Clean Coalition
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Avoided costs from distributed energy resources (DER)

The Distributed Energy Resource Avoided Cost calculator (DERAC) has been adopted by the CPUC to estimate the value of energy, capacity, and services provided by distributed energy resources (DER). The avoided costs components included in DERAC are energy, generation capacity, transmission capacity, distribution capacity, losses, ancillary services, reduced RPS procurement, and environmental savings, including greenhouse gas (GHG) emissions reductions.

Value per megawatt (MW) of avoided conventional generation

Benefits[1]	Annual value per MW	Cumulative 20-year value per MW
Generation capacity	$100,000	$2,000,000
Distribution capacity	$98,000	$1,960,000
New transmission capacity	$40,000	$800,000
Resource adequacy	$33,680	$673,600
RPS value[2]	$116,680	$2,334,000
Reliability value[3]	$1,766	$35,320
CO_2 reduction	513 metric tons	10,260 metric tons
NOx reduction	1.39 metric tons	27.85 metric tons

DERAC forecasts long-term marginal costs to evaluate the cost-effectiveness of DER and provides robust area- and time-specific cost estimates suitable for regulatory local integrated resource planning, cost-effectiveness evaluations, building energy code design, and rate design. Values vary substantially by climate zone, and DERAC captures these regional differences in locational value.

DERAC calculator values may be employed as a consistent metric that includes distribution and resource adequacy value factors, incorporating line loss reduction within these factors, and reflecting climate zone variations.

Avoided costs by climate zone

DERAC establishes the following 20-year levelized values for each value category for specific deployment. This example is for eastern Alameda County, Climate Zone (CZ)12:

- Electric market forward price: $34.89/MWh
- Carbon price: $14.14/ton
- Transmission capacity $34.86/PCAF-kW-yr[4]
- Primary distribution capacity: $52.57/PCAF-kW-yr

[1] Avoided Cost Calculator 2017 v1, avoided full capacity CCNG operation, PG&E territory, starting 2020

[2] Marginal Renewable Energy (avoided RPS) @ $75.29/MWh = $116,680 (or wholesale market electric price value of $64,000, plus $23,200 GHG market value)

[3] DOE Interruption Cost Estimate calculator, https://icecalculator.com/home

[4] Peak Cost Allocation Factor, CAISO systemwide average

- Secondary distribution capacity: $4.01/PCAF-kW-yr
- Marginal transmission capacity $31.13/PCAF-kW-yr
- Marginal primary distribution capacity: $85.34/PCAF-kW-yr
- Marginal secondary distribution capacity: $5.84/PCAF-kW-yr

Climate Zone (CZ) 12, eastern Alameda County

As is evident from these figures, the value of DER varies substantially by time of day and time of year. The value will also vary substantially between climate zones.

The value at any point in time is agnostic to the DER technology deployed. However, various DER will offer different performance profiles, and some DER will be best able to realize avoided cost values specific to each location and period.

2020 DER Avoided Cost Calculator values[5] for 25 MW of rooftop PV
(PG&E territory, 33% ELCC, and 1550 MWh/MW annual output)
Transmission capacity @ $40/kW-yr = $334,000
Distribution capacity @ $98/kW-yr = $818,000
Resource adequacy @ $33.68/kW-yr = $281,000
Generation capacity @ $100/kW-yr = $835,000
Total = $2,268,000 per year, yielding $45,360,000 20-year net present value (NPV)
Plus, marginal renewable energy (avoided RPS) @ $75.29/MWh = $2,917,000
(Or wholesale market electric price value of $1,600,000; plus $581,000 GHG market value)

CAISO peak demand occurs from mid-June to mid-September from 4-5 pm. The lowest effective load carrying capacity (ELCC) of PV during these months is 33%.[6] On this basis, for fixed orientation PV we conservatively assign 33% of the capacity values established in the DERAC model. However, as clearly indicated in the following table,[7] PV orientations for maximizing capacity value and energy yields are very different, and the actual generation profile must be taken into consideration when determining grid impacts and benefits. If capacity value

[5] Avoided Cost Calculator 2017 v1, assuming initial deployment year 2020
[6] Net Qualifying Capacity Report, 2018, https://www.caiso.com/.../NetQualifyingCapacityReport_ComplianceYear-2018.xlsx
[7] S. H. Madaeni, *Comparison of Capacity Value Methods for Photovoltaics in the Western United States*, NREL/TP-6A20-54704, July 2012, https://www.nrel.gov/docs/fy12osti/54704.pdf

warrants, a more western orientation may be achieved in fixed or solar tracking installations to achieve a practical ELCC approaching 100% of nameplate capacity, to reduce annual peak transmission load when evaluating distributed resources serving local loads.

PV Site	**Capacity value**		**Energy yield**	
	Maximum value (%)	Orientation (azimuth, tilt)	Maximum value (GWh)	Orientation (azimuth, tilt)
Barstow, CA	105.0	(90°, 50°)	190.0	(0°, 30°)

Capacity values are design- and location-sensitive. Project analysis should reflect the climate zone (CZ), as well as the distribution planning area (DPA), transmission planning area (TPA), locational marginal price (LMP), local resource adequacy (RA), and other location-specific values as appropriate.

Locational Net Benefits Assessment

Development of the Locational Net Benefits Assessment (LNBA) methodology, and forthcoming publication of LNBA maps, will simplify this analysis and provide common tools and metrics for assessment of benefits. LNBA incorporates and builds upon DERAC, integrating more granular location-specific avoidable investments from investor-owned utility (IOU) distribution planning processes. However, this assessment currently applies only where specific investments have been planned, and where these investments are deemed deferrable. LNBA refinement will continue to improve the accuracy and comprehensiveness of the results, additionally incorporating reliability and resilience, flexible RA, resource integration, public safety, and location-specific avoidable investments from the California Independent System Operator (CAISO) transmission planning process (TPP), such as those identified in the annual TPP, which recently credited DER with $2.6 billion in avoided planned transmission projects.[8]

Avoiding future grid needs is significant. If the growth in DER deployment delays or avoids approaching the limits of the existing energy infrastructure, new investments in that infrastructure will not be needed and will never enter into the planning cycle. These avoided costs would not be captured if only planned capital investments were considered. Refinements have been scoped and proposed in the LNBA Working Group "Long-Term Refinements Final Report" (January 9, 2018); however, the CPUC has not yet issued a Decision on this topic in the Distribution Resources Plan Proceeding (R.14-08-013).

Additional environmental, health, or regional economic impacts and benefits may be considered using tools such as NREL's Jobs and Economic Development Indicator.[9]

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[8] http://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf
[9] https://www.nrel.gov/analysis/jedi/