California IOU

Commercial Rate Design Overview

CPUC Advanced Rate Design Forum

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Traditional Rate Design Goals

- Public utility services must be made available at "just and reasonable" rates. (P.U. Code §§ 451, 454).
- Rate design typically involves a balancing of a number of competing goals:
  - **Fair and equitable to all customers,**
  - **Stable and predictable,**
  - Economically efficient,
  - **Understandable by the public**,
  - Stable revenue collection by the utility,
  - Reflective of the social costs of energy production and consumption, and
  - Mimicking what a fully competitive unregulated market would charge.

Overarching Rate Design Trends

- More accurately reflect cost causation.
- Greater use of time-dependent and dynamic or real-time rates where appropriate
- Remove rate-design barriers to distributed energy resources and end-use electrification
  - Electric vehicles and fleets
  - Behind the meter energy storage
  - Self-generation

The Grid Has Evolved Since 2000

- Continuing Increase in Renewable Generation
  - Both grid-connected and behind the meter
  - Need to integrate renewables into the grid
- Advent of Smart Metering

As a result, [net] loads and supplies have become more time-dependent, but

- **We now have the capability to measure and report metered usage at sub-hourly intervals**

The Grid Has Evolved Since 2000-But Commercial Rates Have Not Kept Pace

- While we introduced default **Critical Peak Pricing [CPP] combined with Time-Of-Use [TOU],** Demand Charge rate designs for larger customers are mostly unchanged since 2000
  - Medium and Large Commercial rates recover capacity costs in monthly demand charges, which
    - predate smart meters*,
    - do not fully utilize smart meter capabilities, and
    - may not accurately reflect cost causation.

*Larger customers had TOU-capable meters and TOU rates by 2000 or before

What is a Monthly Demand Charge?

- A monthly charge imposed based on the customer's highest usage during the month, applied to kW
  - **Non-coincident demand charge or NCD** is based on the customer's highest 15 minutes of usage during the month, regardless of when it occurs.
  - **Coincident demand charge or CD charge** is based on the highest 15 minutes of usage during the during the peak TOU hours of the month

Issues With Demand Charges Generally

- Demand Charges fail to account for load diversity
  - When customers use capacity at different times, their use is not additive
  - **This is a problem for demand charges generally, whether the relevant facilities are peak-driven or not.**
  - RAP will discuss the example of a school and a church using the same local grid, but on different days. Demand charges charge them as if they each had exclusive use of the grid, and their combined bill (if separate accounts) amounts to double-billing for the same (shared) capacity

Issues With Monthly Coincident Demand Charges

- Load diversity remains an issue
- Customer monthly peak TOU period demand often fails to coincide with system peak demands
  - This is especially true for solar and erratic load customers*
    - For solar customers, maximum demands can occur on a cloudy day, while system peak typically occurs on a hot, sunny day.
    - The customer may be overcharged for its true coincident demand, or under-credited for PV capacity provided
  - Could *daily* demand charges, or TOU rates, better reflect cost causation?

*As discussed in D.14-12-080

Demand Charges in Current Rates

Capacity Costs Recovered in Demand Charges
In Selected Medium/Large Commercial Rates

	PG&E (A-10)	PG&E (E-19S)	SCE (TOU-8)	SDG&E (AL-TOU)
Generation Capacity	100% NCD	100% CD	100% CD	100% CD
Transmission	100% NCD	100% NCD	100% NCD	90% NCD / 10% CD
Distribution	100% NCD	70% NCD / 30% CD	100% NCD	39% NCD / 61% CD

Cross-hatching indicates proposed changes are pending in current rate proceedings

Issues in CA Retail Generation Rates

- Use of monthly coincident demand charges to recover capacity costs
  - Monthly demand charges can result in timing mismatch of system coincident demand and customer maximum demand for solar and erratic load customers
    - As discussed in D.14-12-080
  - Need to develop more accurate methodology for measuring and billing coincident peak demand

Other generation issues that are out of scope for this rates forum:

- *What generation capacity costs should be included in marginal costs?*
  - *Long-run capacity costs (e.g., annualized cost of combustion turbine)*
  - *Short-run or market price of capacity*
- *Fair treatment of legacy generation costs for departing load customers*

Issues in CA Retail Transmission Rates
(Transmission is FERC-regulated)

- Currently, transmission is treated as not having significant time dependence
- CAISO's High Voltage Transmission Access Charge (HV-TAC) is a volumetric ($/MWh) non-time-dependent charge
- IOUs allocate transmission costs to customer *classes* based on 12 monthly coincident peak demands (12-CP);
- Individual retail customers pay either
  - Flat volumetric rates (residential and small commercial); or
  - Non-coincident demand charges (medium and large commercial)
- CAISO is considering whether to restructure the HV-TAC to include TOU or Peak demand charges
  - In 2015 CAISO identified 4 pm to 9 pm as peak (or super-peak) hours (not reflected in current Transmission rates)

Issues in CA Distribution Rates
(Medium and Large Commercial)

- NCD charges comprise 39% to 100% of distribution rates
  - The remainder consists of monthly peak-related (coincident) demand charges
- The CPUC has signaled a direction to reduce the usage of NCD charges in distribution rates
  - 2017 SDG&E General Rate Case Ph. 2 Decision (D.17-08-030)
- More generally, the CPUC has encouraged the CA IOUs to time-differentiate their distribution rates
  - 2017 TOU Rulemaking Decision (D.17-01-006)

California PUC DER Action Plan

In 2016 the CPUC endorsed a Distributed Energy Resource (DER) Action Plan:

The scope includes three groups of related proceedings or initiatives:

1. **Rates and Tariffs**
2. **Distribution Grid Infrastructure, Planning, Interconnection and Procurement**
3. **Wholesale DER Market Integration and Interconnection**

"This DER Action Plan … seeks to align the Commission's vision and actions to shape California's distributed energy resources future."

California PUC DER Action Plan (2)

Vision Elements for Rates and Tariffs Include:

- Rates reflect time-varying marginal cost.
- **Rates and demand charges better reflect cost causation and capacity benefits of DERs**

Relevant Action Elements

1.1. By 2017, **complete a review of non-residential demand charges and recommend alignment of pricing with DER vision elements.**

1.4. By 2017, consider changes to nonresidential rate design, **including modification of demand charges.**

1.5. By 2017, establish a forum for considering innovative rates and tariffs.

Conclusion: Evolution of Commercial Rate Design

Year	Dominant Non-Residential Rate Design
2012	• Small & Medium commercial customers mostly on flat rates or non-coincident demand charges; • Large commercial/industrial customers on default critical peak pricing (CPP) with opt-out to TOU; • Medium and large customers on demand charge rates; • Optional partial substitution of volumetric TOU rates for some self-generators
2017	• ALL commercial/industrial customers on default critical peak pricing (CPP) with opt-out to TOU; • Medium and large customers on demand charge rates; • Optional partial substitution of volumetric TOU rates for some self-generators
2019	• Transition away from non-coincident demand charges and toward coincident demand charges, volumetric TOU rates, dynamic rates, and/or real-time pricing?

Appendix

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Issues With Demand Charges Generally

Demand Charges fail to account for load diversity

<u>School & Church Example*</u>

A school and church on adjacent properties each use 50 kW. However the school is closed on weekends (zero usage) and the church is closed on weekdays (zero usage).

Both are served by a utility which bills them an NCD charge of $10/kW-month.

- If separately billed, <u>each</u> would pay $500 per month
- If on a single account, the <u>total</u> bill would be $500 per month

While this is an extreme example, a cost based rate would not yield bills that differ materially between separate and combined accounts

*Example suggested by RAP

DER Action Plan (2)

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Relevant Continuing Elements

1. Time of Use (TOU) Rulemaking (R.15-12-012),

3. **General Rate Case (GRC) Phase 2 (e.g., A.16-06-013) and Rate Design Window cases**, consideration of: fixed charges, TOU periods and rates, nonresidential rate design, including enhancements to dynamic rates.

4. Appropriate rate designs to absorb renewables oversupply.

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