DER Compensation

Colorado Springs Utilities Solar Program Design Study

GE: Debbie Lew, Steve Oltmanns, Genevieve Demijolla, Eduardo Ibanez, Derek Stenclik
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CSU Review: Katie Hardman, Ed Arguello, Mike McAvoy, Thad Clardy

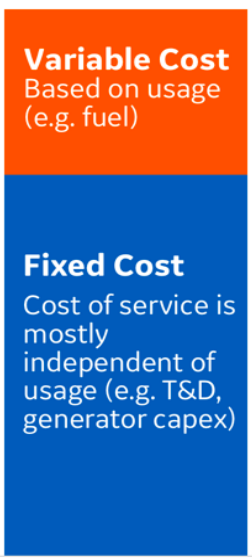
8 October 2017 UVIG Fall Technical Workshop Nashville

CSU found PV to a promising resource in their IRP

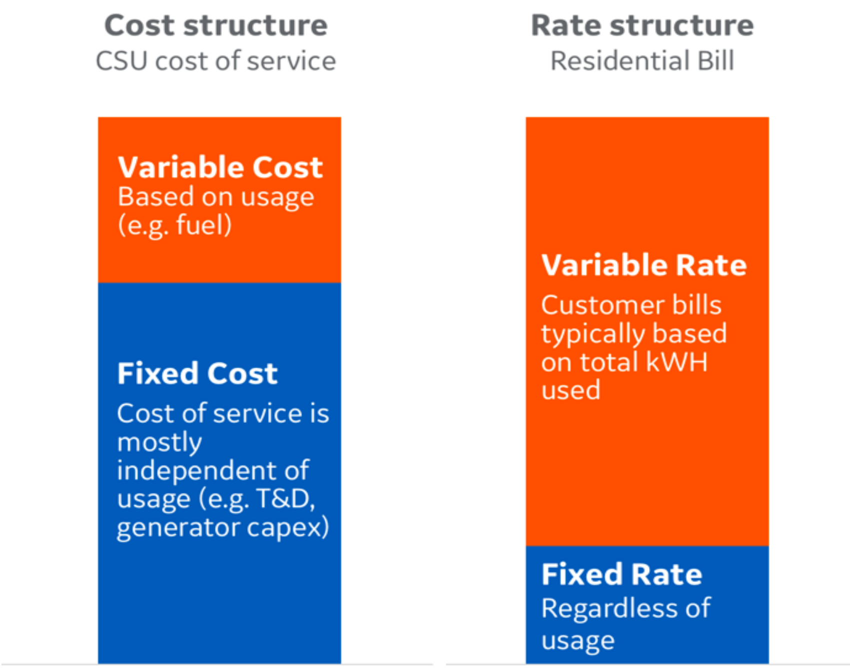
- CSU's system
  - Coal, hydro and gas-based system
  - Inexpensive rates: 7.6 cents/kWh plus fuel adder = 10.5 cents/kWh
  - 0.2% DPV energy penetration today; studied up to 3.3% DPV penetration, which would be similar to California
- CSU's Questions
  - Should they deploy UPV, DPV, utility-owned DPV?
  - They net meter today. Is there cost shifting? How much?
  - What are the implications of different rates to manage DPV but also high demand customers, like A/C users

Cost and revenue structures are mismatched

Cost structure
CSU cost of service



Cost and revenue structures are mismatched



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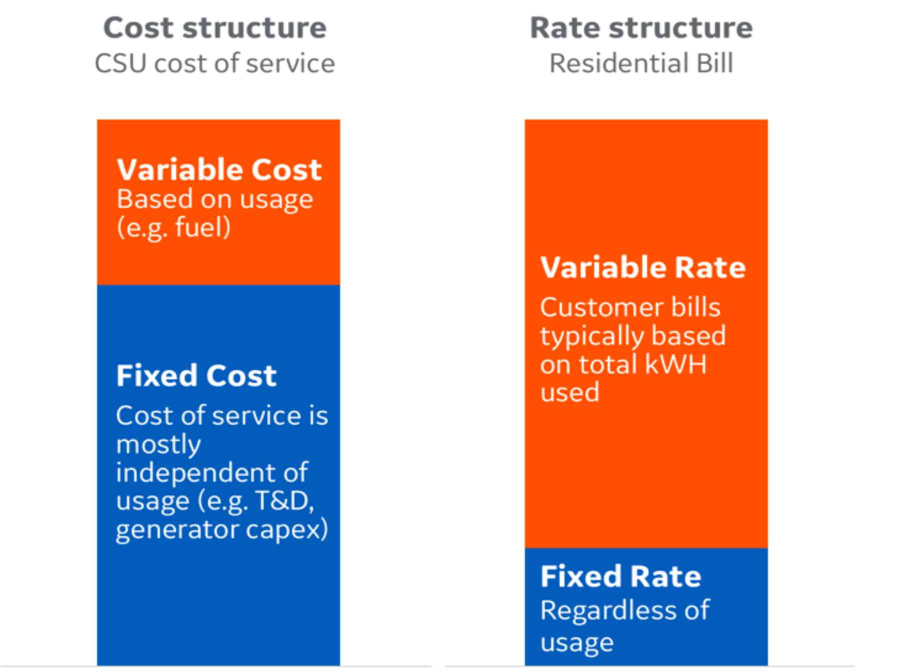
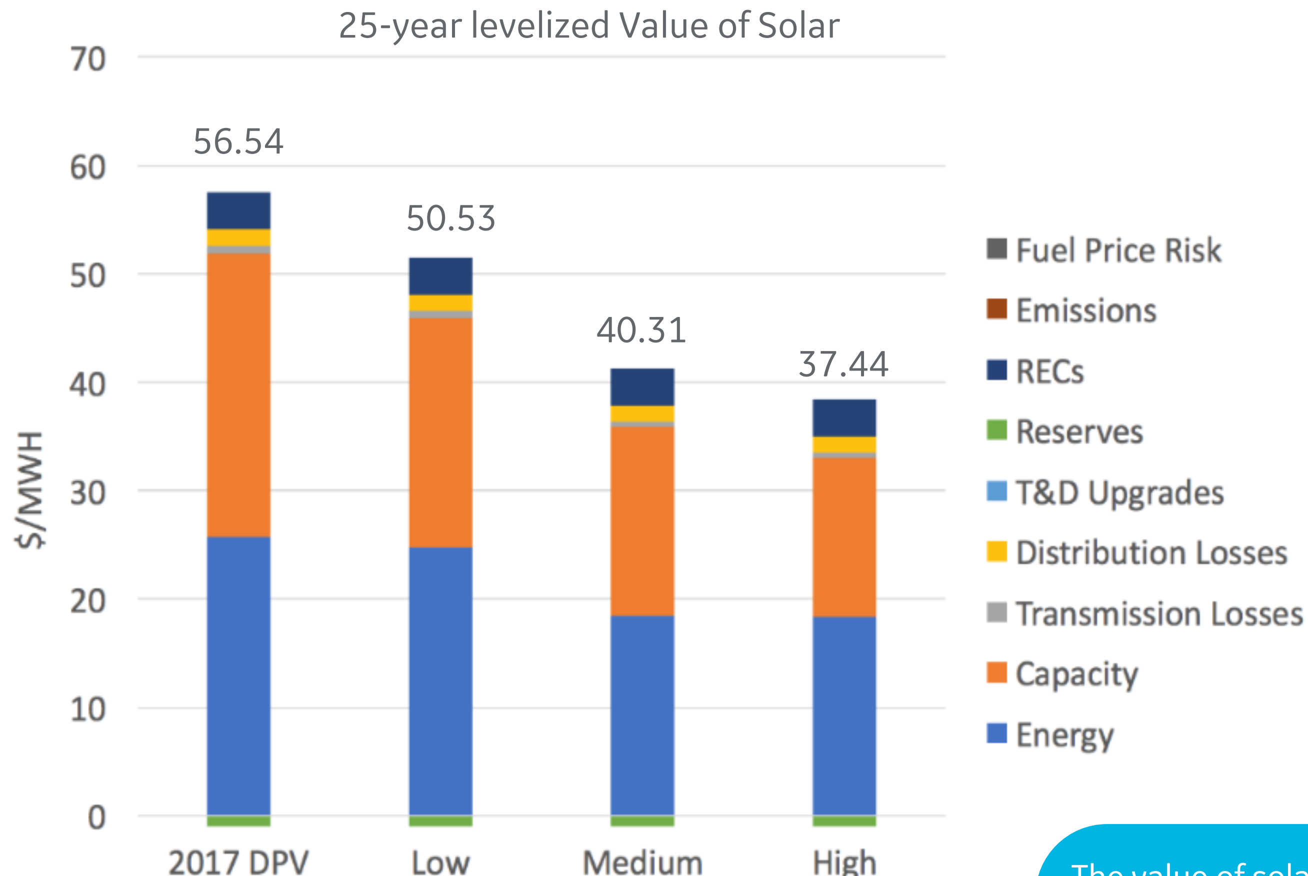


Like most utilities:

- Revenues primarily recovered through variable rates, while costs are primarily fixed.
- Net metering essentially combines an incentive with compensation.
- DPV is just the tip of the iceberg. Need to prepare for behind-the-meter storage, EV's, etc.
- Many utilities are struggling with this same problem

Distributed solar benefits the grid in many ways



DPV	7.1MW	20MW	50MW	100MW
UPV	19MW	89MW	89MW	89MW

The value of solar is less than the variable rate for residential customers

There are many options to examine

Alternative	Description
Increased Fixed or Standby Charge	Customers pay an increased fixed charge each billing period. Better reflects actual fixed portion of cost of service.
Demand Charge	Customers pay a demand charge based on their maximum demand (measured in kW) during that month. Incentivizes customers to reduce demand.
Time-of-Use (TOU) Rates	Customers pay different rates for usage during different time periods (e.g., peak and off-peak). Reflecting actual costs incurred by the utility and incentivizes customers to reduce peak usage and/or shift usage to off-peak periods.
Demand-block/TOU	Combination of TOU rate and a peak demand charge that is only applicable to customers whose demand exceeds a threshold during peak periods.
Buy All, Sell All Value of Solar Tariff (VOST)	CSU buys all DPV generation at a VOS rate, which reflects the value stream of net benefits from DPV. All consumption is purchased at normal retail rates.
Hybrid VOST	Solar generation first offsets onsite consumption, and excess generation is exported to the grid at the VOS rate. There is no carryover of excess kWh from month to month.
Utility-owned Solar (UOS) Rooftop Program	CSU would run a DPV leasing program for customers who want DPV. Customers would receive bill credits based on DPV production. CSU would partner with a developer who owns and maintains the system.

Rate alternatives

Revenue neutral

Mitigate cost-shifting and recover costs from solar customers

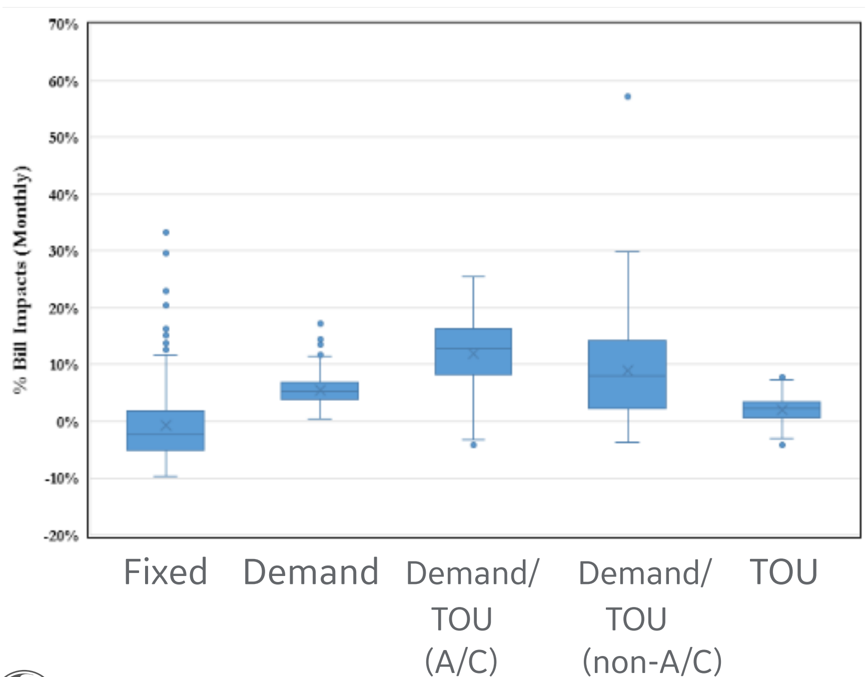
Limit bill impacts to generally less than 25% for non-solar customers

Residential rate options

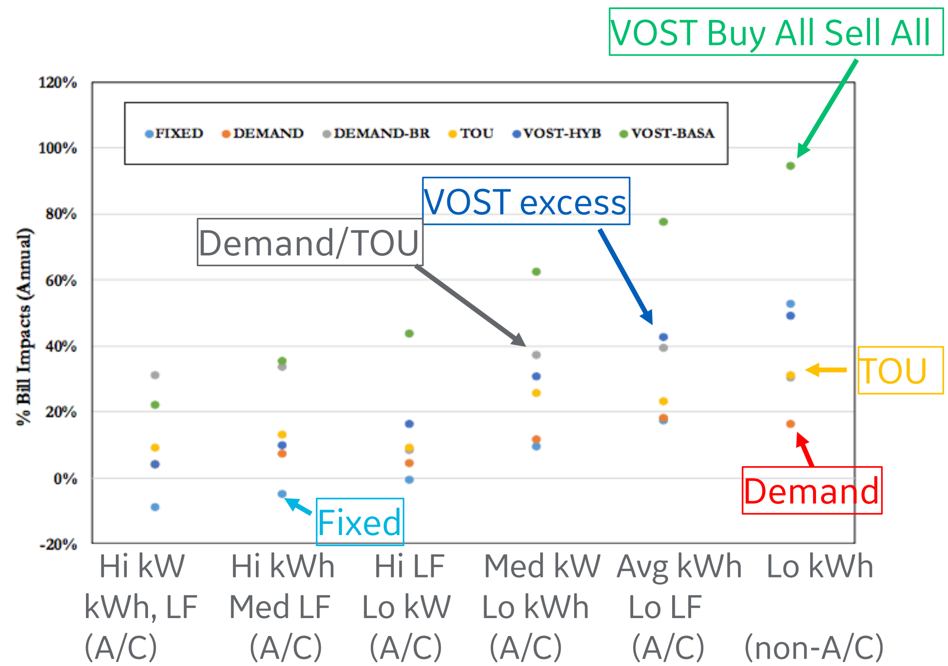
Type of Charge	Description	Current Rate	Fixed charge 150% of Current Charge	Demand Charge 10% of Cost of Service for Demand-Related	Demand Charge w/ Block Structure and TOU 5% of COS for Demand-Related and 50% Off-Peak to Peak Rate Ratio	TOU 50% Off-Peak to Peak Rate Ratio	VOS Hybrid & Buy All/Sell All - 2017 VOS
Fixed charge	Charge per day	$0.5010	$0.7515	$0.5010	$0.5010	$0.5010	$0.5010
Demand Charge	Charge per kW per day			$0.0540			
On Peak Demand	Cut-off for First Block				3 kW		
On Peak BL1	Charge per kW per day				$0.0000		
On Peak BL2	Charge per kW per day				$0.2359		
Energy Charge	Charge per kWh	$0.0763	$0.0637	$0.0725			$0.0763
On Peak Energy	Charge per kWh				$0.1264	$0.1297	
Off Peak Energy	Charge per kWh				$0.0632	$0.0648	
ECA: On Peak	Charge per kWh	$0.0273	$0.0273	$0.0273	$0.0682	$0.0682	$0.0273
ECA: Off Peak	Charge per kWh	$0.0273	$0.0273	$0.0273	$0.0212	$0.0212	$0.0273
ECC	Charge per kWh	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014	$0.0014
Solar Credit	Charge per kWh	NEM	NEM	NEM	NEM	NEM	$0.0565

Rate alternatives impact different customers differently

Impacts on non-solar customers

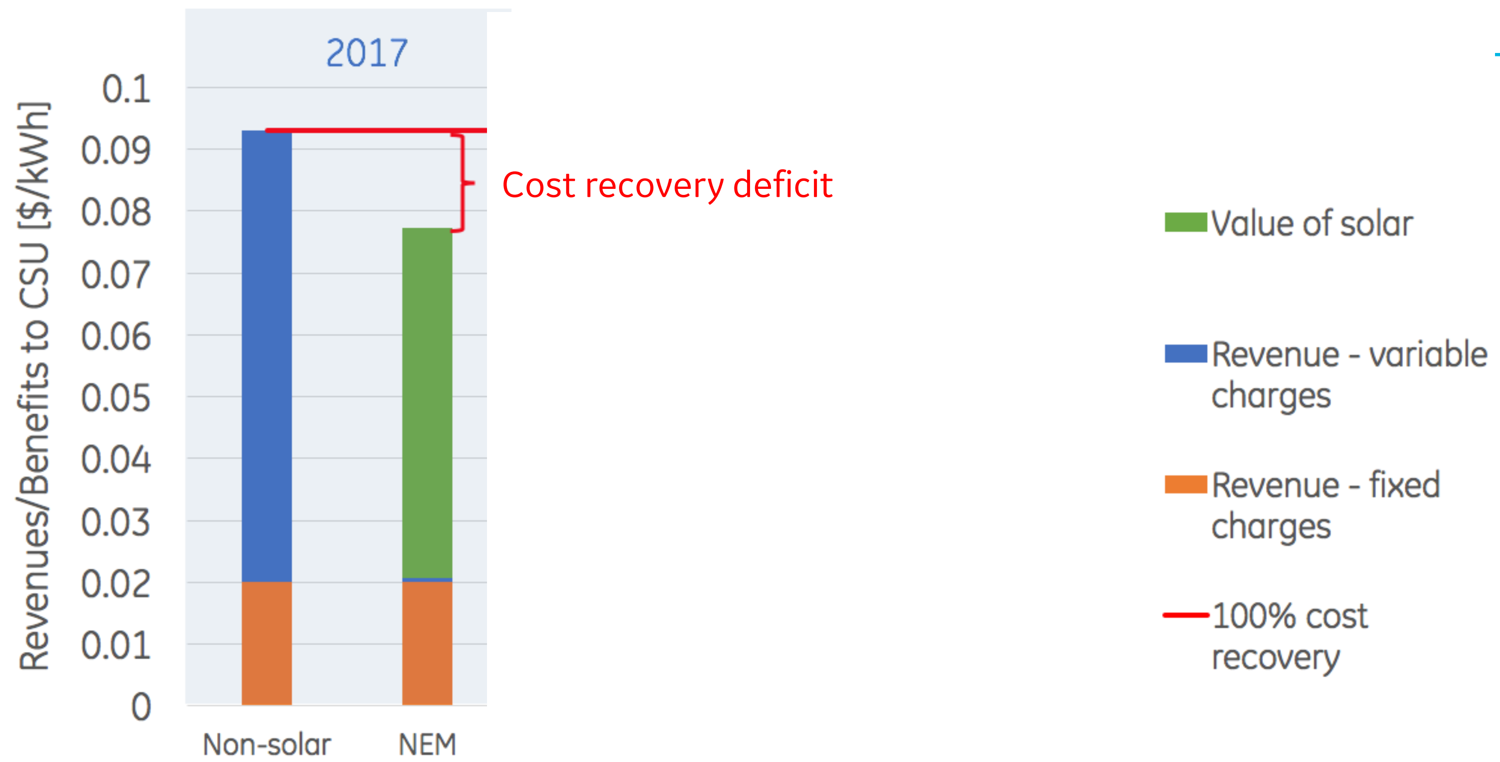


Solar customers: Low and average energy users can be impacted more than high load factor users

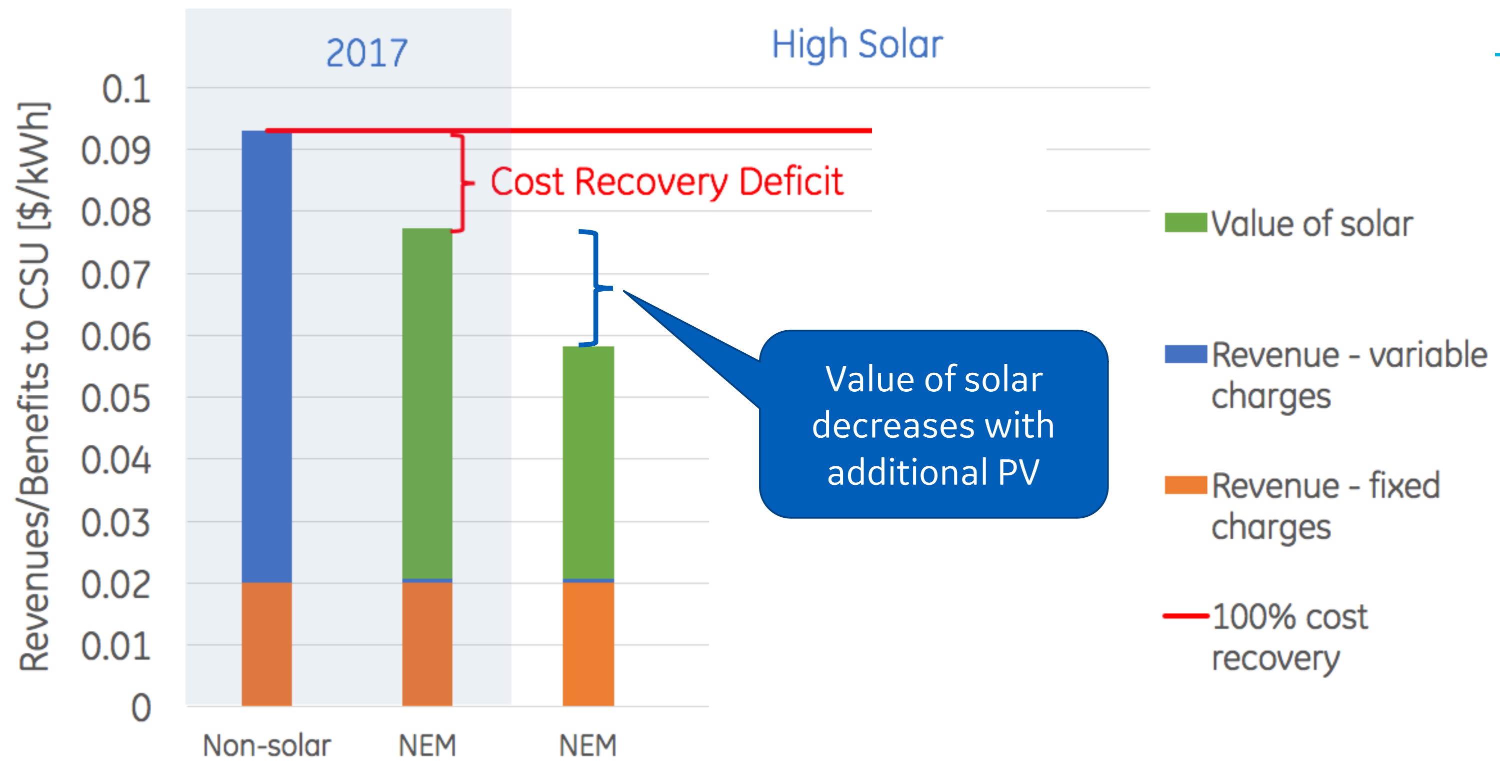


Close the revenue shortfall by increasing revenue

Close the revenue shortfall by increasing revenue



Close the revenue shortfall by increasing revenue



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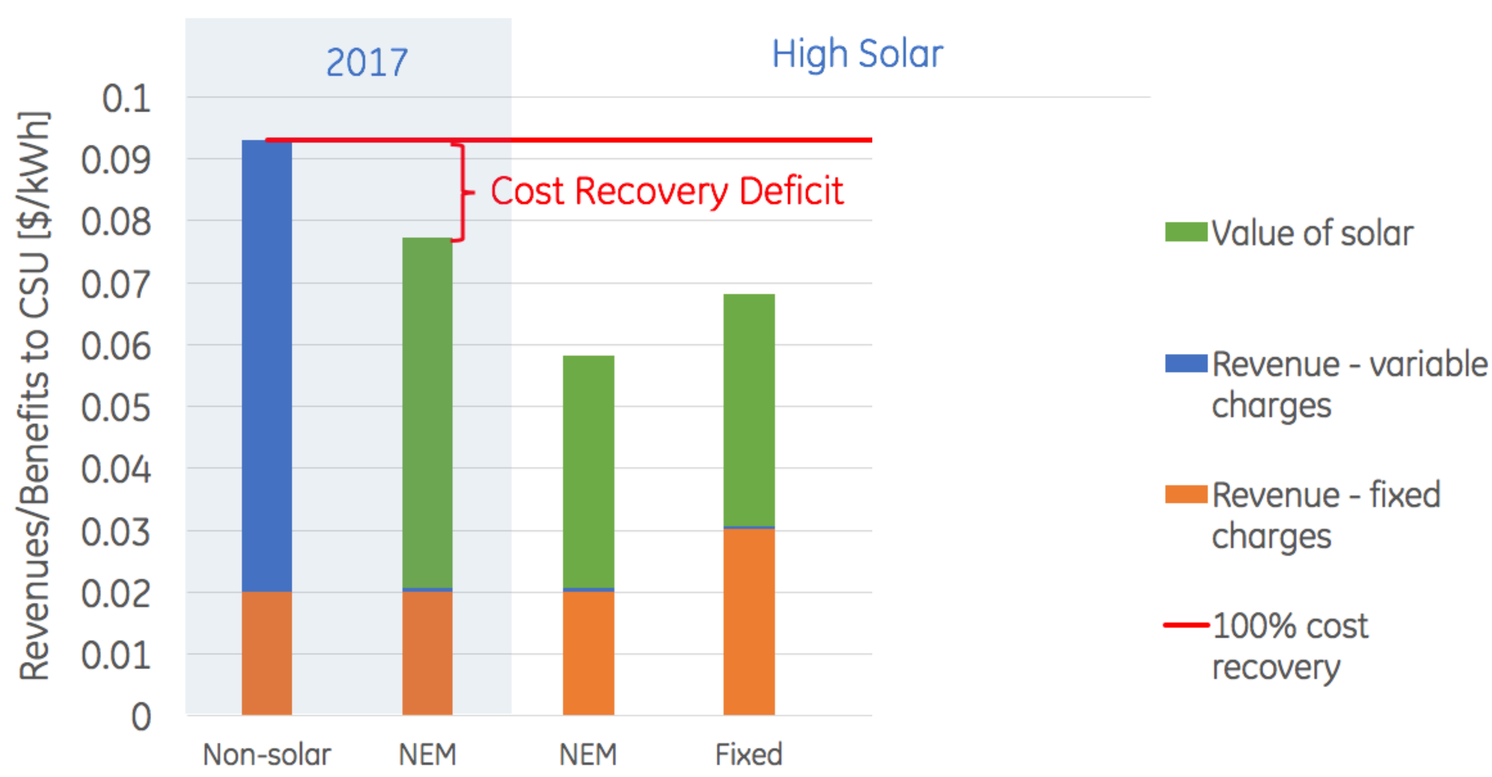

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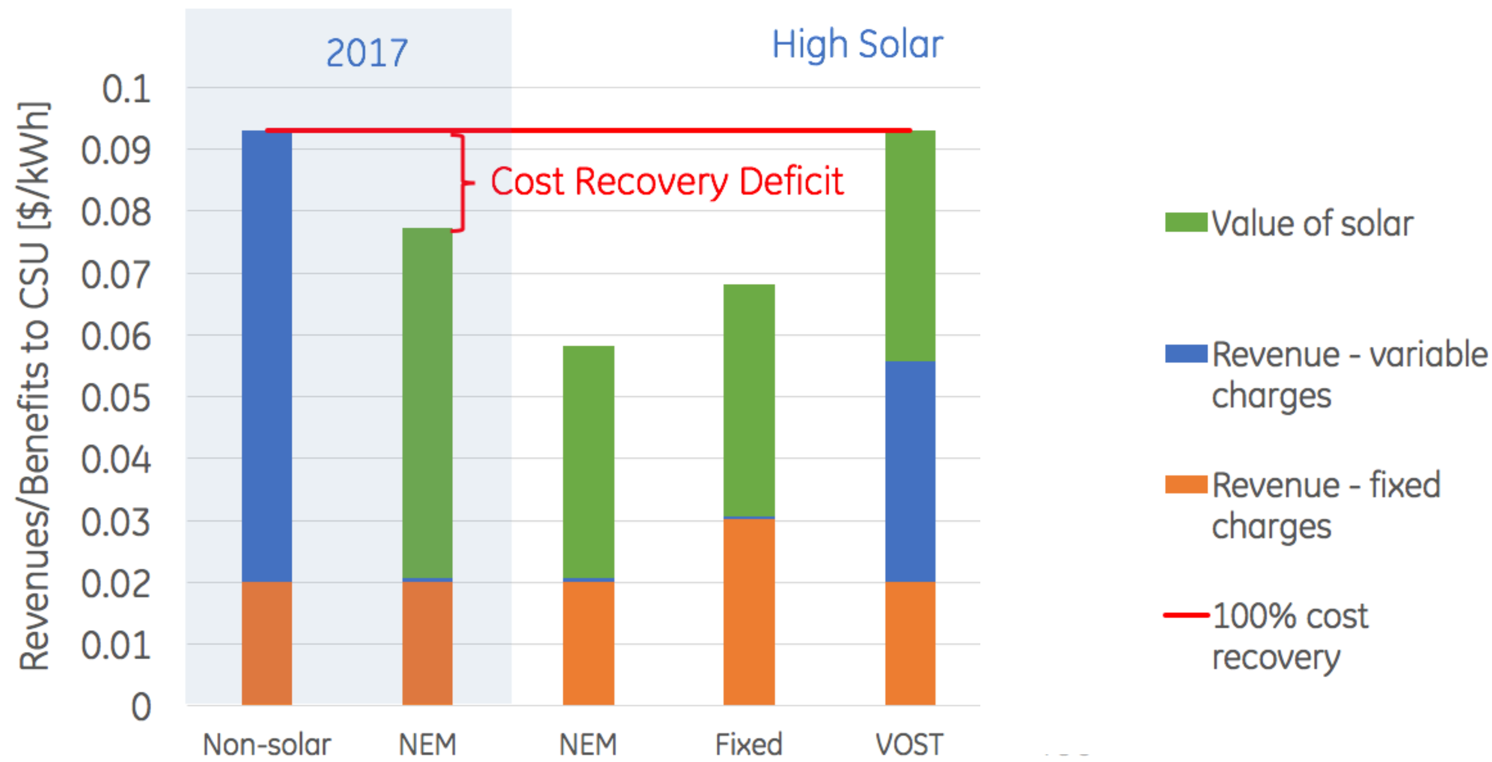
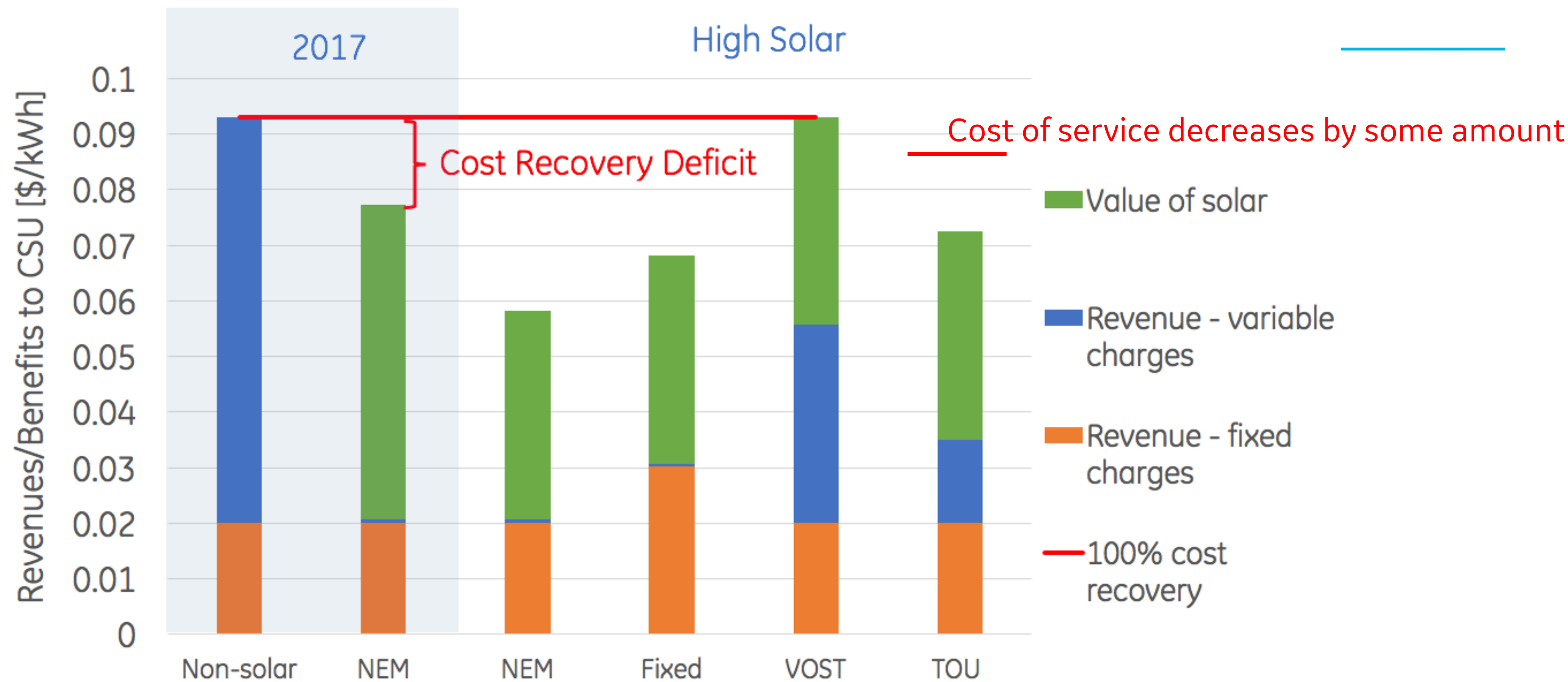


Close the revenue shortfall by increasing revenue, or reducing cost of service

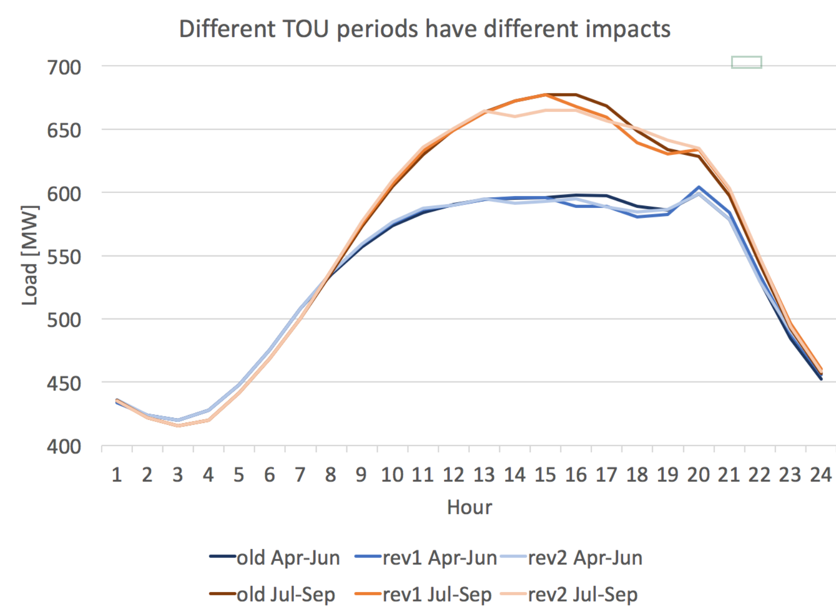


First year CSU deficit	0	$0.2M	$7M	$6M	0	$4M
25-year NPV of CSU deficit	0	$3M	$127M	$101M	0	$72M

TOU rates reduce cost of service – can we quantify that value?

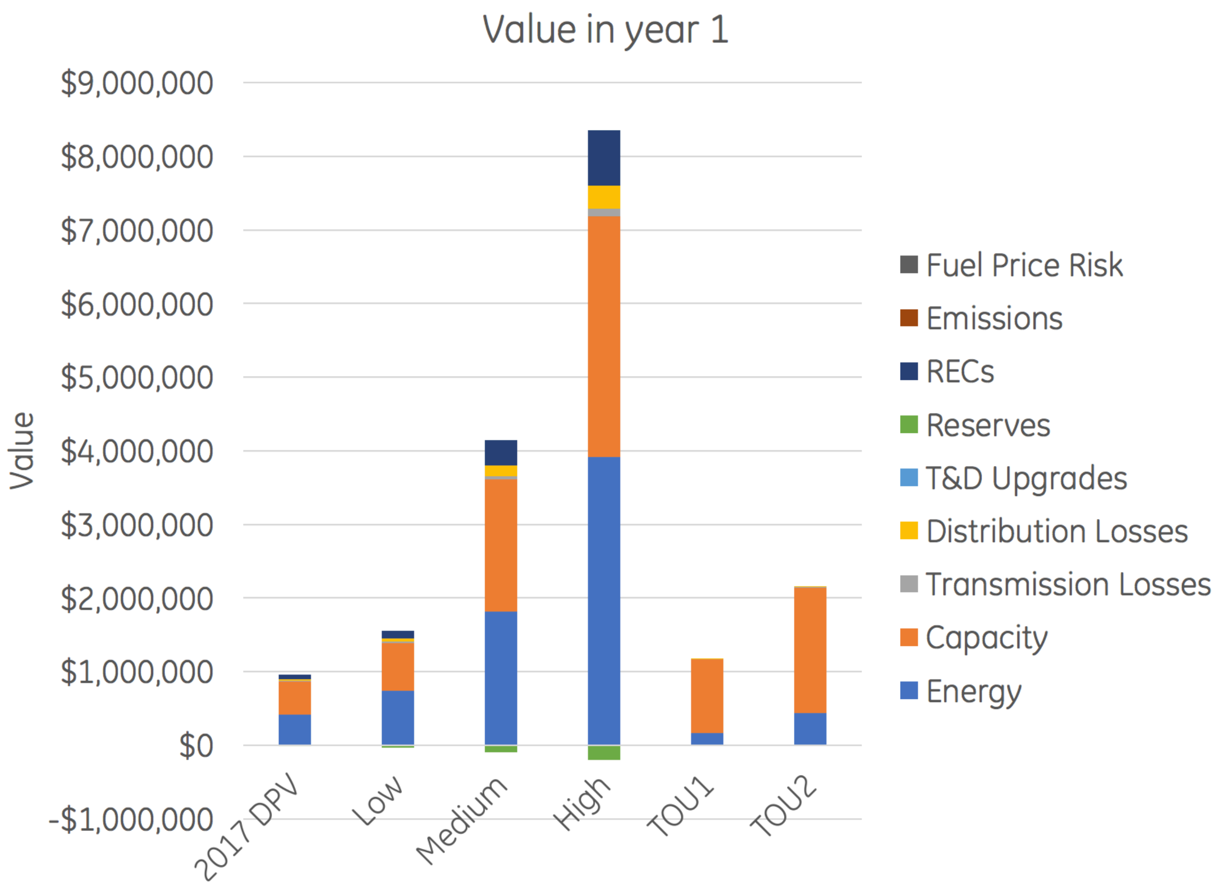
TOU periods don't manage spring season well

Revised TOU peak months and hours



TOU rates have a similar arbitrage impact as storage but without the losses.
A value stream approach can be used.

Alternative rate structures can bring significant value to the system with little capital investment



Both DER compensation and rates need reform

The point isn't just to "cover costs" by increasing charges, but rather to incentivize behavior that creates benefits for everyone.

We should seize this opportunity:

- Address cost-recovery and cost-shifting issues
- Encourage customers to reduce cost of service
- Look for low capital investment options
- Capitalize on AMI and increasingly sophisticated appliances and energy management apps
- Set utilities up for growth of other DERs in the future besides DPV

Value of Solar

Approach

Calculate value that an installation in 2018 would bring to the grid over its 25-year lifetime

Captures the average impact of each Scenario compared to Current Scenario, as opposed to evaluating the marginal impact of the next MW of PV

Account for fuel escalation, non-fuel escalation, and PV degradation over time.

Net benefit calculation, so costs are included to the extent that they can be quantified

System benefits and location-specific benefits to the extent that they can be quantified

Some values can't be calculated without a very specific scenario and significant modeling

Summary of components in VOS

What's in

Capacity

Fuel

Fixed O&M

Variable O&M

Transmission losses and congestion

Distribution losses

T&D upgrade deferrals

Impact on regulating reserves

Impact on ramping reserves

Emissions

Renewable energy credits

Fuel price hedging

Jobs/economic impacts

What's out

Impact on day-ahead forecast uncertainty

Resiliency/reliability

Cycling costs due to wear and tear

Voltage support

Feeder interconnection costs

Spinning/contingency reserves

Stranded costs

Water

Land

Changes in future load due to EV's

Solar Scenarios

Run analysis for each of these scenarios for the year 2018

	Residential DPV	Commercial DPV	Centralized PV
No solar	0	0	0
2017	2.5 MW	4.6 MW	19 MW
Current	2.5 MW	4.6 MW	19 MW (10 MW utility; 4 MW community; 5MW USAF) Plus 70 MW tracking
Low	10 MW	10 MW	19 MW + 70MW tracking
Medium	25 MW	25 MW	19 MW + 70MW tracking
High	50 MW	50 MW	19 MW + 70MW tracking

PV serves 7% of gross load

*All MW are AC

Energy

Production cost modeling (GE-MAPS) simulates day-ahead unit commitment and hourly economic dispatch of the Western Interconnection for one year including transmission and generator constraints. MAPS calculates production cost (fuel, fixed and variable O&M, start-up costs, electricity losses)

Production cost savings is comprised of avoided energy and transmission losses. Transmission losses are estimated at 2.6% of load.

Hold exports fixed so that they do not affect valuation of avoided energy

Gas price varies by month. Average in 2018 was $3.1/MMBTU

Production cost modeling (MAPS) results

For the year 2018	No solar	2017	Current	Low	Medium	High
DPV Capacity [MW_{AC}]	0	7.1	7.1	20	50	100
Utility PV Capacity [MW_{AC}]	0	19	89	89	89	89
DPV generation [MWH/yr]	0	11,759	11,759	33,135	82,836	165,677
Incremental DPV generation [MWH/yr]		11,759		21,375	71,077	153,917
CSU generation [MWH/yr]	4,993,478	4,988,748	4,988,589	4,989,052	4,995,119	4,997,075
Net imports over basecase [MWH/yr]		4,730		(463)	(6,529)	(8,486)
Production cost in 2018 [$]	133,492,933	131,463,147	127,793,390	127,049,741	126,092,158	123,987,019
Average Production cost [$/MWH]	26.73	26.35	25.62	25.47	25.24	24.81
Adjusted production cost [$]*	133,492,933	131,587,808	127,793,390	127,037,957	125,927,343	123,776,477
Adjusted production cost savings [$]		1,905,126		$755,533	$1,866,047	$4,016,913
Adjusted production cost savings [$/MWH]		36.69		35.34	26.25	26.10

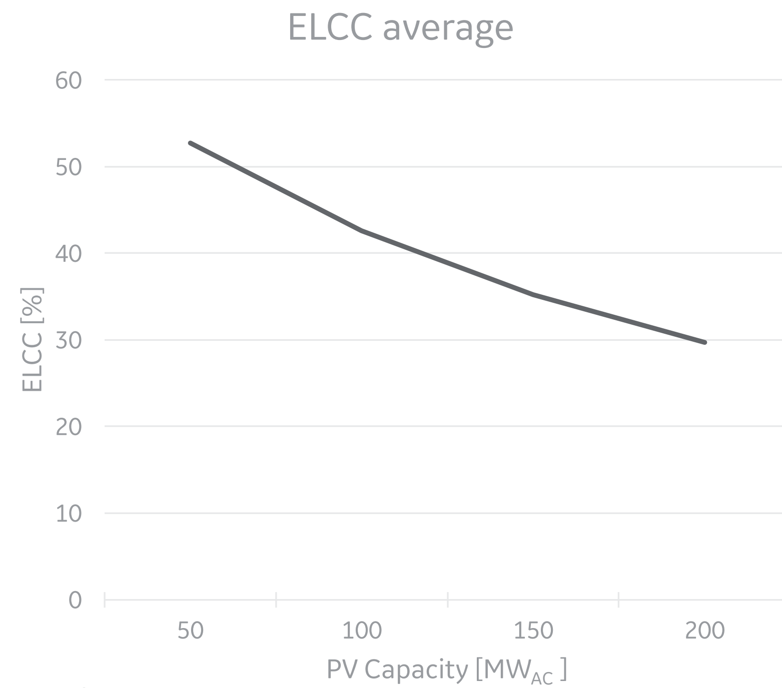
*Adjusted to true up CSU generation to be equal to the Current case; $3.1/MMBTU average gas price

Avoided Energy

For the year 2018	2017	Low	Medium	High
Avoided energy [$]	431,427	735,791	1,817,530	3,912,473
Avoided energy [$/MWH]	35.74	34.42	25.57	25.42

Effective Load Carrying Capability (GE-MARS) results

	50	100	150	200
2011	47.4%	35.0%	27.7%	21.7%
2012	75.6%	64.7%	56.9%	45.2%
2013	44.4%	39.7%	32.9%	28.0%
2014	44.4%	31.9%	24.6%	22.5%
2015	57.0%	42.9%	36.1%	30.4%
2016	47.4%	41.2%	32.9%	30.3%
Average	**52.7%**	**42.6%**	**35.2%**	**29.7%**



Because UPV influences ELCC of DPV, all PV must be evaluated

Avoided capacity due to distribution losses

Peak load occurred at 6/28 at 16:00. From CSU's distribution loss analysis, corrected for CF: at this hour, 17.9 MW_{AC} PV avoids distribution system losses of 654.1 kW. The analysis finds losses to be roughly linear, so 12.9 MW_{AC} of PV capacity avoid 471.4 kW of distribution losses at this hour. Used top 10 peak hours to determine avoided distribution losses for avoided capacity calculation.

$$Multiplier = \frac{1}{1 - AvoidedLoss/PVnameplate}$$

	2017	Low	Medium	High
Average avoided distribution losses [kW] during top 10 peak hours	269kW	488 kW	1,623 kW	3,515 kW
Multiplier for PV capacity	1.04	1.04	1.04	1.04

Capacity value results

For the year 2018		2017	Current	Low	Medium	High
	DPV Capacity [MW_{AC}]	7.1	7.1	20	50	100
	Utility PV Capacity [MW_{AC}]	19	89	89	89	89
	Total PV Capacity [MW_{AC}]	26.1	96.1	109	139	189
A	ELCC for 2011-2016	52.7%	42.6%	42.6%	35.2%	29.7%
B	Value of avoided capacity in 2018 [$/kW/yr]	96.67	96.67	96.67	96.67	96.67
C	Incremental DPV generation [MWH/yr]	11,759		21,375	71,077	153,917
D	Incremental DPV Capacity [MW_{AC}]	7.1		12.9	42.9	92.9
E	Multiplier to include planning reserve margin	1.18		1.18	1.18	1.18
F	Multiplier to include distribution losses impact	1.04		1.04	1.04	1.04
G=D*E*F	Adjusted incremental DPV capacity [MW_{AC}]	8.7		15.8	52.6	113.9
H=G*A	ELCC of adjusted incremental DPV capacity [MW_{AC}]	4.6		6.7	18.5	33.8
H*B/C	Avoided capacity value [$/MWH]	37.72		30.48	25.19	21.25

Avoided or Incremental Reserves

Regulating reserves

- Proxy for May 10 meeting – will use Solar Integration Study result when it is complete
- CSU's 353,827 MWH total PV output out of 4,988,589 MWH generation is 7.1% solar energy penetration
- APS study at 8.8% solar penetration finds $1.61/MWH Balancing reserve cost in 2027. We use CSU fuel escalation costs to back out $1.30/MWH in 2018.
- https://emp.lbl.gov/sites/all/files/lbnl-6525e.pdf

Ramping (flexibility) reserves

- Production simulation results show that adequate ramping capability exists.
- Ramping reserves cost = $0

Transmission

Upgrades

- No projects identified that could be deferred by DPV

Losses

- Avoided transmission losses are evaluated in production cost modeling. These avoided losses are based on line loading at the time of PV production and account for transmission line flows if there is congestion, etc.
- Avoided transmission losses cost estimated at 2.6% of production cost savings.

For year 2018	2017	Low	Medium	High
Avoided transmission losses [$]	11,217	19,641	48,517	104,440
Avoided transmission losses [$/MWH]	0.95	0.92	0.68	0.68

Distribution

Upgrades

- No projects identified that could be deferred by DPV

Integration costs

- There may be costs to integrate DPV systems onto some feeders but these would require detailed modeling of specific scenarios

Benefits

- There may be benefits from use of smart inverters but these capabilities are not envisioned to be needed

Losses

- Utilized hourly estimated losses for one peak day per month – power flow analysis and estimates from CSU distribution staff

Avoided distribution losses

Value each hour of avoided distribution losses with spot price

For the year 2018	2017	Low	Medium	High
Avoided distribution losses	828 MWH	1,516 MWH	5,082 MWH	11,037 MWH
Value of avoided distribution losses	$25,189	$45,040	$149,513	$318,458
Value of avoided distribution losses per MWH of PV generation	$2.14/MWH	$2.11/MWH	$2.10/MWH	$2.07/MWH

Avoided Emissions

Production cost modeling (MAPS) determines the avoided emissions (NO_x, SO_2, CO_2) on the CSU system as a result of the expected PV additions.

	Avoided CO_2 [lbs]	Avoided SO_x [lbs]	Avoided NO_x [lbs]
2017	45,362,283	1,797	49,362
Low	70,865,884	2,738	78,585
Medium	145,288,363	4,303	131,674
High	299,159,690	8,535	248,765

- Value of emissions:
  - CO_2 - valued at zero in CSU's resource plan - $0/MWH
  - SO_2 - allowances are not fully used by CSU - $0/MWH
  - NO_x - valued at zero by CSU- $0/MWH

Avoided renewable energy credits

CSU meets the Colorado Renewable Energy Standard of 10% by 2020 without these DPV scenarios so cost of compliance is zero

CSU's Energy Vision goal is 20% by 2020

- DPV may help CSU meet this internal goal
- Value of a REC to CSU is the difference between avoided incremental cost of new RFP for renewables and avoided energy/capacity value of that renewable. For wind, the nominal REC value is $4.84/MWH in 2018.

Fuel price risk

CSU does not currently hedge fuel prices, and they don’t currently place a value on this.

Avoided fuel price risk = $0

Value of Solar for year 2018

For the year 2018 [$/MWH]	2017	Low	Medium	High
Avoided energy	35.74	34.42	25.57	25.42
Avoided capacity	37.73	30.48	25.19	21.25
Avoided trans. losses	0.95	0.92	0.68	0.68
Avoided dist. losses	2.14	2.11	2.10	2.07
Avoided T&D upgrades	0	0	0	0
Avoided RECs	4.84	4.84	4.84	4.84
Avoided emissions	0	0	0	0
Avoided fuel price risk	0	0	0	0
Ramping reserves	0	0	0	0
Regulating reserves	(1.30)	(1.30)	(1.30)	(1.30)
Total	**80.10**	**71.47**	**57.09**	**52.96**

Levelized value of solar

25 year lifetime value stream

Fuel (2.4%)/non-fuel (2%) escalation rates

5% discount rate

PV degradation rate (-0.5%)

Levelized to Jan 1, 2018

Levelized Value of solar

Levelized over 25 yrs to 2018 dollars [$/MWH]	2017	Low	Medium	High
Avoided energy	25.77	24.82	18.44	18.33
Avoided capacity	26.13	21.11	17.44	14.72
Avoided trans. losses	0.69	0.66	0.49	0.49
Avoided dist. losses	1.54	1.52	1.52	1.49
Avoided T&D upgrades	0	0	0	0
Avoided RECs	3.35	3.35	3.35	3.35
Avoided emissions	0	0	0	0
Avoided fuel price risk	0	0	0	0
Ramping reserves	0	0	0	0
Regulating reserves	(0.94)	(0.94)	(0.94)	(0.94)
Total	**56.54**	**50.53**	**40.31**	**37.44**

Levelized Value of Solar

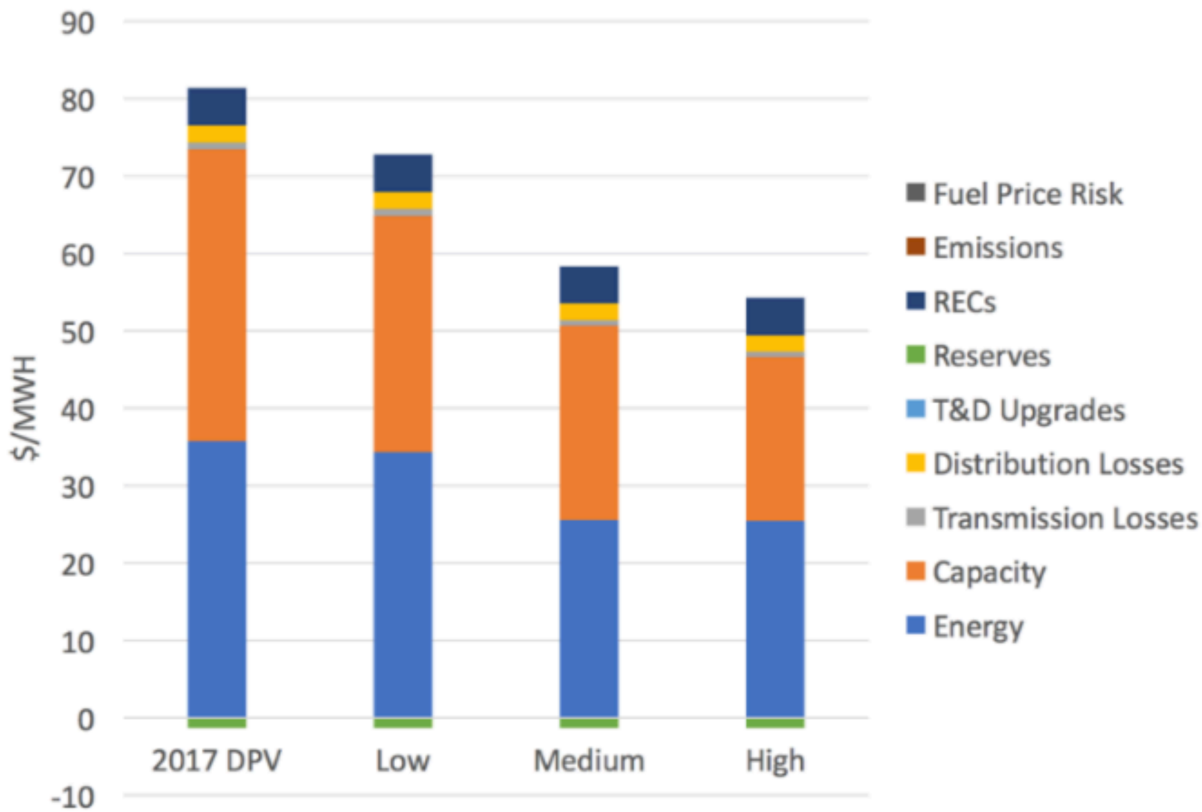


Figure 3-1 VOS for the year 2018

Economic development

This is an optional adder to the VOS calculation (CSU asked for it for their own purposes)

Using NREL Jobs and Economic Development Impact (JEDI) Model which is based on economic Input-Output model

What it captures: project development, construction, module and supply chain, indirect impacts (finance, insurance) and induced impacts (restaurants, retail, real estate).

Capturing economic development impacts using the ***state of Colorado*** as study footprint

PV costs: NREL ATB for year 2018

- CAPEX \$2591/kW_{DC}
- Fixed O&M \$16/kW_{DC}/yr (=\$20/kW_{AC}/yr)

Wages: Bureau of Labor Statistics

- \$22.17/hr PV installer in Colorado in 2018

Construction and annual O&M

- Small installers are more likely to purchased from local distributors
- Small installers (not national companies) are more likely to have all labor and overhead be local

Jobs and economic development depend on whether the installer is local or national

Small, local PV installer – Low Scenario

Local Economic Impacts - Summary Results	Jobs	Earnings $000 (2018)	Output $000 (2018)	Value Added $000 (2018)
During construction and installation period				
Project Development and Onsite Labor Impacts				
Construction and Installation Labor	52.2	$3,503.3		
Construction and Installation Related Services	82.1	$6,074.6		
Subtotal	134.3	$9,577.9	$13,345.7	$11,337.5
Module and Supply Chain Impacts				
Manufacturing Impacts	0.0	$0.0	$0.0	$0.0
Trade (Wholesale and Retail)	31.2	$2,541.3	$6,814.0	$4,236.1
Finance, Insurance and Real Estate	0.0	$0.0	$0.0	$0.0
Professional Services	13.7	$861.3	$2,382.2	$1,410.6
Other Services	33.7	$3,407.5	$9,572.2	$5,721.3
Other Sectors	46.8	$1,412.1	$4,142.4	$2,276.6
Subtotal	125.4	$8,222.1	$22,910.8	$13,644.6
Induced Impacts	86.2	$4,793.8	$14,028.9	$8,183.6
Total Impacts	**345.9**	**$22,593.8**	**$50,285.4**	**$33,165.8**
	Annual Jobs	**Annual Earnings $000 (2018)**	**Annual Output $000 (2018)**	**Annual Output $000 (2018)**
During operating years				
Onsite Labor Impacts				
PV Project Labor Only	2.1	$130.8	$130.8	$130.8
Local Revenue and Supply Chain Impacts	0.8	$59.6	$172.8	$102.8
Induced Impacts	0.6	$31.1	$91.1	$53.2
Total Impacts	**3.5**	**$221.6**	**$394.8**	**$286.8**

2491 construction jobs; 31 annual jobs
$239 M construction value added; $3 M annual value added

National chain PV installer - Low Scenario

Local Economic Impacts - Summary Results	Jobs	Earnings $000 (2018)	Output $000 (2018)	Value Added $000 (2018)
During construction and installation period				
Project Development and Onsite Labor Impacts				
Construction and Installation Labor	52.2	$3,503.3		
Construction and Installation Related Services	5.4	$554.8		
Subtotal	57.6	$4,058.1	$4,439.2	$4,050.3
Module and Supply Chain Impacts				
Manufacturing Impacts	0.0	$0.0	$0.0	$0.0
Trade (Wholesale and Retail)	2.8	$232.7	$624.1	$388.0
Finance, Insurance and Real Estate	0.0	$0.0	$0.0	$0.0
Professional Services	2.5	$170.5	$443.6	$260.2
Other Services	0.0	$0.0	$0.0	$0.0
Other Sectors	16.7	$937.2	$2,412.5	$1,450.2
Subtotal	22.0	$1,340.3	$3,480.2	$2,098.4
Induced Impacts	16.8	$925.2	$2,707.8	$1,579.6
Total Impacts	**96.4**	**$6,323.7**	**$10,627.2**	**$7,728.2**
	Annual Jobs	**Annual Earnings $000 (2018)**	**Annual Output $000 (2018)**	**Annual Output $000 (2018)**
During operating years				
Onsite Labor Impacts				
PV Project Labor Only	2.1	$130.8	$130.8	$130.8
Local Revenue and Supply Chain Impacts	0.8	$59.6	$172.8	$102.8
Induced Impacts	0.6	$31.1	$91.1	$53.2
Total Impacts	**3.5**	**$221.6**	**$394.8**	**$286.8**

694 construction jobs; 31 annual jobs
$56 M construction value added; $3 M annual value added

Regulatory/Legal/Technical considerations

Would be difficult to require VOS for PV customers under current CO statute that requires "net metering service at non-discriminatory rates"

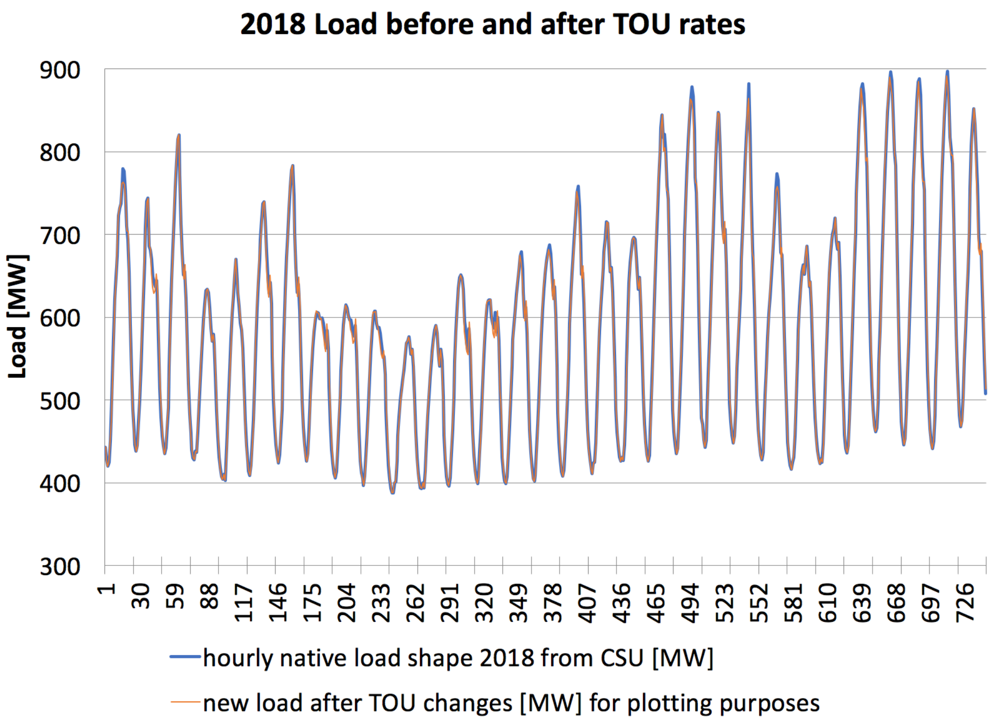
Could be an optional tariff. This could be attractive to some rate classes under some rate options.

May compensate customer with VOS *credit*, not payment, to reduce customer tax implications

Frequent calculations of VOS are recommended due to rapid decline of VOS with penetration and rapidly falling PV costs

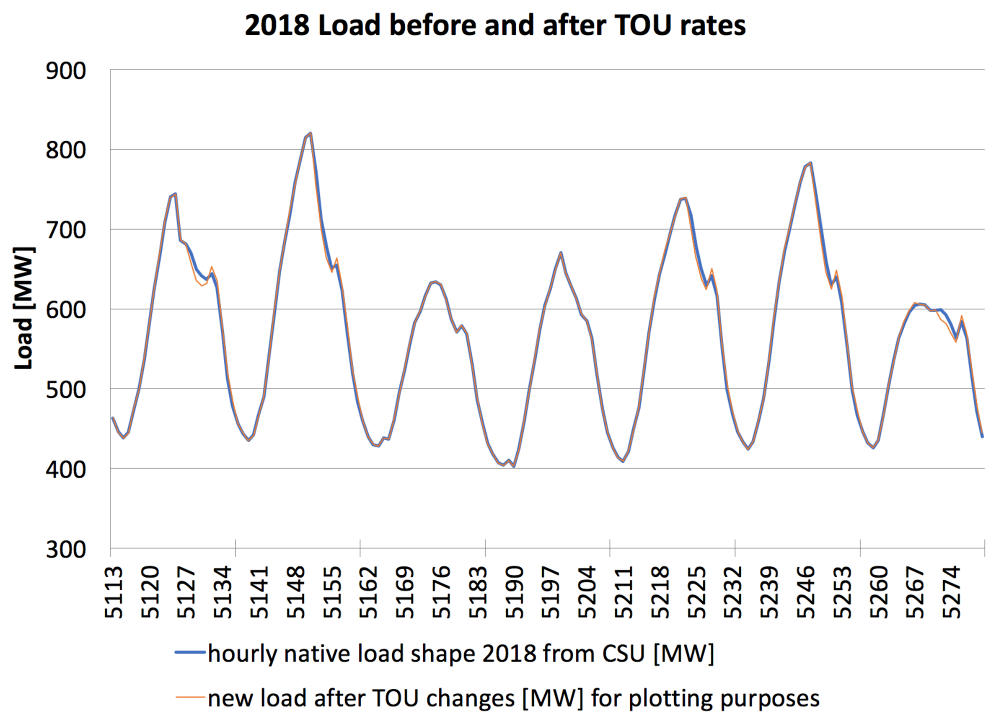
Can help set up CSU for compensation of other DERs

August

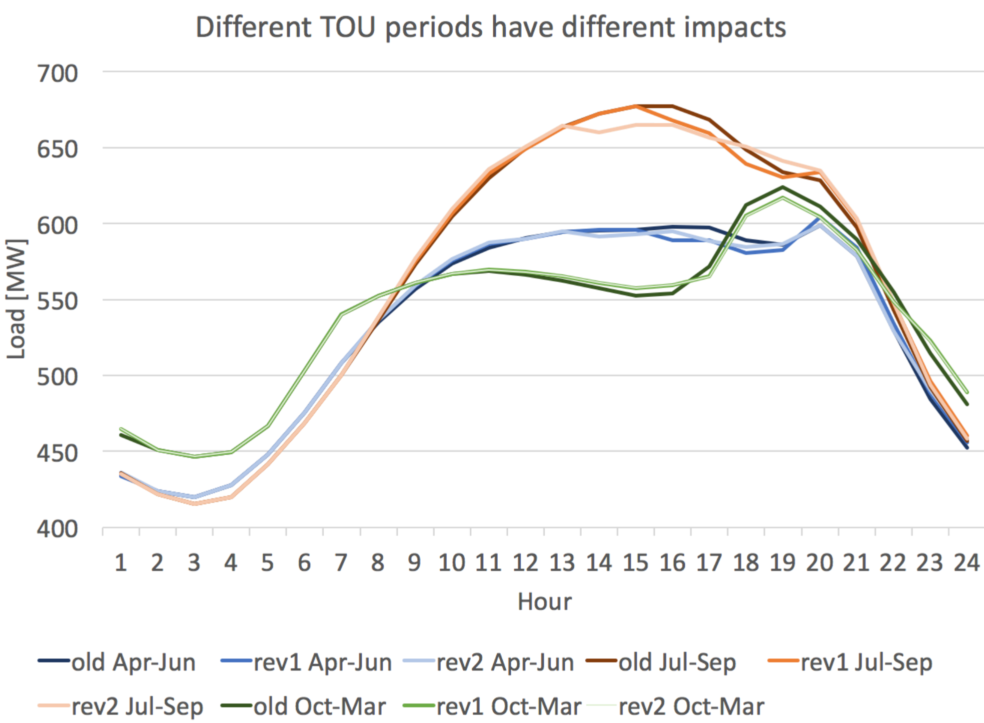


2018 Load before and after TOU rates
Load [MW]
900
800
700
600
500
400
300
1
30
59
88
117
146
175
204
233
262
291
320
349
378
407
436
465
494
523
552
581
610
639
668
697
726
hourly native load shape 2018 from CSU [MW]
new load after TOU changes [MW] for plotting purposes

August 2 - 8



2018 Load before and after TOU rates
Load [MW]
900
800
700
600
500
400
300
5113
5120
5127
5134
5141
5148
5155
5162
5169
5176
5183
5190
5197
5204
5211
5218
5225
5232
5239
5246
5253
5260
5267
5274
hourly native load shape 2018 from CSU [MW]
new load after TOU changes [MW] for plotting purposes


Different TOU periods have different impacts
700
650
600
550
500
450
400
Load [MW]
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
old Apr-Jun
rev1 Apr-Jun
rev2 Apr-Jun
old Jul-Sep
rev1 Jul-Sep
rev2 Jul-Sep
old Oct-Mar
rev1 Oct-Mar
rev2 Oct-Mar

All studies conclude that

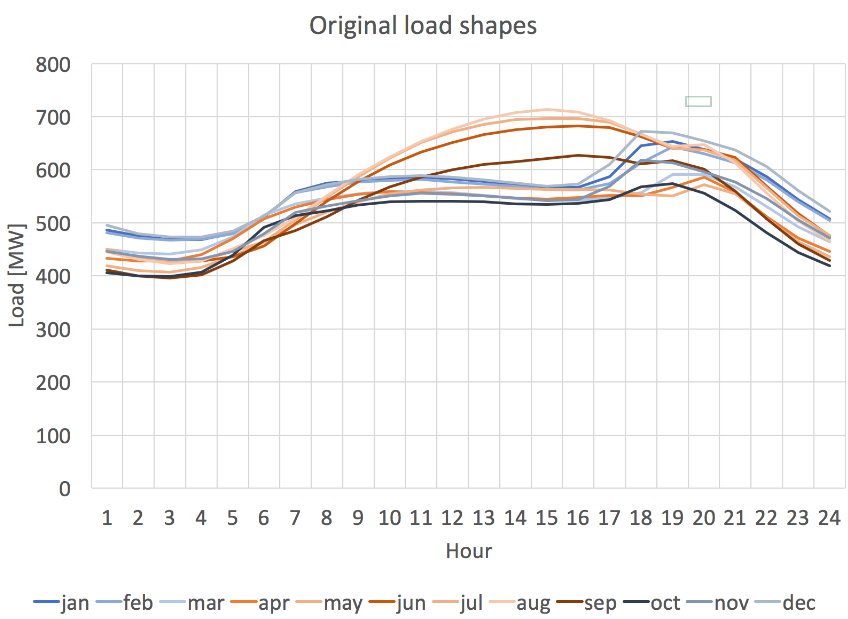
LOAD MUST PARTICIPATE!

Recommendations to CSU

Rate Class	Summary of Recommendations	Key Implementation Considerations
Residential, Small Commercial, General Commercial	• Fixed charge increase can mitigate NEM revenue erosion in the short-run	• Easy implementation for all rate classes, but inequitable impacts and an inefficient price signal to customers
	• TOU volumetric rates encourage grid-friendly behavior, offer customers another choice, • TOU rates have a lower bill impact on non-solar customers and alleviate NEM-related revenue erosion	• Requires new metering infrastructure • Large bill impacts for solar customers if TOU periods are not aligned with solar output • Long-term "Duck Curve" and shifting peak issues with increased DER penetration
	• A combination of a demand charge with a TOU rate may provide the most robust option in terms of the right price signals and fair compensation in anticipation of other DER	• Requires new metering infrastructure • Can be structured to charge customer based on higher peak usage (e.g., a block demand rate) • Potentially confusing and difficult to customers
General Commercial, Industrial	• Current ETL tariff is well-structured to recover cost of service and mitigate NEM-related revenue erosion • An optional Value of Solar "Buy All, Sell All" program may encourage more solar in this class by allowing them more attractive compensation for the value that DPV brings	• Would need a new program design for a C&I VOST to set eligibility, compensation, etc. • Interconnection policies would need to be re-examined • Removes ability for customers to offset onsite • Different tax ramifications than NEM

Mismatch between TOU periods and load

On-peak months shown in red/orange

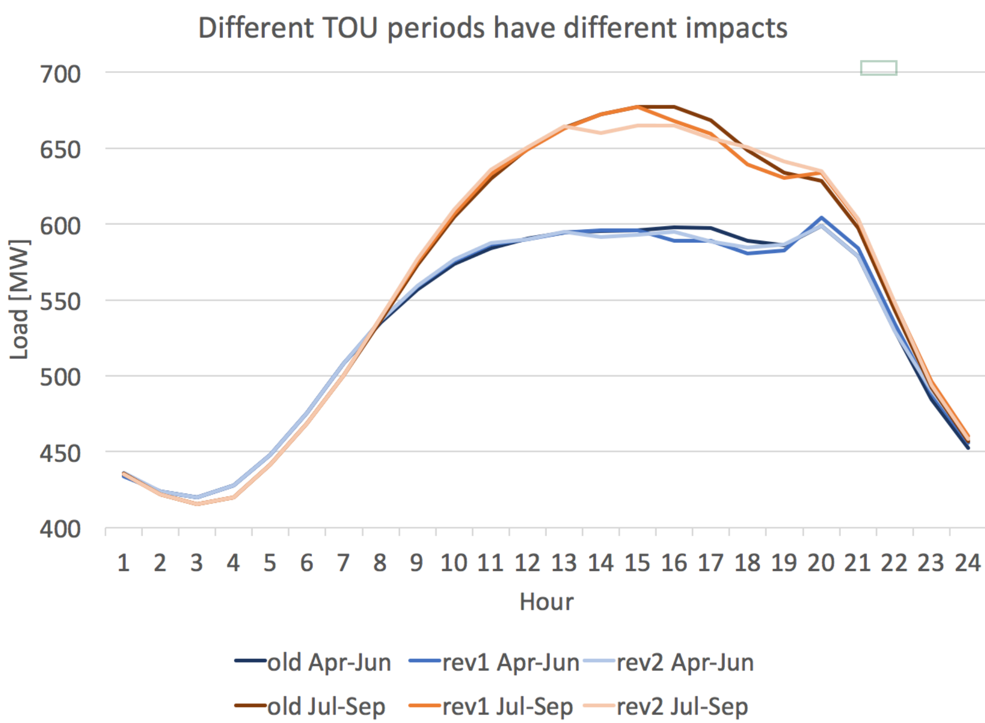


April and May have more similar system peak to winter than to summer months

System peak during summer months is closer to 1-5p than to 3-7p

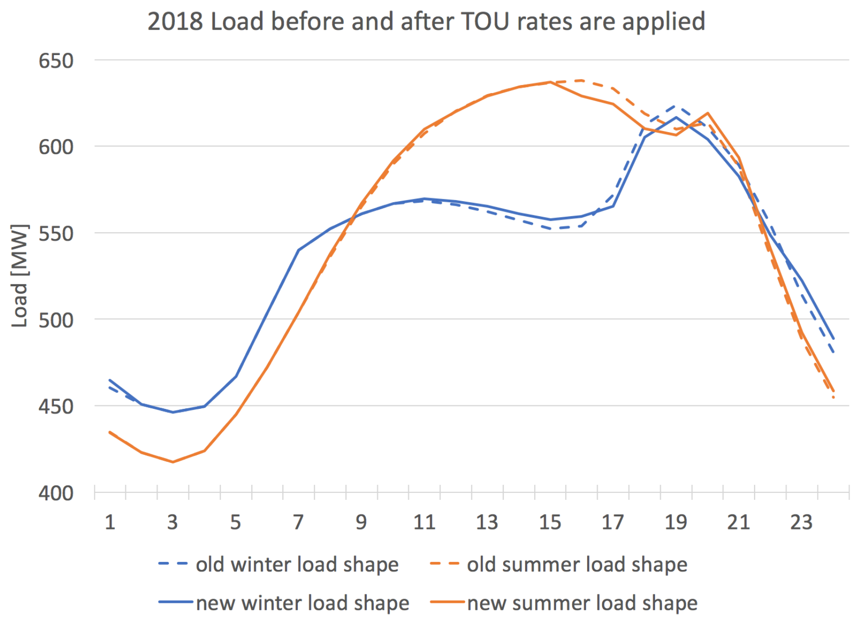
Redefine residential TOU peak/offpeak: summer = Jun-Sep onpeak = 1-5p

Revising TOU periods does better job of flattening load curve



TOU rates reduce cost of service – can we quantify that value?

TOU improves winter shape but less so on summer shape



TOU periods don't manage spring season well

TOU rates are similar to BTM storage but without the losses. A value stream approach can be used.
Note that here, redefining peak vs off-peak periods may be necessary to get value