Experiences with Solar Export Credit Rates and other Emerging Solar Compensation Schemes

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Agenda

- Definitions
- Export rates in successor Net-Energy Metering (NEM) tariffs
- State and utility examples
- Ancillary services and standby charges
- Cost causation and rate design considerations

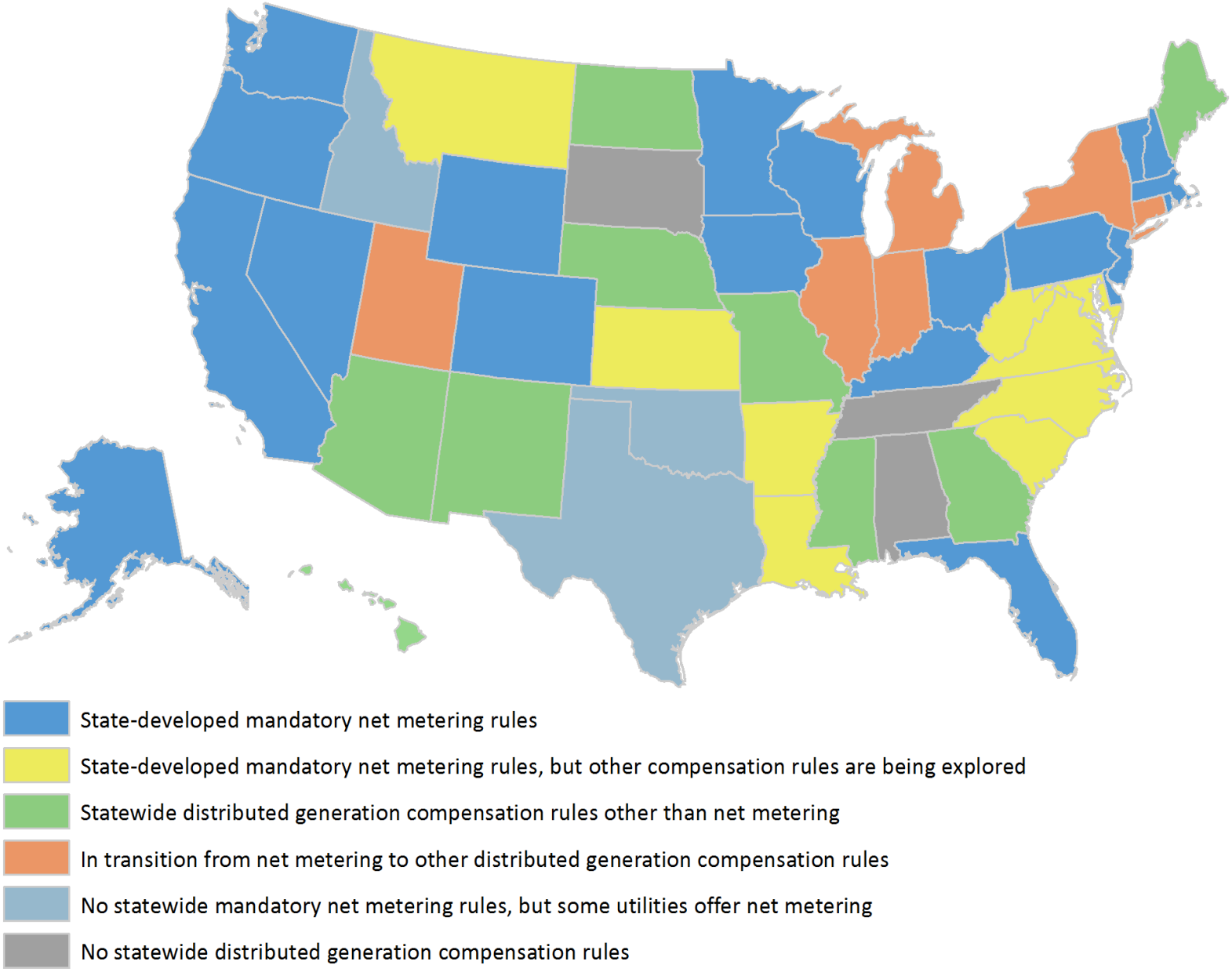
Definitions

- Net metering – exported energy compensated at the retail rate as long as credit for excess generation is not greater than the bill for the customer's usage during the billing period or other specified period.
- Net billing – compensates a customer for excess generation at a rate other than the retail rate for consumption, after netting production and consumption over intervals shorter than the billing period (e.g., 15-minute or 1-hour intervals).
  - A variation on this is the Michigan PSC developed Inflow-Outflow methodology where all exported energy during a billing period is metered and a commission-approved rate other than retail is applied – currently PURPA avoided cost rates.
- Buy-all, sell-all – participating customers purchase all of their service from their utility company. All energy generated by a participating customer is separately metered during each billing period and that output is credited at a commission-approved price. All energy produced on-site is treated the same whether or not it is consumed onsite or exported.

From: Review of State Net Energy Metering and Successor Rate Designs, Tom Stanton, NRRI 2019

Export rates

- States are taking various approaches to net energy metering successor tariffs and establishing **export rates**.
- Some states continue to credit exported energy at the full retail rate, while others are moving toward:
  - Avoided costs,
  - Wholesale prices,
  - Value-based tariffs,
  - Embedded cost-of-service rates,
  - Locational marginal prices,
  - A resource comparison proxy,
  - Inflow & Outflow methodology, or
  - One of these plus an adder.



Adapted by PNNL from North Carolina Clean Energy Technology Center's 50 States of Solar: Q3 2018 Quarterly Report

Successor Net Energy Metering Tariffs

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- Alternatives to full retail rate compensation for excess generation are being explored around the U.S.:
  - Avoided costs (FL, LA, MO, MN, NE, ND, NM, OK, RI)
  - Embedded cost-of-service rate (AK)
  - Solar-specific avoided costs (AZ, GA)
  - Demand charges for residential customers (KS, MT, MA)
  - Time-varying rates as basis for new tariffs (CA, MD)
  - Value-based tariffs (MN, MO, OR, NY)
  - Wholesale prices or marginal costs plus an adder (IN, MS)
  - Transition mechanisms being implemented (NV, NY, OR, UT)
  - Inflow & Outflow Mechanism – proposed compensation monthly average real-time locational marginal price at relevant node (MI)

California Net Metering Successor Tariff

- California's successor NEM tariff makes adjustments to align costs of net metering successor customers more closely with those of non-participating customers (CPUC 2016).
- A few key differences between California's initial policy and its successor:
  - Tariff requires a smart inverter for all interconnection applications;
  - Participating customers must take a time-of-use rate;
  - Participating customers pay a one-time interconnection fee and non-bypassable charges, such as a Nuclear Decommissioning Charge; and
  - The new tariff specifically prohibits new demand charges, grid access charges, standby fees, or similar fixed charges until the impacts of these charges are fully studied.
- Result – both PG&E and SCE proposed optional rate designs (supported by solar some advocates) that pair TOU with net metering, reflect the reality of the value of generation during late afternoon peak, and help solar-plus-storage economics.

Hawaii's New Tariff Options

- In response to increased solar PV penetration rates that Hawaiian Electric indicated its circuits could not handle, the HPUC ended the state's net metering program in 2015 and replaced it with different on-site generation compensation options.
- All new private rooftop solar systems are required to have advanced inverter technology with specific grid support features activated.

Hawaiian Electric Currently Offers:

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- **Customer Grid-Supply (CGS)** - participants receive a PUC-approved credit for exported electricity and are billed at the retail rate for grid electricity they use.
- **Customer Grid-Supply Plus (CGS Plus)** - systems must include grid support technology and allow the utility to remotely monitor system performance, technical compliance, and, if necessary, control for grid stability.
- **Customer Self-Supply (CSS)** is intended only for private rooftop solar installations that are designed to not export any electricity to the grid. Customers are not compensated for any export of energy.
- **Smart Export** customers with a renewable system and battery energy storage system have the option to export energy to the grid from 4 p.m. to 9 a.m. Systems must include grid support technology to manage grid reliability and system performance.
- **Standard Interconnection Agreement (SIA)** is designed for larger customers who wish to offset their electricity bill with on-site generation.

Impact of Hawaii's New Tariffs

- Following November 2017 institution of Smart Export tariff and Customer Grid Supply-plus tariff, PV Permits hit an eight year low.
- Starting in early 2018, residential energy storage across Hawaii has started to grow.
- Over 60% of newly permitted PV systems have included batteries.
- Challenge for installers is finding enough batteries to meet demand.

Source: https://www.utilitydive.com/news/as-rooftop-solar-expands-states-grapple-with-successors-to-net-metering/531888/

Specific State Examples

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- **Arizona**
  - Exported energy is compensated at an avoided cost rate with different rates for different utilities based on a **resource comparison proxy** (RCP)
  - The RCP rate may not be reduced more than 10% a year, is based on a rolling five-year weighted average cost of the utility's solar PV PPAs and utility-owned grid-scale solar PV facilities, and is applicable for 10 years.
  - For projects installed through August 2019, Arizona Public Service's RCP rate for exports is, 11.61¢/kWh, Tucson Electric Power's is 9.64¢/kWh, and UNS Electric's is 11.5¢/kWh.
- **Illinois**
  - Although the state currently has a traditional retail rate compensation net metering policy, the recently passed Future Energy Jobs Act (FEJA) requires a transition to a net metering successor policy that includes a distributed generation rebate program.
  - Once a 5% state aggregate cap is reached, new eligible customers shall only be eligible for energy-related value (no T&D related value).
  - The new rebate is intended to reflect the value of distributed generation to the distribution system.

Specific State Examples, cont'd.

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- **Indiana**
  - S.B 309 enacted in May 2017 phases out traditional retail rate compensation net metering.
  - Distributed generation systems installed in 2018 through July 1, 2022 will receive the **full retail rate** compensation for 30 years. Excess generation from systems installed after July 1, 2022 will be compensated at the utility's **average marginal cost plus 25%.**
- **Nevada**
  - Nevada Legislature restored net metering in 2017 with A.B. 405.
  - The first 80 MW of systems to apply, solar PV systems up to 25 kW in size can net excess generation monthly at a rate equal to 95% of the retail rate for 20 years.
  - For all other systems, exported generation is credited at the avoided cost rate
  - The new 80 MW capacity tranche approach progressively reduces the carryover rate for monthly excess generation from the full retail rate to 95% for the first tranche, 88% for the second tranche, 81% for the third tranche, and 75% for all new installations after the third tranche is filled (NPUC 2017).

Specific State Examples, cont'd.

- **Oregon** - OPUC adopted final methodologies for IOUs to use in calculating their initial Resource Value of Solar. 11 components:
  - Energy
  - Generation Capacity
  - T&D Capacity
  - Line Loss
  - Administration
  - Market Price Response
  - Integration
  - Hedge Value
  - Environmental Compliance
  - RPS Compliance
  - Grid Services
- Utilities filed their updated values in March 2019.
  - Idaho Power calculated 4.273 cents per kWh for standard size projects and 4.716 cents per kWh for utility scale projects.
  - Portland General Electric calculated 4.988 cents per kWh for December 2017 and 5.016 cents per kWh for March 2019.
  - PacifiCorp calculated a real value of 5.086 cents per kWh and a nominal value of 6.244 cents per kWh.

Example Components and magnitudes of Resource Value of Solar calculations

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Impact of March 18, 2019 Updates on PGE's Initial RVOS Compliance:

RVOS Element	December 2017 $/MWh, real levelized value	March 2019 $/MWh real levelized value
Energy	24.98	25.33
Generation Capacity	7.30	7.19
T&D Capacity	8.08	7.91
Line Loss	1.48	1.50
Administration	(5.58)	(5.58)
Market Price Response	1.81	1.81
Integration	(0.83)	(0.83)
Hedge Value	1.25	1.27
Environmental Compliance	11.41	11.57
RPS Compliance	0	0
Grid Services	0	0
RVOS Total	**49.88**	**50.16**

Example Approaches – New York VDER

- In March 2017, the NY PSC issued the value of DER (VDER) Transition Order, which is intended to enable "the transition to a distributed, transactive, and integrated electric system by compensating DERs based on the actual value provided by those resources."
- Provide incentives reflecting the locational value of DER
- Sets a system-wide distribution value and layers on top any location-specific benefits that can be identified
- Approach: Identifying, quantifying, and compensating for:
  - Demand Reduction Value (DRV) - Applies to all projects in a utility's territory and is based on the utility's average cost of service.
  - Locational System Relief Value (LSRV) - Specific to projects that, based on location and characteristics, contribute to meeting a particular utility need and provide a specific, higher value to the distribution system.

Components of VDER

Component	Calculation based on
Energy value	Day-ahead hourly Locational Based Marginal Price grossed up for losses
Capacity value – market value	Monthly NYISO auction price
Capacity value – out of market value	The difference between the market value and the total generating capacity payments made to Value Stack customers
Environmental value – market value	Higher of Tier 1 REC price per kWh, or social cost of Carbon per kWh less Regional Greenhouse Gas Initiative; customers who want to retain RECs will not receive compensation
Environmental value – out of market value	Difference between compensation and market will be recovered from customers within the same service class as the customers receiving benefits from the DER
Demand reduction value	Compensation based on eligible DER performance during 10 highest usage hours at $ per kw-year value
Locational system relief value	Static rate per kW-year value applied to net injected kW
Market transition credit	Static rate per kWh applied to net injected kWh; steps down by tranche

Example Approaches – New York, cont'd

- Utilities determined threshold criteria for determining LSRV zones
  - Example 1: Con Edison threshold – LSRV areas are those where projected energy use in 2021 reaches or exceeds:
    - 98% of current capability in sub-transmission lines or area stations or
    - 90% of the current capability in distribution network areas.
    - Applying criteria, **19%** of Con Edison service territory qualify as LSRV zones
  - Example 2: National Grid threshold - scaled loads on all distribution substations to 2020 and then screened against planning ratings
    - Applying criteria, **16%** of National Grid substations were identified as LSRV areas
- Marginal cost of service (MCOS) studies are the basis for LSRV and DRV compensation calculations
  - Value calculations can be significantly different from one utility to the next.
  - Commission initiated a proceeding to examine MCOS studies and determine what methodologies will lead to the most accurate results
  - Current DRV and LSRV are based on the last MCOS studies accepted by the Commission and these will not be updated until proceeding is complete.
  - Goals of VDER phase 2 include improve MCOS studies and LSRV methodology and standardize them to the extent possible

Recent (April 2019) Changes to NY VDER

- Most recent VDER Order – April 2019
- Demand Reduction Value calculation changes to reflect performance during a larger set of hours and to lock-in the value for ten years
- Continuation of the LSRV, modified to compensate project for performance during utility calls
- Capacity value calculations modified to reflect published NY ISO monthly prices and PV load curves (Alt 1) and to better reflect actual peak hours (Alt 2)

New York VDER Transitional Mechanisms

- VDER includes a number of transitional mechanisms to moderate the changeover from net-energy metering (NEM) to the Value Stack:
  - Phase One NEM – includes a limited continuation of NEM-style compensation
    - Only available to certain residential and small commercial customers with DER onsite who are not on a demand-based rate plan
  - Market Transition Credit – an adder that allows the Value Stack to approach the previous level of compensation under NEM
    - Only available to residential and small commercial customers with DG
  - The Market Transition Credit for Community Distributed Generation (CDG) is sun setting.
- NY-Sun developed a Solar Value Stack Calculator
- VDER applies to:
  - Community distributed generation
  - Large onsite system
  - Remote net metering

Ancillary Services and Standby Rates

- Some states and utilities are exploring explicit cost recovery for ancillary and standby services associated with distributed generation.
- Magnitude matters when considering DG impacts to the grid and ancillary services or standby requirements.
- Low penetrations of small DG systems are unlikely to create significant contingencies larger than normal load fluctuations.
- Where standby rates for DG are used, regulators may want to know:
  - (a) specific events that create concern (b) how DG is impacting the system more than standard load fluctuations, and (c) why the level of backup that must be provided for DG customers exceeds what customers are already paying for to serve full-requirements customers.
- Smart inverters and energy storage change the impacts of DG on the grid and have the potential to transform a DG system from a burden to support.

Cost Causation

- **Cost causation is not an exact science**. Any cost allocation rule involves some kind of judgment and ordering of costs. Rate design offers the chance to align policy goals based on established principles.
- **Distributed generation creates both costs and benefits to the grid.** Detailed analyses and studies can characterize costs and benefits that can be used to inform rate design.
- **Time and location characteristics of distributed generation (DG) impact costs and savings.**
  - Time-varying rates and critical peak pricing type programs are ways to move more toward cost-of-service rates.
  - Locational value assessments and compensation schemes are emerging in New York and California and, although new and somewhat experimental, may become more prominent over time.

Rate Design Considerations

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- Rate design is more of an art than a science - designing rates that balance utility revenues and growth of DG is complicated and challenging.
- In some states, there is a trend toward time-varying rates as a way to maximize the value of DG to the grid, support cost-of-service regulation, and minimize cross-subsidization.
- Increasing cost recovery through fixed charges reduces financial risk to utility revenues, but may have implications to resource efficiency and ratepayer equity.
- There are differences of opinion about use of demand charges.
  - Some think demand charges should be used to recover all or most of the costs a customer imposes on the grid during peak demand periods (EEI 2016).
  - Others think time-varying rates rather than demand charges should be used to recover generation and transmission capacity costs (Linvill et al. 2017).
  - Others see demand charges and time-varying rates as compliments rather than substitutes and think both should be used (Faruqui 2018a).

Cost recovery from fixed and variable charges

Comparing Cost Recovery from Fixed and Variable Charges	
Recovering more costs from fixed charges	**Recovering more costs from variable charges**
A static world view	A dynamic world view
Enhances revenue stability (less sales revenue risk)	Reduces revenue stability (more sales revenue risk)
Weakens price signals and customer control (less resource efficiency)	Strengthens price signals and customer control (more resource efficiency)
Less affordable for low-income households (more regressive)	More affordable for low-income households (less regressive)
May promote self supply and system defection (more expensive)	May limit self supply and system defection (less expensive)
Slight advantage for combined households (single customer charge)	Revenue stability from first blocks of usage (inelastic usage)

Source: Beecher 2017 https://www.financingsustainablewater.org/blog/resisting-fix-pushing-back-impulse-raise-fixed-water-charges

Summary

- Emerging net energy metering successor tariffs include:
  - Avoided costs,
  - Wholesale prices,
  - Value-based tariffs,
  - Embedded cost-of-service rates,
  - Locational marginal prices,
  - A resource comparison proxy,
  - Inflow & Outflow methodology, or
  - One of these plus an adder.
- Rate design is not an exact science.
- Leading states are moving to rates based on temporal and locational granularity, taking into consideration specific projects that can be avoided.

Thanks and Questions

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Extra Slides

Policy Types Already Adopted by States (NRRI 2019)

Policy Types	Vertically Integrated States / Restructured States
NEM 2.0 or NEM Successor Tariff[1]	AZ, CA, HI, ID, IN, LA, MI, NV, UT, VT
	CT, DC, MA, ME, NY
Changing credit rates for excess generation	AZ, CA, GA, HI, IN, KS, LA, MT, NC, NH, NV, SC, UT, WI
	ME, NY, OH, TX
Increasing (decreasing) customer fixed-charges[2]	AL, AK, AR, AZ, (CO), FL, HI, ID, IN, KS, KY, MI, MN, MO, ND, NM, NV, OK, SC, SD, TN, WA, WI, WV
	(CT), DC, DE, MA, NH, NJ, (NY), OH, PA, RI, TX
Assigning demand-charges or stand-by charges	AL, AR, AZ, CA, KS, NC, NM, SC, UT
	MA, NH
Creating a separate customer class for DG	IA, ID, KS, MT, NV
	TX
Providing for third-party or utility-owned DG	AZ, FL, GA, LA, MO, NC, NM, SC, UT, VA, VT
	DC, NY, RI, TX
Adding provisions for community solar[3]	CA, CO, HI, MN, NC, OR, VA, VT, WA
	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, RI

Source: NCSU CETC *50 States of Solar* report series, 2015 through 2018.

[1] See Figure 2, p. 12.

[2] In these instances, the decisions result from specific regulatory commission orders and affect individual utility companies.

[3] See Figure 4, p. 37. Several states have provisions for community solar programs that treat participants as virtual or remote net metering customers. Listed here are those states where legislation provides for community solar programs. Many more states have one or more active community solar projects, but as yet have no statewide law or rules: Most often, those projects were proposed by individual utility companies and approved by state regulatory commissions (or, for those utilities that are not state regulated, were approved by their municipal or cooperative regulatory bodies). See Stanton and Kline 2016.

From: Review of State Net Energy Metering and Successor Rate Designs, Tom Stanton, NRRI 2019

Inflow/outflow methodology

- Inflow/outflow methodology is a variation of net billing
- Approach proposed by the Michigan PSC Staff and approved in principle by the Michigan PSC (April 18, 2018 Order in Case No. 18383).
- Similar to a buy-all, sell-all or net billing rate options, in the inflow/outflow tariff framework, customers pays the standard retail price for all energy delivered through their meter, called inflow, just as other customers who have no on-site generation.
- When a customer's generator produces electricity that is consumed on-site, the customer avoids purchasing that energy at the regular retail rate. Then, all exported energy during a billing period, called outflow, is metered and a commission-approved rate other than retail will be applied to that energy.
- The preliminary Michigan PSC staff proposal was to credit outflow at the Commission-approved PURPA avoided-cost rate established for each utility. With the inflow/outflow method, on-site usage of on-site generation is treated as a simple reduction in use, equivalent to other reductions in usage due to energy conservation or efficiency improvements.

Example Studies – E3 Study for Nevada

- E3 conducted a study for the Public Utilities Commission of Nevada to forecast the costs and benefits of renewable generation systems that qualify for the state's NEM program.
- E3's conducted the following analyses (E3 2014):
  - Cost benefit analysis using 5 different cost tests typically used for energy efficiency
  - Looked at a base case and sensitivities (including impact of rate designs, capturing more costs in fixed charges, and reducing demand charges).
  - Macroeconomic impacts assessment – considered the impact of NEM on jobs and the economy.
  - Demographic analysis – compared median income of NEM participants to state's median income.

E3 Study for Nevada

- Results of a 2016 update:
  - NEM participating customers pay slightly more per kWh to participate in net metering than not,
  - There was a $36 million per year cost shift from NEM participants to non-participants, and
  - With NEM, the utility was required to collect $13 million less from ratepayers than without it

Cost shifts can go both ways

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- 2013 E3 study for the California Public Utilities Commission showed NEM would result in $1.1 billion annual cost shift by 2020 from NEM to non-NEM customers in California if current policies were not reformed
- 2014 E3 study for PUCN showed $36 million lifecycle benefit of NEM qualified resources to non-solar customers; an update of this study in 2016 showed a cost to non-solar customers of $36 million per year
- 2014 E3 research in Hawaii found NEM customer had net benefit while non-NEM customers had net cost
- 2012 Navigant study for Arizona Public Service found customers with solar are subsidizing those without
- 2013 Vermont study showed cost shift from NEM customers to non-NEM customers
- 2015 Missouri study found net benefits of NEM to all customers regardless of whether they have rooftop solar
- 2015 Massachusetts study found that solar provides benefits to all ratepayers in excess of retail rates

Figure 2: Timeline of States Adopting NEM Successor Tariffs

2012	2014	2016	2018	Post-2018
HI	UT	HI[2]	AR	CO[3]	AR[3]	CT[2,3]
	VT	LA	CA	AZ[1,3]	AZ[1]	UT[2,3]
		ME	HI[2]	DC	CT	
		NV	LA[2]	ID[4]	DC[3]	
		NV	MA	IN	HI[2,3]	
		NY	MI	LA	ID[3]	
		UT[2,3]	NH	ME[2]	LA[3]	
			NH[2]	NH[2]	ME[3]	
			NV[2]	NV	MI[2,3]	
			NY[2]	UT[2,3]	UT	
			VT[2]	VT[2]	VT[2,3]	

KEY: Law | Commission Order

Notes: [1] Indicates a decision affecting only one or more individual utility companies.

[2] Indicates additional state legislative or regulatory actions, subsequent to the enabling laws or rules.

[3] Indicates pending regulatory decisions.

[4] Idaho does not have statewide NEM legislation. The Idaho PUC has directed individual regulated utility companies to file NEM tariffs.

From: Review of State Net Energy Metering and Successor Rate Designs, Tom Stanton, NRRI 2019