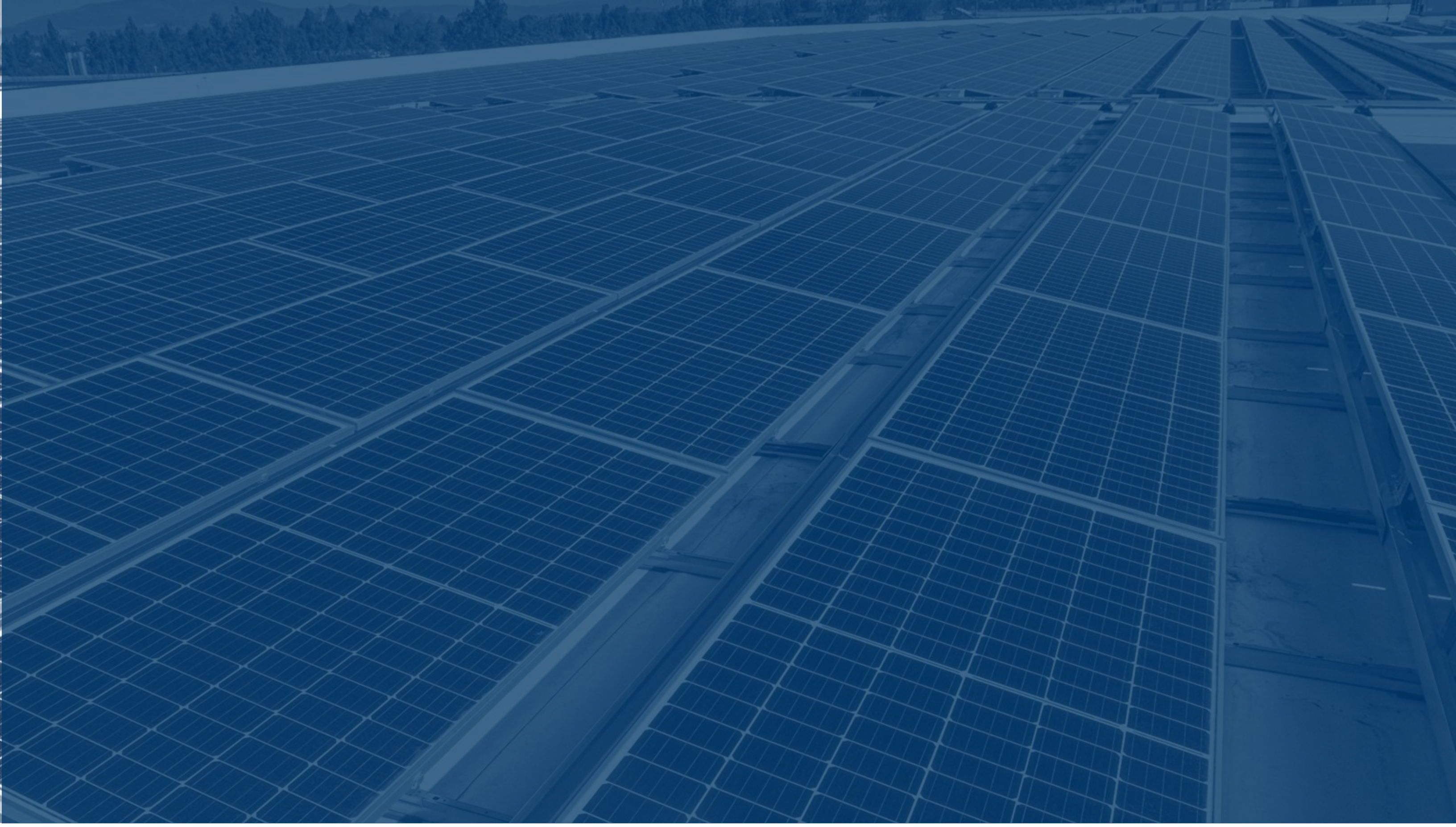

New Hampshire Value of Distributed Energy Resources

Appendices

Submitted to:

New Hampshire
Department of Energy

New Hampshire Department of Energy

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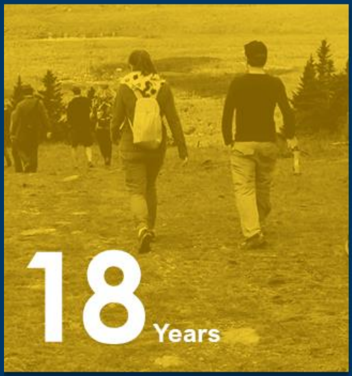
About Dunsky



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Working across buildings, industry, energy and mobility, we support our clients through three key services: we **quantify** opportunities (technical, economic, market); **design** go-to-market strategies (plans, programs, policies); and **evaluate** performance (with a view to continuous improvement).

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

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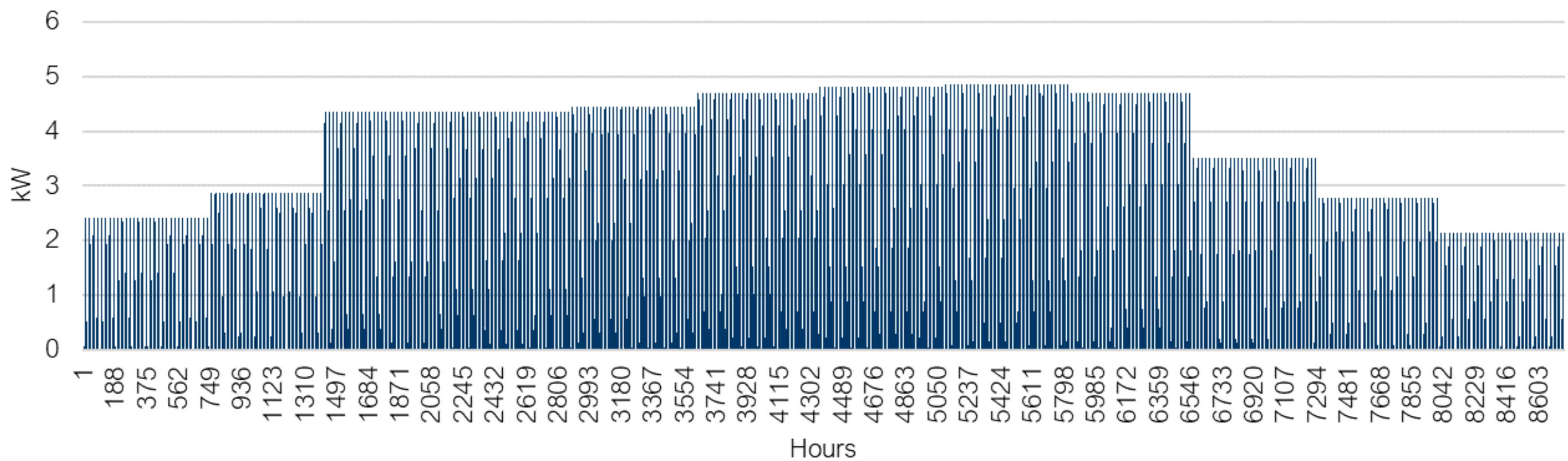


Figure 2. 8,760 Profile for Residential West-Facing Solar PV Array, 7.8 kW DC (6.5 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

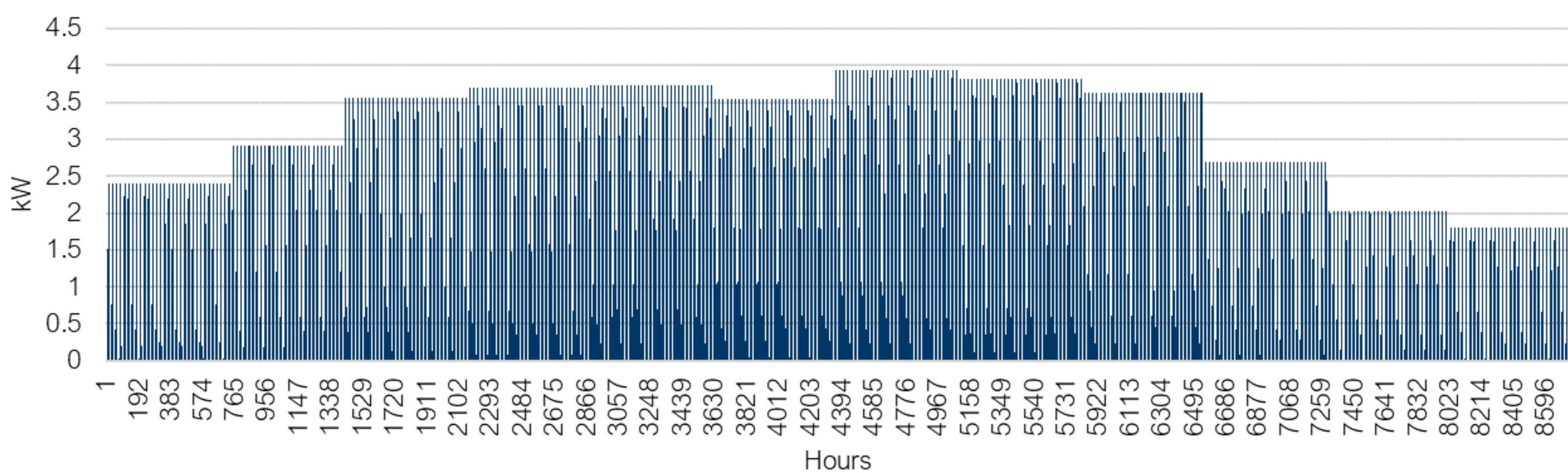


Figure 3. 8,760 Profile for Commercial South-Facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

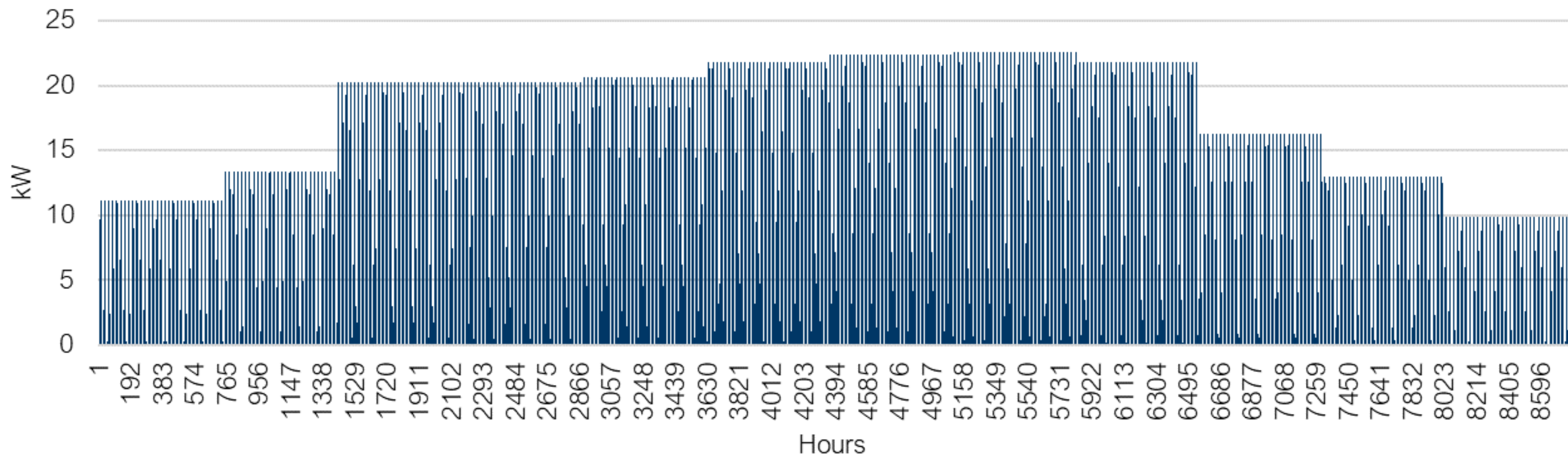


Figure 4. 8,760 Profile for Commercial West-facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

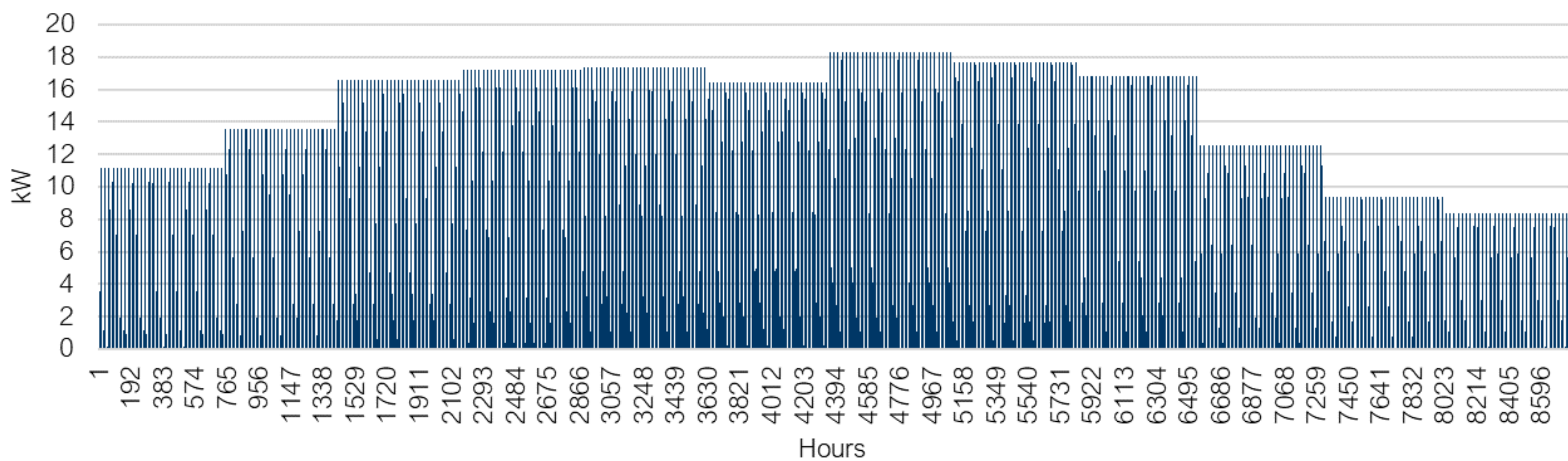


Figure 5. 8,760 Profile for Residential South-Facing Solar PV Array Paired with Storage, 7.8 kW DC (6.5 kW AC), 4-hour duration 10 kWh/2.5kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

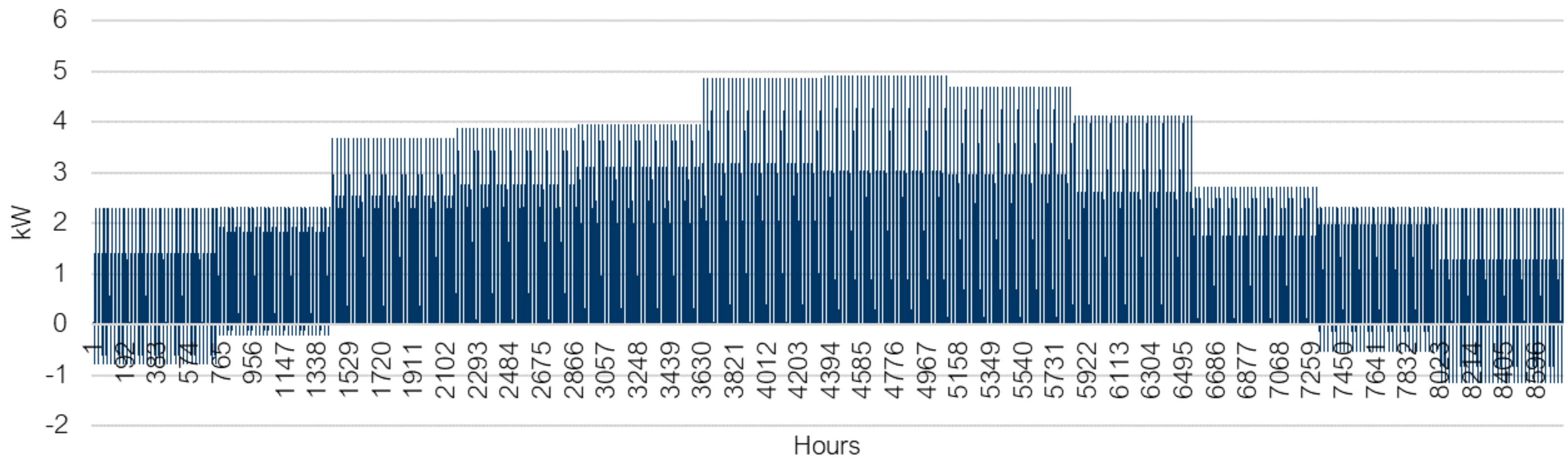


Figure 6. 8,760 Profile for Commercial South-facing Solar Paired with Storage, 36 kW DC Solar (30 kW AC), 4-hour duration 40 kWh/10kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

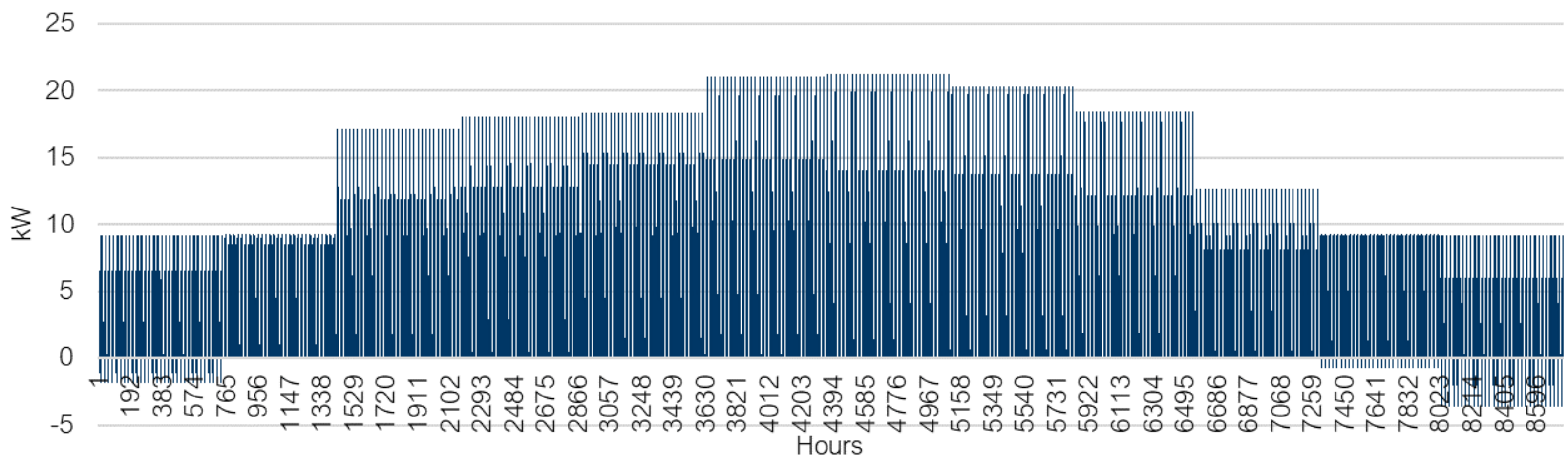


Figure 7. 8,760 Profile for Large Group Host Commercial Solar, 195 kW DC (162 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

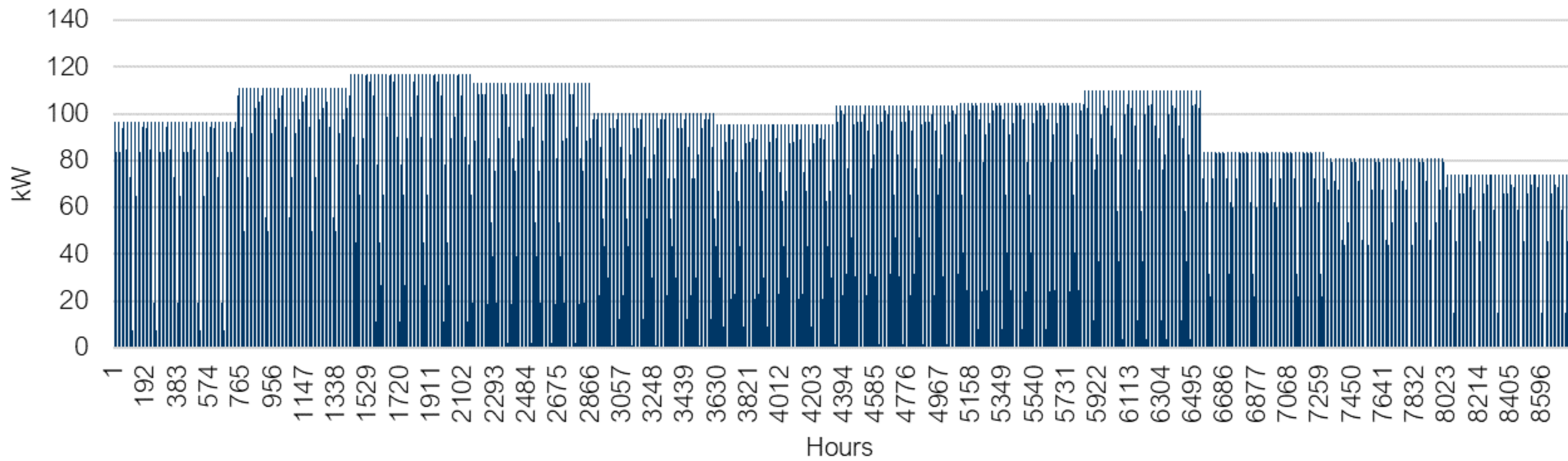
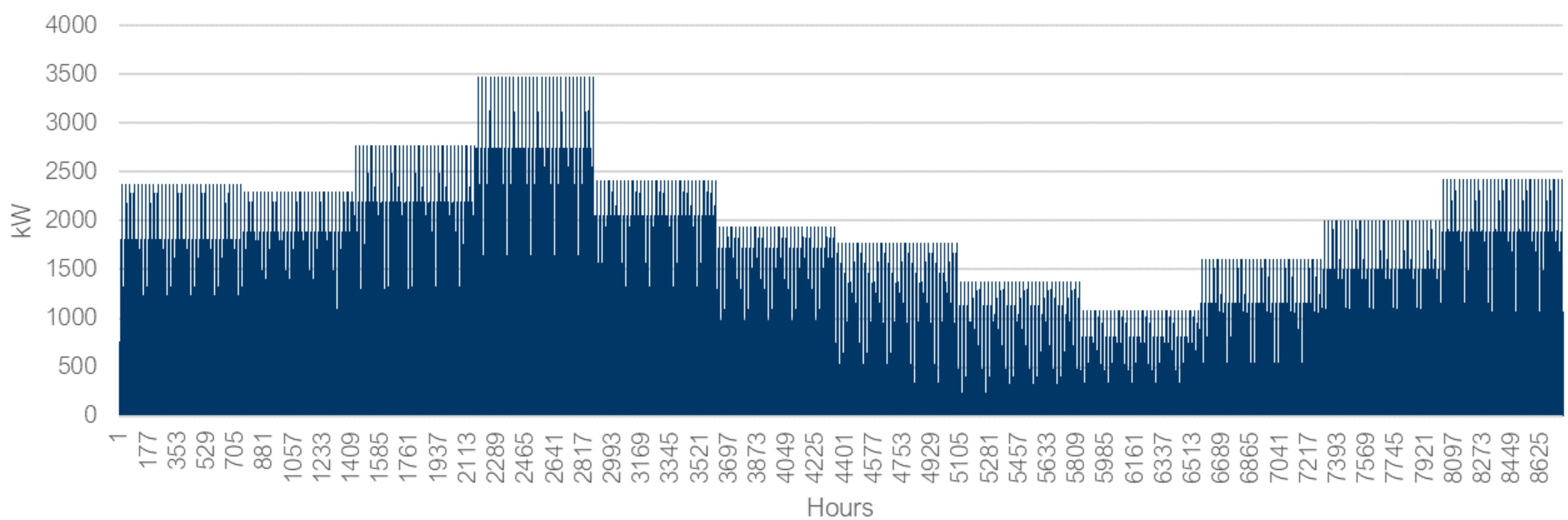


Figure 8. 8,760 Profile for Micro Hydro, 3 MW



B. Results Tables

B.1 Technology-Neutral Value Stack

Table 1. Average Annual Technology-Neutral Value Stack ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.046	0.050	0.045	0.043	0.039	0.037	0.036	0.035	0.036	0.036	0.037	0.037	0.037	0.037	0.039
Transmission Charges	0.020	0.021	0.023	0.024	0.026	0.028	0.030	0.032	0.034	0.036	0.039	0.042	0.045	0.048	0.051
Distribution Capacity	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006
Capacity	0.007	0.006	0.003	0.004	0.004	0.004	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.007	0.006
Distribution Line Losses	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.002
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002
DRIPE	0.004	0.004	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Environmental Externality	0.049	0.048	0.051	0.055	0.056	0.054	0.051	0.048	0.048	0.045	0.047	0.047	0.048	0.048	0.050
Total – Excluding Environmental	0.102	0.105	0.097	0.097	0.095	0.093	0.096	0.097	0.100	0.103	0.106	0.109	0.113	0.117	0.122
Total – Including Environmental	0.151	0.153	0.149	0.152	0.151	0.148	0.147	0.145	0.148	0.149	0.153	0.157	0.161	0.165	0.171

Table 2. Average Annual Technology-Neutral Value, Minimum Hourly Value, and Maximum Hourly Value ($/kWh) (2021$)

	2021			2025			2030			2035		
	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)
Energy	0.046	0.030	0.082	0.039	0.009	0.077	0.036	-0.008	0.144	0.039	-0.008	0.159
Transmission Charges	0.020	0.000	14.945	0.026	0.000	19.453	0.036	0.000	27.334	0.051	0.000	38.407

Distribution Capacity	0.007	0.000	0.667	0.007	0.000	0.614	0.007	0.000	0.613	0.006	0.000	0.602
Capacity	0.007	0.000	63.000	0.004	0.000	37.000	0.006	0.000	51.000	0.006	0.000	52.000
Distribution Line Losses	0.003	0.000	7.674	0.002	0.000	4.982	0.002	0.000	5.760	0.002	0.000	5.873
RPS	0.004	0.004	0.004	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.000	4.474	0.003	0.000	2.905	0.002	0.000	3.358	0.003	0.000	3.424
Risk Premium	0.005	0.001	1.151	0.004	0.000	1.009	0.004	-0.001	0.644	0.004	-0.001	0.726
Ancillary Services	0.002	0.001	0.005	0.002	0.000	0.005	0.001	-0.001	0.006	0.002	-0.001	0.009
DRIPE	0.004	0.001	4.954	0.005	0.000	7.116	0.005	-0.001	8.037	0.005	-0.001	8.541
Distribution OPEX	0.002	0.000	0.149	0.002	0.000	0.149	0.002	0.000	0.149	0.002	0.000	0.149
Utility Admin	0.000	-0.002	0.000	0.000	-0.002	0.000	0.000	-0.002	0.000	0.000	-0.002	0.000
Environmental Externality	0.049	-0.069	0.350	0.056	-0.008	0.160	0.045	0.000	0.119	0.050	0.000	0.112

B.2 Residential and Commercial Solar PV

Table 3. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.044	0.046	0.040	0.038	0.033	0.030	0.029	0.027	0.027	0.027	0.026	0.026	0.026	0.026	0.028
Transmission Charges	0.035	0.038	0.040	0.036	0.037	0.040	0.038	0.041	0.043	0.046	0.049	0.041	0.035	0.037	0.036
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.028	0.022	0.011	0.015	0.016	0.016	0.019	0.019	0.020	0.022	0.022	0.022	0.023	0.025	0.021
Distribution Line Losses	0.005	0.005	0.003	0.004	0.004	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.046	0.047	0.048	0.045	0.040	0.037	0.033	0.032	0.030	0.030	0.030	0.031	0.032	0.034

Total – Excluding Environmental	0.158	0.153	0.136	0.132	0.130	0.127	0.129	0.129	0.131	0.136	0.138	0.129	0.124	0.129	0.125
Total – Including Environmental	0.206	0.200	0.183	0.180	0.176	0.167	0.166	0.162	0.164	0.166	0.168	0.159	0.155	0.161	0.159

Table 4. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.047	0.041	0.039	0.034	0.031	0.030	0.028	0.028	0.028	0.028	0.027	0.027	0.027	0.029
Transmission Charges	0.039	0.041	0.044	0.039	0.041	0.044	0.040	0.043	0.045	0.048	0.051	0.042	0.039	0.041	0.043
Distribution Capacity	0.023	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.020	0.020	0.020	0.019	0.019	0.019
Capacity	0.031	0.025	0.013	0.016	0.018	0.017	0.021	0.021	0.022	0.024	0.024	0.024	0.025	0.028	0.024
Distribution Line Losses	0.006	0.005	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.004
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.047	0.047	0.048	0.046	0.041	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – Excluding Environmental	0.168	0.164	0.145	0.141	0.140	0.138	0.137	0.138	0.141	0.145	0.147	0.137	0.135	0.140	0.139
Total – Including Environmental	0.216	0.210	0.192	0.189	0.186	0.179	0.176	0.173	0.175	0.177	0.179	0.170	0.168	0.174	0.175

Table 35. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.044	0.046	0.040	0.038	0.033	0.030	0.029	0.027	0.027	0.027	0.026	0.026	0.026	0.026	0.028
Transmission Charges	0.035	0.038	0.040	0.036	0.037	0.040	0.038	0.041	0.043	0.046	0.049	0.041	0.035	0.037	0.036
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018

Capacity	0.028	0.022	0.011	0.015	0.016	0.016	0.019	0.019	0.020	0.022	0.022	0.022	0.023	0.025	0.021
Distribution Line Losses	0.004	0.003	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.004	0.003	0.003	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.046	0.047	0.048	0.045	0.040	0.037	0.033	0.032	0.030	0.030	0.030	0.031	0.032	0.034
Total – No Environmental	0.155	0.151	0.134	0.130	0.128	0.126	0.127	0.127	0.130	0.134	0.136	0.127	0.122	0.127	0.123
Total – Including Environmental	0.203	0.198	0.181	0.178	0.174	0.166	0.164	0.160	0.162	0.164	0.166	0.157	0.154	0.159	0.158

Table 46. Average Annual Avoided Cost Value for Commercial West-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.047	0.041	0.039	0.034	0.031	0.030	0.028	0.028	0.028	0.028	0.027	0.027	0.027	0.029
Transmission Charges	0.039	0.041	0.044	0.039	0.041	0.044	0.040	0.043	0.045	0.048	0.051	0.042	0.039	0.041	0.043
Distribution Capacity	0.023	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.020	0.020	0.020	0.019	0.019	0.019
Capacity	0.031	0.025	0.013	0.016	0.018	0.017	0.021	0.021	0.022	0.024	0.024	0.024	0.025	0.028	0.024
Distribution Line Losses	0.004	0.004	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)

Environmental Externality	0.048	0.047	0.047	0.048	0.046	0.041	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – No Environmental	0.165	0.161	0.143	0.139	0.138	0.136	0.135	0.136	0.139	0.144	0.146	0.136	0.133	0.139	0.138
Total – Including Environmental	0.213	0.208	0.190	0.187	0.184	0.177	0.174	0.171	0.173	0.175	0.178	0.168	0.167	0.173	0.174

Table 7. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.032	-	0.003	0.055	0.044	0.024	-	0.003	0.089	0.080
	7	0.034	-	0.004	0.052	0.041	0.028	-	0.003	0.095	0.086
	8	0.042	-	0.004	0.053	0.041	0.031	-	0.003	0.101	0.091
	9	0.044	-	0.004	0.057	0.045	0.030	-	0.003	0.103	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.045	-	0.004	0.055	0.044	0.021	-	0.002	0.104	0.096
	12	0.045	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.045	-	0.004	0.054	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.157	0.057	0.045	0.022	-	0.003	0.104	0.095
	15	0.045	-	0.158	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.044	-	0.004	0.058	0.045	0.046	-	0.004	0.113	0.099
	19	0.042	-	0.055	0.055	0.043	0.049	-	0.005	0.116	0.102
	20	0.038	-	0.004	0.053	0.041	0.046	-	0.004	0.116	0.102
	21	0.037	-	0.004	0.056	0.044	0.046	-	1.532	0.119	0.105
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-

	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.034	-	0.003	0.063	0.053	0.030	-	0.003	0.090	0.081
	7	0.034	-	0.003	0.059	0.049	0.036	-	0.003	0.096	0.086
	8	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.103	0.093
	9	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.110	0.100
	10	0.040	-	0.006	0.060	0.049	0.037	-	0.007	0.118	0.108
	11	0.040	-	0.047	0.061	0.050	0.036	-	0.056	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.080	0.130	0.120
	13	0.040	-	0.079	0.074	0.050	0.038	-	0.095	0.142	0.123
	14	0.040	-	0.275	0.062	0.051	0.039	-	0.689	0.138	0.127
	15	0.041	0.685	0.580	0.115	0.050	0.040	0.746	0.283	0.149	0.127
	16	0.041	-	0.114	0.059	0.048	0.043	-	0.137	0.140	0.127
	17	0.041	-	0.111	0.056	0.044	0.052	-	1.239	0.260	0.129
	18	0.042	-	0.088	0.057	0.044	0.059	-	0.107	0.145	0.129
	19	0.042	-	0.061	0.057	0.045	0.066	-	0.076	0.144	0.128
	20	0.041	-	0.011	0.058	0.047	0.062	-	0.014	0.140	0.124
	21	0.041	-	0.004	0.059	0.048	0.056	-	0.005	0.135	0.121
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.034	-	0.003	0.055	0.044	0.042	-	0.004	0.095	0.083
	8	0.042	-	0.004	0.060	0.048	0.049	-	0.005	0.103	0.089
	9	0.042	-	0.004	0.060	0.048	0.048	-	0.005	0.106	0.092
	10	0.041	-	0.004	0.061	0.049	0.042	-	0.004	0.106	0.093
	11	0.041	-	0.004	0.058	0.047	0.041	-	0.004	0.107	0.094
	12	0.040	-	0.004	0.059	0.047	0.042	-	0.004	0.106	0.094
	13	0.040	-	0.004	0.058	0.046	0.043	-	0.004	0.106	0.093
	14	0.040	-	0.004	0.060	0.048	0.044	-	0.004	0.107	0.094

	15	0.039	-	0.004	0.061	0.049	0.043	-	0.004	0.108	0.094
	16	0.038	-	0.004	0.057	0.045	0.046	-	0.004	0.108	0.094
	17	0.037	-	0.328	0.063	0.051	0.049	-	0.005	0.109	0.096
	18	0.036	-	0.006	0.060	0.048	0.049	-	0.005	0.111	0.097
	19	0.036	-	0.004	0.056	0.045	0.049	-	0.005	0.112	0.099
	20	0.036	-	0.004	0.065	0.054	0.048	-	1.694	0.116	0.104
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.057	-	0.005	0.058	0.041	0.076	-	0.007	0.114	0.094
	8	0.064	-	0.006	0.068	0.051	0.084	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.128	0.106
	10	0.064	-	0.006	0.071	0.054	0.071	-	0.007	0.128	0.108
	11	0.064	-	0.006	0.070	0.053	0.067	-	0.006	0.127	0.107
	12	0.064	-	0.006	0.073	0.055	0.066	-	0.006	0.126	0.106
	13	0.064	-	0.006	0.072	0.055	0.066	-	0.006	0.124	0.104
	14	0.063	-	0.006	0.071	0.053	0.067	-	0.006	0.125	0.103
	15	0.063	-	0.006	0.072	0.054	0.068	-	0.006	0.126	0.102
	16	0.062	-	0.006	0.069	0.050	0.078	-	0.007	0.129	0.103
	17	0.062	-	0.006	0.067	0.048	0.094	-	0.008	0.135	0.109
	18	0.064	-	0.006	0.067	0.050	0.098	-	0.009	0.151	0.126
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.3 Residential and Commercial Solar PV Paired with Storage

Table 8. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.046	0.041	0.039	0.035	0.033	0.032	0.031	0.032	0.032	0.032	0.032	0.032	0.033	0.034
Transmission Charges	0.055	0.058	0.062	0.063	0.072	0.076	0.077	0.082	0.087	0.093	0.099	0.100	0.106	0.113	0.125
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.030	0.024	0.012	0.016	0.017	0.017	0.021	0.020	0.021	0.023	0.023	0.023	0.024	0.027	0.023
Distribution Line Losses	0.005	0.005	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.005	0.005
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004	0.004	0.004
Risk Premium	0.004	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.007	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.008	0.008	0.008
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.047	0.046	0.041	0.047	0.049	0.048	0.045	0.044	0.044	0.041	0.042	0.042	0.042	0.044	0.045
Total – Excluding Environmental	0.181	0.177	0.160	0.163	0.169	0.169	0.173	0.178	0.184	0.192	0.200	0.201	0.207	0.218	0.227
Total – Including Environmental	0.228	0.223	0.202	0.209	0.218	0.217	0.218	0.221	0.228	0.232	0.241	0.243	0.250	0.261	0.272

Table 9. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.046	0.041	0.039	0.035	0.032	0.031	0.031	0.031	0.031	0.032	0.031	0.032	0.032	0.033
Transmission Charges	0.052	0.055	0.059	0.059	0.067	0.071	0.071	0.076	0.081	0.086	0.092	0.092	0.095	0.101	0.112
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.029	0.024	0.012	0.016	0.017	0.016	0.020	0.020	0.021	0.023	0.023	0.023	0.024	0.027	0.023
Distribution Line Losses	0.004	0.004	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.003

RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.047	0.046	0.042	0.047	0.048	0.047	0.044	0.042	0.042	0.039	0.040	0.041	0.041	0.042	0.043
Total – Excluding Environmental	0.174	0.171	0.154	0.156	0.161	0.161	0.165	0.169	0.174	0.182	0.189	0.188	0.193	0.203	0.210
Total – Including Environmental	0.222	0.217	0.197	0.203	0.210	0.208	0.209	0.211	0.217	0.221	0.229	0.229	0.234	0.245	0.254

Table 10. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.032	-	0.003	0.055	0.044	0.024	-	0.003	0.089	0.080
	7	0.034	-	0.004	0.052	0.041	0.028	-	0.003	0.095	0.086
	8	0.042	-	0.004	0.053	0.041	0.031	-	0.003	0.101	0.091
	9	0.044	-	0.004	0.057	0.045	0.030	-	0.003	0.103	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.044	-	0.004	0.055	0.044	0.021	-	0.002	0.104	0.096
	12	0.045	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.045	-	0.004	0.054	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.160	0.057	0.045	0.022	-	0.003	0.104	0.095
	15	0.045	-	0.158	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.046	-	0.004	0.059	0.046	0.048	-	0.005	0.114	0.099
	19	0.046	-	0.142	0.058	0.045	0.054	-	0.005	0.121	0.105
	20	0.046	-	0.004	0.055	0.041	0.055	-	0.508	0.124	0.108

	21	0.046	-	0.004	0.060	0.046	0.055	-	1.034	0.122	0.107
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.034	-	0.003	0.063	0.053	0.030	-	0.003	0.090	0.081
	7	0.034	-	0.003	0.059	0.049	0.036	-	0.003	0.096	0.086
	8	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.103	0.093
	9	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.110	0.100
	10	0.040	-	0.006	0.060	0.049	0.037	-	0.007	0.118	0.108
	11	0.040	-	0.047	0.061	0.050	0.036	-	0.056	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.080	0.130	0.120
	13	0.040	-	0.080	0.074	0.050	0.038	-	0.097	0.142	0.123
	14	0.040	-	0.278	0.062	0.051	0.039	-	0.696	0.138	0.127
	15	0.041	0.685	0.580	0.115	0.050	0.040	0.746	0.283	0.149	0.127
	16	0.041	-	0.114	0.059	0.048	0.043	-	0.137	0.140	0.127
	17	0.041	-	0.112	0.056	0.044	0.052	-	1.249	0.264	0.129
	18	0.042	-	0.090	0.057	0.045	0.060	-	0.109	0.146	0.129
	19	0.042	-	0.066	0.057	0.045	0.067	-	0.081	0.146	0.129
	20	0.041	-	0.019	0.059	0.047	0.065	-	0.024	0.144	0.128
	21	0.041	-	0.004	0.059	0.048	0.056	-	0.005	0.135	0.121
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.034	-	0.003	0.055	0.044	0.042	-	0.004	0.095	0.083

	8	0.042	-	0.004	0.060	0.048	0.049	-	0.005	0.103	0.089
	9	0.042	-	0.004	0.060	0.048	0.048	-	0.005	0.106	0.092
	10	0.041	-	0.004	0.061	0.049	0.042	-	0.004	0.106	0.093
	11	0.032	-	0.003	0.059	0.050	0.027	-	0.003	0.098	0.092
	12	0.036	-	0.004	0.059	0.048	0.034	-	0.003	0.103	0.093
	13	0.035	-	0.004	0.056	0.046	0.035	-	0.003	0.103	0.093
	14	0.030	-	0.003	0.059	0.050	0.029	-	0.003	0.101	0.093
	15	0.039	-	0.004	0.061	0.049	0.043	-	0.004	0.108	0.094
	16	0.038	-	0.004	0.057	0.045	0.046	-	0.004	0.108	0.094
	17	0.036	-	0.407	0.062	0.051	0.048	-	0.004	0.109	0.096
	18	0.042	-	0.149	0.062	0.049	0.057	-	0.005	0.120	0.103
	19	0.042	-	0.004	0.059	0.046	0.059	-	0.550	0.125	0.108
	20	0.042	-	0.168	0.062	0.048	0.059	-	1.119	0.128	0.110
	21	0.045	-	0.005	0.062	0.047	0.063	-	0.006	0.127	0.107
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.057	-	0.005	0.058	0.041	0.076	-	0.007	0.114	0.094
	8	0.064	-	0.006	0.068	0.051	0.084	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.128	0.106
	10	0.064	-	0.006	0.071	0.054	0.071	-	0.007	0.128	0.108
	11	0.066	-	0.006	0.075	0.057	0.075	-	0.007	0.129	0.107
	12	0.070	-	0.007	0.082	0.063	0.085	-	0.008	0.130	0.106
	13	0.070	-	0.007	0.082	0.063	0.086	-	0.008	0.129	0.104
	14	0.067	-	0.006	0.079	0.060	0.080	-	0.007	0.128	0.103
	15	0.063	-	0.006	0.072	0.054	0.068	-	0.006	0.126	0.102
	16	0.062	-	0.006	0.069	0.050	0.078	-	0.007	0.129	0.103
	17	0.062	-	0.006	0.067	0.048	0.094	-	0.008	0.135	0.109
	18	0.067	-	0.160	0.071	0.051	0.108	-	0.009	0.172	0.142
	19	0.067	-	0.327	0.071	0.051	0.110	-	1.625	0.188	0.158

	20	0.067	-	0.006	0.073	0.053	0.109	-	0.009	0.187	0.157
	21	0.066	-	0.006	0.072	0.052	0.108	-	0.009	0.170	0.141
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.4 Large Group Host Commercial Solar PV

Table 11. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.046	0.049	0.043	0.041	0.036	0.033	0.031	0.029	0.029	0.029	0.029	0.028	0.028	0.028	0.030
Transmission Charges	0.024	0.025	0.027	0.024	0.025	0.026	0.024	0.026	0.027	0.029	0.031	0.026	0.023	0.024	0.026
Distribution Capacity	0.014	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.012	0.012	0.012	0.012	0.012
Capacity	0.019	0.015	0.008	0.010	0.011	0.011	0.013	0.013	0.013	0.015	0.015	0.015	0.016	0.017	0.015
Distribution Line Losses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Line Losses	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.003	0.003	0.003	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.047	0.048	0.050	0.047	0.042	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – Excluding Environmental	0.121	0.122	0.108	0.105	0.101	0.099	0.097	0.097	0.098	0.101	0.102	0.096	0.094	0.097	0.097
Total – Including Environmental	0.170	0.169	0.156	0.155	0.148	0.140	0.136	0.132	0.133	0.133	0.134	0.128	0.127	0.131	0.133

Table 12. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.

Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.032	-	0.003	0.049	0.038	0.024	-	0.003	0.086	0.076
	6	0.034	-	0.004	0.058	0.047	0.023	-	0.003	0.089	0.079
	7	0.039	-	0.004	0.055	0.043	0.031	-	0.003	0.096	0.086
	8	0.046	-	0.004	0.054	0.042	0.033	-	0.003	0.101	0.091
	9	0.045	-	0.004	0.057	0.045	0.031	-	0.003	0.104	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.046	-	0.004	0.056	0.044	0.021	-	0.002	0.104	0.096
	12	0.046	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.046	-	0.004	0.055	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.155	0.057	0.045	0.023	-	0.003	0.105	0.095
	15	0.045	-	0.159	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.044	-	0.004	0.058	0.045	0.046	-	0.004	0.113	0.099
	19	0.038	-	0.004	0.053	0.041	0.045	-	0.004	0.114	0.100
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.034	-	0.003	0.062	0.052	0.028	-	0.003	0.086	0.078
	6	0.034	-	0.003	0.073	0.063	0.036	-	0.003	0.092	0.082
	7	0.034	-	0.003	0.061	0.050	0.038	-	0.004	0.097	0.087
	8	0.039	-	0.004	0.061	0.049	0.041	-	0.004	0.104	0.093
	9	0.039	-	0.004	0.060	0.049	0.041	-	0.004	0.111	0.100
	10	0.040	-	0.007	0.061	0.050	0.038	-	0.007	0.119	0.108
	11	0.040	-	0.049	0.061	0.050	0.036	-	0.058	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.081	0.130	0.120
	13	0.040	-	0.083	0.075	0.050	0.038	-	0.099	0.143	0.123

	14	0.040	-	0.279	0.062	0.051	0.040	-	0.697	0.138	0.128
	15	0.041	0.723	0.584	0.118	0.050	0.040	0.787	0.297	0.151	0.128
	16	0.041	-	0.121	0.059	0.048	0.044	-	0.146	0.142	0.128
	17	0.041	-	0.113	0.056	0.044	0.052	-	1.252	0.268	0.129
	18	0.042	-	0.094	0.056	0.044	0.061	-	0.115	0.147	0.130
	19	0.041	-	0.055	0.056	0.044	0.064	-	0.068	0.142	0.126
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.030	-	0.003	0.046	0.036	0.034	-	0.003	0.085	0.075
	7	0.031	-	0.003	0.054	0.043	0.039	-	0.004	0.094	0.083
	8	0.040	-	0.004	0.060	0.048	0.048	-	0.005	0.102	0.088
	9	0.041	-	0.004	0.060	0.048	0.047	-	0.005	0.105	0.092
	10	0.041	-	0.004	0.061	0.049	0.041	-	0.004	0.106	0.093
	11	0.041	-	0.004	0.059	0.046	0.042	-	0.004	0.107	0.094
	12	0.041	-	0.004	0.059	0.047	0.042	-	0.004	0.107	0.094
	13	0.041	-	0.004	0.058	0.046	0.044	-	0.004	0.107	0.094
	14	0.041	-	0.004	0.060	0.048	0.045	-	0.004	0.108	0.094
	15	0.040	-	0.004	0.061	0.049	0.045	-	0.004	0.108	0.094
	16	0.040	-	0.004	0.058	0.046	0.050	-	0.005	0.110	0.094
	17	0.036	-	0.323	0.063	0.051	0.048	-	0.005	0.109	0.095
	18	0.036	-	0.004	0.060	0.049	0.048	-	0.004	0.110	0.098
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	-	-	-	-	-	-	-	-	-	-
	8	0.063	-	0.006	0.068	0.050	0.085	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.129	0.106
	10	0.064	-	0.006	0.071	0.053	0.071	-	0.007	0.128	0.108
	11	0.063	-	0.006	0.070	0.052	0.066	-	0.006	0.127	0.107
	12	0.063	-	0.006	0.072	0.055	0.066	-	0.006	0.126	0.106
	13	0.063	-	0.006	0.072	0.054	0.066	-	0.006	0.124	0.104
	14	0.063	-	0.006	0.071	0.053	0.067	-	0.006	0.125	0.104
	15	0.063	-	0.006	0.073	0.055	0.071	-	0.007	0.127	0.103
	16	0.063	-	0.006	0.072	0.053	0.083	-	0.008	0.131	0.104
	17	0.062	-	0.006	0.066	0.048	0.094	-	0.008	0.135	0.108
	18	-	-	-	-	-	-	-	-	-	-
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.5 Micro Hydro

Table 13. Average Annual Avoided Cost Value for Micro Hydro System ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.049	0.053	0.047	0.044	0.040	0.038	0.036	0.035	0.036	0.036	0.036	0.036	0.036	0.036	0.037
Transmission Charges	0.028	0.030	0.032	0.035	0.038	0.040	0.043	0.046	0.049	0.052	0.055	0.060	0.065	0.069	0.074
Distribution Capacity	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006	0.006
Capacity	0.006	0.005	0.003	0.003	0.004	0.003	0.004	0.004	0.004	0.005	0.005	0.005	0.005	0.006	0.005

Distribution Line Losses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Line Losses	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.004	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.048	0.046	0.046	0.050	0.051	0.051	0.046	0.044	0.045	0.041	0.042	0.043	0.042	0.044	0.045
Total – Excluding Environmental	0.107	0.112	0.104	0.105	0.103	0.102	0.104	0.106	0.110	0.113	0.117	0.122	0.126	0.131	0.136
Total – Including Environmental	0.155	0.158	0.150	0.155	0.154	0.152	0.150	0.150	0.155	0.153	0.159	0.165	0.168	0.174	0.181

Table 14. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	0.039	-	0.002	0.056	0.048	0.031	-	0.002	0.090	0.083
	2	0.038	-	0.002	0.058	0.050	0.030	-	0.002	0.087	0.079
	3	0.039	-	0.002	0.052	0.045	0.028	-	0.002	0.084	0.077
	4	0.039	-	0.002	0.052	0.044	0.027	-	0.002	0.083	0.076
	5	0.039	-	0.002	0.049	0.041	0.026	-	0.002	0.084	0.077
	6	0.040	-	0.002	0.055	0.047	0.027	-	0.002	0.088	0.080
	7	0.041	-	0.002	0.052	0.044	0.032	-	0.002	0.094	0.086
	8	0.046	-	0.003	0.050	0.041	0.033	-	0.002	0.098	0.091
	9	0.045	-	0.003	0.053	0.045	0.030	-	0.002	0.100	0.094
	10	0.045	-	0.003	0.052	0.044	0.024	-	0.001	0.101	0.096
	11	0.045	-	0.003	0.051	0.043	0.021	-	0.001	0.101	0.096
	12	0.045	-	0.003	0.049	0.041	0.022	-	0.001	0.101	0.096
	13	0.045	-	0.003	0.050	0.042	0.022	-	0.001	0.100	0.095
	14	0.045	-	0.154	0.053	0.045	0.022	-	0.001	0.101	0.095
	15	0.045	-	0.177	0.052	0.044	0.023	-	0.001	0.102	0.095
	16	0.045	-	0.003	0.053	0.045	0.028	-	0.002	0.104	0.095
	17	0.045	-	0.003	0.053	0.044	0.040	-	0.002	0.107	0.096
	18	0.046	-	0.003	0.055	0.046	0.048	-	0.003	0.111	0.099

	19	0.047	-	0.156	0.054	0.045	0.055	-	0.003	0.118	0.106
	20	0.047	-	0.003	0.051	0.041	0.055	-	0.498	0.121	0.108
	21	0.046	-	0.003	0.056	0.047	0.055	-	1.069	0.119	0.106
	22	0.046	-	0.003	0.052	0.043	0.052	-	0.003	0.111	0.099
	23	0.045	-	0.003	0.051	0.043	0.047	-	0.002	0.102	0.092
	24	0.040	-	0.002	0.052	0.045	0.040	-	0.002	0.096	0.087

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	0.034	-	0.002	0.050	0.045	0.036	-	0.002	0.092	0.086
	2	0.034	-	0.002	0.055	0.049	0.035	-	0.002	0.088	0.082
	3	0.034	-	0.002	0.058	0.052	0.033	-	0.002	0.085	0.079
	4	0.034	-	0.002	0.058	0.052	0.033	-	0.002	0.084	0.078
	5	0.034	-	0.002	0.061	0.055	0.033	-	0.002	0.085	0.079
	6	0.034	-	0.002	0.061	0.055	0.031	-	0.002	0.087	0.081
	7	0.034	-	0.002	0.055	0.048	0.035	-	0.002	0.093	0.086
	8	0.039	-	0.002	0.055	0.049	0.038	-	0.002	0.100	0.093
	9	0.039	-	0.002	0.055	0.048	0.038	-	0.002	0.107	0.100
	10	0.039	-	0.004	0.055	0.049	0.036	-	0.005	0.114	0.107
	11	0.040	-	0.040	0.056	0.050	0.034	-	0.047	0.120	0.114
	12	0.040	-	0.055	0.058	0.052	0.036	-	0.066	0.125	0.119
	13	0.040	-	0.067	0.112	0.050	0.037	-	0.080	0.178	0.121
	14	0.040	-	0.273	0.057	0.050	0.038	-	0.700	0.133	0.125
	15	0.040	0.528	0.469	0.098	0.050	0.039	0.575	0.178	0.142	0.126
	16	0.041	-	0.107	0.055	0.048	0.043	-	0.129	0.136	0.126
	17	0.041	-	0.105	0.052	0.044	0.051	-	1.189	0.237	0.128
	18	0.042	-	0.083	0.052	0.044	0.059	-	0.101	0.142	0.128
	19	0.041	-	0.058	0.053	0.045	0.066	-	0.071	0.141	0.127
	20	0.041	-	0.014	0.055	0.047	0.063	-	0.017	0.139	0.126
	21	0.041	-	0.022	0.056	0.048	0.060	-	0.027	0.138	0.126
	22	0.041	-	0.011	0.056	0.049	0.056	-	0.013	0.126	0.115
	23	0.040	-	0.002	0.056	0.050	0.049	-	0.003	0.108	0.100
	24	0.034	-	0.002	0.053	0.047	0.040	-	0.002	0.097	0.091

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	0.041	-	0.002	0.047	0.038	0.053	-	0.003	0.097	0.083
	2	0.040	-	0.002	0.055	0.046	0.052	-	0.003	0.093	0.079
	3	0.041	-	0.002	0.055	0.046	0.052	-	0.003	0.091	0.077
	4	0.040	-	0.002	0.052	0.043	0.051	-	0.003	0.089	0.076
	5	0.040	-	0.002	0.051	0.043	0.050	-	0.003	0.089	0.076

	6	0.039	-	0.002	0.049	0.041	0.049	-	0.003	0.092	0.079
	7	0.039	-	0.002	0.052	0.044	0.050	-	0.003	0.098	0.085
	8	0.044	-	0.003	0.057	0.048	0.054	-	0.003	0.103	0.090
	9	0.044	-	0.003	0.057	0.048	0.052	-	0.003	0.105	0.093
	10	0.044	-	0.003	0.057	0.048	0.047	-	0.002	0.106	0.094
	11	0.044	-	0.003	0.055	0.046	0.046	-	0.002	0.107	0.094
	12	0.043	-	0.003	0.054	0.046	0.046	-	0.002	0.106	0.094
	13	0.043	-	0.003	0.055	0.046	0.048	-	0.003	0.106	0.094
	14	0.043	-	0.003	0.056	0.047	0.050	-	0.003	0.107	0.094
	15	0.043	-	0.003	0.058	0.048	0.050	-	0.003	0.108	0.094
	16	0.043	-	0.003	0.055	0.046	0.054	-	0.003	0.109	0.094
	17	0.043	-	0.126	0.059	0.050	0.058	-	0.003	0.113	0.098
	18	0.044	-	0.213	0.059	0.050	0.061	-	0.003	0.121	0.106
	19	0.044	-	0.003	0.056	0.046	0.062	-	0.717	0.126	0.110
	20	0.044	-	0.169	0.057	0.048	0.061	-	0.967	0.128	0.112
	21	0.045	-	0.003	0.057	0.047	0.061	-	0.003	0.123	0.107
	22	0.046	-	0.003	0.058	0.048	0.062	-	0.003	0.115	0.099
	23	0.046	-	0.003	0.057	0.047	0.061	-	0.003	0.108	0.092
	24	0.041	-	0.002	0.048	0.038	0.055	-	0.003	0.102	0.088

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	0.058	-	0.003	0.063	0.050	0.079	-	0.004	0.109	0.090
	2	0.057	-	0.003	0.059	0.045	0.075	-	0.004	0.106	0.087
	3	0.057	-	0.003	0.058	0.045	0.072	-	0.004	0.103	0.085
	4	0.057	-	0.003	0.058	0.045	0.071	-	0.004	0.102	0.084
	5	0.057	-	0.003	0.057	0.044	0.070	-	0.004	0.104	0.085
	6	0.058	-	0.003	0.069	0.055	0.074	-	0.004	0.108	0.088
	7	0.059	-	0.003	0.079	0.065	0.083	-	0.004	0.115	0.094
	8	0.065	-	0.004	0.068	0.053	0.089	-	0.004	0.123	0.102
	9	0.065	-	0.004	0.066	0.052	0.088	-	0.004	0.126	0.106
	10	0.065	-	0.004	0.068	0.054	0.073	-	0.004	0.125	0.108
	11	0.065	-	0.004	0.067	0.054	0.068	-	0.003	0.124	0.107
	12	0.065	-	0.004	0.070	0.056	0.069	-	0.003	0.123	0.106
	13	0.065	-	0.004	0.070	0.056	0.068	-	0.003	0.121	0.104
	14	0.065	-	0.004	0.069	0.056	0.071	-	0.004	0.123	0.103
	15	0.065	-	0.004	0.071	0.057	0.073	-	0.004	0.124	0.102
	16	0.065	-	0.004	0.070	0.055	0.085	-	0.004	0.128	0.104
	17	0.066	-	0.004	0.067	0.052	0.100	-	0.005	0.142	0.116

	18	0.067	-	0.156	0.066	0.051	0.108	-	0.005	0.169	0.142
	19	0.067	-	0.323	0.067	0.051	0.110	-	1.620	0.185	0.158
	20	0.067	-	0.004	0.068	0.053	0.109	-	0.005	0.184	0.157
	21	0.066	-	0.004	0.067	0.052	0.108	-	0.005	0.167	0.141
	22	0.066	-	0.004	0.070	0.055	0.105	-	0.005	0.144	0.119
	23	0.065	-	0.004	0.073	0.058	0.100	-	0.005	0.127	0.102
	24	0.059	-	0.003	0.087	0.073	0.090	-	0.004	0.116	0.094

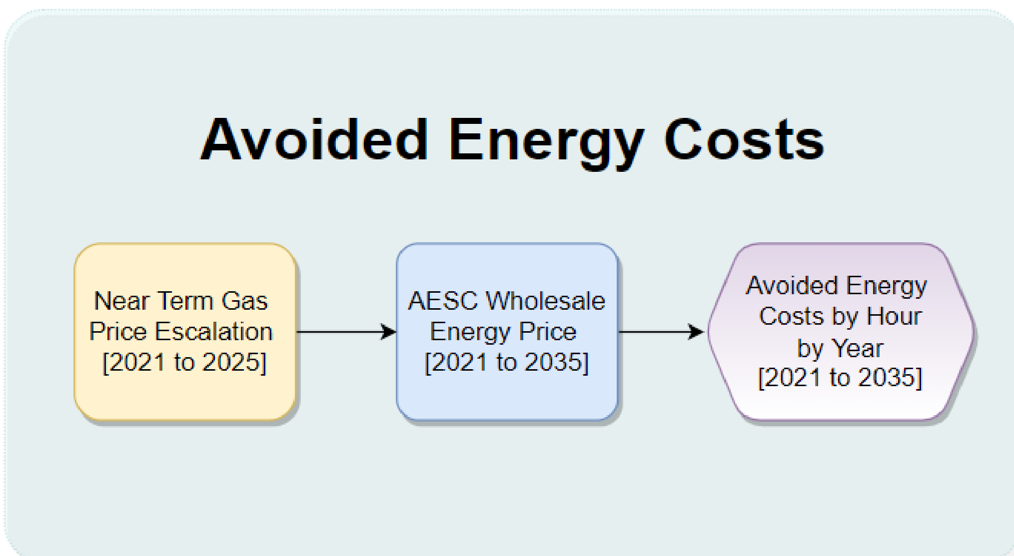
C. Detailed Base Value Stack Methodologies

C.1 Energy

C.1.1 Rationale

This avoided cost criteria represents the cost of energy that would otherwise be generated and procured through the ISO-NE wholesale energy market in the absence of load reductions attributed to distributed generation resources. Hourly LMPs in the New Hampshire zone reflect the displaced variable generation costs associated with the marginal resource(s) in the system and are thus an appropriate measure of the value of avoided energy in the state. The AESC 2021[1] study's hourly wholesale energy avoided cost forecasts are based on detailed modelling, which New England stakeholders vetted, and using this approach is consistent with EE methodology.

C.1.2 Model Map



C.1.3 Avoided Cost Methodology

Step 1: Forecasted Avoided Energy Prices

- Start with the avoided wholesale energy price forecast from the AESC 2021 study, which includes 8760 hourly energy prices for New Hampshire for 2021-2035.[2]

[1] The VDER study uses the latest data from the AESC October 2021 Release (AESC 2021 public files | Powered by Box)

[2] Values from the AESC Counterfactual #2 scenario (and workbook) are used here and throughout the study, as it is deemed the most appropriate of the four counterfactual scenarios included in the AESC 2021 study. The AESC Counterfactual

- Adjust the forecast during the near-term (2021 to 2025) to reflect current and anticipated increases in natural gas prices.[3]

C.1.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic Energy Prices	ISO-NE Day-Ahead Pricing Reports by zone
Forecasted Energy Prices	AESC 2021 study (Counterfactual #2)[4]
Updated Natural Gas Prices	NYMEX Futures for Henry Hub

Assumptions and Notes

- Embedded environmental compliance costs – RGGI cap and trade and SO_2– are included in avoided energy costs.
- Transmission line losses (beyond losses embedded in LMPs), distribution line losses, and the wholesale risk premium are considered separate avoided cost criteria and are thus not accounted for in the avoided energy methodology.

Scenario #2 includes impacts of energy efficiency, active demand response, transportation electrification, and distributed generation but excludes the impact from building electrification.

[3] The AESC uses NYMEX futures prices for the Henry Hub and historical basis differential between Henry Hub and New England trading hubs to establish its short-term natural gas commodity price forecast. Natural gas prices have increased since the AESC 2021 study was finalized, so we updated the short-term natural gas prices based on more recent Henry Hub futures prices. Specifically, we calculated the market heat rate and multiplied this by the higher natural gas prices to derive the new wholesale energy prices. Data was accessed as of February 2022.

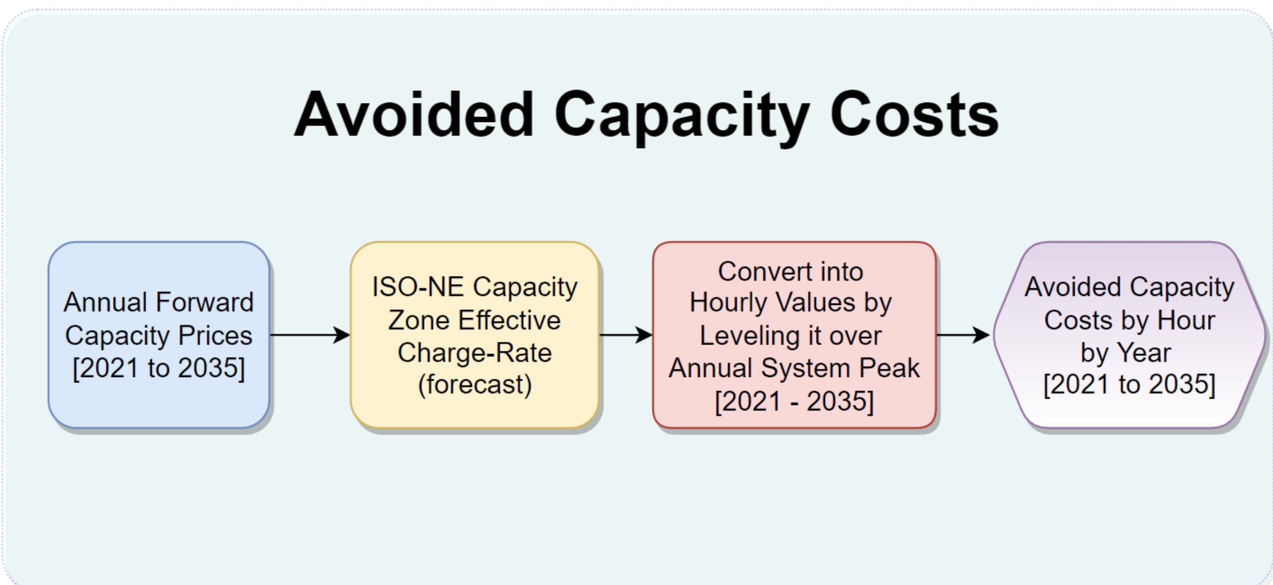
[4] For the NH VDER Study, the ideal avoided cost values would be estimated under a counterfactual scenario that includes region-wide EE, ADR, BE, and transportation electrification impacts along with non-New Hampshire distributed generation impacts. This scenario, unfortunately, is not readily available. However, in lieu of such a scenario, the most appropriate set of AESC avoided costs to utilize for the NH VDER Study is the ones emanating from Counterfactual #2 as this scenario is likely to be most representative of a scenario that includes all demand-side resource impacts sans New Hampshire DG impacts. This is because Counterfactual #2 only excludes the impacts of BE, which is expected to have the smallest influence on avoided costs of importance to the NH VDER study relative to EE and ADR.

C.2 Capacity

C.2.1 Rationale

The VDER Study is primarily focused on estimating the avoided cost impacts from distributed energy resources on New Hampshire regulated load-serving entities. The avoided capacity cost criterion represents the cost of generation capacity that would otherwise be procured through the ISO-NE Forward Capacity Market (FCM). Since individual behind-the-meter distributed generation resources do not qualify for or participate in the FCM[5], these resources provide indirect benefits by reducing ISO-NE peak demand – to the extent that DG production is coincident with system peak – and thus the amount of generation capacity that is procured through the market. From the utility perspective, if customer-sited distributed energy resources reduce utility load during the annual coincident peak hour, the capacity prices assessed on New Hampshire's utilities are reduced, resulting in an in-state avoided cost. In other words, avoidance or reduction of capacity market charges is the basis for the avoided cost calculations, to the extent that DG reduces utilities' peak hourly load in a given year.

C.2.2 Model Map



C.2.3 Avoided Cost Methodology

Step 1: Establish Annual Effective Cleared Capacity Prices (2021-2035)

- We start with the cleared capacity price forecast (2021 to 2035) from the AESC 2021 study and multiply the forecast prices by 1 + the reserve margin (%0.[6] To account for the actual capacity

[5] FERC Order No. 2222 will remove the barriers for aggregated DERs from competing on a level playing field in the organized capacity, energy and ancillary services markets run by regional grid operators.

[6] When establishing market-wide capacity needs, ISO-NE includes a planning reserve margin. This margin provides a buffer, ensuring that there will be adequate capacity should system peak demand be greater than forecasted need. AESC estimates the planning reserve margin to be 14.2% based on actual results from recent auctions. The forecast FCA prices are

charges assessed on utilities, the cleared capacity prices are adjusted using the most recent differential between the FCM Regional Net Clearing Price and the Effective Charge-Rate short-term forecast.[7] The result is the effective cleared capacity prices from 2021 to 2035.

Step 2: Distribute Annual Avoided Capacity Values by Hour

- Identify the ISO-NE's system peak hour by year and forecast any expected shift (due to renewables and increases in beneficial electrification) from 2021 to 2035. Each system year's effective cleared capacity market costs are then distributed over the ISO-NE's annual system peak hour to generate hourly avoided cost values.

C.2.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic Capacity Prices	ISO-NE FCM annual auction results by zone
Forecasted Capacity Prices	AESC 2021 study
Reserve Margin	AESC 2021 study (14.2%)
EffectiveCharge-Rate (by zone)	ISO-NE FCM Net Regional Clearing Price and Effective Charge-Rate Forecast.

Assumptions and Notes: Transmission and distribution line losses and the wholesale risk premium are considered separate avoided cost criteria and are thus not accounted for in the avoided capacity methodology.

multiplied by 1 + the planning reserve margin (114.2%) because each MW that is reduced using DERs *also* reduces the planning reserve margin requirement. So, for example, a 1 MW reduction from DERs results in a 1.142 MW reduction in capacity that must be met through the FCA. The avoided costs are increased to represent the value of each MW reduction, accounting for the planning reserve impacts.

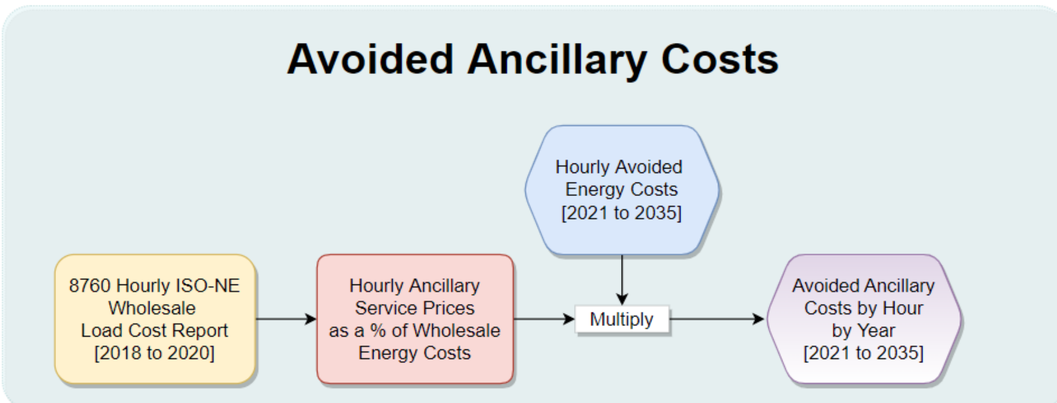
[7] Because Forward Capacity Auctions are held three years in advance, the actual cost of capacity procured on the market at the time that it is needed can vary from the FCA clearing price. The effective charge rate is a factor that is forecasted by ISO-NE which represents the difference between the future-looking auction prices and the actual prices at which resources are procured. Effective charge forecasts are only available on a short-term basis, however. To calculate expected actual capacity prices over the study period, the study team assessed the near-term relationship between the effective charge forecast and the FCA. The team then applied this relationship to the remaining FCA forecast years, considering the planning reserve margin, to estimate actual capacity prices over the study period.

C.3 Ancillary Services and Load Obligation Charges

C.3.1 Rationale

This study is focused on the avoided cost impacts on New Hampshire-regulated electric distribution utilities and the load-serving entities providing electric supply to the utilities' customers. The AESC does not calculate avoided costs for ancillary services and hence was not used as the basis for this methodology. From the utility perspective, if customer-sited distributed energy resources reduce utility load, then ancillary service charges and other load obligation charges assessed on New Hampshire's utilities and LSEs are reduced, resulting in an in-state avoided cost.

C.3.2 Model Map



C.3.3 Avoided Cost Methodology

Step 1: Calculate Historic Hourly Ancillary Service Prices (2018-2020)

- Calculate ancillary service and wholesale load obligation costs[8] as a percentage of hourly energy costs by service or charge.[9]

- For each historic year (2018 to 2020), calculate an hourly ancillary service and load obligation cost as a percentage of wholesale energy cost for each respective hour.

- Average hourly ancillary costs (as a percentage) for each type of ancillary service and load obligation charge across the three historic years to generate an 8760 ancillary avoided cost template.

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[8] The ancillary services included are First and Second Contingency, Forward and Real Time Reserves, Regulation, Inadvertent energy, Net Commitment Period Compensation (NCPC), Auction Revenue Rights (ARR) revenues, NEPOOL expenses, etc. – as charged to wholesale load obligations). Ancillary service cost data was obtained from ISO-NE's Wholesale Load Cost reports for the NH zone.
[9] Ancillary service cost data obtained from ISO-NE's Wholesale Load Cost reports for the NH zone.

Step 2: Forecast Hourly Ancillary Service Prices (2021-2035)

- Multiply the 8760 ancillary avoided cost template from Step 1 by the forecasted wholesale energy prices (2021 to 2035) to develop hourly ancillary service price and wholesale load obligation avoided cost projections.

C.3.4 Inputs, Assumptions, and Notes

Inputs

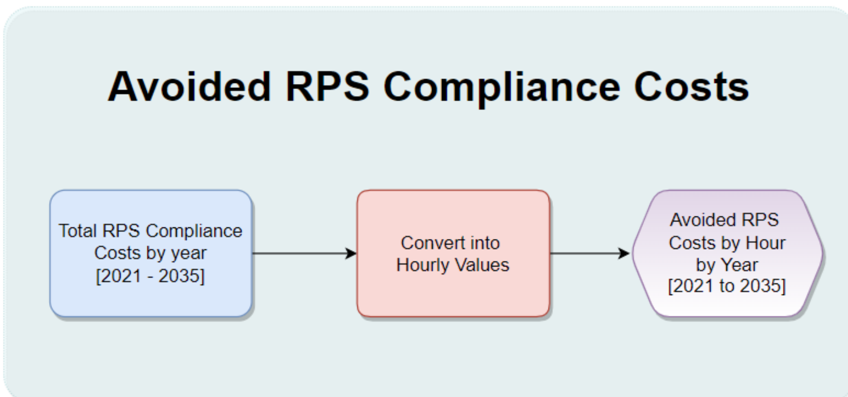
Inputs	Sources
Wholesale Hourly Energy Prices	AESC 2021 study (Counterfactual #2)
Wholesale Ancillary and Load Charges	ISO-NE wholesale monthly reports by zone

C.4 RPS Compliance

C.4.1 Rationale

The AESC Study provides RPS compliance avoided cost forecasts by state, which quantify the avoided costs attributable to reducing the load on which the RPS obligations are assessed. The value of RPS avoided costs is calculated for each sector, accounting for the share of energy produced by DG that is expected to be consumed behind-the-meter and the share expected to be exported back to the grid.[10] Therefore, for this analysis, it is assumed that the avoided RPS compliance costs (per MWh) are equal to the weighted statewide compliance costs across all RPS classes as forecast in the AESC 2021 Study.

C.4.2 Model Map



Overview: The AESC provides RPS compliance avoided cost forecasts by state which summarize the expected cost of meeting RPS obligations

C.4.3 Avoided Cost Methodology

Step 1: Calculate the Total Annual RPS Compliance Costs (2021-2035)

- Sum the RPS compliance costs from the AESC 2021 study for each New Hampshire RPS Class, for each study year (2021 to 2035), under Counterfactual #2.[11] The following RPS classes are included:

RPS Class	Eligibility Notes
Class I	Includes New Non-Thermal
Class I (Thermal)	Thermal Carve out
Class II	New Solar Only
Class III	Existing biomass and methane
Class IV	Existing Small hydro

[10] RPS compliance costs are proportional to retail sales. Reductions in retail sales through behind-the-meter consumption reduces RPS compliance costs, while electricity exported back to the grid does not.
[11] The RPS compliance costs are weighted based on the RPS requirement and expressed as a percentage for each Class.

- Convert to customer sector-specific hourly values by multiplying RPS compliance costs by the behind-the-meter consumption expected for each sector, as outlined in the table below. Apply the avoided cost value to all hours in each respective study year.

Customer-Generator Type	Behind-the-Meter Consumption (% of Total Production) [12]
Residential	38% (hourly netting)
Commercial	24% (hourly netting)
Large Group Host Commercial Solar	0%
Micro Hydro	0%

C.4.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
RPS Compliance Costs (All Classes)	AESC 2021 study (Counterfactual #2)

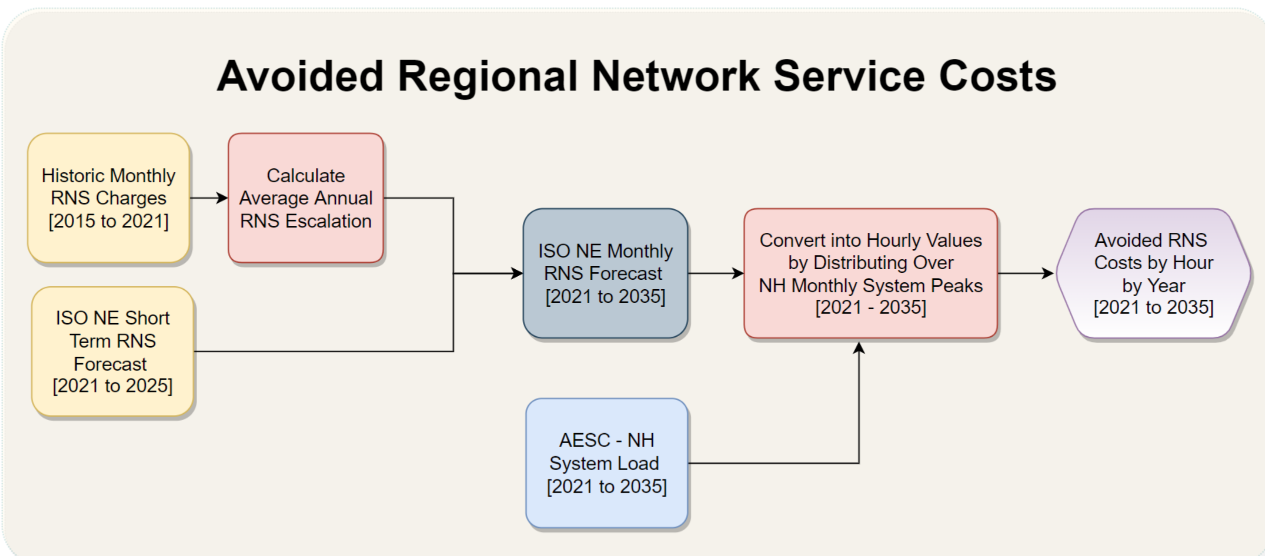
[12] For the purpose of the value stack assessment, we calculated the hourly netting from a south-facing solar PV system then applied this assumption to the west-facing and south-facing solar with storage systems within a given sector. Although the current NEM tariff in New Hampshire uses monthly netting for systems less than 100 kW, hourly netting is an emerging practice used in VDER studies conducted in other jurisdictions given its ability to realize temporal values more granularly.

C.5 Transmission Charges

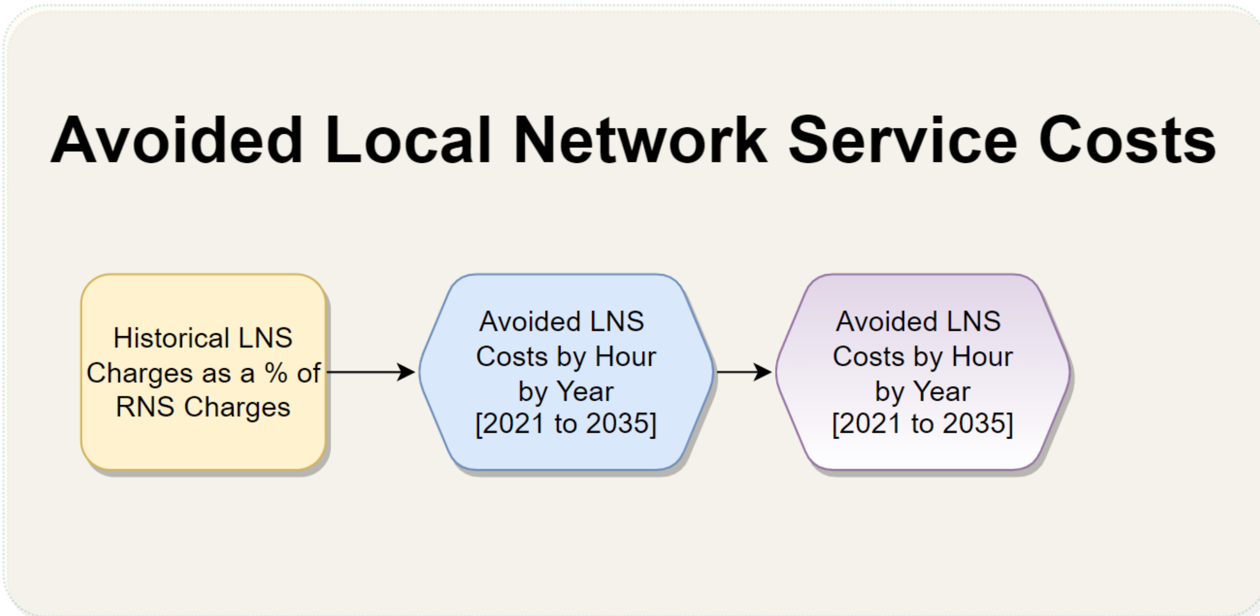
C.5.1 Rationale

RNS and LNS charges are collected to cover the cost of upgrading and maintaining regional bulk transmission infrastructure and localized facilities. Costs are assessed monthly based on a utility's demand that coincides with the peak load hour on the relevant transmission system. Therefore, from a New Hampshire utility perspective, reductions in monthly coincident system peak load attributable to DG resource production will decrease the allocation of RNS and LNS charges assessed to New Hampshire utilities, and thus to ratepayers in the state, representing avoided transmission charges based on DG production. Short-term NEPOOL Reliability Committee/Transmission Committee transmission charge forecasts were found to exceed AESC avoided cost forecasts.[13] Given the discrepancy, these short-term forecasts were used, as described below.

C.5.2 Model Map



[13] The 2021 AESC estimated the PTF avoided cost as $99 per kW-year (2021$). The RNS charge in 2021, as approved by FERC was $140 per kW-year from June 2021 onwards: https://www.iso-ne.com/static-assets/documents/2016/05/rto_bus_prac_sec_2.pdf



Overview: Load cost reports published by ISO-NE used to establish historic monthly RNS and LNS charges in $/kW-month (2016 to 2020).

C.5.3 Avoided Cost Methodology

Step 1: Establish Historic Monthly RNS and LNS Rates (2016-2020)

- Use ISO-NE Load Cost Reports to establish historic monthly RNS and LNS rates for 2016-2020. Use this to calculate historic LNS charges as a portion of historic RNS charges.[14] Include all RNS and LNS cost categories (i.e., infrastructure, reliability, and administrative cost categories) that are allocated based on Monthly Regional Network Load. Adjust rates to $2021 real values for comparison purposes.

Step 2: Establish Projected Monthly RNS and LNS Rates (2021-2035)

- Forecast forward-looking monthly RNS rates using 1) short-term RNS forecasts published by ISO-NE (for near-term study years),[15] 2) the assumption that LNS charges are a fixed percentage of RNS charges, based on historic trends.[16]

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[14] The LNS charges vary considerably from month to month so are a challenge to forecast. As a simplifying approach, we reviewed historic monthly LNS charges as a % of RNS charges over the 2016 to 2020 time frame. On average, LNS charges were 22% of RNS charges during this time frame.

[15] NEPOOL Reliability Committee/Transmission Committee. (2020). RNS Rates: 2020-2024 PTF Forecast. Source: https://www.iso-ne.com/static-assets/documents/2020/08/a02_tc_2020_08_19_rns_5_year_forecast.pptx

[16] Here, LNS charges were assumed to remain constant at 22% of RNS charges. In reality, LNS charges are not a fixed percent of RNS charges and in fact fluctuate from month-to-month – this is a simplifying assumption that uses the average LNS charges as a percent of RNS charges from 2016-2020.

Step 3: Distribute Monthly RNS and LNS Charges by Hour

A) Establish Monthly Peak Load Hours

- Determine each utility's historic monthly Regional Network Load (RNL) – i.e., demand on the New Hampshire transmission network coinciding with the system peak load for each month. Then, based on historic RNL data (over the past 5 years), define the peak hour for each month in the year.

B) Convert Monthly into Hourly Values

- Distribute monthly RNS and LNS charges over the monthly peak hours by multiplying the calculated rates by utility peak contributions across the study year to generate hourly avoided cost values.

Step 4: Establish Hourly Avoided Transmission Charge Costs by Year

- Repeat this process for each forecasted monthly RNS and LNS charge to generate hourly avoided transmission charges for each year of the study period.

C.5.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic RNS Charges	ISO-NE Load Cost Reports
Historic LNS Charges	Utility data request; docket filings
Forecasted RNS Rates	NEPOOL Reliability Committee/Transmission Committee RNS Rates: 2020-2024 PTF Forecast[15]
Regional Network Load	ISO-NE RNL Reports[17]

C.6 Transmission Capacity

This criterion was assessed qualitatively. The rationale and the sources used to inform this assessment are included in the body of the report.

C.7 Distribution Capacity

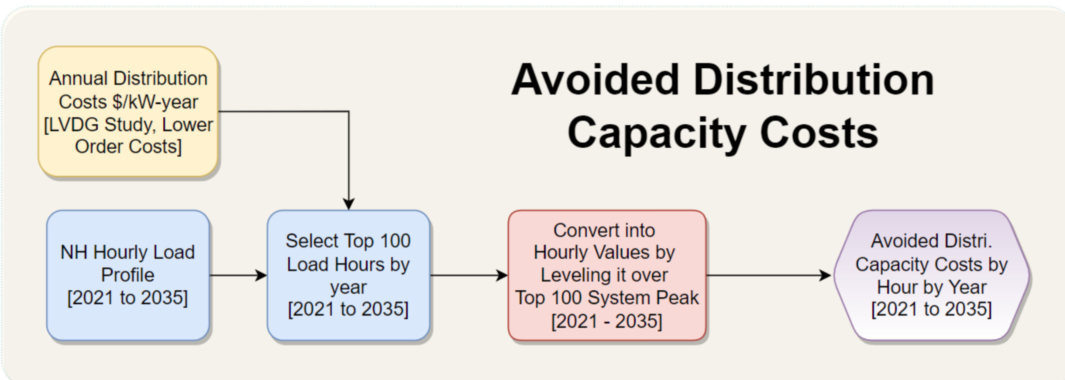
C.7.1 Rationale

Energy produced by net-metered DG has the potential to avoid or defer distribution capacity upgrade costs if it reduces load at hours associated with reliability concerns (i.e., during peak hours that would otherwise drive investments in distribution system upgrades). In connection with the Locational Value

[17] ISO-NE. (2021). Monthly Regional Network Load Cost Report and Historical Regional Network Load Cost Report. Accessible online at: https://www.iso-ne.com/markets-operations/market-performance/load-costs

of Distributed Generation (LVDG) study,[18] New Hampshire's utilities estimated the capital investments that would be required at various substations or circuits as a result of capacity deficiencies based on relevant planning criteria. Beyond those upgrades required to address capacity deficiencies, some investments are also expected to be required to address non-capacity upgrades (e.g., those related to reliability or performance issues), which the LVDG study did not address. Because the capacity-related deficiencies and the related potential avoided costs, reviewed in the LVDG study are highly locational, those costs are not considered in this study, which reviews system-wide avoided costs only.

C.7.2 Model Map



C.7.3 Avoided Cost Methodology

Step 1: Annual Distribution Capacity Costs

- Assess actual and planned distribution-related capital expenditures, by utility, to determine which expenditures are load-related and what components (lower-order and higher-order investments) are included.

- Review utility capital expenditure data and compare it to the LVDG Study results under the base case, which is used to determine which lower-order distribution system investments are not accounted for in that study but could be avoided or deferred as a result of load reductions.

- Use utility data and the LVDG Study to develop an annual per unit ($/kW), system-wide proxy estimate of annual system-wide avoided distribution costs. Use an escalation factor based on inflation to estimate annual distribution capacity costs beyond planned investment needs.[19]

Step 2: Distribute Annual Avoided Distribution Capacity Value by Hour

[18] Guidehouse Inc. (2020). New Hampshire Locational Value of Distributed Generation Study. Accessible online at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF#:~:text=The%20New%20Hampshire%20Public%20Utilities%20Commission%20%28the%20Commission%29,metering%20docket.%20In%20its%20February%202019%20order%2C%201

[19] To the extent possible we used annual avoided cost forecasts from the LVDG study, which are based on a Real Economic Carrying Charge approach. Forecasted lower-order distribution costs were inflation-adjusted.

A) Establish New Hampshire System Load Profiles

- Use New Hampshire zone load profiles in the AESC 2021 study for system load profiles for 2021 through 2035.

B) Establish Distribution of Load During Peak Hours

- Assume distribution system upgrades are driven by reliability concerns associated with the highest distribution peak load hours on the system. Rank the top 100 hours in each year (2021-2035) to select the distribution system peak hours.

- Establish the weighted average of the total sub-set of load during each month/hour pairs. For example, the table below (based on NH 2021 system load) demonstrates that, during the highest load hours, 3.3 percent of load occurs in January from 5-7pm (i.e., hour beginning at 17).

		Month											
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	Number of Days:	*15*	*6*	*0*	*0*	*0*	*5*	*13*	*11*	*2*	*0*	*0*	*11*
Hour Beginning	**0**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	8	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.4%	1.1%	0.0%	0.0%	0.0%	0.0%
	9	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.4%	1.6%	0.0%	0.0%	0.0%	0.0%
	10	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	2.7%	2.1%	0.0%	0.0%	0.0%	0.0%
	11	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.0%	2.2%	0.0%	0.0%	0.0%	0.0%
	12	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.2%	0.0%	0.0%	0.0%
	13	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
	14	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
	15	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
	16	0.2%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.4%
	17	3.3%	0.4%	0.0%	0.0%	0.0%	0.7%	3.0%	2.4%	0.4%	0.0%	0.0%	2.4%
	18	3.3%	1.3%	0.0%	0.0%	0.0%	0.7%	2.7%	2.1%	0.4%	0.0%	0.0%	2.4%
	19	2.3%	0.8%	0.0%	0.0%	0.0%	0.7%	2.3%	1.9%	0.4%	0.0%	0.0%	1.7%
	20	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	2.0%	2.1%	0.2%	0.0%	0.0%	0.4%
	21	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.0%	1.6%	0.0%	0.0%	0.0%	0.0%
	22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%
	23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

C) Establish Hourly Avoided Distribution Costs by Year

- Distribute the annual $/kW avoided distribution cost from Step 1 across hours in a given year based on the peak load hour determination performed in Step 2.B.
  - Note: If a DG system's output covered all of the peak hours, it would realize 100% of the avoided distribution cost value.

- Complete this process for each year of the study through 2035.

C.7.4 Inputs, Assumptions, and Notes

Inputs

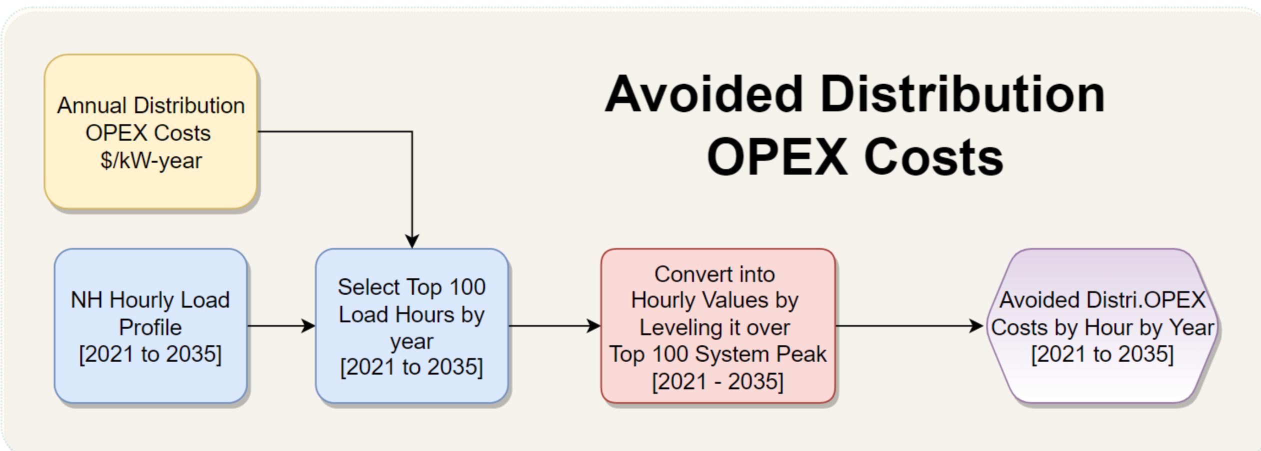
Inputs	Sources
Distribution Capital Expenditure Proxy Value	Utility data and interviews
	LVDG Study
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

C.8 Distribution System Operating Expenses

C.8.1 Rationale

Utilities incur costs to maintain the safe and reliable operation of distribution facilities, which includes maintenance of substations, wires, and poles and repairs and replacements of portions of the distribution system over time. These costs are variable and partially a function of the volume of energy transferred through the system. While this criterion may be a cost and/or avoided cost stream – reflecting an increase or decrease in costs associated with infrastructure and services as a result of DG deployment – for this assessment, we assume that it is a positive avoided cost value and that any costs incurred rather than avoided are achieved under the T&D System Upgrades criterion.

C.8.2 Model Map



C.8.3 Avoided Cost Methodology

Step 1: Annual Distribution OPEX Costs

Ask the utilities to identify distribution system operating expense budget items that could be offset through reduced load. Normalize these costs by expected load increases during the same time period.

Step 2: Distribute Annual Avoided Distribution OPEX Value by Hour

- Assume distribution system operational costs are largely driven by the highest load hours on the system. Rank the top 100 hours in each year (2021-2035) to select the distribution system peak hours.
- Distribute the annual $/kW avoided distribution cost across hours in a given year based on the peak load hour determination performed for the Distribution Capacitycriterion.

C.8.4 Inputs, Assumptions, and Notes

Inputs

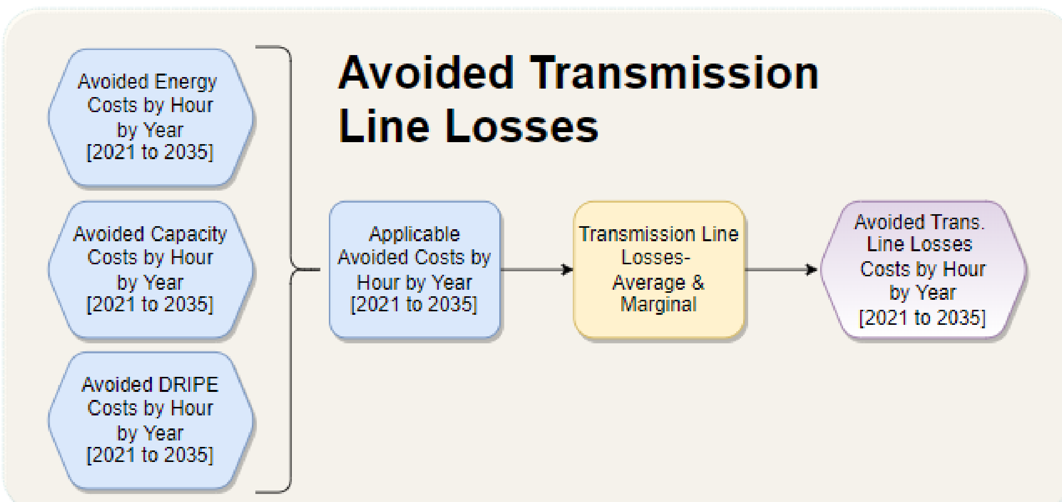
Inputs	Sources
Distribution OPEX Expenditure Proxy Value	Utility data and interviews
	FERC Form 1 Filings
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

C.9 Transmission Line Losses

C.9.1 Rationale

The electricity generated by customer-sited DG resources reduces the amount of energy that would otherwise be distributed through the transmission network. Any surplus energy exported to the system from the DG resources is assumed to be contained within the distribution network, and therefore no transmission backflow occurs due to surplus energy. The avoided transmission line losses apply to the total energy produced by the distributed energy resource. To note, this avoided cost criterion is a cumulative value, incorporating line loss values from all relevant avoided cost criteria: energy, capacity, and wholesale market price suppression. In other words, any inherent value from avoiding transmission line losses attributable to those other criteria has been pulled out (to avoid double-counting) and is included here in this stand-alone transmission line loss criterion.

C.9.2 Model Map



C.9.3 Avoided Cost Methodology

Step 1: Establish an Appropriate Line Loss Factor

- Assess transmission line loss factors from NH electric distribution utilities, AESC 2021, and other relevant valuation studies to determine an appropriate system-wide transmission line loss factor.
- Apply marginal line loss factors to the top 100 NH system peak hours in a year, and average line loss values to the remaining hours.[20]

[20] Line losses vary as a function of grid conditions. During peak loading periods losses can be higher as a result of increased current flows. Average transmission line losses were estimated to be 2.5% while marginal line losses were estimated to be 3.75% (1.5 times the average line loss factors). This assumption was established in a previous study from the Regulatory Assistance Project (RAP) available here.

Step 2: Calculate Historic and Forecasted Hourly Avoided Costs

- Multiply the transmission line loss factor for a given hour by the following avoided cost values for that hour to determine the hourly avoided transmission line loss values:[21]
    - Hourly avoided energy costs (See C.1.)
    - Hourly avoided capacity costs (See C.2.)
    - Hourly avoided DRIPE (See C.11.)

C.9.4 Inputs, Assumptions, and Notes

Inputs:

Inputs	Sources
Transmission Line Losses	AESC 2021 study, NH Utility Data Request (primary), RAP Study (secondary)
NH System Load Profiles	AESC 2021 study, NH Utilities

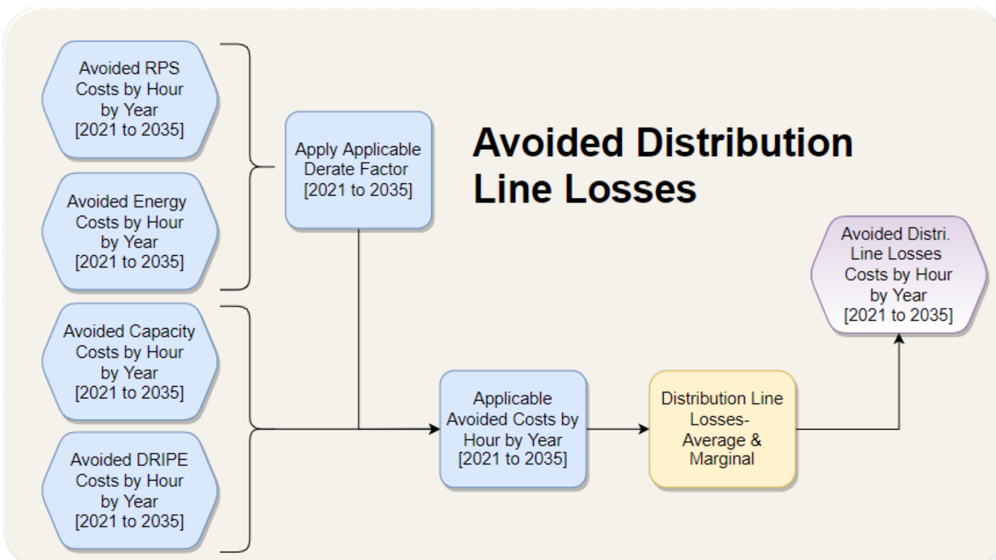
[21] This is consistent with the approach laid out in Table 136 in the AESC.

C.10 Distribution Line Losses

C.10.1 Rationale

The electricity generated by customer-sited DG resources reduces the amount of energy that would otherwise be distributed through the distribution network. Any surplus energy exported back to the grid is assumed to be distributed within the distribution network. Therefore, the avoided distribution line losses apply only to the behind-the-meter or self-consumed portion of the energy produced by the distributed energy resource. To note, this avoided cost criterion is a cumulative value, incorporating line loss value from all relevant avoided cost criteria: energy, capacity, RPS compliance and wholesale market price suppression. In other words, any inherent value from avoiding distribution line losses attributable to those other criteria has been pulled out (to avoid double-counting) and is included here in this stand-alone distribution line loss criterion.

C.10.2 Model Map



C.10.3 Avoided Cost Methodology

Step 1: Establish an Appropriate Line Loss Factor

- Gather sector-specific distribution line loss factors from New Hampshire electric distribution utilities. Apply sector-specific marginal line loss factors to the top 100 NH system peak hours in a year, and sector-specific average line loss factors to the remaining hours.[22]

[22] Line losses vary as a function of grid conditions. During peak loading periods losses can be higher because of increased current flows. Average distribution line losses were estimated to be 7.5% for the residential sector and between 4.4% and 6.4% commercial sector, while marginal line losses were estimated to be 1.5 times the average line loss factors. This assumption was established in a previous study from the Regulatory Assistance Project (RAP) available here.

Step 2: Apply Distribution Line Losses

- Calculate an appropriate derate factor – which is used to reduce the volume of energy produced such that line loss avoided costs only apply to energy that is consumed behind-the-meter – for each customer class and system archetype.
- Calculate line losses for each customer-generator sector and for each hour by multiplying the line loss factor for a given hour by the following avoided cost values in that hour and the derate factor to determine the hourly avoided distribution line loss values:
    - Hourly avoided energy costs (See C.1.)
    - Hourly avoided capacity costs (See C.2.)
    - Hourly avoided RPS costs (See C.4.)
    - Hourly avoided DRIPE (See C.11.)

C.10.4 Inputs, Assumptions, and Notes

Inputs

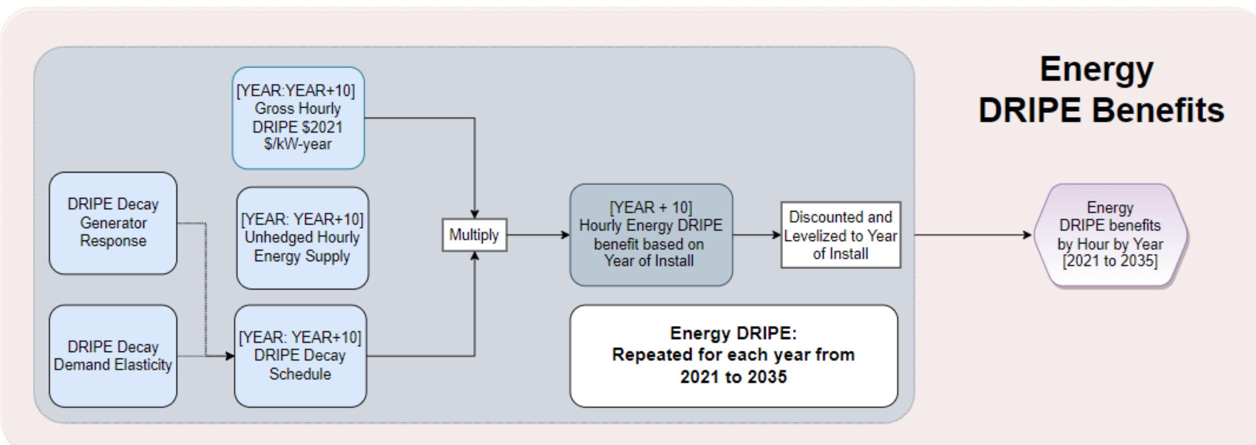
Inputs	Sources
Distribution Line Losses	AESC 2021 study, NH Utility (primary), RAP Study (secondary)
NH System Load Profiles	AESC 2021 study, NH Utilities

C.11 Wholesale Market Price Suppression

C.11.1 Rationale

The electricity produced at the customer-generator's site reduces the overall energy and capacity procured through the wholesale market, resulting in lower market clearing prices. This price suppression effect, also known as Demand Reduction Induced Price Effect, or DRIPE, is ultimately passed on to all market participants. For this analysis, we considered the direct price-suppression benefits that result from reduced energy (Energy DRIPE), reduced Capacity (Capacity DRIPE), and the indirect price-suppression benefits that result from reduced electricity demand on gas prices which in turn reduce electricity prices (Electric-to-Gas-to-Electric Cross-DRIPE).

C.11.2 Model Map – Energy DRIPE



C.11.3 Avoided Cost Methodology– Energy DRIPE

Step 1: Calculate Energy DRIPE for Each Study Year (2021-2035)

a) Calculate Net Energy DRIPE

- Use gross energy DRIPE wholesale values (based on Counterfactual #2 scenario and intrazonal-only values for New Hampshire) from the AESC 2021 study as the starting point for each study year, The values reflect four periods: summer on-peak, summer off-peak, winter on-peak, and winter off-peak.

- Multiply gross energy DRIPE by the percentage of unhedged energy supply in New Hampshire – i.e., the portion of energy purchased on the spot market.

- Multiply the values by the energy DRIPE benefits decay schedule, which varies based on year of DER installation. The benefits decay schedule reflects a lower DRIPE value in future years as a) existing generating resources respond to lower prices by becoming less efficient, and b) customers respond to lower energy prices by increasing demand. To note, based on the methodology in the AESC 2021 study, energy DRIPE value persists for 11 years, including the year of installation.

b) Levelize to Year of Installation

- Discount the series of four net energy DRIPE values for each study year (e.g., for 2021: 2021 to 2031 summer on-peak; 2021 to 2031 summer off-peak; 2021 to 2031 winter on-peak; and 2021-2031 winter off-peak), then calculate the levelized values for the year of installation to develop four net energy DRIPE values for each study year.

Step 2: Convert to Hourly Values

- Convert the four season/peak period values[23] into 8760 hourly values using the following assumptions:
    - The summer on-peak value is applied to the corresponding ISO-NE summer months and on-peak hours. The summer off-peak value is applied to the corresponding ISO-NE summer months and off-peak hours.
    - The winter on-peak value is applied to the corresponding ISO-NE winter months and on-peak hours, while the winter off-peak value is applied to the winter off-peak hours.
- This conversion to hourly values for each year is repeated for all study years (2021-2035).

C.11.4 Inputs, Assumptions, and Notes– Energy DRIPE

Inputs	Sources
Gross Energy DRIPE Forecast	AESC 2021 study*

**See note 2, below.*

Assumptions and Notes

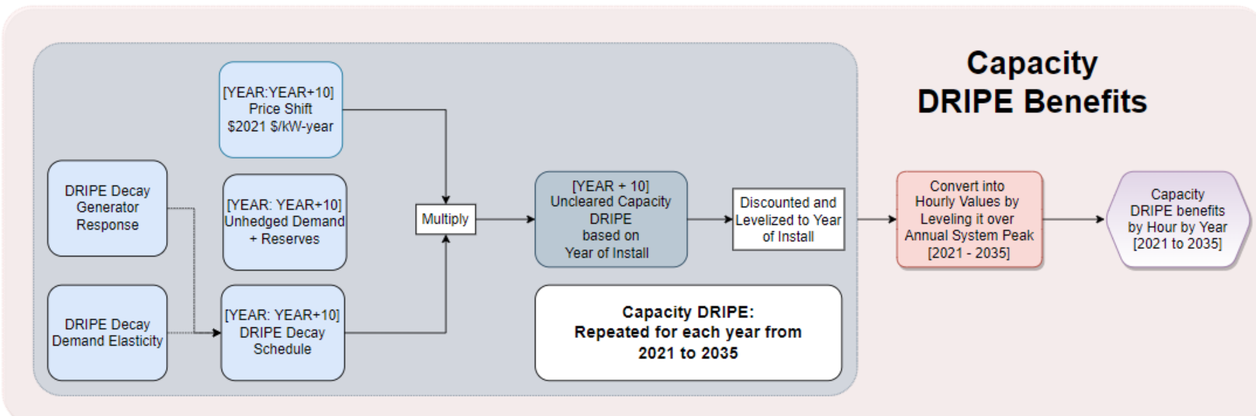
- For systems installed in 2021, the annual energy DRIPE persist through 2031. This is because the AESC assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less efficient and reliable, while customers might respond to lower energy prices by using more energy.

[23] These time periods are defined by ISO-NE as follows: Winter on-peak is October through May, weekdays from 7am to 11pm; winter off-peak is October through May, weekdays from 11 p.m. to 7 a.m., plus weekends and holidays; summer on-peak is June through September, weekdays from 7 a.m. to 11 p.m.; and summer off-peak is June through September, weekdays from 11 p.m. to 7 a.m., plus weekends and holidays

- The DRIPE values from 2021 to 2025 are available in the AESC 2021 Counterfactual Workbook #2. However, because the AESC study does not include values beyond 2025, those DRIPE values are modelled outside the workbook by applying the appropriate decay schedule (corrected for customer demand elasticity and generation effects) to the unhedged energy portion and gross DRIPE values.

- The intrazonal DRIPE values are proportional to the percentage of the zonal load with respect to the ISO-NE system load. Therefore, zones with less load will have lower zone-on-zone energy DRIPE values than zones with higher load.

C.11.5 Model Map – Capacity DRIPE



C.11.6 Avoided Cost Methodology – Capacity DRIPE

Step 1: Calculate Capacity DRIPE for Each Study Year (2021-2035)

c) Calculate Uncleared Capacity DRIPE

- For each study year, multiply New Hampshire's zonal unhedged demand (from the AESC 2021 Counterfactual #2 workbook), plus a reserve margin, by a benefit decay schedule based on the useful life of the DER and by the applicable annual price shift (which is expressed as $/MW-year per MW).[24] As with energy DRIPE, capacity DRIPE value is assumed to persist for 11 years, including the year of installation.

d) Levelize to Year of Installation

- Generate a series of uncleared capacity DRIPE values for each study year (e.g., for 2021, values are generated for 2021 through 2031), and then discount those values and calculate the levelized values for the year of installation.

[24] The uncleared capacity DRIPE methodology is used as the DG resources are not capacity market participants and therefore their impact on capacity wholesale market prices is linked to changes in unhedged load. Further, unlike other avoided cost components, this is a market impact (benefit) and not a potentially avoided cost that would be allocated through a market.

Step 2: Convert to Hourly Values

- Convert the annual values into 8760 hourly values by distributing the value over a set of peak hours based on an effective load carrying capability (ELCC) approach.[25] Repeat this conversion to annual hourly values for all study years (2021-2035).

C.11.7 Inputs, Assumptions, and Notes – Capacity DRIPE

Inputs

Inputs	Sources
Uncleared Capacity DRIPE Forecast	AESC 2021 study*
Reserve margin	AESC 2021 study

**See note 2, below.*

Assumptions and Notes

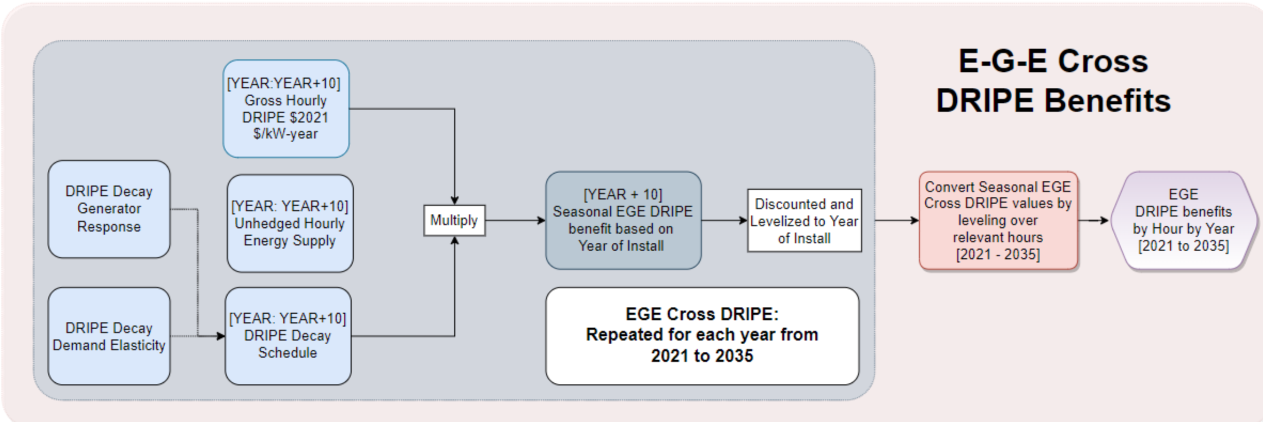
- For systems installed in 2021, the annual capacity DRIPE persist through 2031. This is because the AESC 2021 study assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less efficient and reliable, and customers might respond to lower energy prices by using more energy.

- The DRIPE values from 2021 to 2025 are available in the AESC 2021 Counterfactual Workbook #2. However, because the AESC study does not include values beyond 2025, those DRIPE values are modelled outside the workbook by using the appropriate decay schedule (corrected for customer demand elasticity and generation effects).

- The intrazonal DRIPE values are proportional to the percentage of the zonal load with respect to the ISO-NE system load. Therefore, zones with less load will have lower zone-on-zone Capacity DRIPE values than zones with higher load.

[25] ISO-NE has indicated that it will employ an ELCC approach for assessing resource capacity contribution to resource adequacy in the Forward Capacity Market. Because a strict application would require probabilistic modelling, a simplified approach is used here.

C.11.8 Model Map – Electric-to-Gas-to-Electric Cross DRIPE



C.11.9 Avoided Cost Methodology – Electric-to-Gas-to-Electric Cross DRIPE

Step 1: Calculate Electric-Gas-Electric Cross DRIPE for Each Study Year (2021-2035)

e) Calculate Electric-Gas-Electric Cross DRIPE for Summer and Winter

- For each study year, multiply New Hampshire's zonal unhedged energy demand (from the AESC 2021 Counterfactual #2 workbook) by a decay schedule based on the useful life of the DER multiplied by the applicable Electric-Gas-Electric coefficient (which is expressed as $/TWh per MWh/Period Reduced). As with energy DRIPE, Electric-Gas-Electric Cross DRIPE value persists for 11 years, including the year of installation.

f) Levelize to Year of Installation

- Generate Electric-Gas-Electric Cross DRIPE values for each study year (e.g., for 2021, values are generated for 2021 through 2031), and then discount those values and calculate the levelized values for the year of installation.

Step 2: Convert to Hourly Values

- Convert the seasonal $/kWh values (summer/winter) by distributing over the hours corresponding to each season. This conversion to hourly values is repeated for each year of the study period (2021-2035).

C.11.10 Inputs, Assumptions, and Notes – Electric-to-Gas-to-Electric Cross DRIPE

Inputs

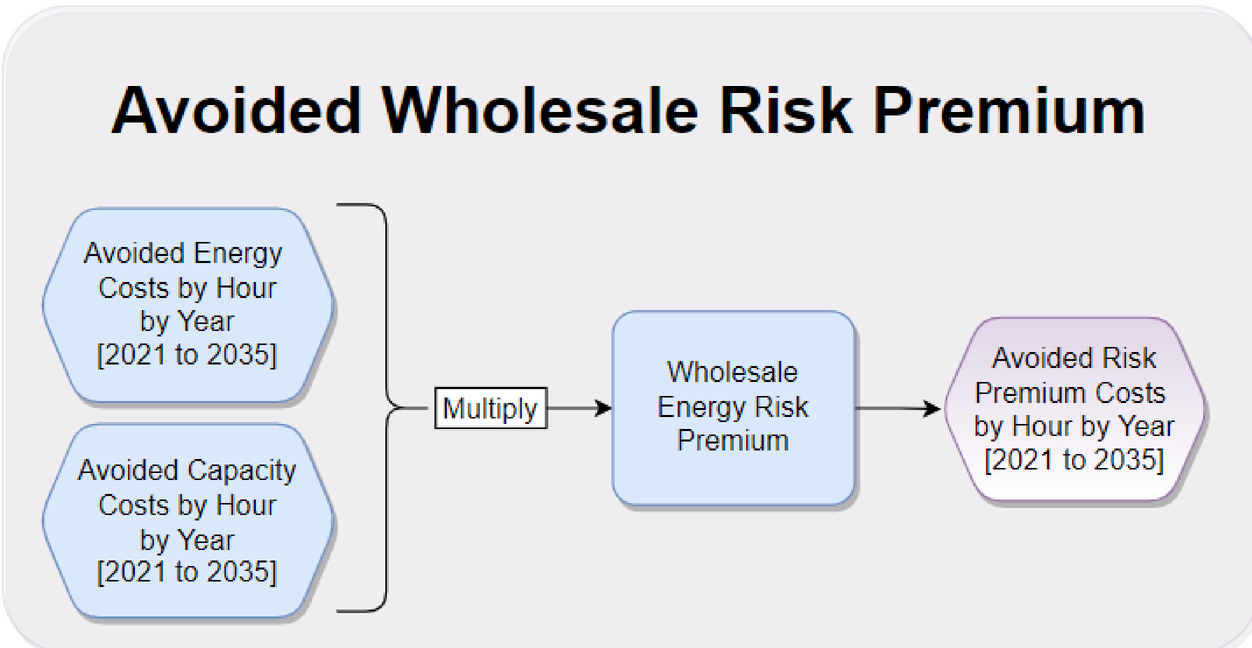
Inputs	Sources
E-G-E DRIPE Coefficients	AESC 2021 study

C.12 Hedging/Wholesale Risk Premium

C.12.1 Rationale

The full retail price of electricity is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary services. In part, this is because the wholesale suppliers of retail customer load requirements incur various market risks when they set contract prices in advance of supply delivery periods. Therefore, every reduction in wholesale energy and capacity obligations may reduce the supplier's cost to mitigate such risks.

C.12.2 Model Map



C.12.3 Avoided Cost Methodology

Step 1: Determine Risk Premium

- Use a literature review of other studies, utility-specific data, and the AESC 2021 study to determine the most appropriate value for this study[26].

Step 1: Apply to Wholesale Energy and Capacity Costs

- Apply the risk premium to wholesale hourly energy prices (historical and forecasted), including T&D line losses.

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[26] AESC 2021 applies the same wholesale risk premium of 8% to avoided wholesale energy prices and to avoided wholesale capacity prices,

- Similarly, multiply wholesale hourly capacity prices (historical and forecasted), including T&D line losses, by the wholesale risk premium value.

- Calculate the total wholesale risk premium by summing of the wholesale energy risk premium and the wholesale capacity risk premium.

C.12.4 Inputs, Assumptions, and Notes

Inputs:

Inputs	Sources
Wholesale Risk Premium	AESC 2021 study, utility-specific data, and other sources

Assumptions and Notes

- In keeping with the approach used in the AESC 2021 study, the same wholesale risk premium is applied to avoided wholesale hourly energy prices and avoided wholesale hourly capacity prices.
- Retail suppliers mitigate some risk by hedging their costs in advance, but there is still uncertainty in the final price borne by the supplier. The wholesale risk premium reflects suppliers' costs to mitigate wholesale risks associated with unavailable resources and changes in load. As such, it is applied to retail sales, and thus total wholesale energy and capacity costs must be adjusted upward to account for T&D line losses.

C.13 Distribution Utility Administration Costs

C.13.1 Rationale

An increase in solar installed capacity may affect associated electric distribution utility administration costs, including NEM program administration, metering, billing, collections, unreimbursed interconnection costs, evaluation, and load research.

C.13.2 Avoided Cost Methodology

Step 1: Develop DG-Related Costs to Utilities

- Gather NEM program administration costs associated with metering and billing, collections, unreimbursed interconnection costs, evaluation, load research, etc. from the electric distribution utilities.
- The applicable cost inputs – metering, program administration, interconnection and engineering costs were bundled together as utility administration costs. The administration costs were developed on a per-installation basis and appropriately scaled based on the DG forecasts developed for each utility and segment.
- Levelize these costs over solar forecasts to estimate the program administration costs by year.

C.13.3 Inputs, Assumptions, and Notes

Assumptions:
NEM program credits for customer-generator net exports are not accounted for under this cost component, which covers costs specific to NEM program implementation and administration and are not directly attributable to DG deployment levels.

C.14 Transmission and Distribution System Upgrades

C.14.1 Rationale

In the context of this study, the Transmission and Distribution System Upgrades component is an incurred cost item. It encompasses all costs related to transmission and distribution system upgrades that are driven by the addition of net-metered DG to the grid, with the exception of those covered by DG customer payments or reimbursements. However, it is challenging within the scope of this study to isolate those transmission and distribution system upgrade costs that are attributable to DG installations or any investments funded by DG customers that result in avoided costs or benefits to other ratepayers. As such, a qualitative review was completed for this criterion and the findings are included in the main body of the report.

C.15 Environmental Externalities

C.15.1 Rationale

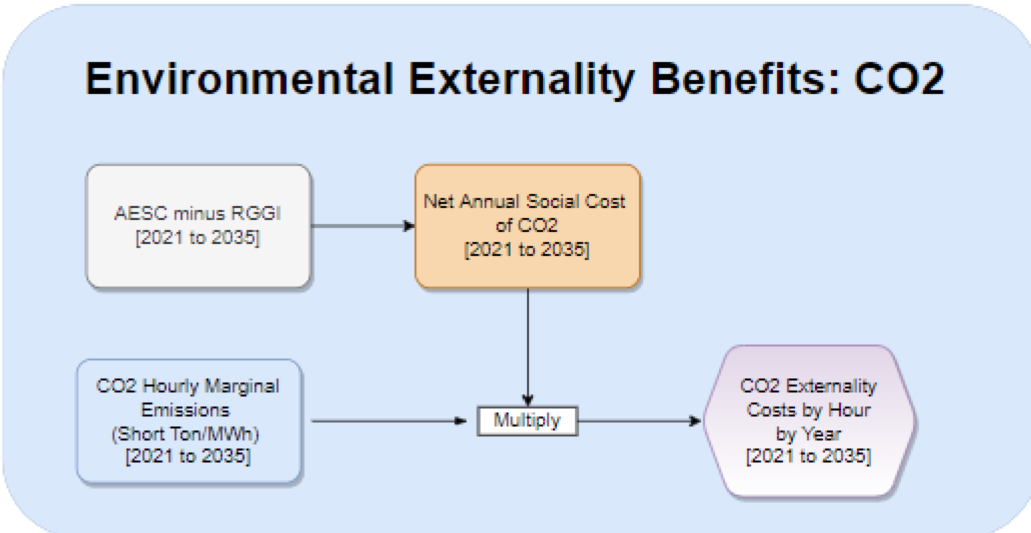
The electricity generated from a DG resource may reduce marginal emissions from fossil fuel plants. A portion of the avoided costs of such reduced emissions are already included as environmental program compliance costs embedded in wholesale energy prices. This study sensitivity focuses on evaluating the remaining non-embedded environmental externalities avoided costs resulting from DG resource electricity production.

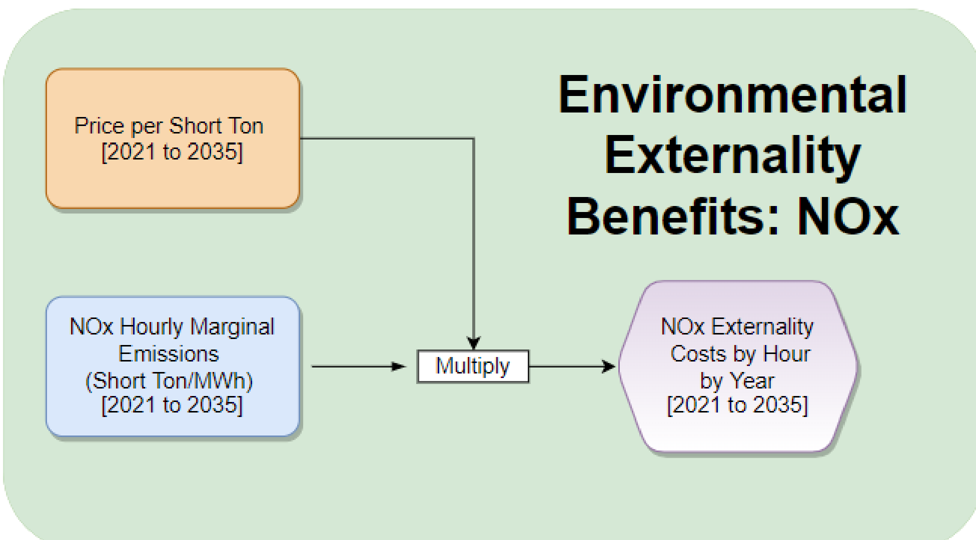
SO_2 emissions: The AESC 2021 study assumes that all coal-fired generation, the primary source of SO_2 emissions from electricity generation, is taken offline by 2025. For this analysis, the value of SO_2 emissions is assumed to be minimal and therefore it is not included in the environmental externalities value.

Particulate matter: The AESC wholesale energy price forecasts do not include any costs associated with particulate matter. When considering energy generation, particulate matter is primarily produced by coal and biomass combustion. Because coal-fired generation is assumed to be taken offline by 2025, the impacts of particulate matter from coal combustion are not included in the environmental externalities value. Although biomass remains a generation source throughout the study period, it provides baseload power rather than marginal generation. Because biomass facilities do not generate electricity on the margin, reductions in biomass-related particulate matter emissions are not expected as a result of net-metered DER load reductions. The impacts of particulate matter are therefore also excluded from the environmental externalities value.

Methane: Although the societal costs of methane are considerable on a per ton basis, methane emissions are challenging to quantify and forecast as they primarily occur upstream from power generation during the production, processing, storage, transmission, and distribution of natural gas and oil, and have not been thoroughly monitored or studied. In addition, the U.S. government is taking steps to substantially reduce upstream methane emissions through a proposed rule applicable to new and existing facilities, which targets a 74% reduction in methane emissions from oil and gas production from 2005 levels by 2030. Given the challenges inherent in developing methane emissions forecasts for ISO-NE, and in view of federal government proposals to reduce methane emissions during the study period, methane is not included in the environmental externalities value.

C.15.2 Model Map





C.15.3 Avoided Cost Methodology

Step 1: Calculate Environmental Externality Benefit of CO_2 (2021-2035)

- Select the social cost of carbon forecast from the AESC 2021 study (October 12, 2021)[27] (based on the 2% discount rate) as the gross Social Cost of Carbon (SCC, $/short ton).[28]

[27] Of the two approaches to estimate the cost of carbon, the marginal abatement cost test is challenging from a regional perspective, given that several variables such as technology price, technical potential and policies change over a period of time.

[28] This AESC SCC scenario is based on the New York State SCC – which was developed while the federal SCC was suspended. We believe this is an appropriate scenario for the VDER study, in view of the regional proximity to and similarities between New York

- Calculate the net SCC for each year by calculating the difference between the forecasted gross SCC and forecasted RGGI allowance prices. As RGGI allowance prices are already embedded in wholesale energy market prices, these are subtracted from the gross SCC values to establish a net SCC over the study period.
- Multiply the net SCC by the corresponding AESC 8760 hourly marginal emission rates (short ton per MWh) (2021 to 2035), as outlined in the AESC 2021 study workbooks, to determine the environmental externality avoided cost for CO_2.

Step 2: Calculate Environmental Externality Benefit of NO_x (2021-2035)

- Note that the AESC 2021 study assumes no embedded NO_x prices, because the New England states are exempt from the CSAPR program and state specific regulations in Massachusetts and Connecticut are unlikely to be binding. Therefore, the externality benefit of NO_x is equal to the AESC price per short ton of NO_x with no further adjustment. The value of the externality benefit of NO_x for this study was $14,700 per short ton throughout the study period.
- Multiply the price per short ton of NO_x in AESC 2021 by the corresponding AESC 8760 hourly marginal emission rates (2021 to 2035), as outlined in the AESC study workbooks, to determine the environmental externality benefit for NO_x.

C.15.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
CO_2 Marginal Emissions Rates	AESC 2021 study
Societal Cost of Carbon (2% discount rate scenario)	AESC 2021 study (October 2021 update), NYS SCC
RGGI Allowance Price Forecast	AESC 2021 study
NO_x Marginal Emissions Rates	AESC 2021 study
Short Ton Price of NO_x	AESC 2021 study

and the New England states in terms of energy landscape and policy context. Moreover, the NYS SCC Guideline values consider the global impact of emissions, use reasonable discount rates, and consider high impact events through low discount rates. The net SCC (after removing RGGI) ranged from $111 per short ton to $128 per short ton from 2021 to 2035.

Assumptions:

- The environmental externalities benefit associated with avoided Transmission and Distribution Line Losses have been included in the environmental externalities avoided cost component because this avoided cost component is treated as a sensitivity in the study.

C.16 Distribution Grid Support Services

C.16.1 Rationale

Generally speaking, this component may be an incurred cost or an avoided cost, reflecting an increase or decrease in costs associated with distribution system support services required as DG resource penetration increases. For the purpose of this study, this criterion is assumed to represent an avoided cost stream, with any incurred costs included under the T&D System Upgrades component. This criterion was evaluated using a qualitative review.

C.17 Resilience Services

C.17.1 Rationale

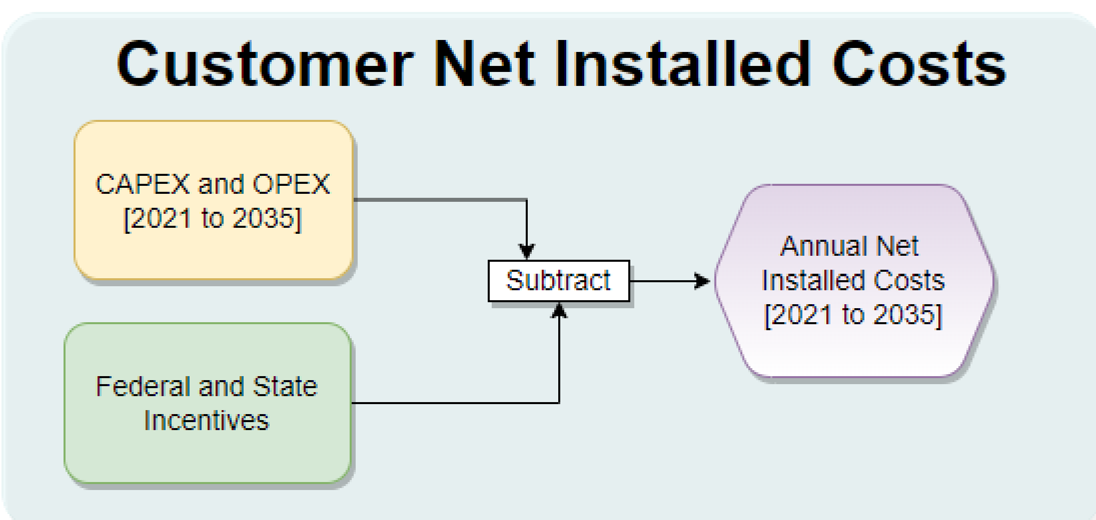
In this study, resilience services are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[29] Resiliency has the potential to provide significant value, although this value is expected to be highly context-specific. This criterion was assessed using a qualitative review.

C.18 Customer Installed Costs

C.18.1 Rationale

This component was not considered as part of the avoided cost value stack, but may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).

C.18.2 Model Map



[29] This definition was sourced from the U.S. DOE Office of Energy Efficiency and Renewable Energy, available online: https://www.energy.gov/eere/femp/distributed-energy-resources-resilience.

C.18.3 Methodology

Step 1: Develop DG Customer's CAPEX and OPEX Projections

- Develop projections of upfront capital costs (CAPEX) and annual operational costs (OPEX[30]) over the lifetime of the DG system, using NREL's Annual Technology Baseline[31].

Step 2: Determine Applicable Federal and State Incentives

- Develop annual incentive projections for solar PV systems based on federal investment tax credits and New Hampshire renewable energy rebates for residential and commercial projects.
- Federal ITC assumed to be applied for residential PV systems (26% until 2022, 22%% in 2023 and 0% after) and commercial and utility-scale PV systems (26% until 2022, 22%% in 2023 and 10% after). ITC assumed to be applied to solar + storage systems as well.

Step 3: Customer Installed Costs

- Calculate customer installed costs over the study period by summing the net present value of the CAPEX and OPEX costs, minus available incentives.
- The costs are expressed as a net $/kW cost as well as a levelized cost per kWh over system production for each system type – residential and commercial solar (south facing and west facing), residential and commercial solar and energy storage and small hydro.

C.18.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Solar CAPEX and OPEX Costs	NREL's Annual Technology Baseline (ATB)
Solar System Sizes: Residential, Commercial and LGHC[32]	NH Utility Data

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[30] Opex costs include admin feed, labor, insurance, land lease payments, operating labour, property taxes, sit security, project management, general (scheduled and unscheduled) maintenance, the annualized present value of large component replacement (inverters) Commercial PV | Electricity | 2021 | ATB | NREL

[31] Data | Electricity | 2021 | ATB | NREL, Capex and opex costs for solar PV (residential, commercial), energy storage costs (residential, commercial) and small hydro were based on the NREL's Annual Technology Baseline

[32] System sizes are align with the system assumptions used throughout the study period.

D. High Load Growth Scenarios Methodology

The value of distributed energy resources will vary to some degree according to projected load growth in New Hampshire. In part, future electricity load forecasts will depend on the deployment of building electrification and transportation electrification technologies. Uncertainty around the future deployment of those technologies, however, translates into uncertainty regarding projected load growth in the state. The High Load Growth Scenarios (HLGS) sensitivity analysis considers several scenarios for increased load growth to investigate the impact of such future load increases on avoided cost value stack criteria.

The following steps outline the approach used to complete the HLGS analysis through the development of three scenarios that estimate a) the incremental impact of electrification on system load, and b) the incremental impact of that electrification on avoided cost criteria in the value stack.

D.1 Estimating Incremental Impact on System Load

The base value stack avoided costs are based in large part on the Avoided Energy Supply Costs in New England (AESC) 2021 study, counterfactual #2 scenario. The HLGS loads are therefore compared to the loads under AESC counterfactual #2 to assess incremental impacts. Building electrification and transportation electrification are varied under multiple scenarios under the HLGS sensitivity analysis, as described below.

The HLGS analysis included three scenarios:

1. Scenario 1: Impact of AESC building electrification (BE)[33]

2. Scenario 2: Impact of AESC building electrification and high transportation electrification[34]

3. Scenario 3: Impact of high building electrification[35] and high transportation electrification

[33] The AESC counterfactual #2 did not include the programmatic resource impacts of building electrification measures, but these impacts were included in counterfactuals #3 and #4. The building electrification measure impact included in counterfactuals #3 and #4 was added to counterfactual #2 to derive Scenario 1.

[34] The AESC included transportation electrification impacts across all four counterfactual scenarios, so some degree of transportation electrification was considered in the base avoided cost values taken from the AESC counterfactual #2 scenario. For HLGS scenarios 2 and 3, transportation electrification was assumed to exceed the AESC assumptions such that light-duty vehicle uptake aligned with a market share target of 26% by 2026, 90% by 2030, and 100% by 2035. Data availability on medium- and heavy-duty vehicle stocks and sales in New Hampshire was limited, so market share targets could not be established. Deployment was instead accelerated over AESC assumptions to align with the modified uptake trends in the light-duty sector, resulting in load impacts that exceeded AESC values by up to 58% at the mid-point of the study, but were approximately aligned with AESC assumptions by 2035.

[35] The high building electrification assumptions included an accelerated timeline for heat pump installations in residential buildings, exceeding AESC assumptions by up to 30% at the study mid-point, and 14% by the study end point.

Scenario	BE	TE
Scenario 1: Impact of BE	AESC	AESC
Scenario 2: Impact of BE and high TE	AESC	High
Scenario 3: Impact of high BE and high TE	High	High

Each scenario's hourly demand curve was compared to the hourly demand curve under the AESC 2021 study counterfactual #2 to estimate incremental load impacts.

D.2 Estimating Incremental Impacts on Avoided Costs

Although load growth may impact the total costs ($) associated with many of the value stack criteria, the focus of this analysis is to understand impacts to the avoided cost per unit energy or unit demand ($/kWh or $/kW). Avoided cost per unit energy or per unit demand impacts may arise for those avoided cost criteria that are impacted by wholesale market adjustments resulting from changes in load. Those adjustments are similar to DRIPE, and in fact the elasticity factors used to calculate impacts (described below) are a precursor to DRIPE.

To calculate the HLGS impacts on avoided costs, the change in hourly demand (or the incremental load impacts) associated with each HLGS scenario are compared to the base case, AESC counterfactual #2. Next, the change in demand is multiplied by the hourly elasticity factor to calculate the percentage change in avoided cost, as shown in the following equation:[36]

$$\%\ change\ in\ avoided\ cost = elasticity\ \times \%\ change\ in\ demand$$

The percent change in avoided cost (avoided cost impact) is calculated for the volumetric (kWh) and demand (kW) criteria. Volumetric avoided cost impacts are calculated using the change in hourly demand between the scenarios and the base case, while capacity avoided cost changes are calculated using the change in annual peak demand.

Volumetric avoided cost impacts are applied to the following avoided cost criteria (that depend on wholesale energy prices):

- Energy
- Ancillary services and load obligation charges
- Risk premium/hedging
- DRIPE Energy
- RPS compliance

[36] Price elasticity factors (and the equation used for this analysis) were calculated in the AESC 2021 study using the relationships between prices ($/MWh or $/kW-year, for energy and capacity respectively) and demand (MW).

Capacity avoided cost impacts are applied to the following cost criteria (that depend on wholesale capacity costs):

- Capacity costs
- DRIPE Capacity

A number of avoided cost criteria are expected to remain unchanged. **That is not to say that the total costs ($) will not change with increases in load, but rather that the costs per unit energy or per unit demand cost criteria are not expected to change.** These cost criteria are:

- Transmission capacity
- Distribution capacity
- Transmission charges
- Transmission and distribution line losses
- Utility administrative costs
- T&D system upgrades
- Distribution OPEX

Increases in marginal demand would also increase the high emitting resources on the margin, which could increase the emissions rates for CO_2 and NO_x under the different HLGS scenarios. Therefore, the impact on environmental externalities is modeled by conducting a regression analysis that compares the demand with the AESC marginal emissions rates to estimate the emissions levels under the three HLGS scenarios.

E. Market Resource Value Scenario Methodology

The market resource value scenario (MRVS) sensitivity analysis estimates the value of aggregated DER resources participating directly in relevant wholesale power markets for those criteria where there is a readily discernible market value or a value that is different than those established in the load reduction value estimates. Specifically, the MRVS analysis considered the ability of DERs to realize value in the wholesale power markets through provision of **energy**, **capacity**, and **ancillary services**. The methodology used for each value category is described below.

E.1 Energy Value

The market value of energy produced by aggregated DER resources is reflected by zonal LMPs for ISO-NE's New Hampshire load zone. The study team relied on the AESC 2021 wholesale energy forecasts for these values. The values were further adjusted to reflect expected near-term increases in the value of energy. Specifically, hourly price profiles were adjusted for recent increases in natural gas prices and resulting LMPs over the 2021-2025 period. Under the MRVS, the value of energy is considered to be the same as in the base avoided cost value stack.

E.2 Capacity Value

The value of capacity generated by aggregated DER resources assumes participation in ISO-NE's Forward Capacity Market (FCM). The study team relied on the AESC 2021 FCM forecast for these values. The FCM values were converted to hourly values (in $/kWh) using summer and winter reliability hours for establishing Qualified Capacity,[37] which is the basis for capacity credit for which FCM payments are made to generation resources.

E.3 Ancillary Services Value

The value of ancillary services is based on the ability of aggregated DER resources to provide reserves and regulation under ISO-NE's FERC Order 2222 compliance filing as dispatchable DER aggregations. Provision of such services typically requires that resources do *not* participate in the energy market, however, so DER provision of those services is expected to be uneconomic.[38] As such, we did not conduct a detailed quantitative analysis of ancillary services value but included qualitative insights instead.

[37] Qualified Capacity refers to the capacity that a resource is capable of providing in the summer or winter during specific capacity commitment periods. This is calculated by taking the average median production during the summer reliability hours ending 14:00-18:00 (June to September) and winter hours ending 18:00-19:00 (October to May).

[38] For example, for a solar resource to provide operating reserves, it requires "headroom," which would allow it to increase output in response to a generator activation instruction from ISO-NE. To provide this headroom the generator would need to be dispatched down, resulting in an energy market opportunity cost for the operator.

F. Rate and Bill Impacts Assessment

The Rate and Bill Impacts Assessment is a supplementary study to the Avoided Cost Value Stack Analysis. The assessment provides high-level analysis of the impacts of future DG deployment in New Hampshire on ratepayers, considering both the benefits and the costs that would be incurred by the utilities and load-serving entities. The overall goal of the assessment is to serve as a future-looking estimate of the direction and magnitude of the impacts of future DG deployment on all ratepayers and any potential cost-shifting between customers with and without DG. The Rate and Bill Impacts Assessment is not intended to be a projection of future electricity rates and cost recovery, but it serves as a future-looking approximation of the impacts of projected future DG adoption on retail electricity rates for and bills issued to New Hampshire electric customers.

F.1 Modelling Approach

F.1.1 Rationale

Customers that install distributed generation resources can offset a part of their electric load and thus reduce their electric bills. Some portion of the electricity generated is self-consumed while the remaining portion is generally exported back to the utility distribution system. The electricity generated from distributed resources creates both an upward pressure on rates (due to lost utility revenues and program cost recovery) as well as a downward pressure on rates attributable to avoided utility costs.

F.1.2 Modelling Considerations

The following considerations were made while conducting the Rate and Bill Impacts Assessment:

Electric Retail Rates: Impacts on retail electric rates resulting from the future deployment of behind-the-meter distributed solar PV systems in New Hampshire are evaluated.

Three Electric Utilities: Impacts are assessed for the three electric utilities regulated by the New Hampshire PUC: Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty (Liberty), and Unitil Energy Systems, Inc. (Unitil).

Three Customer Classes: Residential, small general service, and large general service customer classes are modeled as a representation of customers impacted by the adoption of behind-the-meter distributed solar PV systems.

Two Scenarios: The analysis is conducted under two scenarios for DG compensation to illustrate the impacts of different potential DG program designs on ratepayers:

- **Net Energy Metering (NEM) Tariff Scenario:** This scenario reflects the current net-metering program, based on the alternative net metering tariff adopted by the PUC in 2017. The net export credit rate is based on the alternative net metering tariff, where monthly net exports from systems up to 100 kW capacity are compensated at 25% of the underlying distribution rate component and 100% of the underlying generation and transmission rate components, while hourly net exports from eligible systems larger than 100 kW are compensated at 100% of the underlying generation rate component.
- **Avoided Cost Value (ACV) Tariff Scenario**: An alternative net export compensation tariff approach based on the outcomes of the VDER Study value stack analysis, where customers are compensated for net exports to the grid based on the avoided cost values determined through the study.

Three Customer Archetypes: The assessment evaluated the rate and bill impacts for three customer archetypes:

- **Typical DG Customer**: Represents a typical utility customer who adopts a behind-the-meter solar PV system for each customer class.
- **Typical Non-DG Customer:** Represents a typical utility customer in each customer class who does not deploy a solar PV system.
- **Average Utility Customer**: Represents the average impacts on a utility customer, without regard to whether the customer has or does not have DG. The rate and bill impacts are computed at the rate class level where the total consumption is divided by the number of customers across each rate class and utility.

Decoupling: Utilities in the state have implemented – or plan to implement - a revenue decoupling mechanism. For simplicity, the study analysis assumes annual reconciliation (i.e., annual rate cases) and assumes that utilities will recover all costs associated with non-avoidable fixed costs. In reality, utilities may have less frequent rate cases. This simplifying assumption avoids the complexity of analysis while still meeting the objectives of the study.

F.1.3 Modelling Framework

Rate Impact Assessment

The equation below highlights the theoretical model used to assess the rate impacts of future DG deployment. The rates post-DG are impacted by the fixed costs and program costs, which are recovered over the load post-DG. When a customer-sited distributed energy resource generates electricity, the utility experiences an immediate reduction in energy consumption, thus leading to a certain amount of lost revenues. However, that generation also generates avoided cost values for the utility and load-serving entities. The "net" of these two components (i.e., the difference between lost revenues and avoided costs) is estimated to represent non-avoidable fixed costs that the utilities would need to recover from ratepayers. Additionally, the analytical framework is intended to account for rate impacts associated with the recovery of program costs and net export bill credits over fewer energy sales.

To summarize, future DG deployment is assumed to have several distinct impacts on rates:

A. Lost revenues to utilities as a result of reductions in electricity consumption.
B. Avoided costs, as indicated and quantified by the Avoided Cost Value Stack assessment.
C. Program and/or system costs incurred by utilities to accommodate DG installation and operation, which include program administration costs and the bill credits provided for net exports.
D. System costs that are recovered over lower energy sales due to the load reductions.

The "net" of these components (i.e., the difference between lost revenues and avoided costs) is estimated to represent proxy of the required fixed cost recovery

A Utilities' revenues are reduced

B Utilities capture benefits from avoided costs

$$Rates_{Post\ DG} = Rates_{Pre\ DG} + \frac{\overbrace{(Lost\ Revenues\ - Avoided\ Costs)}^{\textit{Fixed Cost Recovery}} + \overbrace{(Admin\ Costs + Export\ Bill\ Credits)}^{\textit{Program Costs Recovery}}}{Load\ _{Post-DG}}$$

D Costs are recovered over fewer kWh

C Utilities need recover costs to accommodate DG / operate programs

The above framework is applied for the generation, transmission, and distribution components of rates, considering only appropriate determinants under each. For example, the program cost recovery is applied only to the distribution component of rates. In calculating the rate impacts for each customer class, avoided costs, lost revenues, and program costs are calculated across all customer classes and then redistributed back to individual customer classes based on the principle of 100% cost causation.

Additionally, the framework considers the rate components (e.g., volumetric $/kWh and demand charge $/kW) applicable to each customer class.

Bill Impacts Assessment

As a final step, pre- and post-DG bills are estimated for a typical DG customer, a typical non-DG customer, and the average utility customer in each customer class and by each utility. For each customer class, estimated consumption is multiplied by pre- and post-DG rates to assess the incremental impacts on customer bills attributable to future DG deployment.

F.2 Methodology

F.2.1 Step 1: Develop Baseline (No-DG) and DG scenarios

To assess the impacts of future DG deployment, a non-DG scenario must be developed to serve as a baseline. The non-DG scenario is a hypothetical illustration of the system in the absence of projected new DG capacity and is used to evaluate the impacts attributable to future incremental DG deployment. To develop the DG and non-DG scenarios, the following metrics are estimated for each utility and year of the study period:

- **Load (energy and demand) by utility and rate class with and without DG :** this is calculated by:

    a) Removing the impacts of any annual DG projections included in utilities' current load forecasts (Load Pre-DG), and

$$\mathrm{Load}_{Pre-DG} = \mathrm{Load} - \text{adjustments to remove cumulative "new" DG projections}$$

    b) Adding the DG projections used in the VDER Study (Load post-DG).

$$\mathrm{Load}_{Post-DG} = \mathrm{Load}_{Pre-DG} - \text{Total DG Production Forecasts}$$

- **Annual production by average DG customer in each rate class[39]:** Estimated by dividing total forecasted DG production in a given year by the forecasted number of DG customers.

$$Average\ DG\ Production\ per\ DG\ customer = \frac{\text{Total Forecasted DG Production (GWh)}}{\text{Total Number of Forecasted DG Customers}}$$

[39] Behind-the-meter solar PV is assumed to be the dominant distributed generation resource for this assessment.

Additionally, assumptions are made to estimate the portion of DG production consumed behind-the-meter versus that exported to the grid (see key assumptions and sources section below). Grid exports are estimated based on an assessment of system sizing practices, DG generation, and customer load patterns.

- **Electricity consumption and demand[40] for DG, non-DG, and average utility customer in each customer class:**

  To simplify the analysis, all customers in a given customer class, regardless of DG deployment, are assumed to have the same average annual electricity consumption pre-DG, as calculated by the following equation:

$$\text{Avg Consumption}_{Pre-DG} = \frac{\text{Total Consumption}_{Pre-DG}}{\text{Total Customers}_{Pre-DG}}$$

  Consumption post-DG will be calculated as follows for different customer archetypes:

Typical DG Customer	$\text{Consumption}_{DG\ Customer} = \text{Avg Consumption}_{Pre\ DG} - \text{Avg DG Production}$
Typical non-DG Customer	$\text{Consumption}_{Non-DG\ Customer} = \text{Avg Consumption}_{Pre-DG}$
Average Utility Customer	$\text{Consumption}_{Avg\ Customer} = \frac{\text{Total Consumption}_{Post\ DG}}{\text{Total Customers}_{Post\ DG}}$

F.2.2 Step 2: Assess Rate Impacts

First, we calculate the lost revenues associated with each customer class for each utility. The lost revenue is the anticipated revenue lost due to reduced electricity sales:

$$Lost\ Revenue\ = DG\ Production\ x\ Rate_{Pre-DG}$$

[40] A coincidence factor for each customer class will be applied to the system peak demand to estimate customer billed demand (e.g., monthly peak load).

Next, we calculate the avoided costs associated with DG production. The avoided cost value is informed by the value stack assessment by each component (generation, transmission, and distribution). Environmental externalities are not included in any of the avoided cost streams.

$$Avoided\ Costs\ = DG\ Production\ x\ Avoided\ Costs_{Generation,\ Distribution,\ Transmission}$$

The net difference between the lost revenue and the avoided costs serves as a proxy for the fixed cost recovery. For each of the rate components, the following avoided costs are considered:

- Generation: Avoided energy, RPS, ancillary services, distribution and transmission line losses, and risk premium are considered pass-through components[41], while avoided capacity and DRIPE benefits are considered to have an impact on rates.
- Distribution: The avoided distribution costs include avoided distribution CAPEX and OPEX, distribution grid services, T&D system upgrades, and resiliency services.
- Transmission: Transmission capacity and transmission charges are considered under the rate and bill impacts assessment; the rate impacts assessment assumes only the portion attributable to the New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%.

To calculate the program cost recovery, we use both the administration costs and the net export bill credits. The administration costs are the costs incurred by the utilities to administer DG programs and include metering costs, costs for full time engineers to conduct site inspections, and other administrative costs.

The export bill credits represent the compensation provided for DG net electricity exports. Under the NEM Tariff scenario, the export credit rate is based on the alternative net metering tariff, where monthly net exports from systems up to 100 kW capacity are compensated at 25% of the underlying distribution rate component and 100% of the underlying generation and transmission rate components, while hourly net exports from eligible systems larger than 100 kW are compensated at 100% of the underlying generation rate component. The compensation is the net export credits netted by the applicable avoided costs. Under the Alternative ACV Tariff scenario, the net export credits are compensated at the avoided costs determined through the value stack analysis. The compensation under this scenario is the export credit compensation netted by the applicable avoided costs, which in this case is zero.

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[41] Certain cost components such as energy, ancillary services, line losses and risk premium are passed on directly from the market to the end customer through the utility. When a customer generates electricity behind the meter – the avoided energy, ancillary services, line losses and risk premium costs will affect the customer bill but won't change the utility's revenue requirement. DRIPE will affect the clearing price for wholesale energy, thereby affecting the generation rate. In line with other similar studies on rate and bill impact assessment in New Hampshire, avoided capacity costs are considered to impact rates.

$$Export\ Bill\ Credit = [(Export\ Rate - Avoided\ Cost\ Rate) x\ \%\ of\ \ Production\ Exported]$$

The fixed cost recovery and program cost recovery portion of the relevant revenue requirement calculation is distributed over the net system load (post-DG) and its impact is recorded against the pre-DG rate for each year of the study. Thus, the rate impacts are presented as the average annual percentage increase or decrease in rates relative to the non-DG scenario over the period 2021 to 2035 for each customer class to indicate the long-term impact of future DG deployment.

F.2.3 Step 3: Assess Bill Impacts

The pre- and post-DG customer bills are calculated for each customer archetype. As an example, the bill impacts from non-DG customers are shown as follows:

$$\text{PreDG Bills}_{\ Non-DG\ Customer} = \text{Consumption}_{Non-DG\ Customer}\ \text{x Rates}_{\ Pre-DG}$$

$$\text{PostDG Bills}_{\ Non-DG\ Customer} = \text{Consumption}_{Non-DG\ Customer}\ \text{x Rates}_{\ Post-DG}$$

$$\text{Bill Impact}_{\ Non-DG\ Customer} = \frac{Post\ DG\ Bills_{Non-DG\ Customer}}{\text{PreDG Bills}_{\ Non-DG\ Customer}} - 1$$

Although the bill impacts are calculated for each year during the study period, the bill impacts are presented as the average annual percentage increase or decrease in customers’ bills attributable to future DG deployment over the period 2021 to 2035 for each of the typical customer archetypes, in each case considered to estimate bill reductions and potential cost-shifting between DG customers and non-DG customers and by the average customer.

F.3 Key Assumptions and Sources

F.3.1 Customer Class Assumptions

The retail electric customers for each utility are segregated into three broad classes: Residential, Small General Service, and Large General Service. The customer count for each rate class across the three utilities were informed by data provided by the utilities. The classification of commercial customers was based on the average annual electric sales. Small general service customers were assumed to have electric sales less than 1 million kWh, while all customers with electric sales greater than 1 million kWh were classified as large general service.

The rate and bill impacts assessment analyzes the impacts of avoided costs on generation, distribution, and transmission rate components. Environmental Externalities are not included in the rate and bill impacts assessment. For each of the three rate components, the following assumptions were made for the rate and bill impacts assessment:

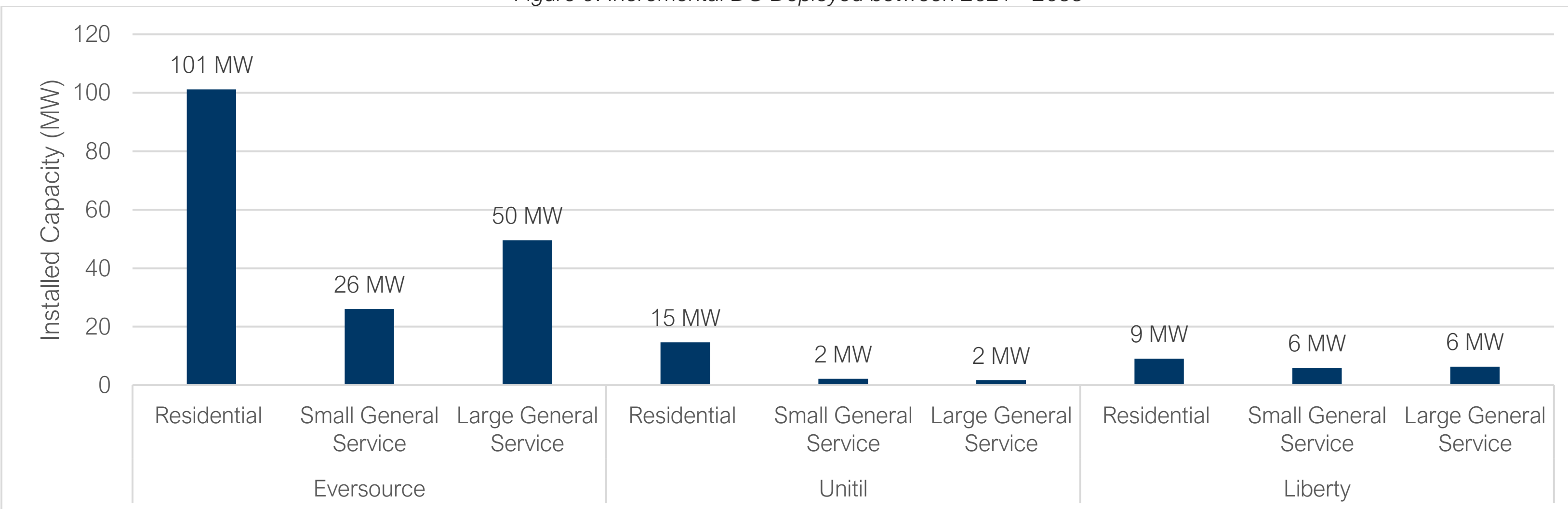
- Generation: Avoided energy, RPS, ancillary services, distribution and transmission line losses, and risk premium are considered pass-through components, while avoided capacity and DRIPE benefits were considered to have an impact on rates.
- Distribution: The avoided distribution costs include avoided distribution CAPEX and OPEX, Distribution Grid Services, T&D System Upgrades, and Resiliency Services.
- Transmission: Transmission Capacity and Transmission Charges are considered for the rate and bill impacts assessments; the rate impacts assessment assumes only the portion attributable to the part of New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%.

PV system sizes are based on aggregated utility data (AC kW):

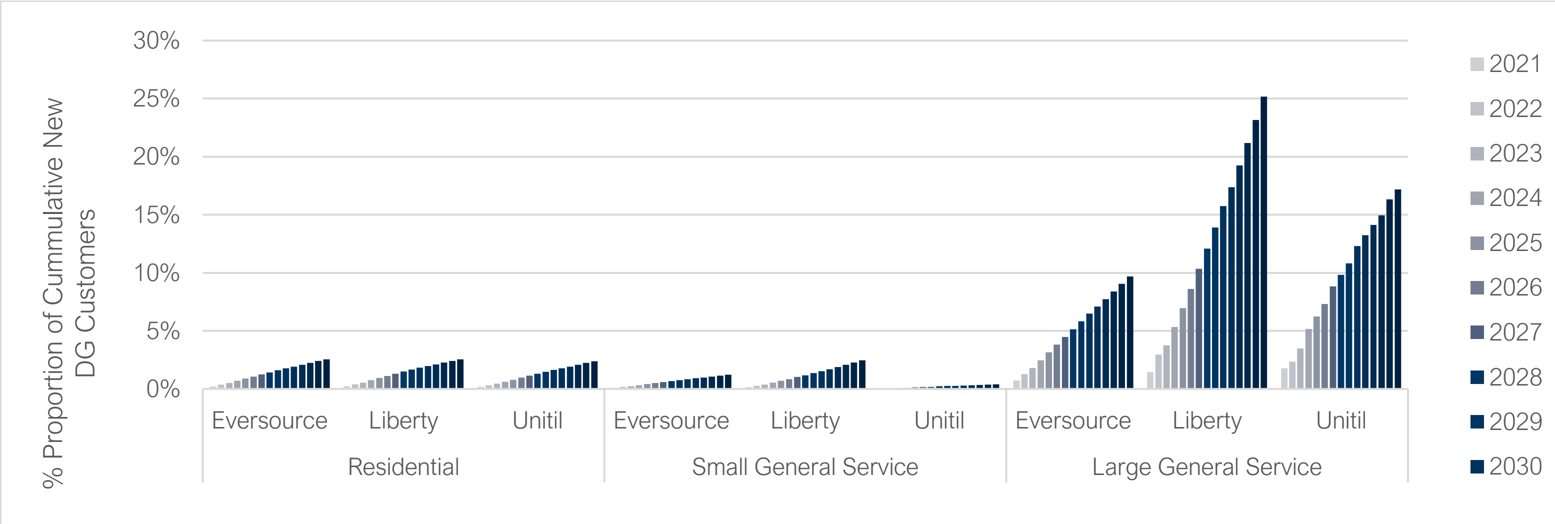
Customer Class	Eversource	Unitil	Liberty	% Self-Consumed
Residential	7.6	12.2	10.1	72% (Monthly Netting)
Small General Service	24.5	43.0	41.3	65% (Monthly Netting)
Large General Service	329.2	47.2	209.6	99% (Hourly Netting)

Incremental DG Capacity deployed over the study period:

Figure 9: Incremental DG Deployed between 2021 - 2035



Percentage of customers with DG by 2035:



Inputs	Sources
Load Forecasts by Customer Class (energy, demand, number of customers)	Utility load forecasts
Utility and Rate Class Specific Transmission and Distribution Line Losses[42]	Utility data
Customer Rates	Utility tariffs
DG Projections by Customer Class	Utility load forecasts
DG Program Budgets	Utility interviews
Peak Coincidence by Customer Class	Utility system load data

[42] The utility and rate class specific T&D losses were used to calculate the avoided costs and lost revenues for the rate and bill impact assessment.