sourced from various distributed resources (demand response, energy storage, combined heat and power, etc.), renewables, conventional sources, other suppliers and exchanges, and include energy, capacity, tolling arrangements, natural gas transportation and storage, emissions compliance products, transmission rights, and various financial/insurance products.

Long-Term Procurement

Meet long-term portfolio hedge requirements by negotiating and executing power purchase agreements (PPAs) via competitive solicitations.

Congestion Revenue Rights Strategy and CAISO CRR Nominations & Bids

Construct auction bidding strategies based on the CCE's portfolio (and exposure to transmission congestions costs), and engage in CAISO quarterly and annual nominations and auctions.

Integrated Resource Planning

Incorporate feedback from CCE management and involved stakeholder groups on the various assumptions and methodologies involved in long-term planning, and to produce an annual Integrated Resources Plan (IRP). This function draws upon many of the "Planning and Analysis" functions detailed above, particularly "fundamental modeling", and should conform to IRP guidelines being defined by CCEs, the CPUC, CEC and CARB in accordance with the intent of SB350 (which seeks to harmonize and coordinate long-term planning in California across the agencies and load-serving entities involved).

Credit Monitoring

Construct and maintain credit profiles for energy counterparties, analyze creditworthiness and ratings, negotiate credit provisions in contracting, monitor credit limits and exceptions, monitor collateral activity and execute calls, monitor and advise on market risk and credit enhancements, and ensure compliance with regulatory and policy mandates.

Operational Functions

The provision of these activities is extremely time-sensitive, in that any delay may directly impact the performance of the CCE (i.e. incurring unplanned costs, failing to satisfy customer inquiries, delaying receipt of revenues, or hindering management functions).

Dispatchable DER Program Operations

NOTE that these functions span all of the subsections that follow, but have been broken out here separately for clarity:

1) Enrollment process management
   a) Enrolling customers and registering assets with CAISO (eligibility, meter requirements, approvals, etc.)
2) Portfolio implementation services
3) Active management of DER operations
   a) Capacity nominations, event dispatch, outage management, etc.
4) Retail rate and tariff impact and optimization
5) Wholesale market participation
   a) Maximize DER investment by bidding resources in applicable markets
      i) Day-ahead
      ii) Real-time energy
      iii) Ancillary Services
   b) Resource and bid optimization
   c) Demand Response Provider (DRP), DERP and Scheduling Coordinator (SC) services
      i) Resource registration
      ii) Bidding
      iii) Award management
      iv) Dispatch
      v) Telemetry
      vi) Revenue quality meter data
      vii) Settlements and verification
6) Performance measurement, validation and settlements
7) Integration with other systems (MDMS, etc.)
8) Program management reporting ('lessons learned', etc.)

Energy Market Operations

Energy Contract Management & Trade Capture

Administer energy-related contracts and conduct supporting activities such as counterparty credit monitoring, verification of collateral and compliance with contract terms, exercising of contract options, renegotiation of contracts, dispute resolution, invoice verification and payment processing in accordance with contract terms. Note that this also includes straight-through processing for trade capture and validation, to support active risk management, handling both physical (electricity and fuel) and financial products.

Scheduling and Active Risk Management (Trading)
Provide day-ahead and real-time schedule coordination and/or scheduling agent services in the coordination and submission of bids for CCE loads, bids, ancillary services and various other transactions in CAISO markets. This includes forecasting, scheduling and dispatch, outage management, asset optimization, development of bidding strategies, physical and financial trading (including congestion/virtual bidding, as appropriate) and short-term contract management including the re-marketing of excess power, management of emission-compliance products, and related compliance activities (e-tags, etc., as applicable).

This function requires the maintenance of primary and backup dispatch centers that operate on a real-time, continuous (24/7/365) basis.

Note that separate contractors will likely be used to provide and coordinate wholesale generation and Distributed Energy Resource functions (given the specialized nature of the latter).

Settlements and Operations Services
Validate energy transactions (contract and CAISO market receipts and payments) under the terms of contract or tariff provisions, identify issues or discrepancies, and initiate and resolve disputes. This function requires, for verifying CAISO market transactions, shadow settlement software to independently calculate charges based on data published by CAISO and compare the results to settlement statements, as well as analytical capabilities to identify and investigate any differences. This is necessary to verify that the CCE's incurred costs and received revenues are correct.

Data Management (Retail, Wholesale and DER)

Bulk Power Information and Data Management
Interface with CAISO and collect and maintain a database of wholesale market data, documentation and records, develop and implement various analytical and reporting tools, and support energy-related settlement, compliance, reporting and information requirements.

Distributed Energy Information and Data Management
Interface with a variety of Distributed Energy Resources and aggregators to predict, track and verify capacity and other performance attributes of DER for operational use. For example, solar generation output based on weather forecast and irradiance data, capacity available for dispatch from microgrids, demand response and electric vehicle managed charging aggregators, etc. This data may be sourced via IOU, CCE installed telemetry or third-party gateways and use proprietary or industry standards (many of which are evolving). This function supports the integration of distributed energy into a variety of management and operation functions (such as scheduling and contract management).

Renewable Generation Data and Reporting
Act as QRE (Qualified Reporting Entity) for small-scale renewable generators and report revenue quality meter data to WREGIS (the Western Renewable Energy Generation Information System).

Customer Relationship Management (CRM) Database

Receive, error check and securely store customer data (individual account, usage, billing and customer contact attributes, as well as summary datasets for the CCE territory) using a variety of data exchange protocols and data formats. Sources of data include:

- Electronic Data Interchange (detailed below, EDI is a monthly summary of each customer's usage and the primary format used for billing and compliance purposes);
- GreenButton (a summary of Smart Meter data revealing customer usage on a 15 minute or hourly basis, i.e. more granular than EDI format);
- CCE INFO Tariff (summary datasets available to the CCE and updated as requested under specialized tariffs from IOU;
- Information from Customer Care functions related to distributed energy and communications with the customer;
- Data relevant to Distributed Energy Resources from a variety of sources, including gas usage and account data, building data (e.g. size, type of building and date of construction), commercial real estate data (lease types, occupancy, business type, etc.), and weather and climactic data.

Note that this requires integration with Customer Care operations, and the data collected supports a variety of management and operation functions.

Electronic Data Interchange (EDI)

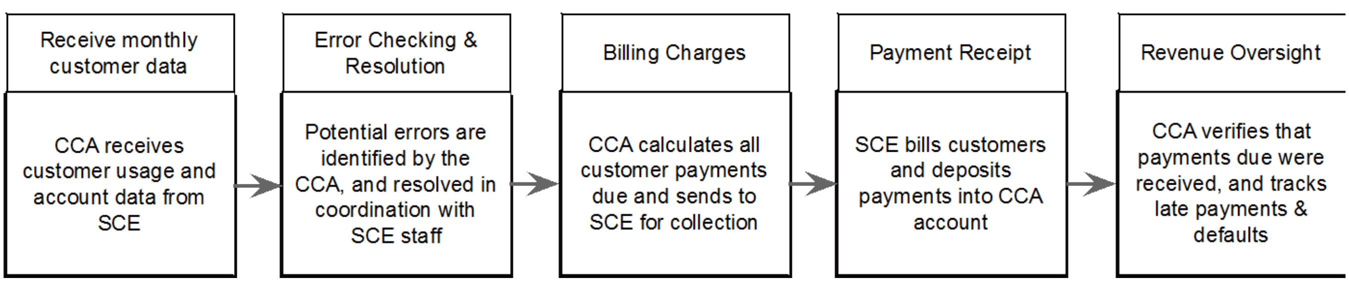
Routinely and securely exchange data relating to customer accounts, usage and bills with IOU using a third-party Value-Added Network (VAN). VANs are private network providers that lease communication lines to subscribers (e.g. CCEs), and provide specialized services to ensure the security of the data transactions.

Retail Customer Billing

Billing and Verification Services

Receive monthly customer usage and account data from IOU on a rolling basis, identify and resolve any errors in the data supplied (often in coordination with relevant IOU staff), calculate all customer charges and provide to IOU for collection, and verify that payments due were received (or otherwise to identify and track any incidents of non-payment).

Note that this process requires automated software processes, quality controls and staff capacity sufficient to resolve discrepancies and submit billing statements to IOU on a relatively tight timeline; bills for individual customers that are not received within IOU's "billing window" will be delayed until the next billing cycle (a month later). These processes are summarized in the graph below:



Additionally, this process must integrate billing determinants associated with Distributed Energy Resources that may come from third-parties other than IOU.

Internal Reporting and Compliance

Analyze and prepare datasets to support business processes and oversight functions and to prepare compliance filings (Federal, state and CAISO) that rely on customer data.

Retail Customer Care

Customer Call Center

Inbound Call Handling

Field customer call inquiries in an expeditious manner and in accordance with established scripts and issue escalation procedures, to establish IVR (interactive voice recording) as required, and to refer customers to IOU for certain inquiries. Scripting should employ proven customer retention strategies. This function requires coordination with IOU customer service representatives to facilitate and enhance the joint responsibilities CCEs and utilities share in fielding customer inquiries.

Outbound Customer Calling

Actively solicit customers for enrollment in programs and rate options, as instructed by CCE management and in accordance with established scripts. For example, customers may be targeted for enrollment in demand response or other distributed energy programs and offerings. Additionally, to employ 'win-back' strategies for re-enrolling customers that have opted-out.

Other Customer Channels

Initiate or respond to customer inquiries in an expert and timely fashion received via email, online chat and other social media channels.