Appendices to Ontario Distributed Energy Resources Impact Study

January 18, 2021

Submitted to:
The Ontario Energy Board

Submitted by:
ICF

Table of Contents

I. Appendix A – Additional Projection Details

1. Solar Photovoltaics

1.1 Scenario Summary – Additional Metric

The projections of annual solar photovoltaics (PV) energy output (GWh) across the three Scenarios are depicted in Figure 1 and detailed in Table 1.

Figure 1. Solar PV – Annual Energy Output (GWh) and CAGR (%) Projections by Scenario

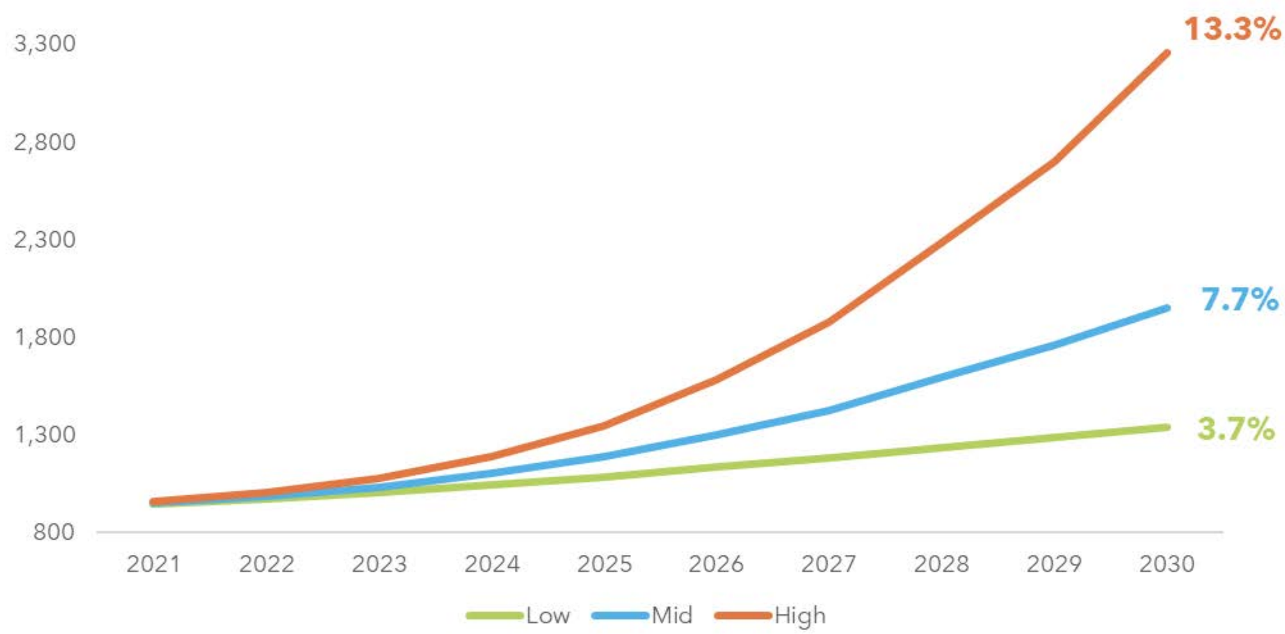


Table 1. Solar PV – Annual Energy Output (GWh) Projections by Scenario

Year	Low	Mid	High
2021	950.5	954.6	959.1
2022	974.1	988.1	1,004.4
2023	1,004.9	1,035.6	1,076.6
2024	1,043.7	1,105.4	1,193.4
2025	1,084.8	1,188.3	1,346.9
2026	1,134.8	1,304.7	1,587.7
2027	1,182.9	1,429.7	1,876.7
2028	1,239.2	1,599.7	2,286.4
2029	1,286.4	1,759.0	2,700.3
2030	1,339.9	1,954.9	3,256.2

The energy outputs generally follow the trajectories of the provincial cumulative capacity projections as PV output is closely linked to system size. While the projections assumed similar system sizes within a single customer class across Scenarios, the differences in energy impact values across the Scenarios arise due to variations in projections of installed capacity.

Additionally, solar PV energy output represents a decrease in load from a system perspective, as the technology reduces the energy purchase obligation for host customers. While the modeling does assume some annual degradation in solar PV energy output due to natural wear and tear, the energy output from annual incremental installations offsets the lost PV production. As a result, the charts show a positive slope for energy output across all Scenarios.

1.2 Customer Class Comparison

Because of the number of combinations that result from four customer classes, three Scenarios, and three metrics, the summaries in this section are only for the Mid Scenario. The full extent of Scenario projections by customer class can be found in in the sections that follow.

The projections of solar PV by cumulative capacity (MW) across the four customer classes are depicted in Figure 2 and detailed in Table 2.

Figure 2. Solar PV – Mid Scenario Cumulative Capacity (MW) and CAGR (%) Projections by Customer Class

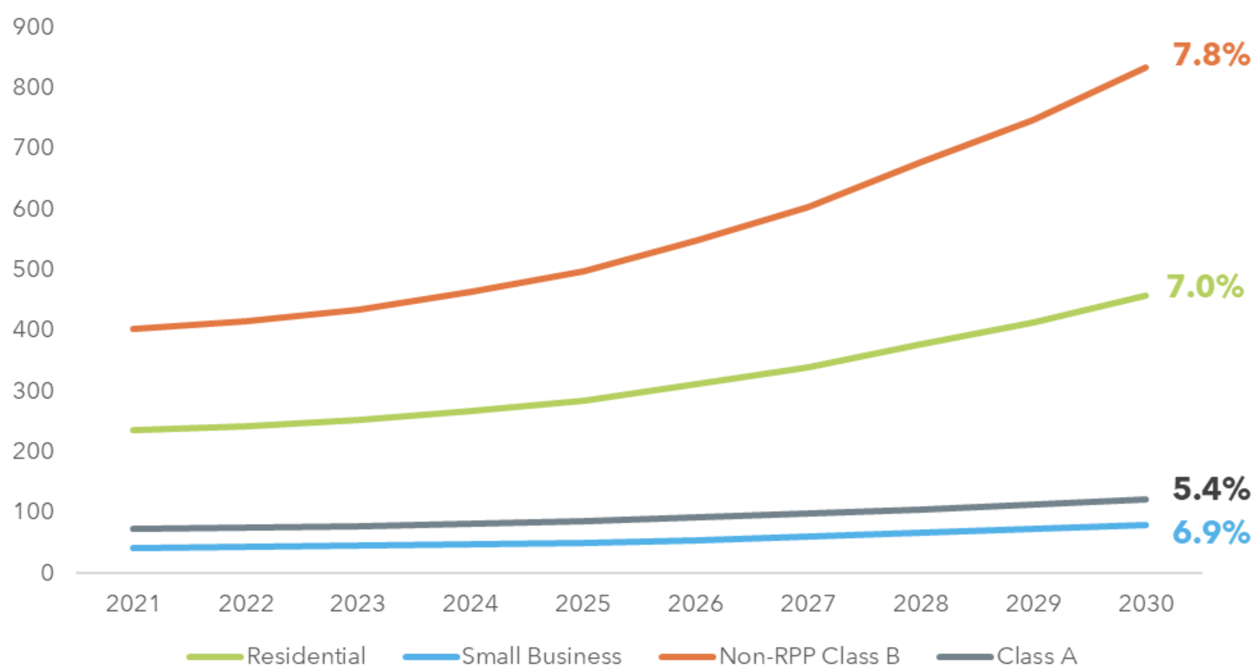


Table 2. Solar PV – Mid Scenario Cumulative Capacity (MW) Projections by Customer Class

Year	Residential	Small Business	Non-RPP Class B	Class A
2021	235.4	41.5	401.9	72.7
2022	241.9	42.7	414.7	74.8
2023	251.9	44.4	433.4	77.7
2024	266.6	47.0	462.8	81.6
2025	284.9	50.1	497.7	86.0
2026	310.7	54.6	548.2	91.6
2027	338.6	59.4	602.7	97.3
2028	377.0	66.0	677.4	105.1
2029	412.9	72.2	747.1	112.0
2030	457.2	79.7	832.8	121.1

The span of annual growth rates – compound annual growth rates (CAGRs), as measured by cumulative MW capacity growth – over the study period for residential solar PV in these projections ranges from 3.8% in the Low Scenario up to 13.0% in the High Scenario. By comparison,[1] from 2009 to 2017 the national CAGR for equivalent residential solar installations in the United States was 51.5%.[2] However, some U.S. states are, given their latitudes and climates, not close comparables for Ontario; for example, Nevada (61.4%), Texas (72.0%), and New Mexico (76.2%). Other U.S. states – such as Wisconsin, Michigan, and Illinois – are significantly better proxies for Ontario, and their CAGRs for the 2009 to 2017 period were lower (in this case, 30.0%, 30.4%, and 32.2%, respectively).

While non-residential customers make for a harder comparison (because the definitions of different commercial and industrial classes vary more by jurisdiction), these same general comparisons hold for the other customer classes as well. The span of CAGRs for non-RPP Class B solar PV in these projections ranges from 3.3% in the Low Scenario up to 12.8% in the High Scenario over the course of the study period, while Class A projections range from 3.2% to 10.0% for the duration of the study period. From 2009 to 2017, the national non-residential solar PV CAGR in the United States was 39.7%. As with residential customers, though, the commercial and industrial CAGRs for that period varied widely in the U.S., from states largely dissimilar to Ontario (e.g., New Mexico, 54.5%; Tennessee, 70.5%; and Georgia, 87.6%) to ones that are a closer match in terms of latitude and climate (e.g., Oregon, 28.3%; Wisconsin, 29.4%; and Illinois, 36.3%).

Following the end of the FIT and microFIT programs, it is expected that the vast majority of potential customers will turn to Ontario's Net Metering program to help make a more compelling business case for investing in solar PV projects. Commercial and industrial (C&I) customers are likely to constitute the bulk of total capacity due to their participation in net metering, continuing

[1] The same caveats about the limitations of historical growth rates as reliable indicators of future growth rates, as well as the limitations of comparing different regions, described above in Section III.1.1, apply here as well.

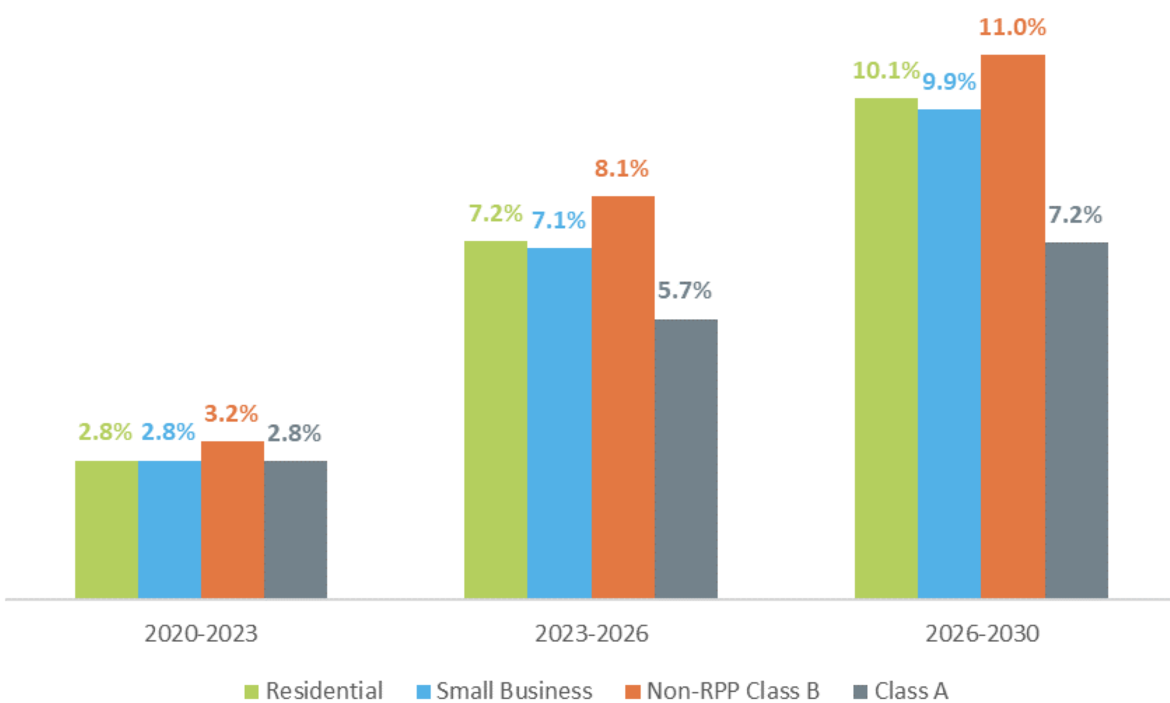
[2] All growth rates used as comparison derived from: Wood Mackenzie Power and Renewables and SEIA, US Solar Market Insight Full Report, March 2019.

the trend that has been seen historically in the province[3]. Of the C&I customers, non-RPP Class B customers are likely to make up most of the installs given their relatively high tariff rates compared to Class A customers; higher rates present a larger incentive to take advantage of bill savings in addition participation in the Net Metering program.

Participation in the wholesale market may also improve the business case for PV systems, particularly for C&I customers. However, in the Mid Scenario, there are still barriers to participation such as minimum size thresholds and the registration processes that would need to be addressed in order to facilitate greater participation of DER in the wholesale market and access to energy and capacity revenue streams.

The projected solar PV CAGRs by customer class in the Mid Scenario are broken down further into shorter timeframes in Figure 3 below.[4]

Figure 3. Solar PV – Mid Scenario Compound Annual Growth Rate (%) Projections by Timeframe and Customer Class



[3] Compass Renewable Energy Consulting, Market Analysis of Ontario's Renewable Energy Sector, June 30, 2017. Available online: https://www.ontarioenergyreport.ca/pdfs/COMPLETE%20FINAL_MOE%20Ontario%20Market%20Assessment_July%2020,%202017.pdf

[4] Please note that the three timeframes used here (2020-2023, 2023-2026, and 2026-2030) are very similar but slightly different than the ones used to assess the timing of impacts in Section IV (2021-2023, 2024-2026, and 2027-2030). That difference is due to the need for an "anchor" year in CAGR calculations (e.g., in order to measure a CAGR for 2021-2013, the calculation needs to be "anchored" in 2020), but in essence the two difference breakdowns of the 2021-2030 period are intended to be the same.

As with the Scenarios as a whole, each customer class sees a general acceleration of annual solar PV adoption growth over the course of the ten-year period. However, while all four classes grow at very similar rates over the first period, they then diverge, with Non-RPP Class B customers growing at the fastest rate over the subsequent two period and Class A customers growing the slowest during that period. This is due largely to the lower tariff rates for Class A customers.

The projections of annual solar PV energy output (GWh) across the four customer classes are depicted in Figure 4 and detailed in Table 3. The projections of annual solar PV energy output (GWh) across the four customer classes are depicted in Figure 4 and detailed in Table 3.

Figure 4. Solar PV – Mid Scenario Annual Energy Output (GWh) and CAGR (%) Projections by Customer Class

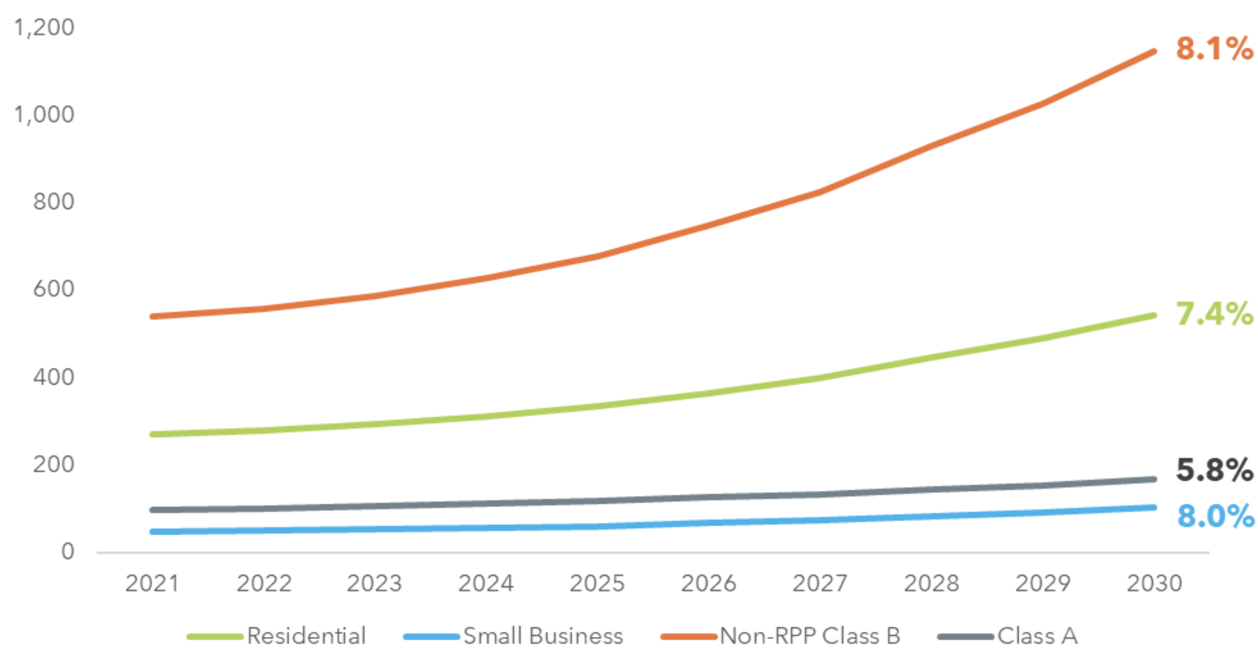


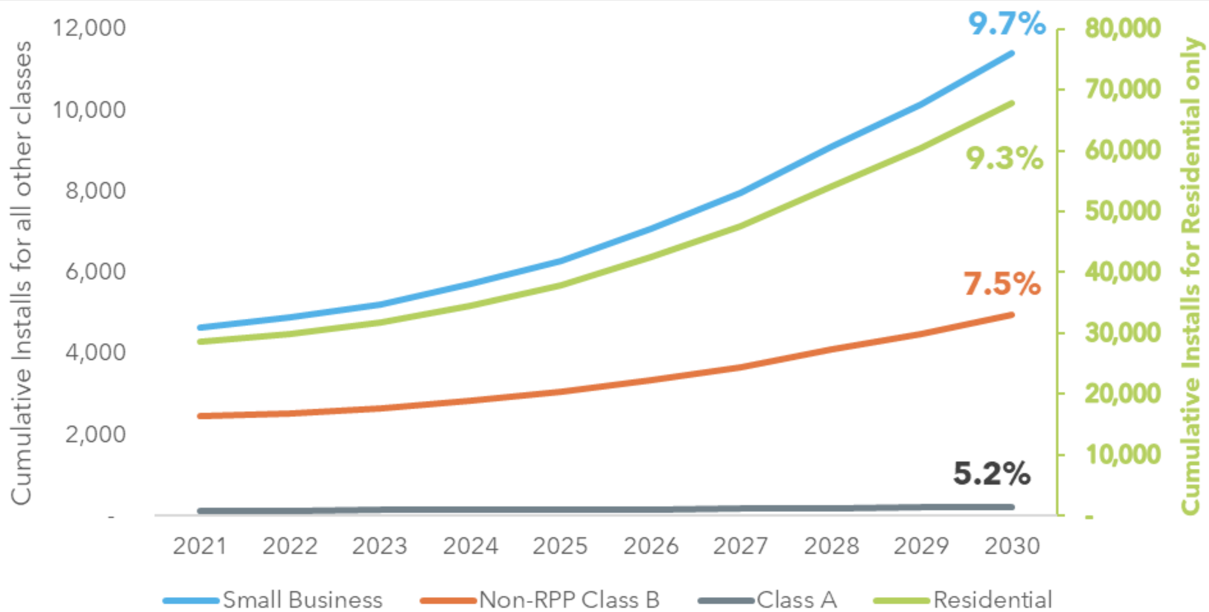
Table 3. Solar PV – Mid Scenario Annual Energy Output (GWh) Projections by Customer Class

Year	Residential	Small Business	Non-RPP Class B	Class A
2021	271.2	48.0	538.0	97.4
2022	280.1	49.8	557.7	100.6
2023	292.9	52.3	585.4	104.9
2024	311.2	56.1	627.5	110.7
2025	333.8	60.5	677.1	117.0
2026	365.0	66.7	747.7	125.2
2027	398.9	73.5	824.0	133.3
2028	444.9	82.6	927.8	144.4
2029	488.3	91.2	1,025.2	154.3
2030	541.5	101.7	1,144.5	167.2

The energy outputs by customer class generally follow the trajectories of the cumulative capacity levels. As with the Scenarios as a whole, the energy output from annual incremental installations is projected to more than offset the lost PV production from equipment degradation for each customer class individually, although those margins are fairly slim for small business and Class A customers. The analysis assumes that all customers of a class deploy solar PV systems of the same size. In reality, however, there is likely to be significant variation in installation sizes across customers based on space constraints, resource availability, project economics, and site-specific considerations.

The projections of cumulative solar PV installations across the four customer classes are depicted in Figure 5[5] and detailed in Table 4.

Figure 5. Solar PV – Mid Scenario Cumulative Number of Installations and CAGR (%) Projections by Customer Class



[5] Please note the two different scales in play, which is due to the number of residential installations differing so much from the other three customer classes

Table 4. Solar PV – Mid Scenario Cumulative Number of Installations Projections by Customer Class

Year	Residential	Small Business	Non-RPP Class B	Class A
2021	28,534	4,655	2,453	133
2022	29,810	4,880	2,535	137
2023	31,730	5,219	2,653	143
2024	34,496	5,707	2,835	150
2025	37,886	6,278	3,046	158
2026	42,555	7,089	3,347	168
2027	47,516	7,945	3,665	178
2028	54,202	9,093	4,092	191
2029	60,333	10,140	4,482	203
2030	67,742	11,399	4,953	218

As noted above, lower tariff rates for Class A customers (compared to non-RPP Class B customers) make it less lucrative for them to invest in PV systems. As a result, the projections show fewer installations by Class A customers (compared to those by non-RPP Class B customers). Additionally, there are generally fewer larger commercial and industrial customers in the province, which explains why the cumulative installs by Class A customers appear flat in the study period in Figure 5 (alongside residential installations), despite the average annual growth of 5.2%.

Residential customers tend to install smaller PV systems (typically lower than 10 kW), so the number of installations by this group can be considerably higher (given the sheer number of residential customers) despite middle-of-the-pack capacity projections. Small business customers also tend to install smaller PV systems, but they face greater financial and administrative barriers such as access to capital and the structure of leasing agreements between tenants and landlords. Accordingly, it is anticipated that small business customers will have considerably fewer installations than residential customers.[6]

Even though the cumulative installs by commercial and industrial customers are anticipated to be less than those by residential customers, it is not surprising that they constitute a greater proportion of installed capacity as they are more likely to invest in larger PV systems.

1.3 Residential Summary

The projections of residential solar PV by cumulative capacity (MW) across the three Scenarios are depicted in Figure 6 and detailed in Table 5.

[6] However, on a per capita basis, the adoption of PV systems by small businesses is projected to be slightly higher than residential installs.

Figure 6. Residential Solar PV – Cumulative Capacity (MW) Projections by Scenario

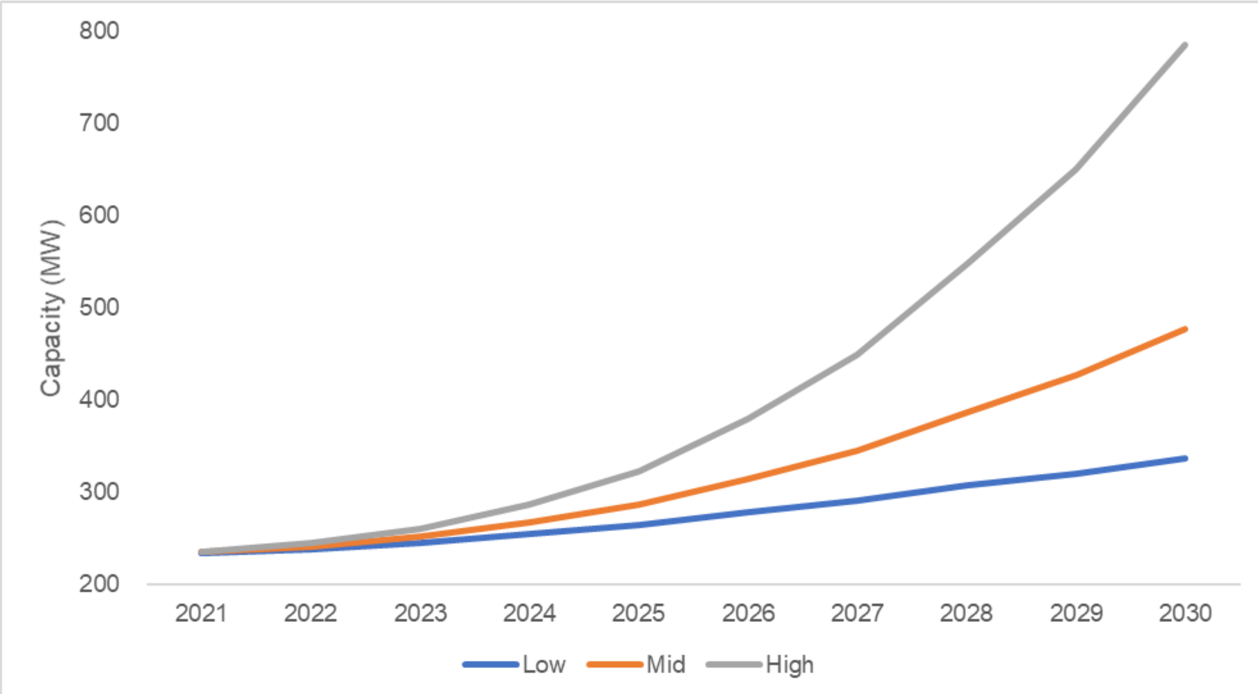


Table 5. Residential Solar PV – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2021	234.6	235.5	236.5
2022	239.1	242.1	246.0
2023	245.9	252.5	261.4
2024	255.0	267.8	287.5
2025	265.1	287.2	322.8
2026	278.3	314.7	379.8
2027	291.3	345.0	448.9
2028	307.3	387.2	548.4
2029	321.0	427.3	650.2
2030	337.2	477.3	784.2

The projections of residential solar PV by annual energy output (GWh) across the three Scenarios are depicted in Figure 7 and detailed in Table 6.

Figure 7. Residential Solar PV – Annual Energy Output (GWh) Projections by Scenario

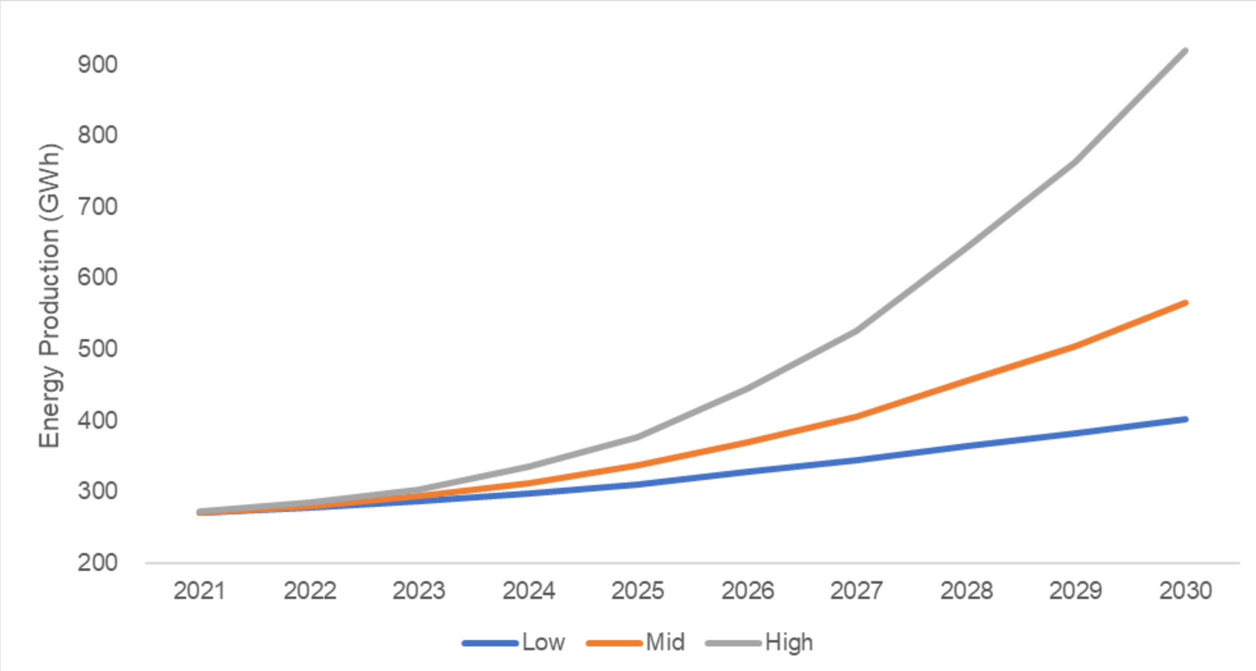


Table 6. Residential Solar PV – Annual Energy Output (GWh) Projections by Scenario

Year	Low	Mid	High
2021	270.4	271.3	272.5
2022	276.9	280.3	284.8
2023	286.0	293.6	303.8
2024	297.9	312.6	335.2
2025	311.0	336.4	377.4
2026	327.6	369.7	444.7
2027	344.2	406.3	526.1
2028	364.3	456.7	642.9
2029	381.8	504.9	762.8
2030	402.3	564.8	920.3

The projections of residential solar PV by number of cumulative installations across the three Scenarios are depicted in Figure 8 and detailed in Table 7.

Figure 8. Residential Solar PV – Cumulative Number of Installations Projections by Scenario

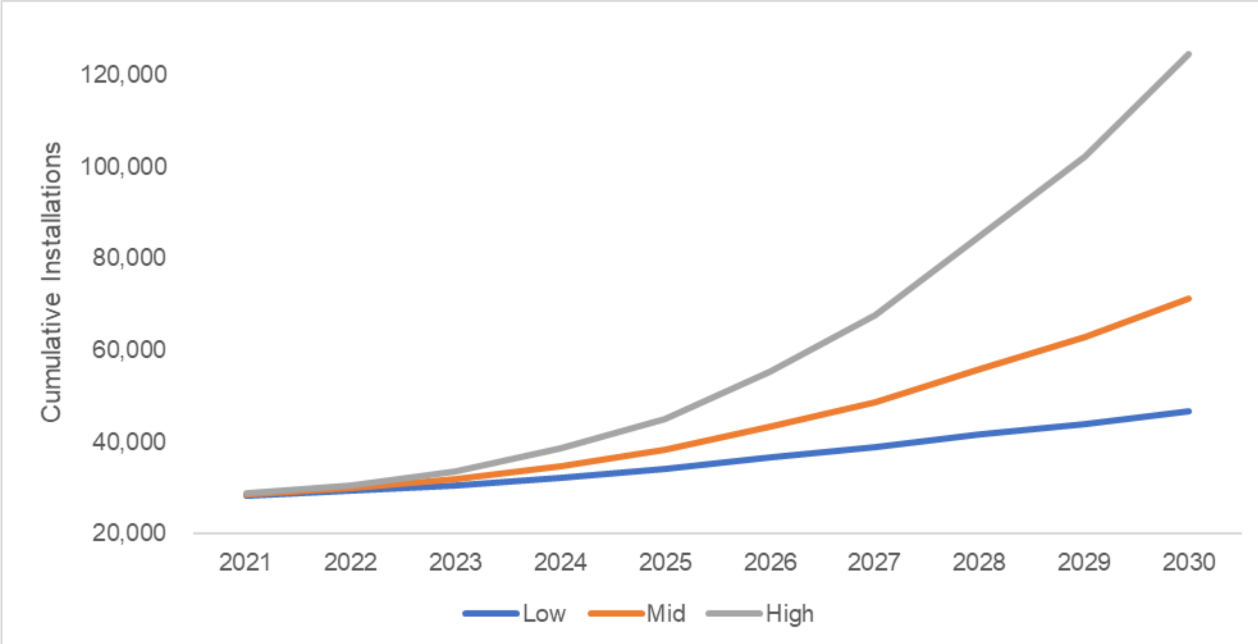


Table 7. Residential Solar PV – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2021	28,378	28,544	28,746
2022	29,265	29,854	30,620
2023	30,556	31,843	33,570
2024	32,281	34,733	38,488
2025	34,153	38,312	45,016
2026	36,530	43,302	55,342
2027	38,846	48,682	67,610
2028	41,631	56,030	84,938
2029	43,965	62,874	102,314
2030	46,688	71,239	124,746

1.4 Small Business Summary

The projections of small business solar PV by cumulative capacity (MW) across the three Scenarios are depicted in Figure 9 and detailed in Table 8.

Figure 9. Small Business Solar PV – Cumulative Capacity (MW) Projections by Scenario

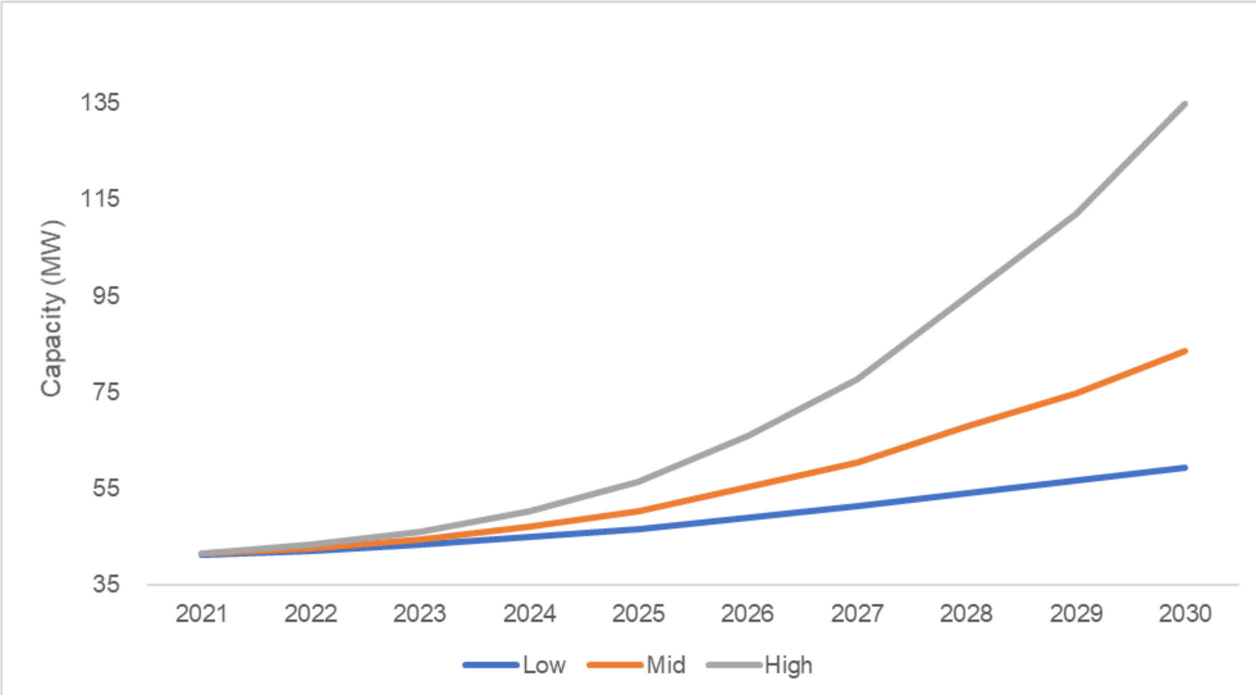


Table 8. Small Business Solar PV – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2021	41.4	41.5	41.7
2022	42.2	42.7	43.4
2023	43.4	44.6	46.1
2024	45.0	47.3	50.5
2025	46.8	50.5	56.6
2026	49.1	55.3	66.0
2027	51.4	60.6	77.7
2028	54.2	67.9	94.7
2029	56.6	74.9	112.0
2030	59.5	83.6	134.8

The projections of small business solar PV by annual energy output (GWh) across the three Scenarios are depicted in Figure 10 and detailed in Table 9.

Figure 10. Small Business Solar PV – Annual Energy Output (GWh) Projections by Scenario

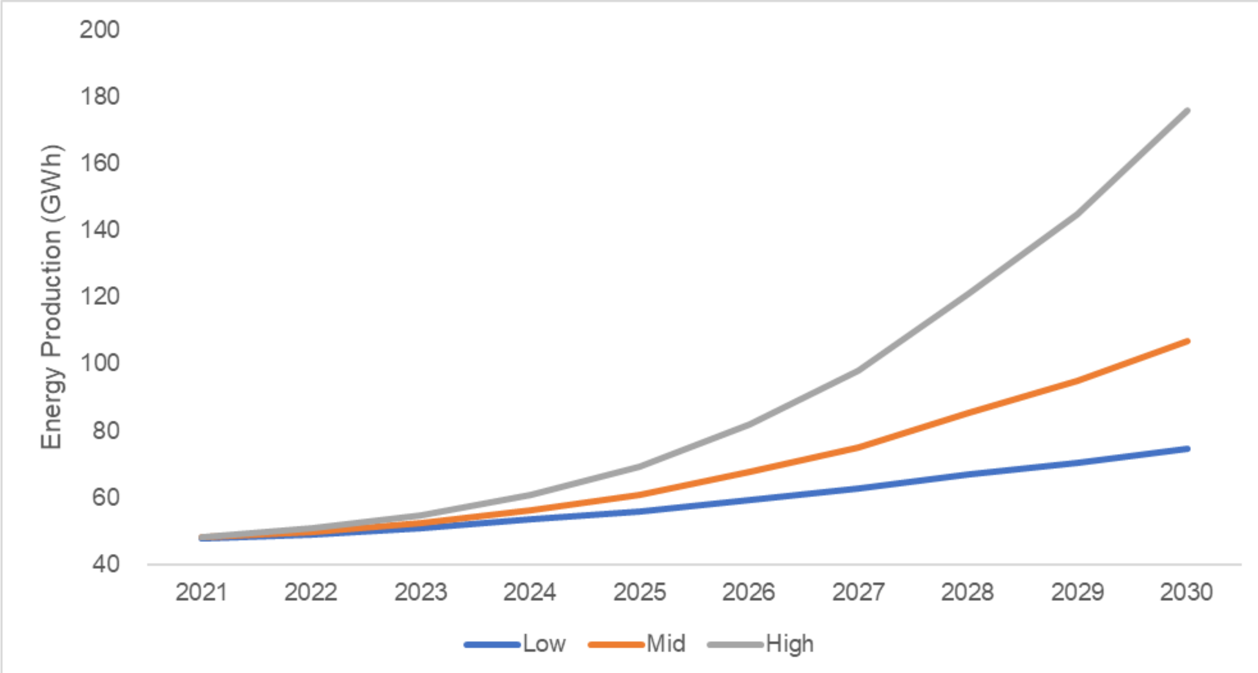


Table 9. Small Business Solar PV – Annual Energy Output (GWh) Projections by Scenario

Year	Low	Mid	High
2021	47.8	48.0	48.2
2022	49.1	49.8	50.7
2023	50.9	52.5	54.6
2024	53.3	56.4	60.7
2025	56.0	61.0	69.1
2026	59.3	67.7	82.0
2027	62.7	75.0	98.0
2028	66.8	85.2	121.1
2029	70.3	94.9	144.7
2030	74.5	107.0	175.8

The projections of small business solar PV by number of cumulative installations across the three Scenarios are depicted in Figure 11 and detailed in Table 10.

Figure 11. Small Business Solar PV – Cumulative Number of Installations Projections by Scenario

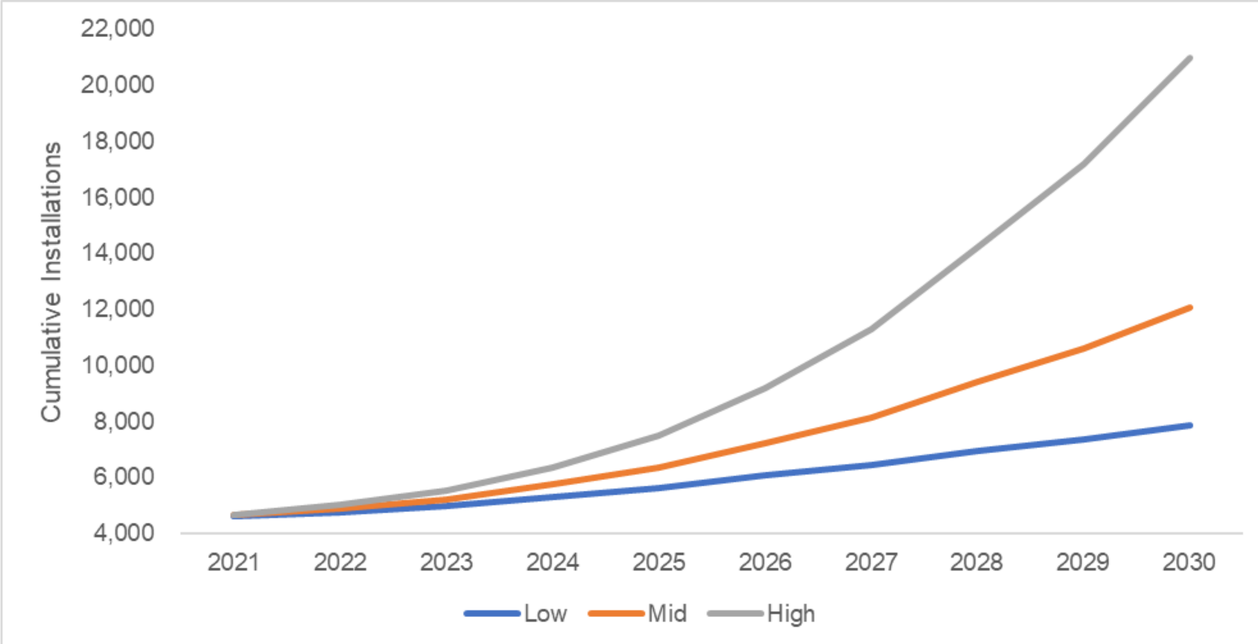


Table 10. Small Business Solar PV – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2021	4,627	4,657	4,692
2022	4,784	4,888	5,023
2023	5,012	5,239	5,543
2024	5,316	5,749	6,369
2025	5,646	6,351	7,499
2026	6,066	7,220	9,199
2027	6,474	8,156	11,286
2028	6,966	9,435	14,233
2029	7,378	10,627	17,188
2030	7,858	12,083	21,003

1.5 Non-RPP Class B Summary

The projections of non-RPP Class B solar PV by cumulative capacity (MW) across the three Scenarios are depicted in Figure 12 and detailed in Table 11.

Figure 12. Non-RPP Class B Solar PV – Cumulative Capacity (MW) Projections by Scenario

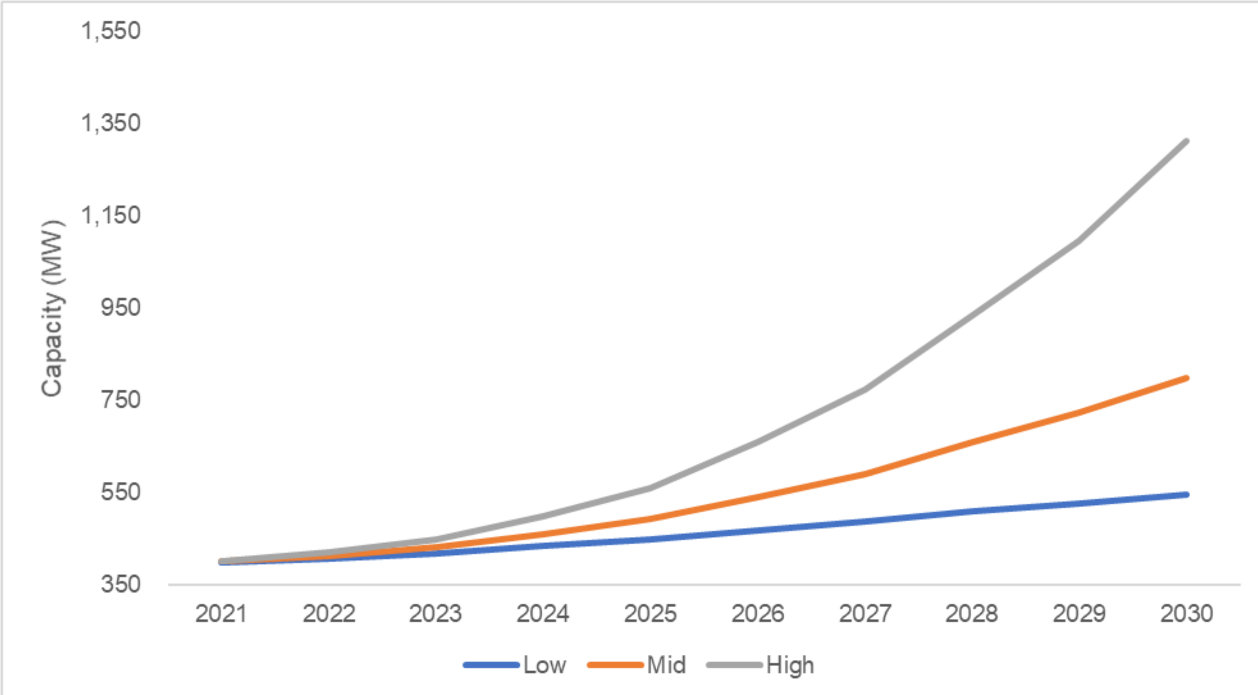


Table 11. Non-RPP Class B Solar PV – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2021	400.1	401.9	403.8
2022	408.5	414.4	421.2
2023	420.1	432.5	450.5
2024	435.0	460.7	498.8
2025	450.6	493.9	561.7
2026	470.0	541.4	659.9
2027	488.3	591.8	774.7
2028	509.9	660.1	935.8
2029	527.4	722.8	1,095.3
2030	547.0	799.1	1,310.4

The projections of non-RPP Class B solar PV by annual energy output (GWh) across the three Scenarios are depicted in Figure 13 and detailed in Table 12.

Figure 13: Non-RPP Class B Solar PV – Annual Energy Output (GWh) Projections by Scenario

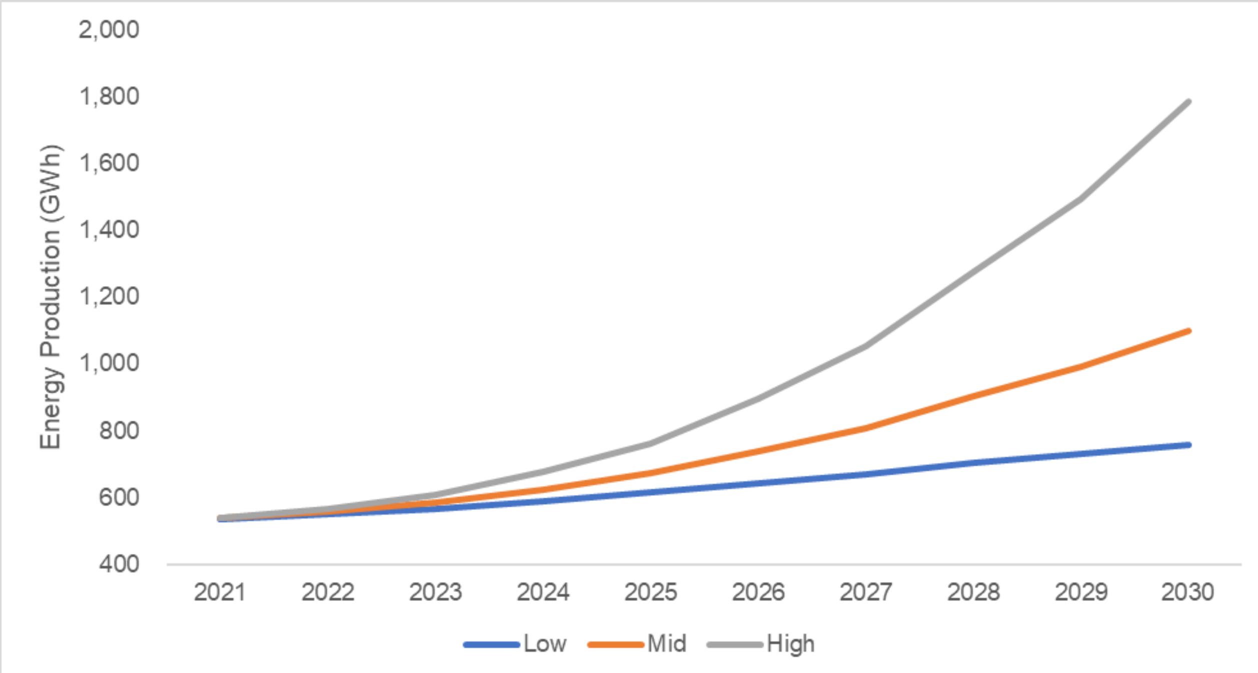


Table 12. Non-RPP Class B Solar PV – Annual Energy Output (GWh) Projections by Scenario

Year	Low	Mid	High
2021	535.6	537.9	540.4
2022	549.5	557.3	566.3
2023	567.6	584.3	608.2
2024	590.3	624.7	675.6
2025	614.1	672.1	762.8
2026	643.0	738.6	897.4
2027	670.5	809.5	1,054.8
2028	702.6	904.5	1,274.6
2029	729.4	992.5	1,493.4
2030	759.3	1,099.1	1,787.5

The projections of non-RPP Class B solar PV by number of cumulative installations across the three Scenarios are depicted in Figure 14 and detailed in Table 13.

Figure 14. Non-RPP Class B Solar PV – Cumulative Number of Installations Projections by Scenario

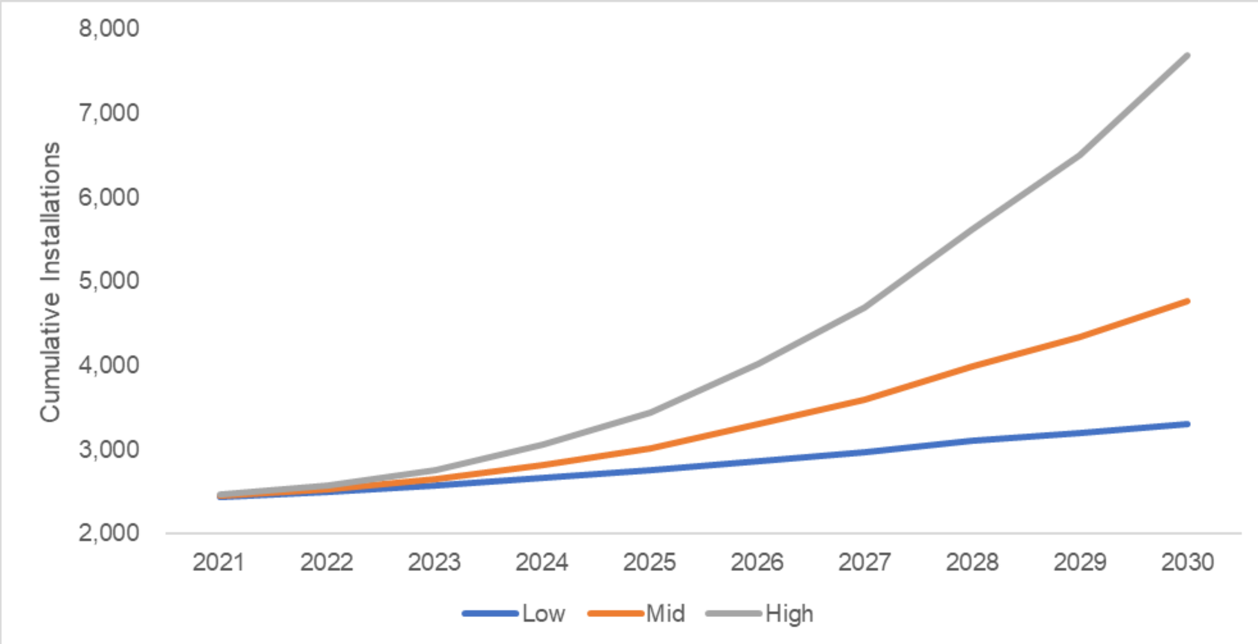


Table 13. Non-RPP Class B Solar PV – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2021	2,441	2,452	2,465
2022	2,495	2,533	2,577
2023	2,568	2,648	2,762
2024	2,660	2,822	3,061
2025	2,755	3,023	3,443
2026	2,870	3,306	4,026
2027	2,977	3,600	4,696
2028	3,100	3,990	5,617
2029	3,198	4,341	6,511
2030	3,306	4,761	7,693

1.6 Class A Summary

The projections of Class A solar PV by cumulative capacity (MW) across the three Scenarios are depicted in Figure 15 and detailed in Table 14.

Figure 15. Class A Solar PV – Cumulative Capacity (MW) Projections by Scenario

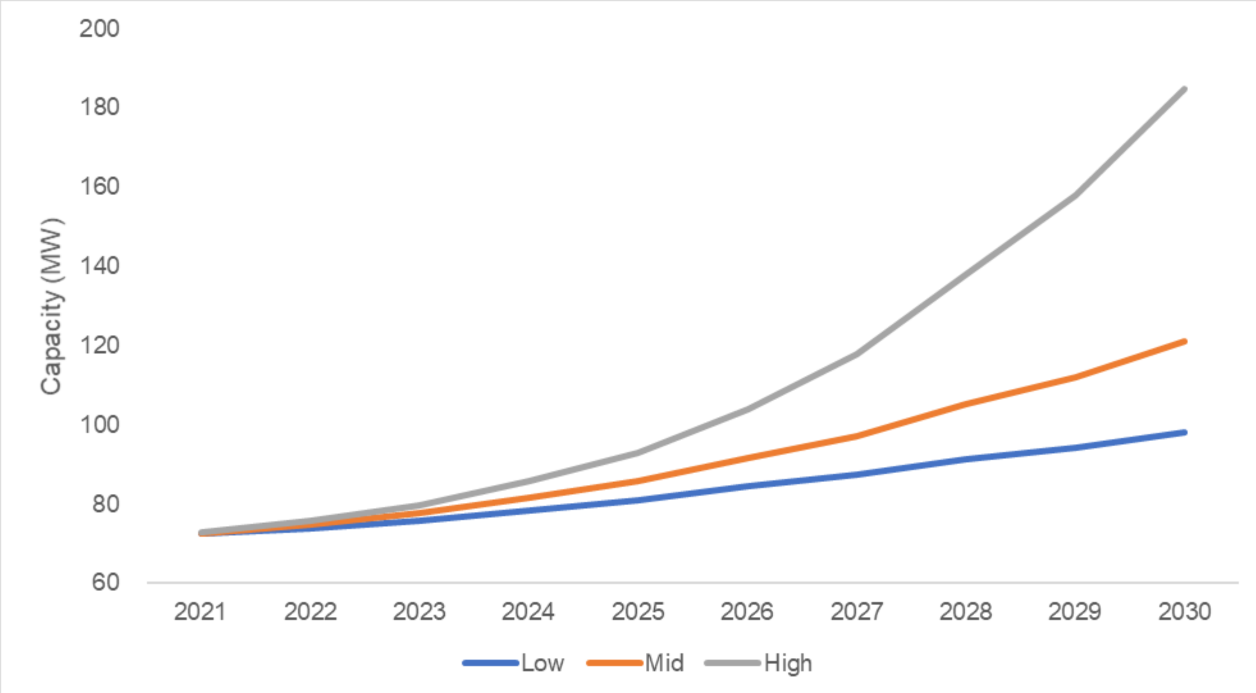


Table 14. Class A Solar PV – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2021	72.5	72.7	73.0
2022	73.9	74.8	75.8
2023	75.9	77.7	79.8
2024	78.4	81.6	85.8
2025	81.1	86.0	92.9
2026	84.4	91.6	104.0
2027	87.6	97.3	117.9
2028	91.4	105.1	138.0
2029	94.4	112.0	157.9
2030	98.0	121.1	184.8

The projections of Class A solar PV by annual energy output (GWh) across the three Scenarios are depicted in Figure 16 and detailed in Table 15.

Figure 16. Class A Solar PV – Annual Energy Output (GWh) Projections by Scenario

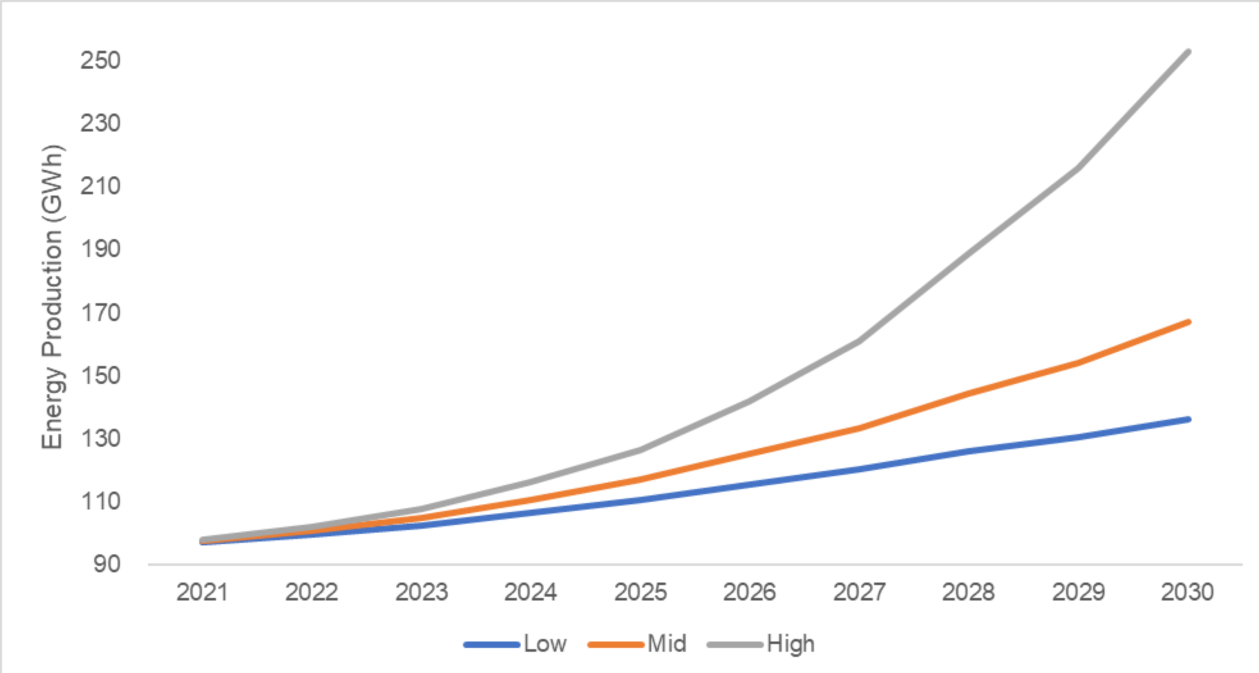


Table 15. Class A Solar PV – Annual Energy Output (GWh) Projections by Scenario

Year	Low	Mid	High
2021	97.0	97.4	97.8
2022	99.4	100.6	101.9
2023	102.5	104.9	107.8
2024	106.3	110.7	116.3
2025	110.5	117.0	126.3
2026	115.5	125.2	141.8
2027	120.3	133.3	161.0
2028	125.9	144.4	188.6
2029	130.6	154.3	216.0
2030	136.0	167.2	253.0

The projections of Class A solar PV by number of cumulative installations across the three Scenarios are depicted in Figure 17 and detailed in Table 16.

Figure 17. Class A Solar PV – Cumulative Number of Installations Projections by Scenario

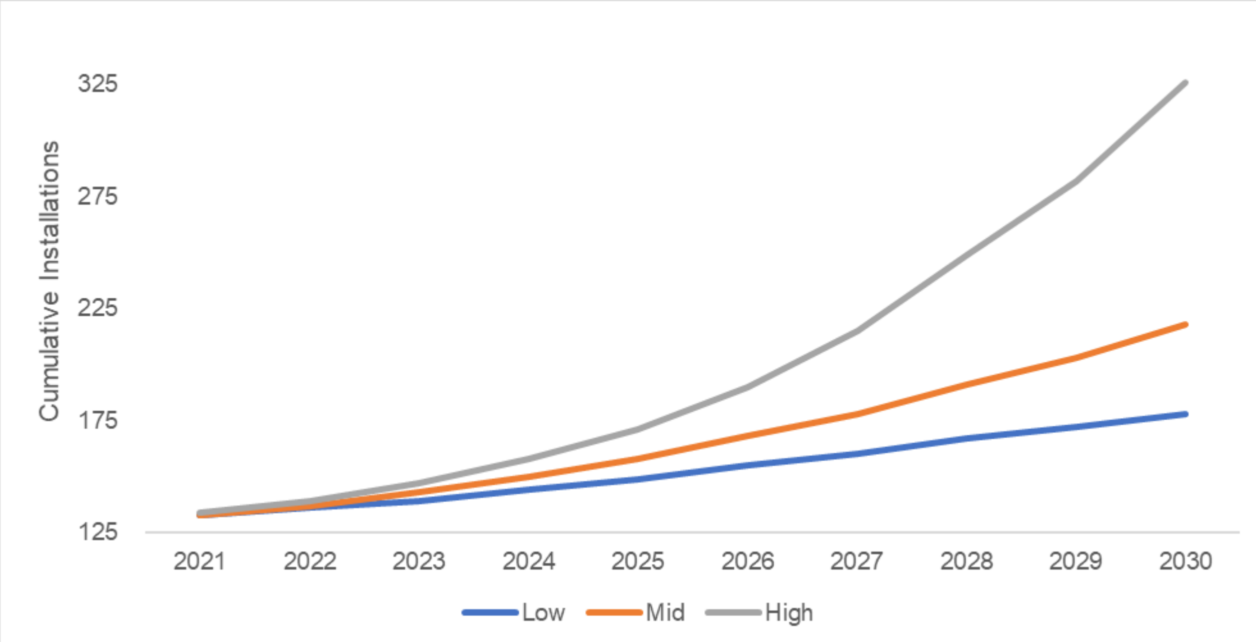


Table 16. Class A Solar PV – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2021	133	133	134
2022	136	137	139
2023	139	143	147
2024	144	150	158
2025	149	158	171
2026	155	168	190
2027	160	178	215
2028	167	191	249
2029	172	203	282
2030	178	218	326

2. Energy Storage

2.1 Scenario Summary – Additional Metric

The projections of energy storage annual net energy charging impact (MWh) across the three Scenarios are depicted in Figure 18 and detailed in Table 17.

Figure 18. Energy Storage – Annual Net Energy Charging Impact Output (MWh) and CAGR (%) Projections by Scenario

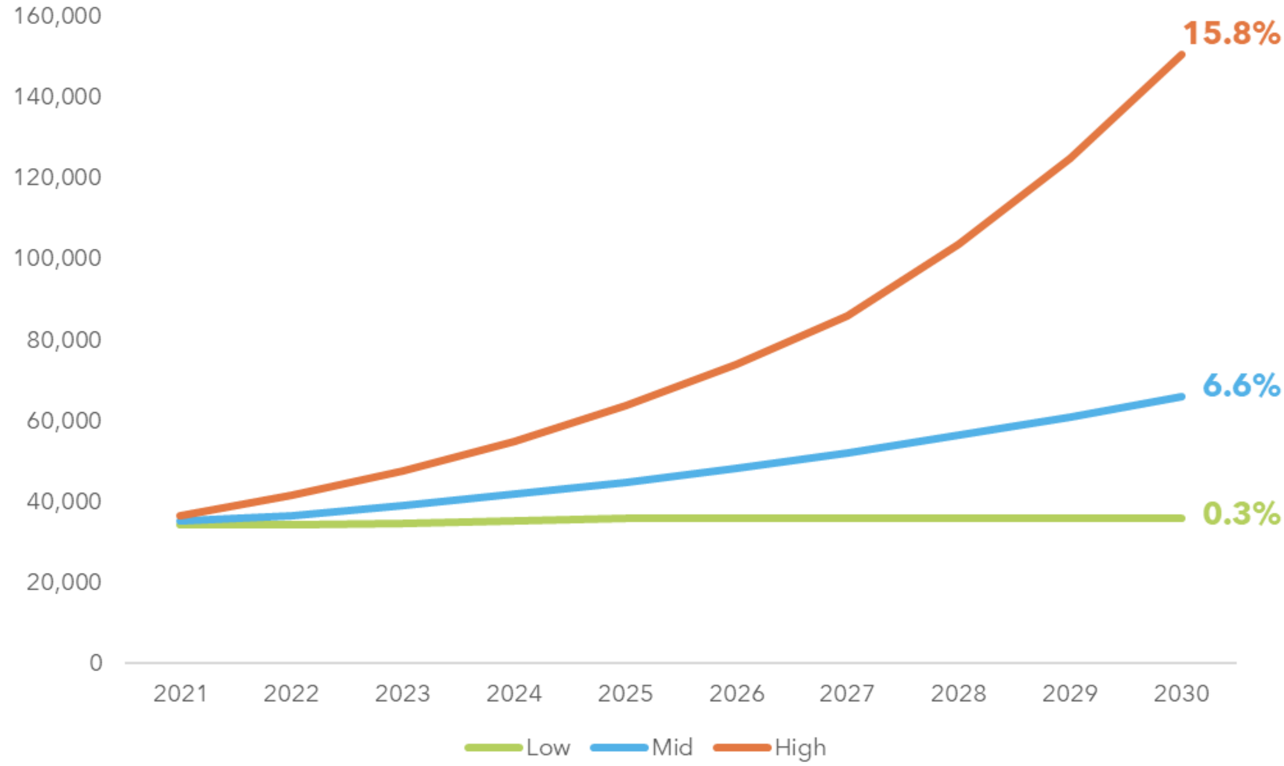


Table 17. Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

Year	Low	Mid	High
2021	34,399.0	35,127.4	36,520.9
2022	34,359.8	36,689.9	41,747.9
2023	34,789.9	39,118.6	47,773.1
2024	35,269.0	41,808.2	54,925.0
2025	35,826.9	44,900.5	63,649.1
2026	35,803.2	48,355.4	74,045.8
2027	35,781.6	52,081.9	85,980.9
2028	35,814.3	56,351.3	103,849.0
2029	35,863.8	60,909.6	124,912.7
2030	35,951.0	66,043.3	150,511.7

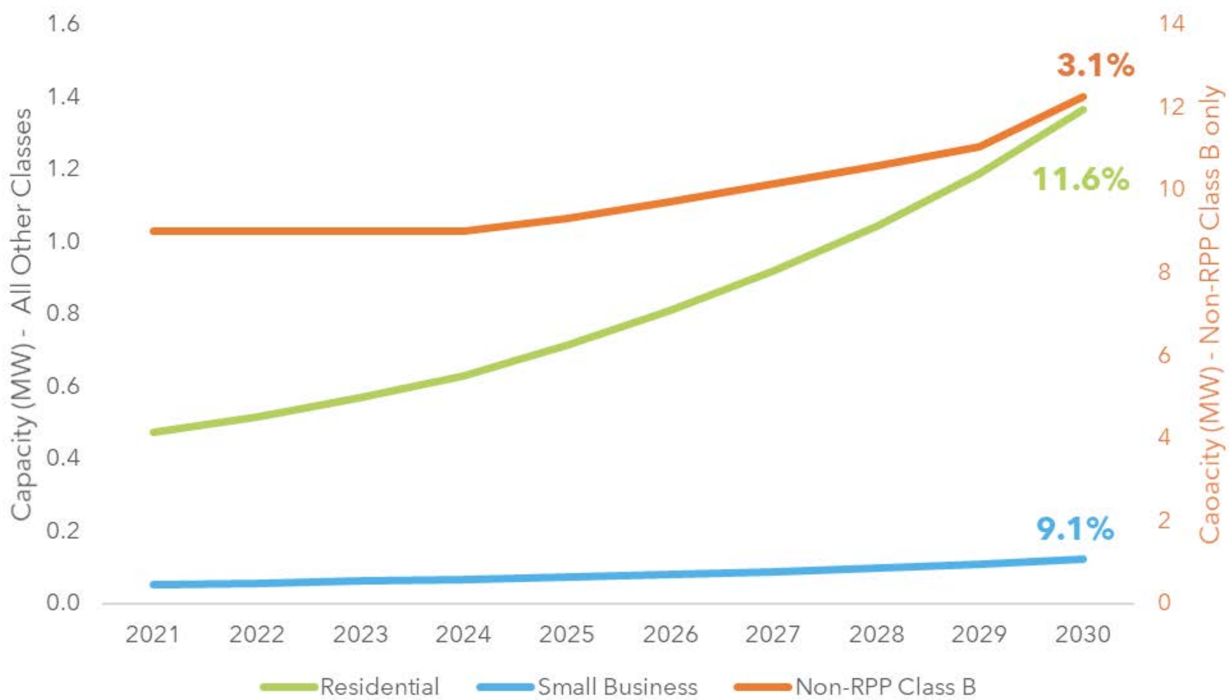
The energy outputs generally follow the trajectories of the provincial cumulative capacity projections as storage energy output is dependent on a system's energy capacity. While similar system sizes were assumed across Scenarios, the differences in net energy impact values across the Scenarios arise due to variations in projections of installed capacity. Battery storage output represents an increase in load from a system perspective. While batteries charge at their full rated energy capacity, some energy is lost due to round-trip efficiency losses during a discharge cycle. Consequently, the discharging energy is lower than the charging energy. While the modeling does assume some annual degradation in storage energy output due to natural wear and tear, the energy output from annual incremental installations offsets the lost storage production. As a result, the charts show a positive slope for energy output across all Scenarios – although that slope is very flat in the Low Scenario and does indicate some years of regression.

2.2 Customer Class Comparison

Because of the number of combinations that result from four customer classes, three Scenarios, and three metrics, the summaries in this section are only for the Mid Scenario. The full extent of Scenario projections by customer class can be found in the sections that follow.

The projections of cumulative energy storage capacity (MW) across the four customer classes are depicted in Figure 19[7] and Figure 20[8] and detailed in Table 18 for the Mid Scenario. Battery storage energy capacity (MWh) scales at a similar rate to power capacity as the kWh/ kW ratio and battery durations remain unchanged for each of the customer classes over the duration of the study period (4 hours for residential, small business and non-RPP Class B customers and 2 hours for Class A customers).

Figure 19. Energy Storage – Mid Scenario Cumulative Capacity (MW) and CAGR (%) Projections by Customer Class



[7] Please note the two different scales in play, which is due to the level of Non-RPP Class B capacity so greatly exceeding that of the other two customer classes included in the chart
[8] Because of the vastly different scales, it was necessary to present Class A separately from the other three customer classes

Figure 20. Energy Storage – Mid Scenario Class A Cumulative Capacity (MW) and CAGR (%) Projection

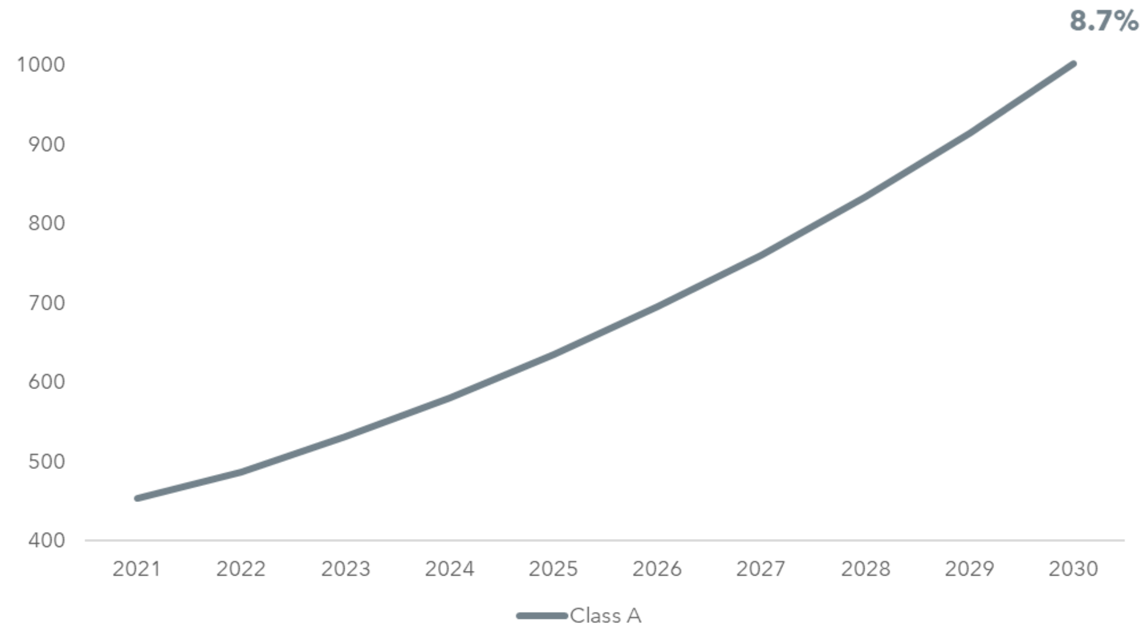


Table 18. Energy Storage – Mid Scenario Cumulative Capacity (MW) Projections by Customer Class

Year	Residential	Small Business	Non-RPP Class B	Class A
2021	0.47	0.05	9.0	453.6
2022	0.51	0.06	9.0	486.4
2023	0.57	0.06	9.0	531.7
2024	0.63	0.07	9.0	581.2
2025	0.71	0.07	9.3	635.3
2026	0.81	0.08	9.7	695.1
2027	0.92	0.09	10.1	761.1
2028	1.04	0.10	10.6	833.7
2029	1.19	0.11	11.0	913.6
2030	1.37	0.12	12.3	1001.7

The span of CAGRs (as measured by cumulative MW capacity growth) for residential storage in these projections ranges from 4.1% in the Low Scenario up to 25.2% in the High Scenario over the study period. By comparison,[9] from 2012 to 2017 the national CAGR for equivalent residential storage installations in the United States was 187.0%.[10] However, there was wide divergence among U.S. states during that period, with CAGRs ranging from 62.4% (New York) up through 134.5% (Hawaii) and even all the way to 404.6% (California). It should be noted that

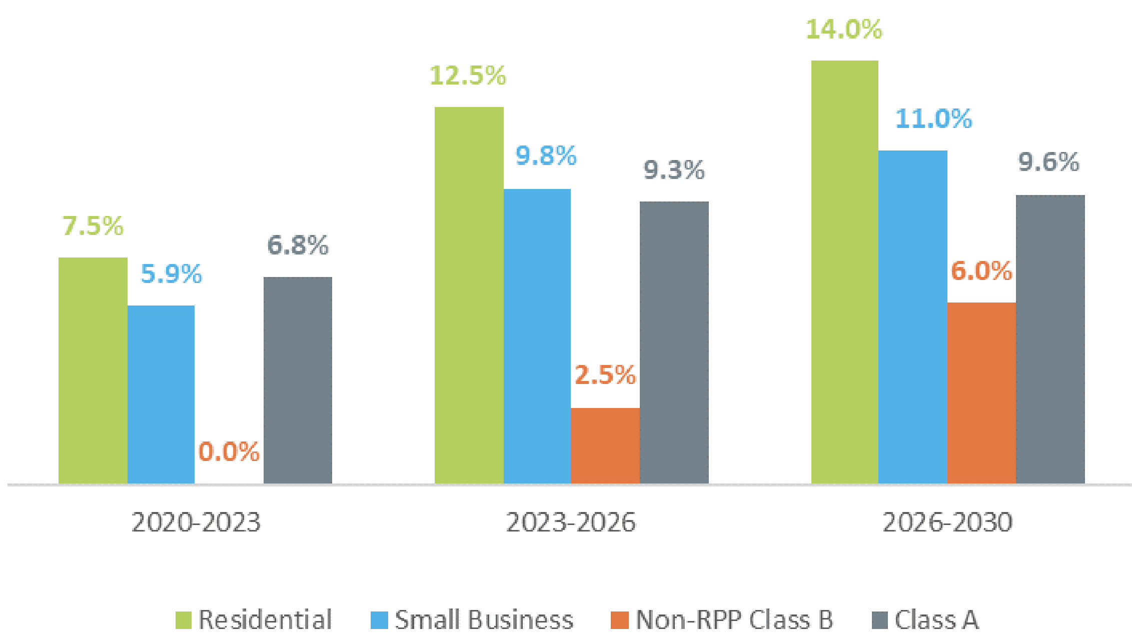
[9] The same caveats about the limitations of historical growth rates as reliable indicators of future growth rates, as well as the limitations of comparing different regions, described above in Section III.2.1, apply here as well.
[10] All growth rates used as comparison derived from: Wood Mackenzie Power and Renewables and SEIA, US Solar Market Insight Full Report, March 2019.

extremely high CAGRs could also be indicative of very rapid DER growth from a relatively low starting value or baseline.

While non-residential customers make for a harder comparison (because the definitions of different commercial and industrial classes vary more by jurisdiction), these same general comparisons hold for the other customer classes as well. The span of CAGRs for non-RPP Class B storage in these projections ranges from 0.3% in the Low Scenario up to 8.3% in the High Scenario over the study period, while Class A projections range from 3.0% to 17.3% over the study period. From 2012 to 2017, the national non-residential storage CAGR in the United States was 134.2%. As with residential customers, though, the commercial and industrial CAGRS for this period varied widely in the U.S., ranging from rates such as 20.7% (PJM, excluding New Jersey) and 45.3% (New Jersey) up to 74.6% (New York) and 134.4% (California).

The projected energy storage CAGRs by customer class for the Mid Scenario are broken down further into shorter timeframes in Figure 21 below.[11]

Figure 21. Energy Storage – Mid Scenario Compound Annual Growth Rate (%) Projections by Timeframe and Customer Class



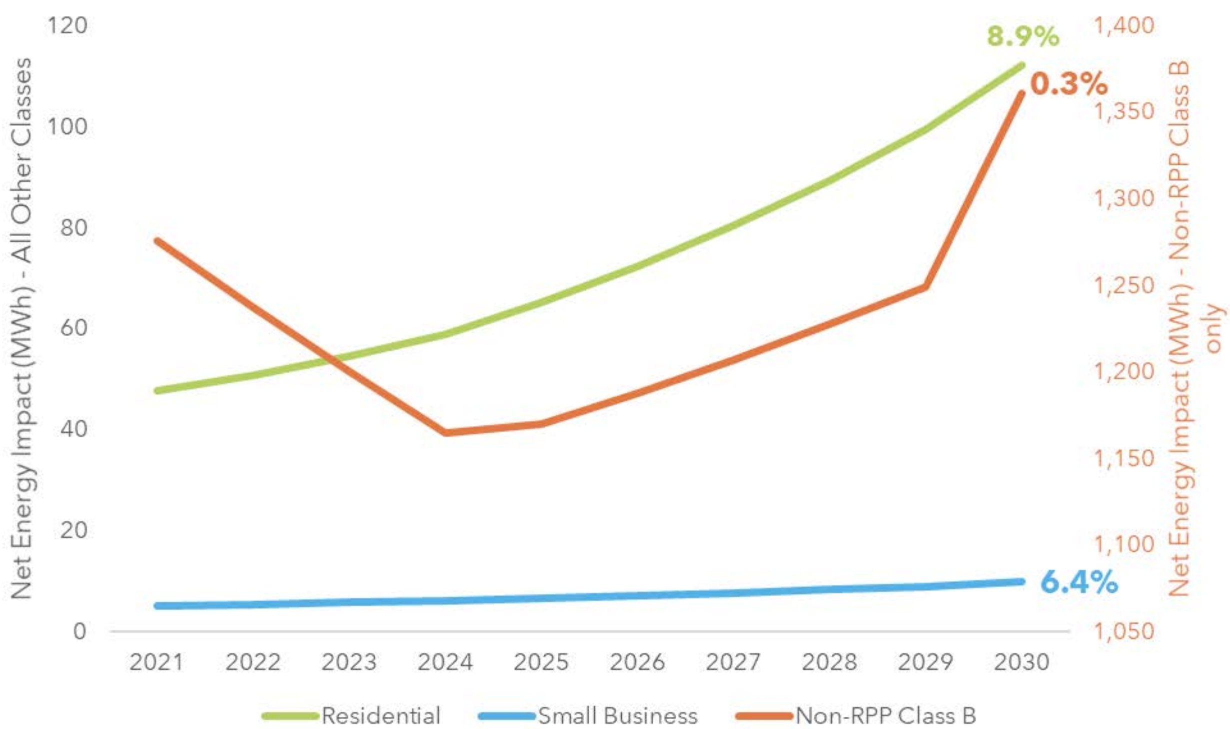
As with the combined storage Scenarios, all four customer classes are projected to experience growth that accelerates as the Study period unfolds. However, as can be seen above, the growth rates themselves diverge somewhat dramatically. Non-RPP Class B customers in particular stand out as a laggard group, due primarily to the relatively poor storage project economics for this class. At present, non-RPP Class B customers can primarily utilize storage as an arbitrage asset and to serve as a source of backup power. However, the economic benefits from these value streams are not adequately rich enough when compared to the costs

[11] Please see footnote 4 above

of purchasing and connecting storage. Nevertheless, ongoing efforts to remove barriers for participation of DER in the IAMs[12] as well as falling technology costs are likely to result in some, albeit few, storage installations by non-RPP Class B customers.

The projections of energy storage annual net energy charging impact (MWh) across the four customer classes are depicted in Figure 22[13] and Figure 23[14] and detailed in Table 19.

Figure 22. Energy Storage – Mid Scenario Annual Net Energy Charging Impact Output (MWh) and CAGR (%) Projections by Customer Class



---

12 IESO, Draft Report Exploring Expanded DER Participation in the IESO-Administered Markets – Part II: Options to Enhance DER Participation, 2020. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx.

13 Please note the two different scales in play, which is due to the level of Non-RPP Class B net energy charging impact so greatly exceeding that of the other two customer classes included in the chart

14 Because of the vastly different scales, it was necessary to present Class A separately from the other three customer classes

Figure 23. Energy Storage – Mid Scenario Class A Annual Net Energy Charging Impact Output (MWh) and CAGR (%) Projection

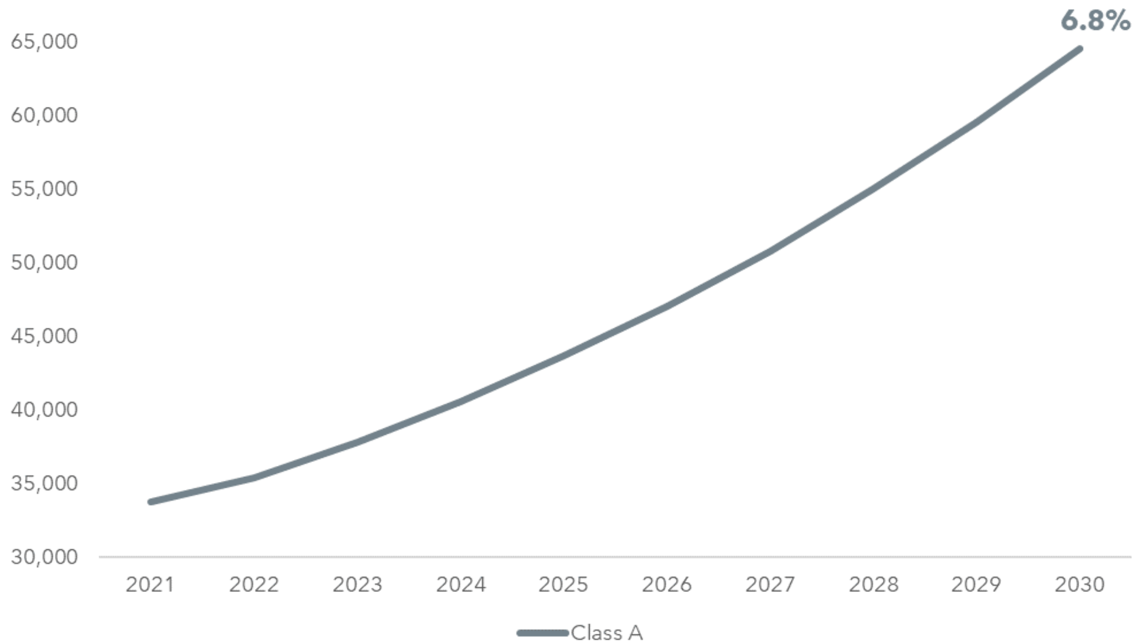


Table 19. Energy Storage – Mid Scenario Annual Net Energy Charging Impact Output (MWh) Projections by Customer Class

Year	Residential	Small Business	Non-RPP Class B	Class A
2021	47.9	5.3	1,276.0	33,798.2
2022	50.7	5.5	1,237.7	35,395.9
2023	54.7	5.8	1,200.6	37,857.5
2024	59.0	6.1	1,164.6	40,578.5
2025	65.3	6.6	1,170.0	43,658.5
2026	72.4	7.1	1,188.1	47,087.8
2027	80.4	7.7	1,207.3	50,786.4
2028	89.4	8.3	1,227.7	55,025.9
2029	99.5	9.0	1,248.9	59,552.2
2030	112.2	9.9	1,360.7	64,560.5

The net energy impact for the projects follow a similar trajectory across customer classes apart from non-RPP Class B customers. For this customer class, the net energy impact is projected to briefly decrease in the first half of the study period. Non-RPP Class B customers are not projected to install any new assets in those years and the energy capacity of existing storage devices reduces due to wear and tear and degradation (an energy capacity degradation rate of 3% per year for storage was assumed). As a result, the available energy capacity from installed assets is reduced. The net energy impact increases in the later years of the study period for non-RPP Class B customers as new devices are installed.

The projections of cumulative energy storage installations across the four customer classes are depicted in Figure 24 and detailed in Table 20.

Figure 24. Energy Storage – Mid Scenario Cumulative Number of Installations Projections and CAGR (%) by Customer Class

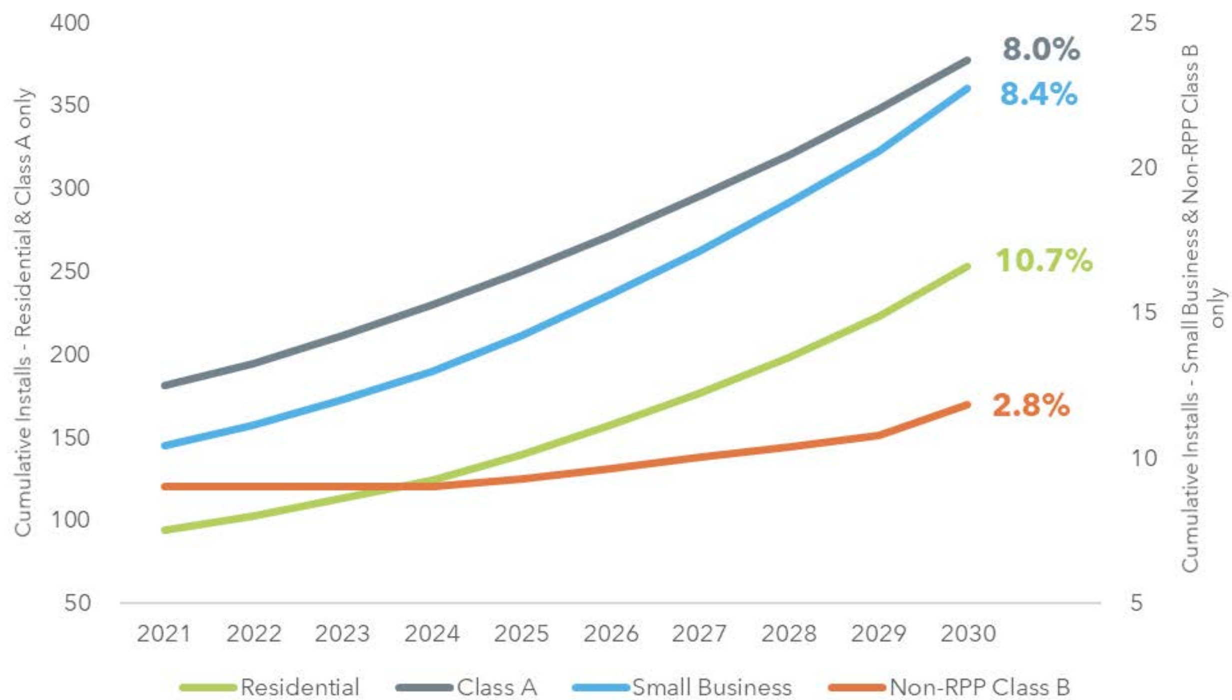


Table 20. Energy Storage – Mid Scenario Cumulative Number of Installations Projections by Customer Class

Year	Residential	Small Business	Non-RPP Class B	Class A
2021	94	10	9	181
2022	103	11	9	194
2023	113	12	9	212
2024	125	13	9	230
2025	140	14	9	250
2026	157	16	10	272
2027	177	17	10	295
2028	199	19	10	321
2029	223	21	11	348
2030	253	23	12	378

The Mid Scenario projects a steady increase in cumulative storage capacity and cumulative installations in the 2021-2023 period across all customer classes except for non-RPP Class B. Adoption rates increase slightly in the 2023-2026 timeframe as the technology matures and there is one additional non-RPP Class B installation. Adoption rates increase slightly again in the 2026-2030 period, and the projections show more than 1,000 MW of battery energy storage capacity in Ontario at the end of 2030.

For residential and small business customers, the opportunity to use storage as an energy arbitrage tool between on- and off-peak times in conjunction with rapidly dropping technology costs are the primary drivers for increased storage adoption. As a simplifying assumption, battery energy is assumed to only serve a customer's native load (reducing electricity purchases) and does not export to the grid under a net-metering type of arrangement. It is anticipated that size thresholds and other participation requirements (such as telemetry and metering conditions) will likely preclude the participation of individual residential and small business customers in the IAMs across Scenarios. It is also assumed that initiatives like IESO's Sector Evolution and White Paper Series [15] as well as the IESO Capacity Auction[16] are likely to result in new opportunities for project developers to bid DER aggregations into the IAMs. ICF incorporated this assumption in the second half of the study period in the High Scenario. Furthermore, in the High Scenario, ICF assumed that distribution companies include storage as part of pilots and non-wires alternatives solutions. These factors contribute to increased storage uptake.

As noted above, there are significant challenges to non-RPP Class B adoption of storage, but some projects could emerge. For Class A customers, participation in the industrial conservation initiative (ICI) to reduce GA charges is a lucrative value stream and the strongest incentive for storage adoption. Project economics for Class A customers are very favourable, contributing to higher adoption rates relative to non-RPP Class B customers. It is also expected that both Class A and non-RPP Class B customers will use storage assets as sources of backup power.

2.3 Residential Summary

The projections of residential energy storage by cumulative capacity (MW) across the three Scenarios are depicted in Figure 25 and detailed in Table 21.

---

[15] For example, the IESO is assessing barriers and seeking to expand DER participation in the IAMs. More information is provided in the whitepapers:
Exploring Expanded DER Participation in the IESO-Administered Markets. Part-I: Conceptual Models for DER Participation. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-paper-series-Conceptual-Models-for-DER-Participation.ashx
Exploring Expanded DER Participation in the IESO-Administered Markets. Part-II: Options to Enhance DER Participation. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx
More information is also available on the IESO's Innovation and Sector Evolution White Paper Series Page. Available online: https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Innovation-and-Sector-Evolution-White-Paper-Series

[16] There may be a need to review and introduce market design changes (such as modifying the dispatchability requirements for aggregation rules) in the Capacity Auction to allow the participation of DER aggregators. Any such changes will likely not occur until the implementation of the Market Renewal Program. More information can be found here: Capacity Auction (ieso.ca) and here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx

Figure 25. Residential Energy Storage – Cumulative Capacity (MW) Projections by Scenario

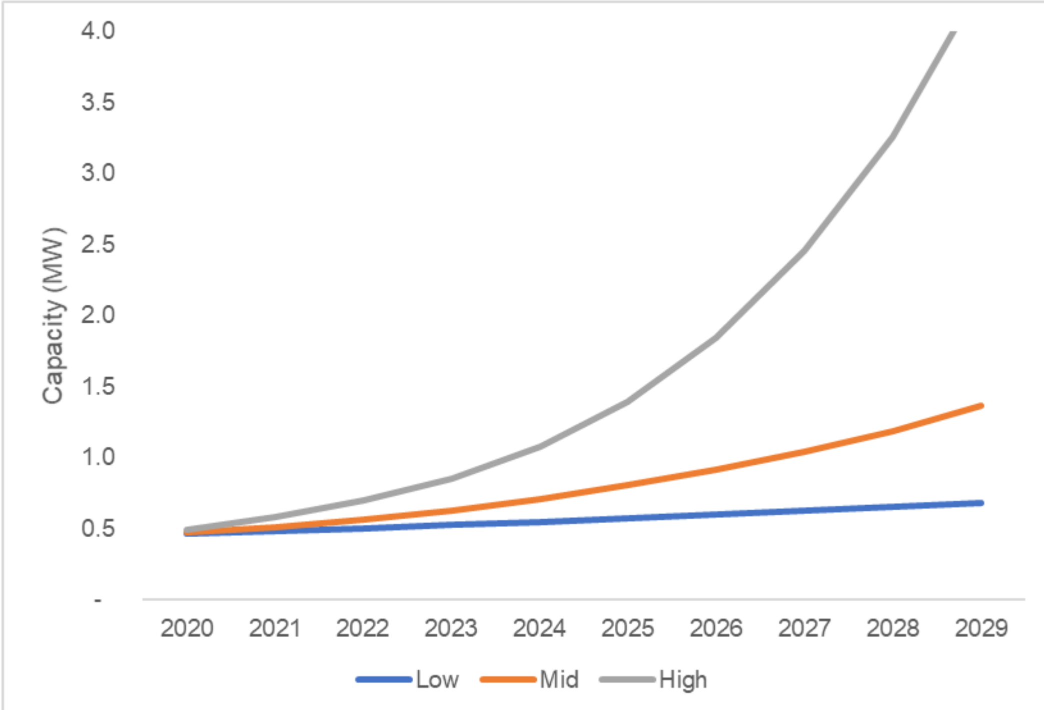


Table 21. Residential Energy Storage – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2020	0.46	0.46	0.46
2021	0.47	0.47	0.50
2022	0.48	0.51	0.58
2023	0.50	0.57	0.70
2024	0.53	0.63	0.86
2025	0.55	0.71	1.08
2026	0.57	0.81	1.40
2027	0.60	0.92	1.85
2028	0.63	1.04	2.45
2029	0.66	1.19	3.26
2030	0.69	1.37	4.34

The projections of residential energy storage by annual net energy charging impact (MWh) across the three Scenarios are depicted in Figure 26 and detailed in Table 22.

Figure 26. Residential Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

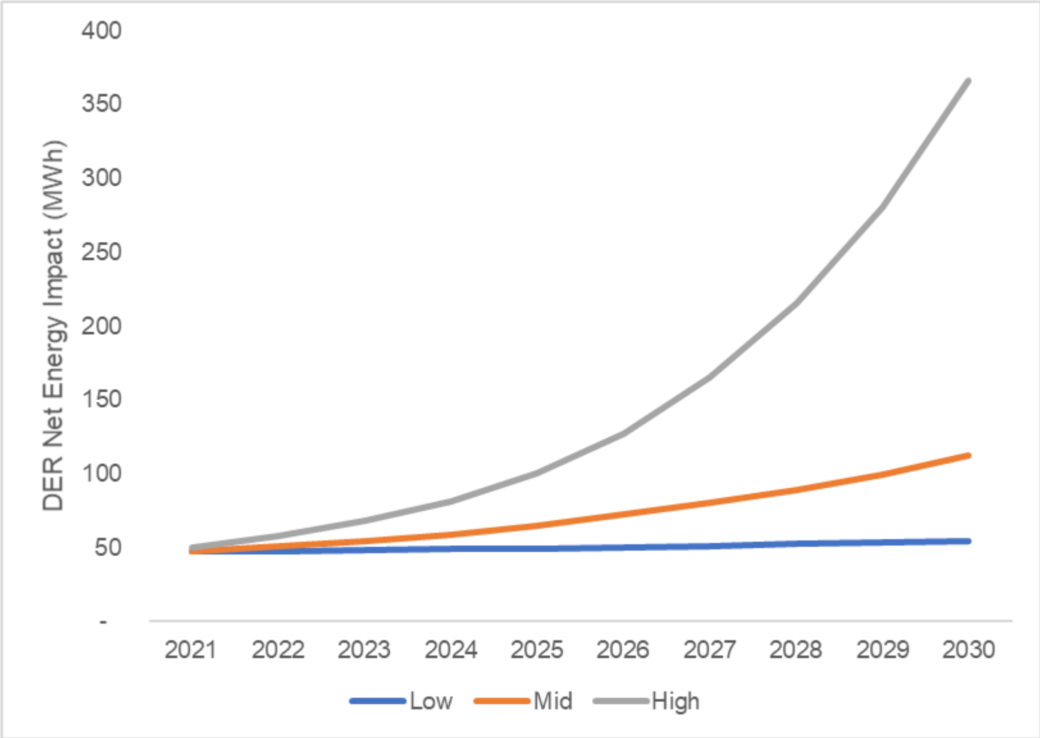


Table 22. Residential Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

Year	Low	Mid	High
2020	47.8	47.8	47.8
2021	47.4	47.9	50.4
2022	47.4	50.7	57.7
2023	48.2	54.7	68.0
2024	49.0	59.0	81.3
2025	49.8	65.3	100.3
2026	50.6	72.4	127.0
2027	51.5	80.4	165.3
2028	52.4	89.4	215.3
2029	53.3	99.5	280.7
2030	54.3	112.2	366.3

The projections of residential energy storage by number of cumulative installations across the three Scenarios are depicted in Figure 27 and detailed in Table 23.

Figure 27. Residential Energy Storage – Cumulative Number of Installations Projections by Scenario

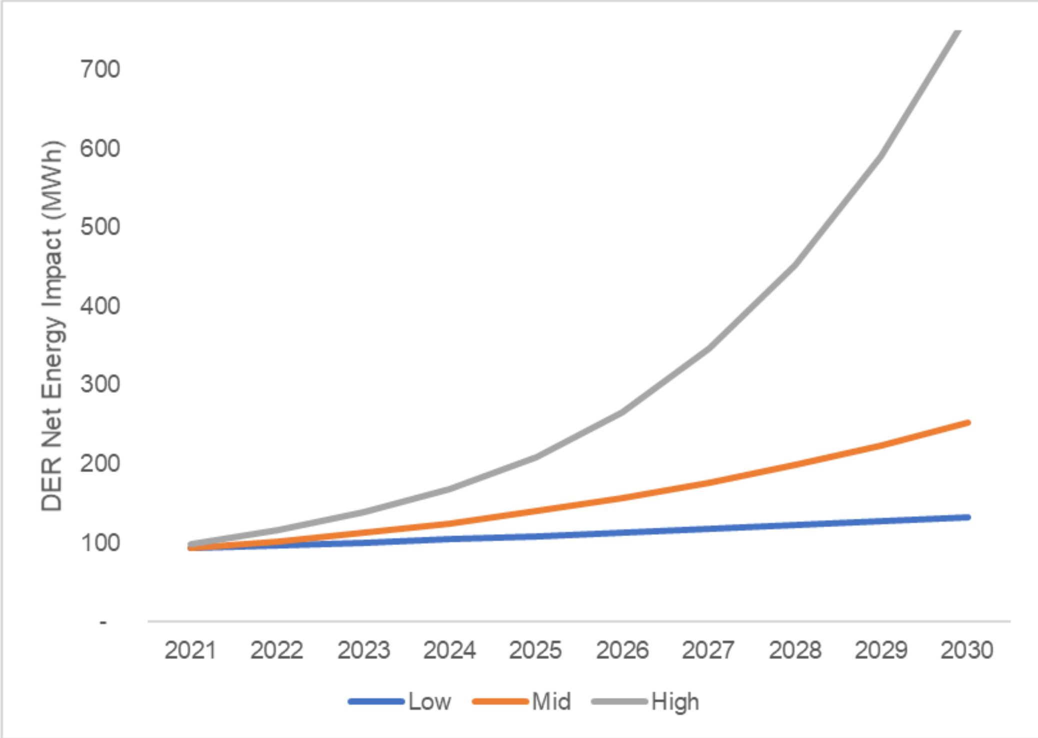


Table 23. Residential Energy Storage – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2020	92	92	92
2021	94	94	99
2022	96	103	116
2023	100	113	139
2024	105	125	169
2025	109	140	210
2026	114	157	267
2027	118	177	347
2028	123	199	453
2029	128	223	590
2030	133	253	770

2.4 Small Business Summary

The projections of small business energy storage by cumulative capacity (MW) across the three Scenarios are depicted in Figure 28 and detailed in Table 24.

Figure 28. Small Business Energy Storage – Cumulative Capacity (MW) Projections by Scenario

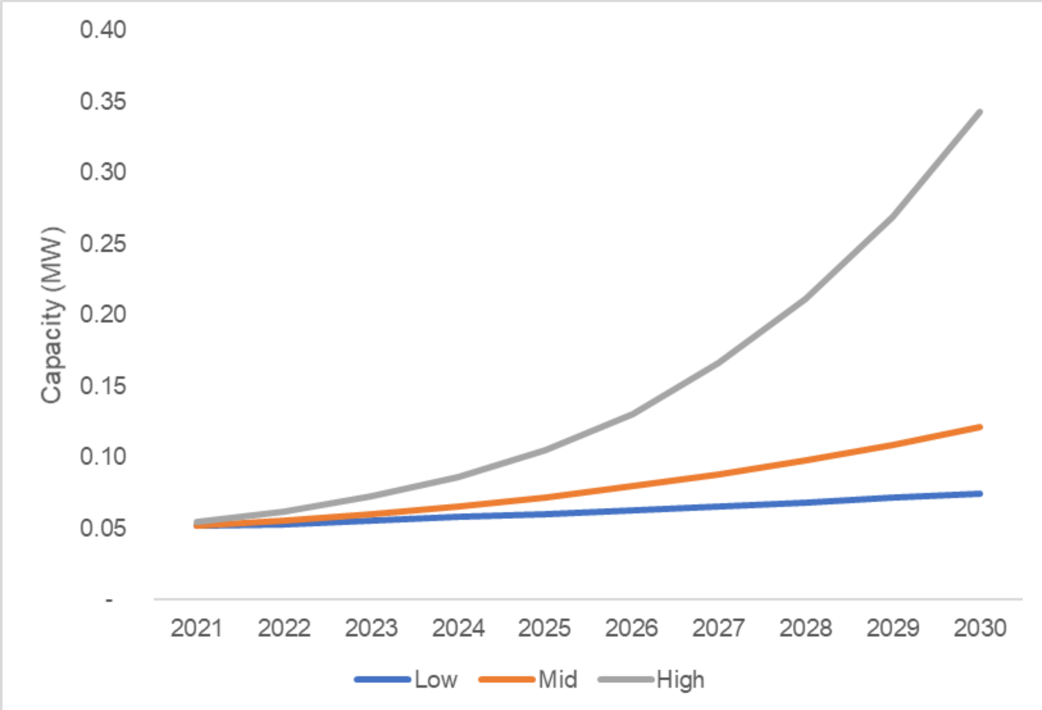


Table 24. Small Business Energy Storage – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2020	0.05	0.05	0.05
2021	0.05	0.05	0.05
2022	0.05	0.06	0.06
2023	0.06	0.06	0.07
2024	0.06	0.07	0.09
2025	0.06	0.07	0.11
2026	0.06	0.08	0.13
2027	0.07	0.09	0.17
2028	0.07	0.10	0.21
2029	0.07	0.11	0.27
2030	0.07	0.12	0.34

The projections of small business energy storage by annual net energy charging impact (MWh) across the three Scenarios are depicted in Figure 29 and detailed in Table 25.

Figure 29. Small Business Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

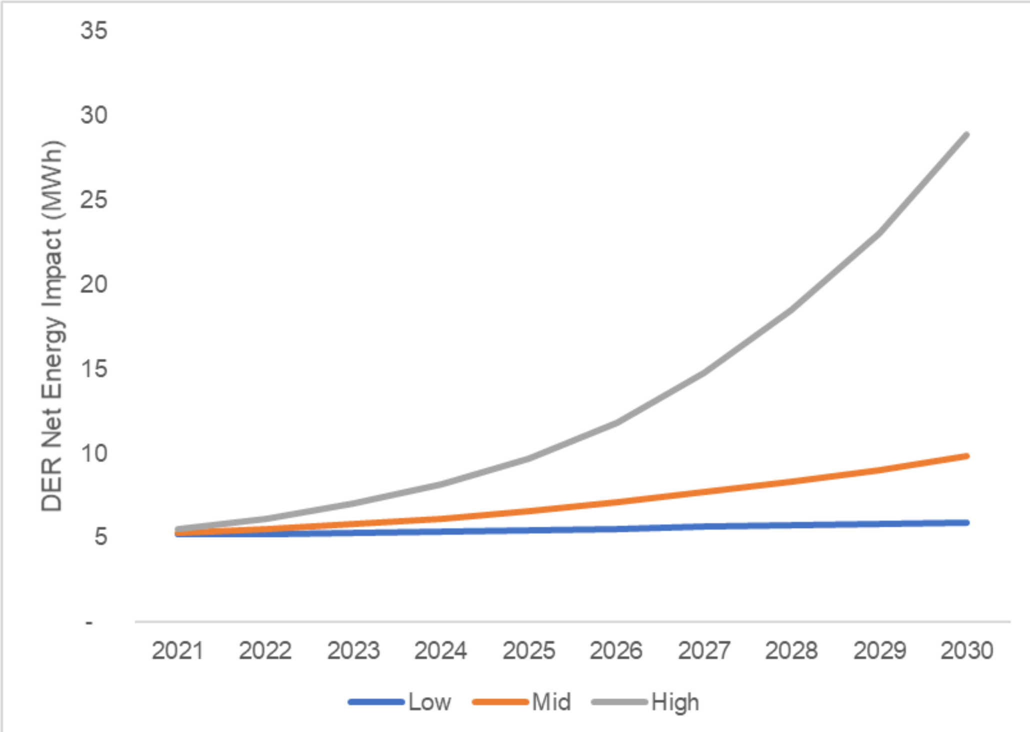


Table 25. Small Business Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

Year	Low	Mid	High
2020	5.3	5.3	5.3
2021	5.3	5.3	5.5
2022	5.3	5.5	6.2
2023	5.3	5.8	7.1
2024	5.4	6.1	8.2
2025	5.5	6.6	9.7
2026	5.6	7.1	11.8
2027	5.6	7.7	14.8
2028	5.7	8.3	18.4
2029	5.8	9.0	23.1
2030	5.9	9.9	28.8

The projections of small business energy storage by number of cumulative installations across the three Scenarios are depicted in Figure 30 and detailed in Table 26.

Figure 30. Small Business Energy Storage – Cumulative Number of Installations Projections by Scenario

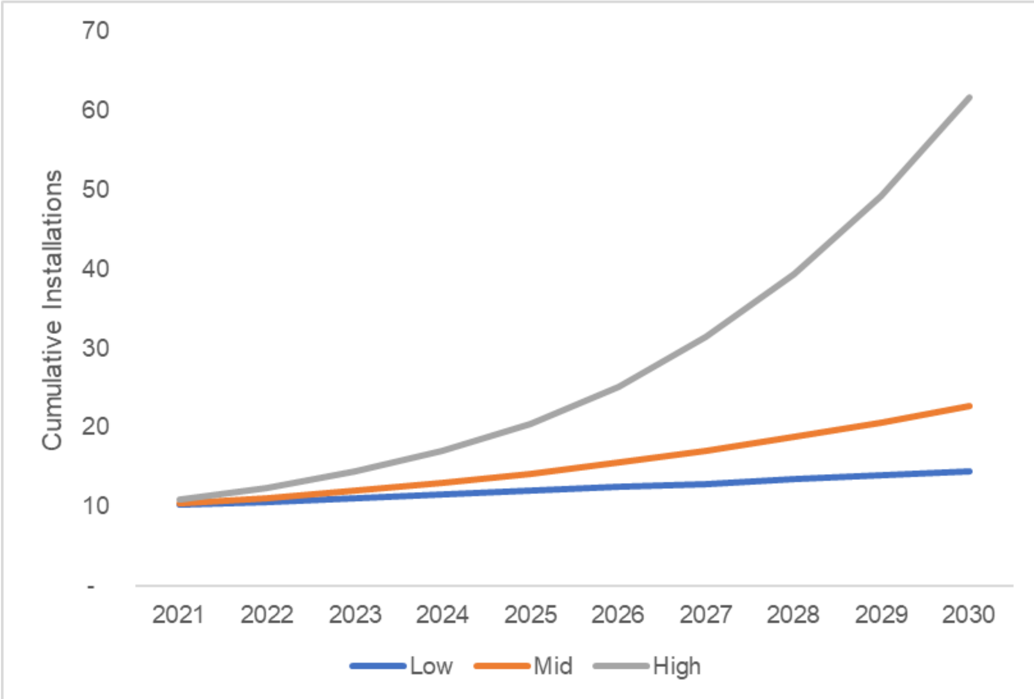


Table 26. Small Business Energy Storage – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2020	10	10	10
2021	10	10	11
2022	11	11	12
2023	11	12	14
2024	12	13	17
2025	12	14	20
2026	12	16	25
2027	13	17	31
2028	13	19	39
2029	14	21	49
2030	14	23	62

2.5 Non-RPP Class B Summary

The projections of non-RPP Class B energy storage by cumulative capacity (MW) across the three Scenarios are depicted in Figure 31 and detailed in Table 27.

Figure 31. Non-RPP Class B Energy Storage – Cumulative Capacity (MW) Projections by Scenario

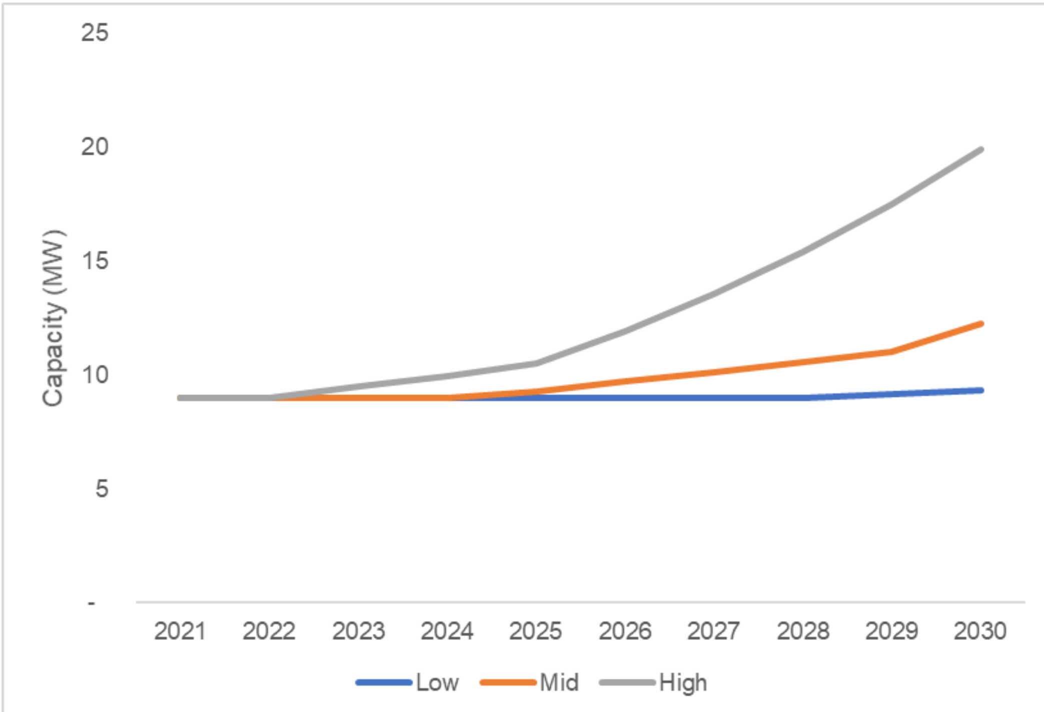


Table 27. Non-RPP Class B Energy Storage – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2020	9.0	9.0	9.0
2021	9.0	9.0	9.0
2022	9.0	9.0	9.0
2023	9.0	9.0	9.5
2024	9.0	9.0	10.0
2025	9.0	9.3	10.5
2026	9.0	9.7	11.9
2027	9.0	10.1	13.6
2028	9.0	10.6	15.4
2029	9.2	11.0	17.5
2030	9.3	12.3	19.9

The projections of non-RPP Class B energy storage by annual net energy charging impact (MWh) across the three Scenarios are depicted in Figure 32 and detailed in Table 28.

Figure 32. Non-RPP Class B Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

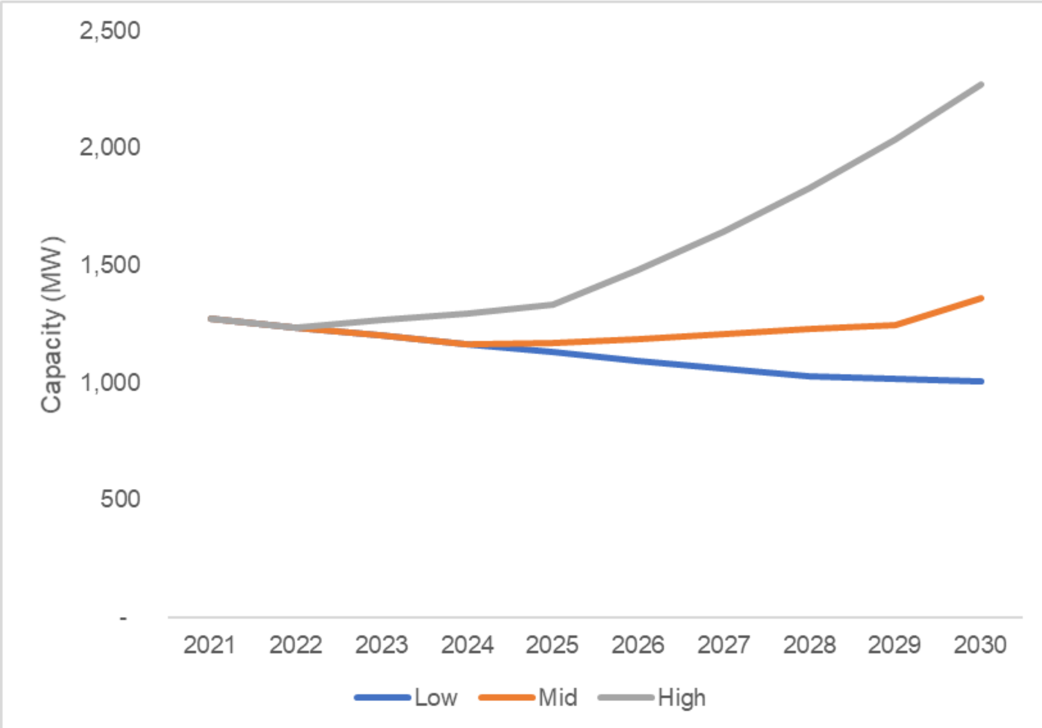


Table 28. Non-RPP Class B Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

Year	Low	Mid	High
2020	1,315.5	1,315.5	1,315.5
2021	1,276.0	1,276.0	1,276.0
2022	1,237.7	1,237.7	1,237.7
2023	1,200.6	1,200.6	1,267.0
2024	1,164.6	1,164.6	1,298.2
2025	1,129.6	1,170.0	1,331.7
2026	1,095.7	1,188.1	1,479.5
2027	1,062.9	1,207.3	1,645.2
2028	1,031.0	1,227.7	1,831.0
2029	1,019.3	1,248.9	2,038.9
2030	1,008.0	1,360.7	2,272.1

The projections of non-RPP Class B energy storage by number of cumulative installations across the three Scenarios are depicted in Figure 33 and detailed in Table 29.

Figure 33. Non-RPP Class B Energy Storage – Cumulative Number of Installations Projections by Scenario

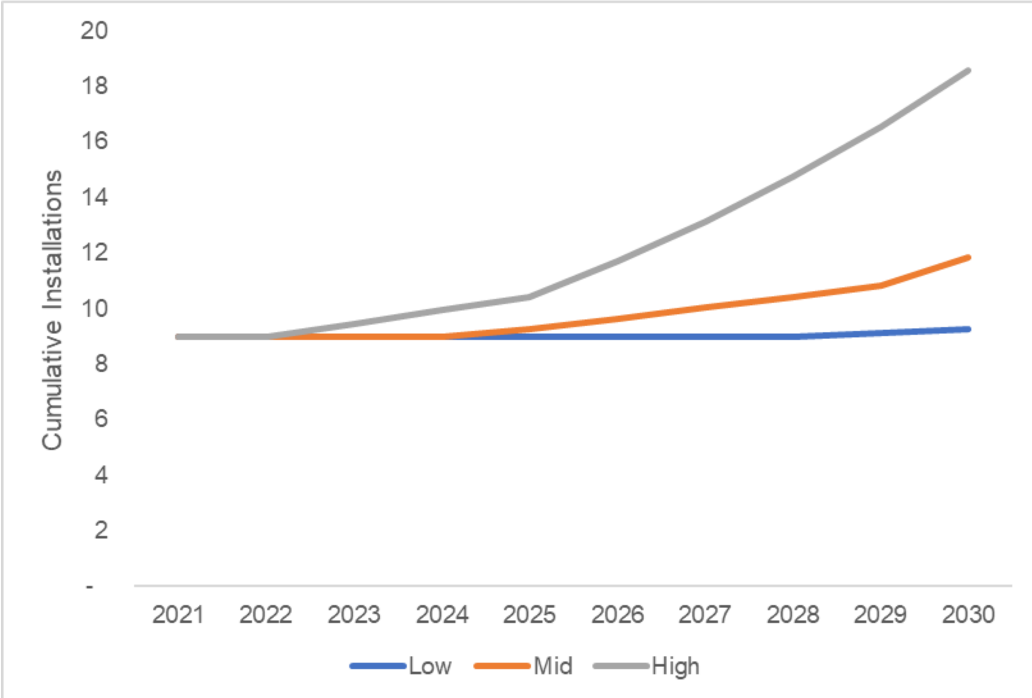


Table 29. Non-RPP Class B Energy Storage – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2020	9	9	9
2021	9	9	9
2022	9	9	9
2023	9	9	9
2024	9	9	10
2025	9	9	10
2026	9	10	12
2027	9	10	13
2028	9	10	15
2029	9	11	17
2030	9	12	19

2.6 Class A Summary

The projections of Class A energy storage by cumulative capacity (MW) across the three Scenarios are depicted in Figure 34 and detailed in Table 30.

Figure 34. Class A Energy Storage – Cumulative Capacity (MW) Projections by Scenario

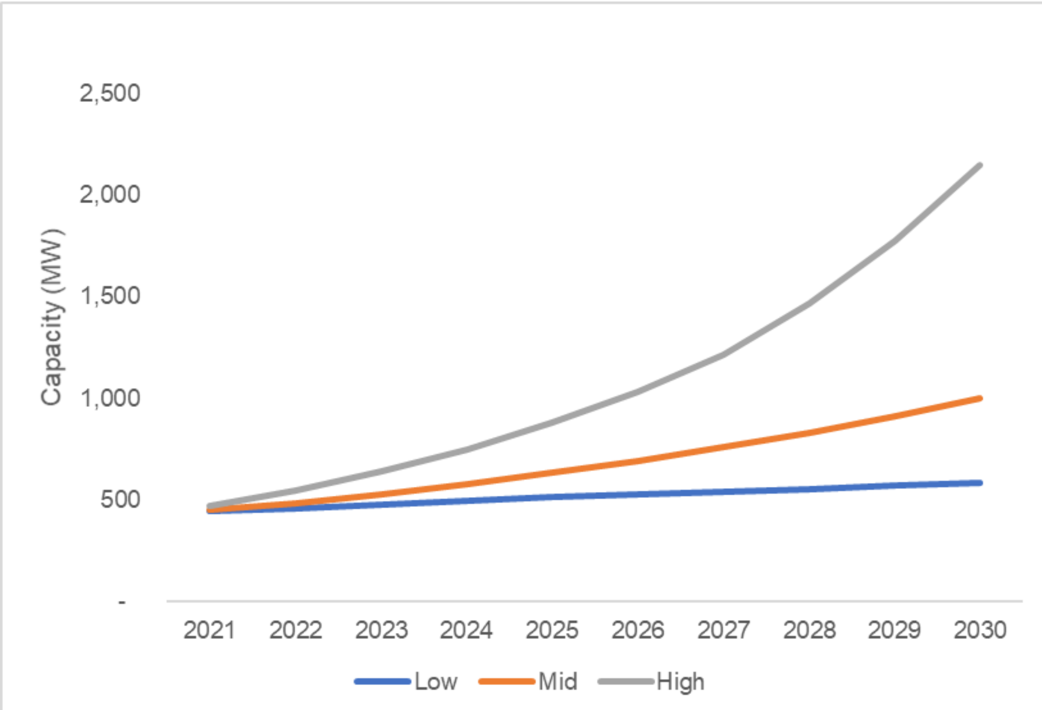


Table 30. Class A Energy Storage – Cumulative Capacity (MW) Projections by Scenario

Year	Low	Mid	High
2020	436.0	436.0	436.0
2021	444.3	453.6	471.5
2022	456.8	486.4	550.7
2023	475.5	531.7	643.2
2024	495.0	581.2	752.3
2025	515.3	635.3	881.7
2026	528.5	695.1	1,034.0
2027	542.1	761.1	1,213.5
2028	556.0	833.7	1,467.5
2029	570.3	913.6	1,776.0
2030	585.0	1,001.7	2,151.1

The projections of Class A energy storage by annual net energy charging impact (MWh) across the three Scenarios are depicted in Figure 35 and detailed in Table 31.

Figure 35. Class A Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

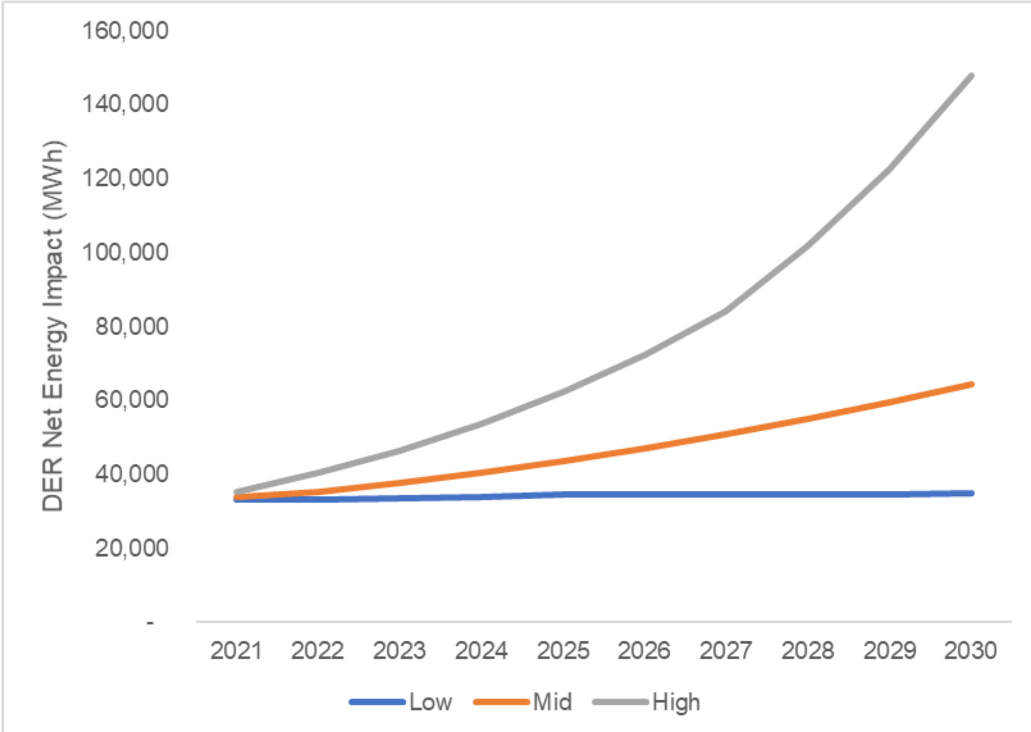


Table 31. Class A Energy Storage – Annual Net Energy Charging Impact Output (MWh) Projections by Scenario

Year	Low	Mid	High
2020	33,427.7	33,427.7	33,427.7
2021	33,070.4	33,798.2	35,188.9
2022	33,069.4	35,395.9	40,446.3
2023	33,535.8	37,857.5	46,431.1
2024	34,050.1	40,578.5	53,537.3
2025	34,642.0	43,658.5	62,207.5
2026	34,651.3	47,087.8	72,427.3
2027	34,661.7	50,786.4	84,155.6
2028	34,725.2	55,025.9	101,784.2
2029	34,785.4	59,552.2	122,570.0
2030	34,882.7	64,560.5	147,844.6

The projections of Class A energy storage by number of cumulative installations across the three Scenarios are depicted in Figure 36 and detailed in Table 32.

Figure 36. Class A Energy Storage – Cumulative Number of Installations Projections by Scenario

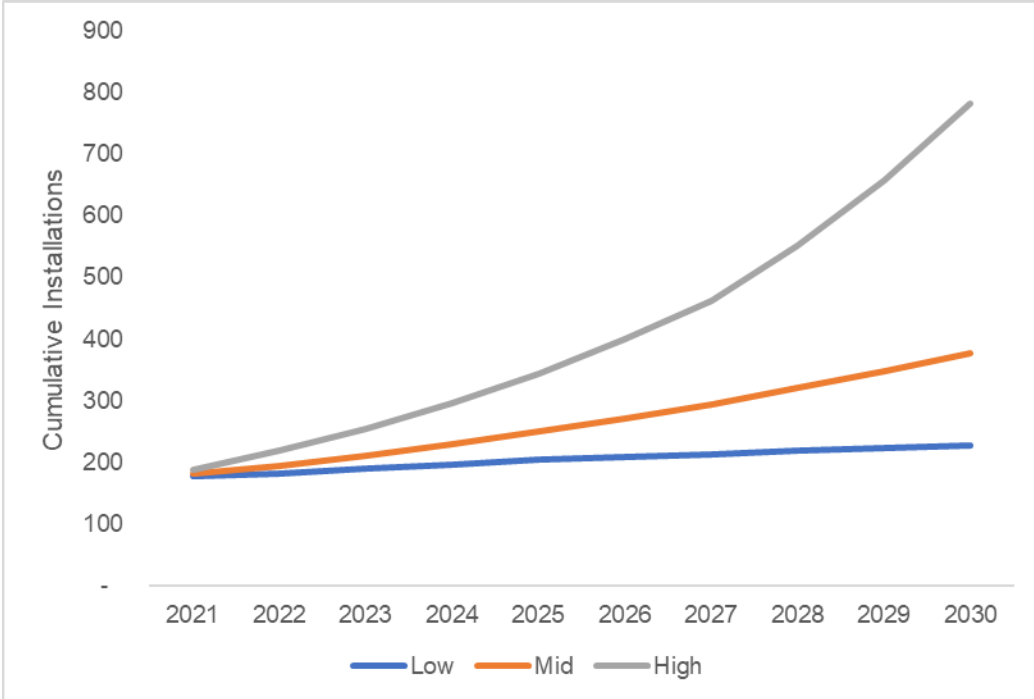


Table 32. Class A Energy Storage – Cumulative Number of Installations Projections by Scenario

Year	Low	Mid	High
2020	174	174	174
2021	178	181	189
2022	183	194	220
2023	190	212	255
2024	197	230	296
2025	205	250	344
2026	209	272	399
2027	214	295	463
2028	219	321	552
2029	224	348	657
2030	229	378	782

II. Appendix B – Parameter Detail

1. Technology

The study considers two of the most common DER technologies that can inject power into the distribution system, solar PV and battery energy storage, for the following reasons. Unlike traditional energy efficiency (EE) and demand response (DR) measures, these injecting resources have a greater impact on system planning and operations. For example, solar PV is a resource whose output is correlated with weather and solar irradiation. Consequently, planners must develop detailed weather and PV output forecasts to understand the impact and contribution of solar PV to serving system load. Furthermore, distribution circuits have not typically been designed to accommodate generation resources and the two-way power flows introduced by DER such as solar PV and storage injecting power into the system at the grid edge. This can have impacts on voltage and power quality, which has implications for the safe and reliable provision of electricity to customers. Enhanced standards, connection rules and new technologies (such as smart inverters) can streamline the integration of injecting resources into the distribution system.

With respect to battery storage, the Study only considered electrochemical battery storage technology. Lithium-ion batteries form the majority of current global and Ontario energy storage deployments and is likely to remain the dominant chemistry going forward. Nonetheless, our analysis is chemistry-agnostic and the variation in capital costs across the three adoption Scenarios can capture the emergence and popularity of new chemistries. The study did not consider pumped hydro storage (PHS) and compressed air energy storage (CAES) as these are physically large resources subject to siting restrictions, are utility-scale resources, and are unlikely to serve individual customers. Thermal energy storage (TES) does not commonly inject power into the grid unless a molten salt storage system is coupled with a concentrated solar PV.

The study did not consider co-located PV+storage systems; i.e., the study considered standalone PV and standalone storage systems. For residential and small business customers, installing PV+storage would be financially attractive if customers were on TOU rates, were subject to demand charges, or customers received NEM compensation at a value lower than the retail rate. In each of these cases, customers could use onsite solar PV to charge their battery systems and then withdraw the energy when grid retail rates were higher, thus reducing their total bill. Customers would consume energy from the grid only at times when PV production was not sufficient to meet demand and/or grid rates were lower. However, in Ontario, NEM has historically been the most prominent incentive for PV and storage adoption. Residential NEM customers are also compensated at the retail rate and are not subject to demand charges. Nonetheless, while the economic case for PV+storage for residential and small business customers is weak, there might be a few specific instances of adoption of these systems in conjunction with one another.

Regarding non-RPP Class B and Class A customers, the PV+storage assets installed by these customers are likely to be much larger in size and would constitute a large capital investment. From a customer viewpoint, the added advantage of PV+storage would be an improved ability to reduce energy costs. Nonetheless, to save energy costs, customers within both classes would need to forecast wholesale prices accurately to coordinate battery charging behavior, such that PV is used to charge storage during the low-priced hours. The lucrativeness of this value stream relative to revenue streams from standalone asset deployment (such as the ability to reduce demand charges or Global Adjustment charges) is also likely to depend heavily on individual customers' load profiles and site characteristics. The framework developed within the context of this Study provides a more generalized approach that could capture the diversity in non-RPP Class B and Class A customers in Ontario.

The sources and inputs for technology costs are shown in the table below.

Table 33. Technology Cost Inputs

Scenario	Low	Mid	High
Solar	NREL ATB 2020 **Conservative** forecast	NREL ATB 2020 **Moderate** forecast	NREL ATB 2020 **Advanced** forecast
Storage	Wood Mackenzie Research **High** Cost Case	Wood Mackenzie Research **Mid** Cost Case	Wood Mackenzie Research **Low** Cost Case

2. Value Streams

Customers derive value from DER in different ways, depending on how the technology can perform, what value streams it is eligible for, and what kinds of customer costs might be offset. The value streams in this Study were held constant for each technology for each of the Scenarios; their magnitude, of course, differed depending on other factors, such as rates. The key value streams, which were applied to specific technologies and customer classes, were:

- Avoided energy costs. This category consists of two sub-categories:
  - Bill savings for customers who adopt PV or storage. DER can reduce the amount of energy customers need to purchase from the grid, reducing their energy costs.
  - Avoided GA charges for Class A customers who adopt storage. Class A customers can use storage to reduce their consumption during system peaks, thus reducing their GA charges.
- Wholesale market energy revenues
- Backup power

Other value streams that were less readily quantifiable were incorporated via the Market Adjustment Factor or the Policy Adjustment Factor. The calculated value streams represented the potential range of revenues that PV and storage can earn, both theoretical and currently monetizable. The value streams were defined such that no overlaps exist between them.

Not all value streams are equally relevant for each technology or customer class. The table below depicts which value streams were assumed to be applicable to each customer class by technology.

Table 34. Customer Value Stream Assumptions – All Scenarios

Technology	Customer Class	Avoided Energy Costs	Wholesale Market Energy Revenues	ToU Bill Management	Backup Power	Avoided Global Adjustment Charges
Solar	All	✓	✓			
Storage	Residential & Small Business			✓	✓	
	Non-RPP Class B		✓		✓	
	Class A		✓		✓	✓

3. Tariffs and Prices

Tariffs and rates provide an indication of the magnitude of each value stream that can be accessed by a customer adopting a certain DER technology. For example, a wide spread between on- and off-peak TOU rates may indicate an opportunity for energy arbitrage by a storage device while very high volumetric retail rates could make solar PV an attractive option for a customer via a NEM tariff. Tariffs can provide a powerful economic signal and act in conjunction with capital costs to incentivize or disincentivize resource adoption.

The baseline HOEP and GA rates are the pre-COVID-19 rates from 2019 but with reduced GA rates for both non-RPP Class B and Class A customers as per the 2020 Ontario Budget Announcement. Based on the illustrative examples provided in the Budget, this translates into a 22% and a 23% reduction in GA rates for Class A and non-RPP Class B rates, respectively. It is assumed that this persists for the duration of the study period.

Forward-looking variations between the Low, Mid, and High Scenarios are handled via the mechanisms described in the projection methodology. The Mid Scenario assumed that tariffs would continue to escalate at rates based on historical precedent and projections from Ontario's 2017 LTEP. The Study assumed that the tariffs in the Low Scenario are lower than the Mid (hence reducing the incentive to offset energy purchases from the grid) while rates in the High Scenario are higher (increasing the incentive to self-consume energy from DER and reduce grid electricity purchases).

The price growth assumptions for solar PV and storage for commercial and industrial customers are the inverse of each other. For solar PV in the Low Scenario, and for storage in the High Scenario, the changes in HOEP and GA rates for non-RPP Class B and Class A customers are assumed to be 80% of the average forecasted changes in HOEP and GA rates from 2021-2030 as described in the LTEP 2017 projections. Furthermore, for solar PV in the High Scenario, and for storage in the Low Scenario, the changes in HOEP and GA rates for non-RPP Class B and Class A customers are assumed to be 120% of the average forecasted changes in HOEP and GA rates from 2021-2030 as described in the LTEP 2017 projections. This is because the LTEP projections indicate a decline in GA costs over time. Hence, applying a high growth rate (120%) to the decreasing trend in GA costs would have meant that the GA costs in the High Scenario would have been lower and decreasing at a faster rate than the GA costs in the Low Scenario. This is a counterintuitive assumption from the perspective of storage economics and adoption. However, for solar PV, project economics are dependent on both HOEP and GA charges. All else being equal, higher electric rates are more conducive to PV adoption. As overall prices increase (primarily due to changes in HOEP), the price growth assumptions of 80% of baseline (for the Low Scenario) and 120% of baseline (for the High Scenario) were maintained for solar PV. For this reason, the price growth rate assumptions for solar PV and storage are the inverse of each other.

Table 35. Residential Tariff and Price Assumptions

Scenario	Low	Mid	High
RPP Bills & Supply Costs	Increase annually at 80% of the escalation rate in the Mid scenario rates.	RPP supply costs increase annually at rates similar to the rate of change in HOEP and GA components per the LTEP 2017 projections. The projections indicate an increase in HOEP and a decrease in GA costs. The baseline ToU rates for residential customers used to calculate the projections are the November 2020 rates and the baseline OER applied to the RPP bill is 33.2%. The impact of the OER was reduced in the projections to account for the lower GA rates (due to the GA decrements as per the 2020 Ontario Budget Announcement as well as the application of LTEP assumptions) by a proportion that ensured that the total RPP bills were still increasing at 2% per year.	Increase annually at 120% of the escalation rate in the Mid scenario rates.
Distribution Costs	Increase by 2% annually during the study period, using November 2020 data as the baseline.		

Table 36. Commercial & Industrial Tariff and Price Assumptions

Scenario	Low	Mid	High
Baseline (for both solar and storage)	Baseline assumptions for HOEP and GA values are the same as in the Mid scenario, with the same reductions in GA rates and including persistence for the duration of the study period. Forward-looking variations between Mid and Low are handled via the mechanisms desribed in the projection methodology.	The baseline HOEP and GA rates are the pre-COVID-19 rates from 2019 but with reduced GA rates for both non-RPP Class B and Class A customers as per the 2020 Ontario Budget Announcement. Based on the illustrative examples provided in the Budget, this translates into a 22% and a 23% reduction in GA rates for Class A and non-RPP Class B rates, respectively. It is assumed that this persists for the duration of the study period.	Baseline assumptions for HOEP and GA values are the same as in the Mid scenario, with the same reductions in GA rates and including persistence for the duration of the study period. Forward-looking variations between Mid and High are handled via the mechanisms described in the projection methodology.
Solar	The changes in HOEP and GA rates for non-RPP Class B and Class A are assumed to be 80% of the rate of average forecasted changes in the HOEP and GA rates from 2021-2030 in the LTEP 2017. The analysis assumes that the ICI hiatus will terminate at the end of 2020. Baseline years for HOEP and GA values are the same as in the Mid scenario.	HOEP and GA rates for non-RPP Class B and Class A vary annually at the average annual % change of forecasted rates from 2021-2030 in the LTEP 2017. The baseline HOEP and GA rates used to calculate the increases are the pre-COVID-19 rate from 2019. The analysis assumes that the ICI hiatus will terminate at the end of 2020.	The changes in HOEP and GA rates for non-RPP Class B and Class A are assumed to be 120% of the rate of average forecasted changes in the HOEP and GA rates from 2021-2030 in the LTEP 2017. The analysis assumes that the ICI hiatus will terminate at the end of 2020. Baseline years for HOEP and GA values are the same as in the Mid scenario.
Storage	The changes in HOEP and GA rates for non-RPP Class B and Class A are assumed to be 120% of the rate of average forecasted changes in the HOEP and GA rates from 2021-2030 in the LTEP 2017. The analysis assumes that the ICI hiatus will terminate at the end of 2020. Baseline years for HOEP and GA values are the same as specified in the Mid scenario.		The changes in HOEP and GA rates for non-RPP Class B and Class A are assumed to be 80% of the rate of average forecasted changes in the HOEP and GA rates from 2021-2030 in the LTEP 2017. The analysis assumes that the ICI hiatus will terminate at the end of 2020. Baseline years for HOEP and GA values are the same as in the Mid scenario.

4. COVID-19

As noted previously, ICF's assumptions related to the impact of the COVID-19 pandemic on DER adoption were informed by insights from London Economics International, which is conducting a *COVID-19 Impact Study* for the OEB as part of the Utility Remuneration and Responding to Distributed Energy Resources initiatives.[17] ICF varied these adjustments by Scenario based on a likely timeline for vaccine development, distribution, and the inoculation of the provincial population.[18] Accordingly, the Low Scenario considered a slow vaccination scenario, the Mid Scenario a relatively faster vaccination scenario, and the High Scenario incorporated the most rapid scenario.

The specific assumptions are shown in the table below.

[17] See https://www.oeb.ca/sites/default/files/ltr-utility-remuneration-20200924.pdf

[18] These assumptions were informed by insights from London Economics International, which conducted a *COVID-19 Impact Study* for the OEB as part of the Utility Remuneration and Responding to Distributed Energy Resources initiatives; see https://www.oeb.ca/sites/default/files/LEI_COVID-19_impact_study_20201216.pdf

Table 37. COVID-19 Assumptions

Scenario	Low	Mid	High
Milestones	• Q3 2021: Approval of a somewhat to passably effective vaccine • Q3 2022: Roll-out, distribution, and delivery complete (by end of Q)	• Q2 2021: Approval of a moderately to largely effective vaccine • Q1 2022: Roll-out, distribution, and delivery complete (by end of Q)	• Q1 2021: Approval of a fully (i.e., almost entirely) effective vaccine • Q3 2021: Roll-out, distribution, and delivery complete (by end of Q)
Effects	• Q1-Q3 2021: Severely dampened adoption rates • Q4 2021-Q2 2022: Moderately dampened adoption rates • Q3-Q4 2022: Somewhat dampened adoption rates as consumer confidence begins to return • Q1 2023 onward: "Normal" adoption rates for the scenario, but based off of an extensively reduced 2021 and somewhat to fairly reduced 2022; extensive permanent demand reduction (the "90% economy")	• Q1-Q2 2021: Severely dampened adoption rates • Q3-Q4 2021: Moderately dampened adoption rates • Q1-Q2 2022: Somewhat dampened adoption rates as consumer confidence begins to return • Q3 2022 onward: "Normal" adoption rates for the scenario, but based off of a fairly reduced 2021; some permanent demand reduction	• Q1 2021: Severely dampened adoption rates • Q2 2021: Moderately dampened adoption rates • Q3-Q4 2021: Somewhat dampened adoption rates as consumer confidence begins to return • Q1 2022 onward: "Normal" adoption rates for the scenario, but based off of a somewhat reduced 2021; no or very little permanent demand reduction

5. Policy

In addition to price signals from technology costs and tariffs, policy mechanisms can also act as strong enablers or deterrents for DER adoption. Clear rules and regulations set forth by policymakers can provide transparency and confidence to project developers and customers and provide the foundation for long-term decisions.

The core economic analysis at the heart of both the solar and storage projection models incorporated two key policy factors:

- Variances in the timing of the integration of distribution-connected resources into the IAMs as a result of the IESO addressing current participation barriers.
    - While all three Scenarios assume that the Market Renewal Program (MRP)[19] initiatives are put in place by 2023, they differ in terms of when distributed solar PV and battery energy storage resources are assumed to be able to actually access wholesale market revenues more substantially (see Appendix B for more information)
    - Unlike the Low and Mid Adoption Scenarios, the High Scenarios assumes some of the barriers to participation in IESO's Administered Markets are addressed within the study period (for instance, reducing the minimum threshold and improving registration processes)

[19] Any changes to market design rules to accommodate integration of DERs in the IAMs will likely not occur before the implementation of the MRP. More information can be found here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx.

- Variances in NEM compensation
  - The Scenarios also vary in terms of NEM compensation. The Ontario government issues a formula for NEM compensation that LDCs are required to follow, although the individual applications of it may depend on LDC-specific charges and therefore likely vary from LDC to LDC. Therefore, NEM compensation is at least partially a policy issue.
  - The Mid Scenario assumes that NEM compensation continues at the status quo – i.e., compensation for export at the retail rate. In the Low and High Scenarios, the compensation is assumed to be lower and higher, respectively, and thus has an accelerating or dampening impact on adoption.

Note that the policy assumptions below only account for one key known initiative related to wholesale markets, and that even then only one wholesale market value stream (energy market revenues) is incorporated into the core economic modeling. Other wholesale market value streams (capacity market revenues, operating reserve revenues, and regulation revenues), as well as other future policy changes, are accounted for via the Policy Adjustment Factor (see Appendix C). The one other policy-impacted factor is NEM compensation, which was handled via the tariffs and prices assumptions above.

Table 38. Policy Assumptions

Low	Mid	High
The Market Renewal Program (MRP) initiatives are put in place by 2023 and integration of distribution connected resources into wholesale markets takes a further six years (i.e., occurring in 2029).	MRP initiatives are put in place by 2023 and integration of distribution connected resources into wholesale markets takes a further three years (i.e., occurring in 2026).	MRP initiatives are put in place by 2023 and integration of distribution connected resources takes one additional year (i.e., occurring in 2024).

III. Appendix C – Supplemental Methodology Detail

1. General Approach

ICF's approach to developing 10-year projections for solar PV and storage by customer class for Ontario included a multi-step, iterative process that resulted in projected values for annual and cumulative installed capacity.

1.1 Metrics

The following primary metrics were reported:

- **Capacity**
  - o The rated generating capacity of the systems installed in Ontario and measured in kW and MW. This is shown separately for PV and storage capacity for more detailed analysis.
  - o The cumulative generating capacity by technology is calculated in the projection models and presented in charts.
- **Installations**
  - o The number of systems (of both technology types) installed in Ontario over the projection period.
  - o This metric is calculated in the projection models and presented in charts on a cumulative basis.

A third set of metrics were calculated, including: **Energy Output and Net Energy Charging Impact.**

- The ***energy output*** metric is applicable only to solar PV installations. This metric indicates the energy produced by solar PV during the projection period and is measured in GWh.
  - o As solar PV is an energy generating resource, the energy output from solar PV reduces the overall energy requirement for utilities in Ontario and customers.
  - o The annual energy output by technology is calculated in the projection models based on the cumulative installed capacity and is presented in the charts below.
- The ***net energy charging impact*** metric is applicable only to battery storage. Batteries can both charge from and discharge energy to the grid, however, a fraction of the charging energy is lost during a battery's discharge cycle due to round-trip efficiency losses. Hence, the battery's discharging energy is lower than its charging energy. As a result, a battery represents a net addition to existing load. The net energy charging impact is measured in MWh.
  - o The annual net energy charging impact by customer class is calculated in the projection models based on the cumulative installed capacity and presented in the charts below.

1.2 Customer Class

Customers are classified for the Study based on how the Global Adjustment (GA)[20] and the Hourly Ontario Electricity Price (HOEP)[21] costs are recovered depending on the billing structure that they fall under. This is based on several factors including the type of customer and the magnitude of electricity consumption, as well as the decisions to opt-in or out of programs like the Industrial Conservation Initiative (ICI)[22]. The primary differentiation is the peak demand by customer classes, with Class B inclusive of three sets of customer sub-classes with peak electricity demand less than 1000 kW while those with demand of 1000 kW or more are considered Class A. Class B is then further divided by those participating in the Regulated Price Plan (residential customers and general service customers with a peak demand less than 50 kW) and those who are not.

The four customer classes used in this Study's projections are:

- **Residential:** The tariff structure for the residential segment aligns with the billing for the Regulated Price Plan (RPP) based on Time of Use (TOU) rates as defined by the OEB.[23]

- **Small Business:** The small business segment does not neatly fit into a single billing category – e.g., Some small businesses may fall under 'General Service consumers with an average monthly peak demand less than 50 kW' while others may fall under the General Service consumers with equal to or greater than 50kW of average monthly peak demand. Based on recommendations from the OEB, the tariff structure of the small business segment is assumed to be the same as the residential described above – i.e., RPP TOU structure.

- **Non-RPP Class B Commercial:** This category includes commercial customers with average monthly demand greater than or equal to 50 kW and not participating in the ICI program. The tariff structure for the non-RPP Class B customers is assumed to align with the billing for the General Service consumers with an average monthly peak demand between 50 kW and 999 kW (GS 50 – 999 kW) and not participating in the ICI

[20] The global adjustment (GA) is a regular billing fee paid by Ontario consumers to cover the fixed cost to build and maintain generation assets in the province, and to fund Ontario's conservation programs. More information can be found here: What is Global Adjustment? (ieso.ca)
[21] In the IESO-administered market, the Hourly Ontario Energy Price (HOEP) is charged to local distribution companies (LDCs), other non-dispatchable loads and paid to self-scheduling generators. More information can be found here: Monthly Market Report (ieso.ca)
[22] The Industrial Conservation Initiative (ICI) is a form of demand response that allows participating customers (Class A) to manage their global adjustment (GA) costs by reducing demand during peak periods based on their percentage contribution to the top five peak Ontario demand hours over a 12-month base period. More information can be found here: Industrial Conservation Initiative Backgrounder (ieso.ca)
[23] For the sake of simplicity, the analysis does not incorporate the tiered prices billing structure that is offered to net metered customers. The analysis also assumed that PV and storage only serve native load and do not export to the grid. According to the OEB RPP Roadmap published on November 16, 2015, most RPP eligible customers have smart meters and over 96% pay the TOU structure in the RPP. More information can be found here: RPP Roadmap - Report of the Board - November 16, 2015 (oeb.ca)

program. The non-RPP Class B customers are charged an hourly Ontario Electricity Price (HOEP) plus a flat $/MWh Global Adjustment (GA) rate.

- **Class A Commercial & Industrial:** The tariff structure for the Class A customers was assumed to align with the billing for the General Service consumers with an average monthly peak demand greater than 1000kW in addition to GS 500 – 999 kW customers that satisfy the NAICS code beginning with "31", "32", "33", "1114" and opt into the Industrial Conservation Initiative program. Class A customers are charged HOEP plus a non-volumetric GA charge based on share of customer's consumption in the five peak demand hours during the previous base period.

1.3 Projection Methodology

The projection process varied by technology type but included the following primary tasks:

- ICF developed estimates for average technology system sizes, rates and tariffs, value streams and capital and O&M costs for each customer class. We also collected information on policy and market developments that could reasonably impact technology adoption over the course of the study period.
- ICF used information on existing installs to estimate representative solar PV sizes for each customer class. ICF examined the IESO's microFIT and FIT data and the information on NEM installations from the OEB to understand the range of sizes of historical installations. Since the figures reported in these sources were not broken down by customer class, ICF used its professional opinion in estimating representative technology sizes by customer class. ICF assumed that residential and small business customers would install relatively smaller PV systems due to space constraints and lower average loads and non-RPP Class B customers would install larger systems. Class A customers, with larger average loads, were assumed to install the largest systems.
- ICF also used information on existing storage installs and publicly available data from storage vendors to develop representative battery storage sizes for each customer class. ICF examined the OEB's NEM data, the IESO's DER data and the US Department of Energy's (DOE) Global Energy Storage Database to understand the range of sizes of historical installations. Since these sources do not delineate information by customer class, ICF used its professional opinion in estimating representative technology sizes. ICF assumed that residential and small business customers would install the smallest storage systems due to space constraints and lower average loads and non-RPP Class B customers would install larger systems. Class A customers, with larger average loads, were assumed to install the largest systems.
- ICF gathered technology capital cost projections for solar PV from the NREL 2020 ATB and storage capital cost projections from Wood Mackenzie Research data. ICF gathered O&M cost projections for both technologies from the NREL 2020 ATB. For both technologies, ICF assigned residential capital and O&M costs to the residential and small business customer classes. ICF assigned commercial capital and O&M costs to the non-RPP Class B and Class A customer segments.

- ICF identified the value streams and revenues accessible by each technology and customer class. ICF identified the value streams based on a literature review, survey of external markets and discussions with the OEB.
- The next step was to conduct a forward-looking economic analysis by quantifying the value streams and analytical metrics (LCOE-to-avoided-cost ratio for solar PV and payback period for battery storage) for each technology.
- As part of the economic analysis, ICF projected annual TOU prices, Hourly Ontario Energy Prices (HOEP) and Global Adjustment (GA) charges to conduct the economic analysis.
    - For residential and small business regulated price plan (RPP) customers, ICF used the November 2020 TOU rates as a baseline. RPP bills were assumed to increase at an annual rate of 2% in the Mid Scenario. The RPP supply costs were adjusted down for the Low Scenario and up for the High Scenario to generate projected supply costs for each Scenario for each year in the study period. Distribution charges were assumed to increase at an annual rate of 2% from a November 2020 baseline across scenarios.
    - ICF used pre-COVID HOEP and GA rates from 2019 as a baseline to project future HOEP and GA values. The GA rates for both non-RPP Class B and Class A customers were decremented as per the 2020 Ontario Budget Announcement.[24] ICF assumed the decrement would persist for the duration of the study period. For the Mid Scenario, ICF used the average annual percentage change in projected rates from 2021-2030 in the 2017 LTEP to project future HOEP and GA rates for non-RPP Class B and Class A customers from the baseline. The rates were then adjusted for the Low and High Scenarios. Each scenario assumed a termination of the ICI hiatus at the end of 2020.
- ICF also projected annual, hourly Ontario wholesale market energy prices and utilized these as inputs to calculate wholesale market energy revenues. While the modeling of Ontario's energy system reflected assumptions consistent with Ontario's Annual Planning Outlook, the wholesale prices are meant to be indicative of future trends and do not represent an official ICF view.
    - For solar PV, ICF assumed that the total energy output from the PV asset for a representative customer from each customer class was bid into the wholesale energy market. The hourly PV output was used in conjunction with hourly wholesale energy prices to estimate annual wholesale energy market revenues.
    - For storage, ICF constructed a simplified annual hourly battery dispatch schedule for non-RPP Class B and Class A customers. Batteries were assumed to charge at night during the low-priced hours and discharge during the evening at high-priced hours. The annual hourly battery dispatch was used in conjunction with the annual prices to estimate annual wholesale energy market revenues.
- ICF then calculated project economics (LCOE-to-avoided-cost ratio for solar PV and payback period for battery storage) for each technology, Scenario, and customer class for each year of the study period based on estimates of future value streams. ICF then examined the economic metrics in conjunction with policy and market factors to arrive at annual growth rates for each technology, Scenario, and customer class.

[24] Available online: https://budget.ontario.ca/2020/pdf/2020-ontario-budget-en.pdf

- ICF used the annual growth rates to project future adoption of each technology based on the established 2020 installation baselines.
- ICF compared the projections against historical and future adoption trajectories from proxy regions[25] to calibrate the analysis. While regulatory conditions and market forces do differ between jurisdictions, the reference areas act as helpful proxies when exploring possible future outcomes. For example, solar PV installations in Ontario are not likely to reach levels or be as aggressive as seen in California or Hawaii due to differences in solar irradiation and regulatory structures. However, similarities in resource adoption between Ontario and Wisconsin or Michigan may exist. Hence, to benchmark the projections, ICF examined adoption CAGRS, annual growth rates, historical annual installations, and predictions of future deployment for both solar PV and storage. The exercise aided in establishing realistic upper and lower bounds for the projections and refining the analysis.
- The key initial output for the projections for both technologies is an estimate of deployed capacity, both in terms of annual incremental additions as well as cumulative totals. From these values, ICF then calculated the incremental load impact and estimates for number of installed systems by customer class.

As mentioned previously, ICF adjusted annual technology adoption rates via a Policy Adjustment Factor and a Market Adjustment Factor. The purpose of incorporation of these Factors was to account for the effects of future changes in policy, customer sentiment and behaviour, demographics, innovation, future policy and regulatory changes, some wholesale market revenues, and broader societal considerations on potential resource adoption to the extent possible. These are important factors but very difficult if not impossible to accurately quantify at this time; therefore, the intent was to keep them out of the core, customer-centric project economics engine at the heart of the modeling.

While project economics often play the most important role in the adoption of DER, community influences and a conducive regulatory and policy environment can have an enhancing impact as well. Therefore, ICF used the MAF and PAF to modulate the projections such that customer adoption and resource deployment decisions are not tied solely to economic considerations but also to externalities. In both the case of the MAF and PAF, ICF considered the cumulative effect of all items under each one (see below) swinging in either direction would have, inferred an alteration to “normal” adoption rates (i.e., the rates resulting from the processes described in detail below), and then applied the adjustments to the Scenarios. ICF also customized the MAF and PAF to specific customer classes and the differences between the effects on solar vs. storage. Some particular aspects of each adjustment factor included:

Market Adjustment Factor: The MAF is intended to incorporate considerations on customer outlook and sentiment with respect to DER, environmental concerns and the willingness to adopt the newest and latest technology. To develop annual values for the MAF by customer class and technology, ICF followed the steps described below.

ICF examined resource forecasting techniques cited in the literature to ascertain how societal factors have been treated in the context of DER adoption studies. Among the techniques

[25] Markets included California, New York, Massachusetts, New Mexico, Oregon, Wisconsin, Illinois, Michigan, Nevada, and Texas.

examined was the Bass Diffusion Model,[26] which has been used prominently and frequently in DER adoption studies.[27] This model forecasts the adoption of a new technology by consumers, with the speed and timing of adoption depending on the degree of innovativeness and degree of imitation by the adopters. The model incorporates two coefficients in the calculation process – a coefficient of imitation and coefficient of innovation. With respect to DER, the sum of these coefficients has been observed to range between 0.2 and 1.8 in the literature.[28] ICF used this range as a guide to assign MAFs for solar PV and battery energy storage.

Additional aspects considered in the development of the MAF included variables related to:

- Customer decision-making
    - E.g., a "green" premium where customers are willing to pay more for low-carbon technologies
- Technology developments
    - E.g., algorithmic solutions aiding in the optimization of value streams
- Market providers
    - E.g., new business models emerging from developers, aggregators, etc.

Policy Adjustment Factor: The intent of the PAF is to incorporate the impacts of non-energy wholesale market revenues (capacity, operating reserves, and regulation) and the potential effects of future policy changes on resource adoption. To develop annual values for the PAF by customer class and technology, ICF followed the steps described below.

ICF calculated hypothetical wholesale electricity market revenues for a single year for non-RPP Class B and Class A customers with solar PV and battery storage based on publicly available 2019 data. ICF calculated the revenues separately for each technology and customer type, and did not consider a combined PV + storage installation scenario. The wholesale market revenue streams considered were energy revenues, operating reserves revenues, capacity market payments and payments for regulation services. ICF then ascertained the relative contribution of each value stream to the total accessible wholesale market revenue pool. The relative weighting was then used in conjunction with available information on emerging and future policies (such as NEM, LTEP, and emissions performance standards) to arrive at a final value for a PAF.

Additional aspects considered in the development of the PAF included variables related to:

- New regulatory policies
    - E.g., other items stemming from the Responding to DERs initiative and/or other consultations
- Federal or province-level legislation

[26] The Bass Diffusion Model describes how new products are adopted in a population by classifying individuals as "innovators" or "imitators". The model has been widely used for sales and technology forecasting.

[27] Changgui Dong, Benjamin Sigrin, Gregory Brinkman, Forecasting Residential Solar Photovoltaic Deployment in California, 2016

[28] Digka G. Paschalia, The Non-Linear Bass Diffusion Model on Renewable Energy Technologies in European Countries, October 2012

  - o E.g., next iteration of the Long-Term Energy Plan and revisions to the Ontario's Emissions Performance Standards (EPS), O. Reg. 24/17 Net Metering, .O. Reg. 507/18 Broader Public Sector: Energy Reporting and CDM Plans
- Federal or province-level executive activity
  - o E.g., Orders in Council

2. Solar Photovoltaics

ICF projected the future adoption of distribution-connected solar PV for residential, small business, non-RPP Class B and Class A customers in Ontario for three adoption Scenarios – Low, Mid, and High. Data on installed and existing solar capacity in Ontario in the various customer classes formed the basis for the projections. ICF's projections incorporate capital costs, operations, and maintenance (O&M) costs and information from other US states (New York, Michigan, Wisconsin, Nevada, Texas, California). In addition, ICF examined solar PV adoption trends in mature U.S. markets to modulate and inform the future growth of solar PV.

Figure 37. Solar PV Annual Growth Rate Calculation

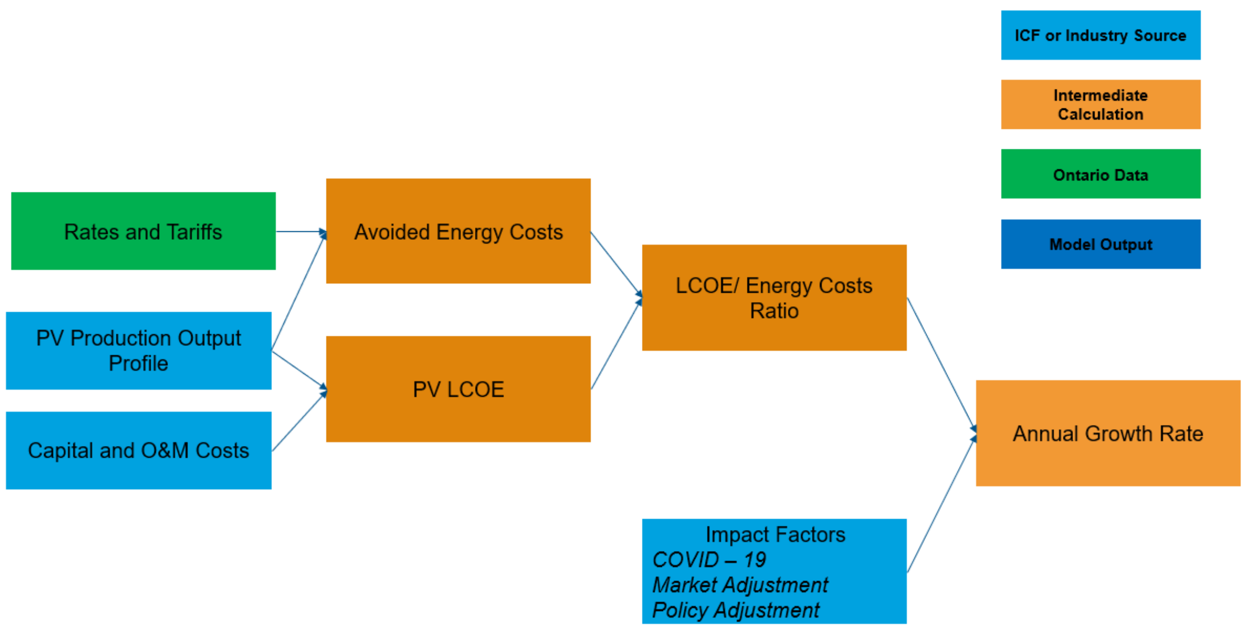
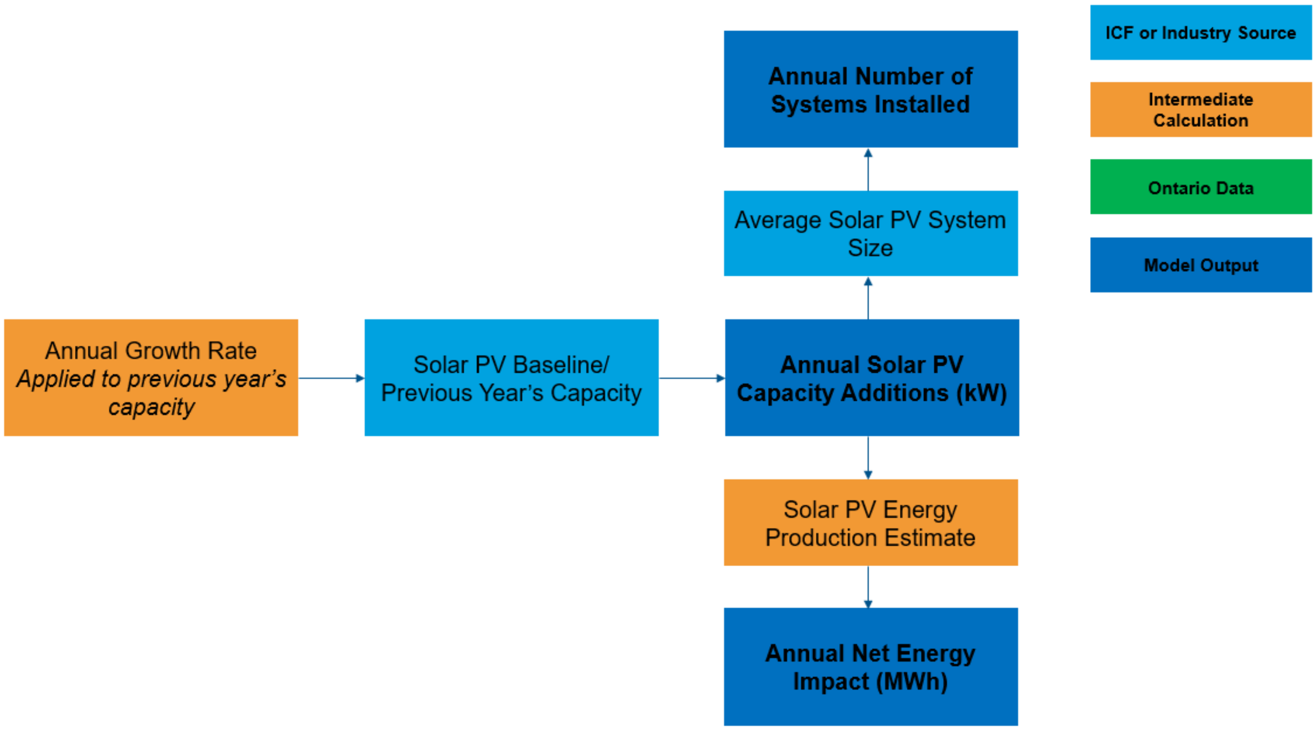


Figure 38. Solar PV Model Schematic



Key assumptions, inputs, and calculations that impacted the projection Scenarios are listed below by topical area.

2.1 Solar PV Economics

- ICF developed estimates for avoided electricity costs from the customers' perspectives based on either TOU rates or HOEP and GA values depending on customer class, as well as wholesale market energy revenues. ICF also projected future TOU rates and HOEP and GA values as described previously.
- Baseline TOU avoided costs for residential and small business customers were developed by using a set of estimated hourly PV production (8760) values and mapping these to the currently available TOU rates. Baseline avoided costs for non-RPP Class B and Class A customers were developed using estimated 8760 PV production values and an average annual HOEP and GA rate.
- For Class A and non-RPP Class B customers, ICF calculated baseline wholesale energy market revenues based on a set of estimated hourly PV production (8760) values. The wholesale energy market revenues were added to bill savings to determine the avoided energy costs for each customer class.
- The baseline avoided costs were then escalated by the annual percentage change in projected ToU rates (for residential and small business customers) and projected HOEP + GA supply costs (for non-RPP Class B and Class A customers) to arrive at PV avoided costs for each year of the study period.

- ICF developed representative solar production profiles using NREL's PVWatts tool for each customer class. To account for Ontario's size and geographic diversity, ICF used a single representative city from five provincial regions (Northeastern - Sudbury, Central/ GTA - Toronto, Southwestern - London, Eastern - Ottawa, Northwestern – Thunder Bay) to develop location-specific PV profiles. These PV profiles were aggregated to arrive at weighted Ontario-wide average PV output profiles for each customer class.
- ICF considered the following baseline PV installation sizes based on analysis of historical installations from microFIT and FIT programs and NEM data. ICF assumed a size increase of 2% per year due to technological improvements.
    - Residential and Small Business customers: 5 kW
    - Non-RPP Class B customers: 70 kW, 200 kW, 350 kW[29]
    - Class A customers: 500 kW and 2000 kW[30]
- ICF reduced solar production by 0.5% per year to account for typical PV system degradation losses over time. This annualized data was used to calculate the average cost for solar power in comparison to avoided costs. The PV production values did not vary by Scenario.
- Technology costs were based on long-term forecasts for installed solar pricing, by customer class, and included average operations and maintenance (O&M) cost estimates. The NREL 2020 Annual Technology Baseline (ATB) is the source for these costs. Total project lifetime costs were estimated based on gross technology costs plus estimates for 20 years of O&M costs. As a simplifying assumption, depreciation benefits were not factored in. These values differed based on Scenario, with the Low Scenario using the highest published cost estimates over time and the High Scenario using the lowest cost estimates.
- ICF calculated the Levelized Cost of Electricity (LCOE) using the total technology costs divided by the solar PV production over a 20-year lifetime. This is a conservative approach because the systems are likely to have value for more than twenty years.

2.2 Solar PV Growth Rates

- ICF developed baseline adoption curves for Ontario were developed using trends from US states. ICF examined a few states with a range of historic PV adoption trends. These formed the inputs to generating a time- and market-adjusted annual growth rate that was then modified as described below.
- ICF made modifications to the baseline adoption curves by Scenario to reflect the reduced adoption potential in the Low Scenario and higher potential in the High Scenario. Modifications to the baseline adoption curves were made by customer class that reflect the different economic benefit potential on decision-making processes for residential, commercial, and industrial classes.
- ICF included three impact factors to account for the impact of macroeconomic, societal and policy considerations on the forecast:

---

[29] IESO's Active Contracted Generation List. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/power-data/supply/IESO-Active-Contracted-Generation-List.ashx
[30] IESO's Active Contracted Generation List. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/power-data/supply/IESO-Active-Contracted-Generation-List.ashx

  - A "COVID-19" impact factor to account for the economic impacts of the ongoing COVID-19 pandemic. ICF adjusted the COVID-19 factors by Scenario but did not vary them by customer class.
  - A "Market Adjustment Factor" to consider variables such as consumer sentiment – the desire to install innovative technology, adopt green resources and be environmentally conscious and to imitate first adopters. ICF developed individual factors for each customer class and scenario.
  - A "Policy Adjustment Factor" to account for wholesale electricity market revenues (capacity, operating reserve, and regulation) and future changes in policy and legislation at the Federal and Provincial level, such as NEM, LTEP, and emissions performance standards. ICF developed individual factors for each customer class and scenario.
- In the final determination for growth rates that were applied to the annual forecasts, ICF determined and used the ratio of LCOE-to-avoided-cost as a final adjustment to the adoption baseline. The lower LCOE-to-avoided-cost ratio (net savings potential for customers) resulted in higher growth rates, and decreased growth rates for lower savings potential.
- The baselines of currently installed solar PV capacity (in terms of capacity and number of installs) were grounded in estimates of existing solar PV capacity in Ontario. The baseline values were calculated as follows:
  - For residential and small business customers, microFIT and Net Metering Data were used for determining capacity and number of installs in the baseline year.
  - For C&I customers (both non-RPP Class B and Class A), distributed solar FIT as well as Net Metering were used for determining the capacity and number of installs in the baseline year.
  - Only rooftop mounted solar PV was considered for all customer classes. Upon analysis of the IESO's Active Contracted Generation List, ICF found that over 80% ground mounted PV cumulative installed capacity was sized larger than 5 MW and up to 10 MW. Such large investments are typically the work of standalone developers and not associated with individual customers. Given that there was no adequate indicator for determining which of the ground-mounted projects were load-serving, and to prevent accounting for generator-only projects, ICF removed ground-mounted PV projects from the list of baseline installs.
  - Since the figures reported in these sources were not broken down by customer class, ICF used its professional opinion in delineating the numbers by customer class. For instance, installations by non-RPP Class B customers were assumed to be below 500 kW and for Class A customers to be equal to or greater than 500 kW. Additionally, 85% of microFIT installs were assumed to be done by residential customers and 15% by small business customers, given that small business customers face greater financial and administrative barriers compared to residential customers.

The baselines for current participation of PV assets in the IAMs were calculated as follows:

- ICF assumed that none of the existing DER assets installed by residential and small business customers are participating in the wholesale market in the baseline year of

2020. This is based on the fact that the current minimum size threshold for participation in the IESO's IAMs is 1 MW[31] and PV sizes installed by residential and small businesses (for instance, as observed from the microFIT program) tend to be much smaller than that threshold.

- For the Commercial and Industrial (C&I) customers, ICF used the IESO data available on distributed solar FIT contracts as well as the current market rules for participation to determine the number of solar PV assets that meet the minimum size threshold and could participate in IESO's IAM. Given the existing barriers for participation, ICF assumed that only 5% of the solar PV assets owned by C&I customers that would be eligible under existing requirements participated in IESO's IAM in the baseline year of 2020.
- Participation rates were then assumed to escalate by 5% on an annual basis in the Mid Adoption Scenario and adjusted lower and higher for the Low and High Adoption Scenarios, respectively.

2.3 Conversions to Load Impact and Installation Volume

- ICF developed calculations for the net load impact to the grid and provided these in the forecast outputs based on the average annual solar output for representative system sizes, with an annual degradation of 0.5% applied to prior year output. The intended use is to estimate the net reduction in overall load served by the grid from the deployed solar capacity in each Scenario.
- Installation volume estimates are provided in the forecast outputs based on total deployed capacity divided by average system sizes by customer class. The intended use is to understand the potential volume of connection activity annually and the number of systems over time that will be connected to the grid.

[31] IESO, 2020, Exploring Expanded DER Participation in the IESO-Administered Markets, Part 1 – Conceptual Models for DER Participation, Innovation and Sector Evolution White Paper Series. Available online here: http://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-paper-series-Conceptual-Models-for-DER-Participation.pdf?la=en

3. Energy Storage

ICF projected the future adoption of DER battery energy storage for residential, small business, non-RPP Class B and Class A customers in Ontario for three adoption Scenarios – Low, Mid, and High. ICF's projections factored capital costs, operations and maintenance (O&M) costs, and information on rebates and incentives. In addition, ICF examined storage adoption trends from other U.S. markets (such as California, Hawaii, Massachusetts, New York, New Jersey, and Arizona) to modulate and inform the projections.

Figure 39. Storage Annual Growth Rate Calculation

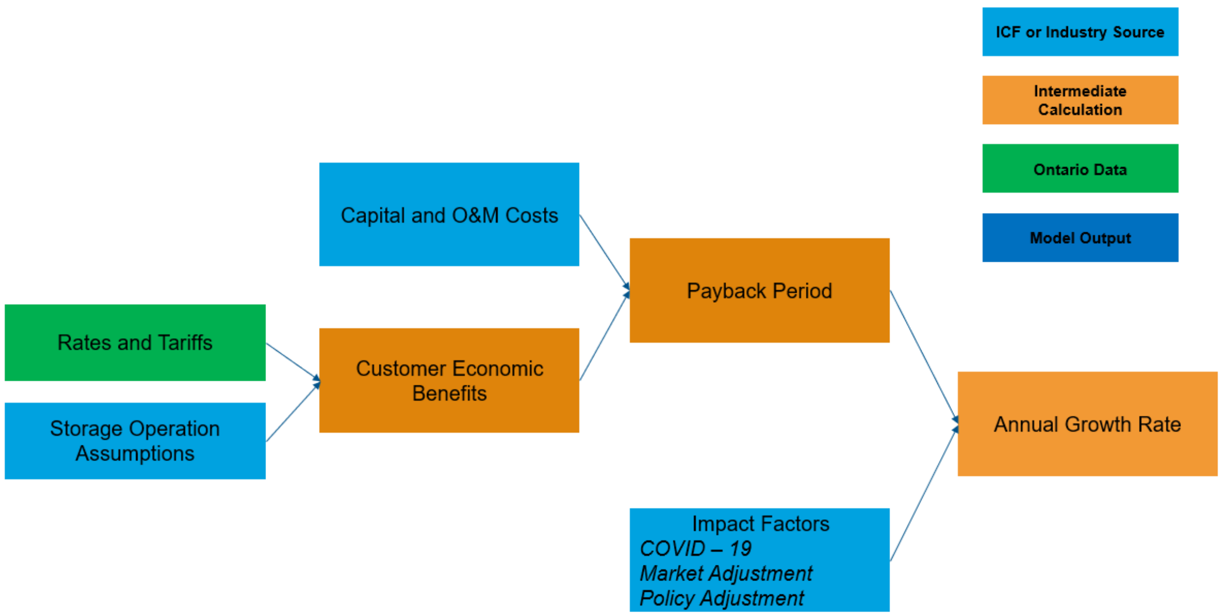
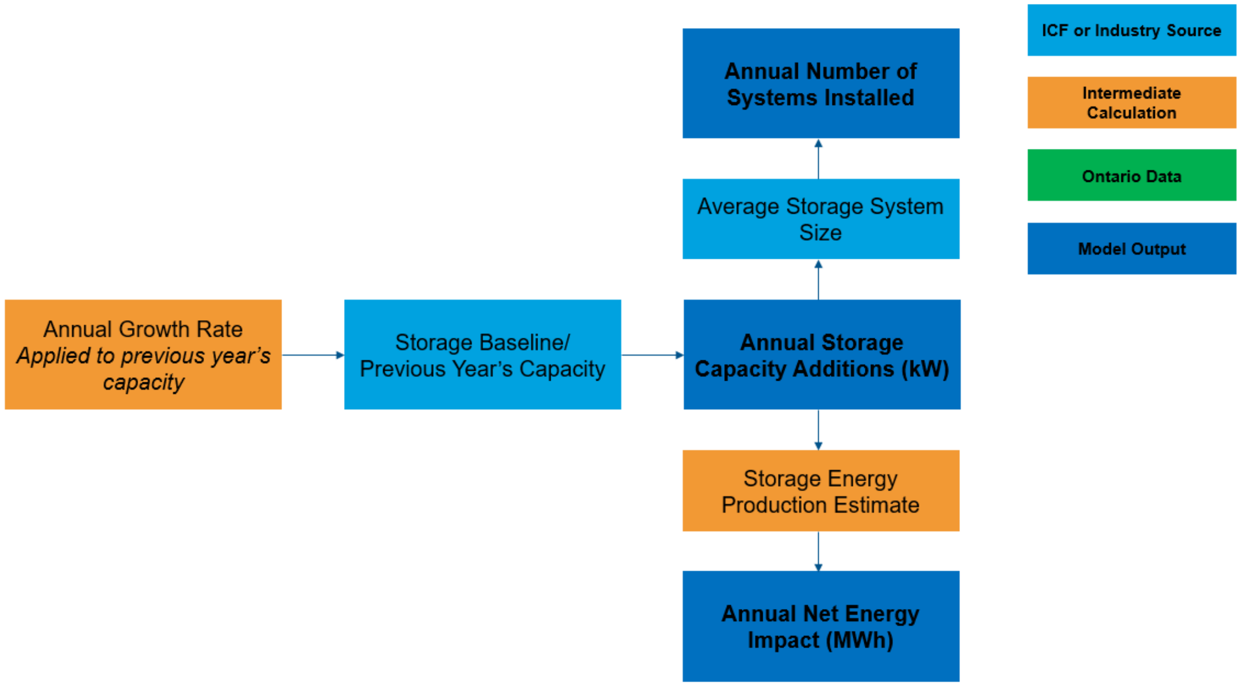


Figure 40. Storage Model Schematic



Key assumptions, inputs, and calculations that impact the various scenarios are listed below by topical area.

3.1 Storage Economics

- ICF developed estimates for storage value streams and use cases by customer class. The value streams included TOU retail rate energy arbitrage, wholesale market energy revenues, reductions in global adjustment charges and resiliency/ back-up power.
- ICF used the same TOU rates and HOEP and GA values for each of the solar PV and storage models.
- The use cases for storage included resiliency/back-up power and TOU energy arbitrage for residential and small business customers, wholesale energy revenues and resiliency/back-up power for non-RPP Class B customers and global adjustment charge savings, wholesale energy market revenues and resiliency/back-up power for Class A customers. This approach estimated not only the net savings/value created for the customer but also the annual load impact (increase) in Ontario.
    - For residential and small business customers, ICF developed annual hourly (8760) output schedules using the baseline TOU rates to estimate the value to customers from energy arbitrage. The battery is assumed to charge during the off-peak hours and discharge during the on-peak price periods.
    - For non-RPP Class B customers, ICF calculated baseline wholesale energy market revenues based on an annual 8760 battery output schedule. A battery is assumed to charge during the low-priced hours and discharge during the high-priced hours. ICF calculated the value of resiliency/ back-up power based on publicly available data on the value of lost load to average consumers.

    - For Class A customers, ICF calculated baseline wholesale energy market revenues based on an annual 8760 battery output schedule. A battery is assumed to charge during the low-priced hours and discharge during the high-priced hours. ICF calculated the value of resiliency/ back-up power based on publicly available data on the value of lost load to average consumers. Baseline global adjustment savings were calculated based on the assumptions from the literature[32] that if a Class A customer were to reduce their peak demand by 1 MW during each of the top five system peak demand hours, they would save $520,000. This value was decremented in accordance with the 2020 Ontario budget announcement for the analysis, yielding a new savings value of $405,000.
    - To estimate the value of resiliency, ICF first calculated the average battery energy capacity that would be available to the battery owner at the end of a representative day after a 24-hour charge and discharge cycle.
        - If an outage were to occur outside of a battery's pre-determined charge or discharge schedule, there is a high probability that the battery would be charged to its full energy capacity, and that it could completely discharge to serve native load. However, high-impact outage events are difficult to predict and may also occur during the charge or discharge hours when the battery was only partially charged. Hence, the average battery capacity is used to estimate the maximum available battery energy that might be available to serve native load.
    - Assuming one high impact outage event per year, ICF used publicly available estimates of the value of lost load in conjunction with the average available battery capacity to calculate the savings to a customer from being able to continue to serve native load during an outage.[33]
- ICF then escalated the baseline value streams by the annual percentage change in projected TOU rates (for residential and small business customers) and projected HOEP + GA supply costs (for non-RPP Class B and Class A customers) to arrive at value streams for each year of the study period.
- ICF considered the following baseline storage installation sizes based on an analysis of publicly available data from storage vendors and the US DOE's Global Energy Storage Database. ICF assumed a size increase of 2% per year due to technological improvements.
    - Residential and Small Business customers: 5 kW/ 20 kWh
    - Non-RPP Class B customers: 1 MW/ 4 MWh
    - Class A customers: 2.5 MW/ 5 MWh

[32] OEB Market Surveillance Panel, The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches, December 2018. Available online: MSP Report - The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches (Dec 18, 2018) (oeb.ca)

[33] An estimate of value of lost load was obtained from: Brian Rivard, Don't leave me stranded: What to do with Ontario's Global Adjustment?, July 2019

- Technology costs for each of the Scenarios over the study period were based on data from the Wood MacKenzie Q3 2018 Energy Storage Monitor and O&M costs were based on NREL 2020 ATB forecasts.
- ICF calculated payback periods based on the technology costs, divided by the net value to customers. The payback periods varied across the customer classes and across scenarios due to the different tariff structures, rates, and dispatch assumptions.

3.2 Storage Growth Rates

- The storage market is relatively nascent and has a shorter and less robust adoption history compared to solar PV. This meant that ICF could not calibrate the storage projections against data on a wide variety of external market examples. However, baseline adoption curves were developed taking a conservative approach to potential adoption adapted from the limited examples available and by incorporating external factors.
- ICF included three impact factors to account for the impact of macroeconomic, societal and policy considerations on the forecast:
    - A "COVID-19" impact factor to account for the economic impacts of the ongoing COVID-19 pandemic. ICF adjusted the COVID-19 factors by Scenario but did not vary them by customer class.
    - A "Market Adjustment Factor" to consider variables such as consumer sentiment – the desire to install innovative technology, adopt green resources and be environmentally conscious and to imitate first adopters. ICF developed individual factors for each customer class and scenario.
    - A "Policy Adjustment Factor" to account for wholesale electricity market revenues (capacity, operating reserve and regulation) and future changes in policy and legislation at the Federal and Provincial level, such as NEM, LTEP, and emissions performance standards. ICF developed individual factors for each customer class and scenario.
- ICF modified these individual parameters to adjust the adoption curves by Scenario to reflect the reduced adoption potential in the Low Scenario and higher potential in the High Scenario. Modifications were made by customer class that reflect the different economic benefit potential on decision-making processes for residential, commercial, and industrial classes and the projected payback periods.
- The baselines of currently installed storage capacity (in terms of capacity and number of installs) were grounded in estimates of existing storage capacity in Ontario. The baseline values were calculated as follows:
    - 90% of currently installed NEM storage capacity was assigned to the residential sector – 458 kW[34].
    - 10% of currently installed NEM storage capacity was assigned to the small business sector – 51 kW.

[34] The OEB provided ICF with aggregate Ontario storage capacity (509 kW) currently enrolled in NEM programs.

  - 20% of the storage capacity currently enrolled in the IAM's was assigned to non-RPP Class B customers - 9,010 kW[35]
  - 80% of the storage capacity enrolled in the IAM's and 400 MW of BTM storage capacity was assigned to Class A customers – 436,040 kW.[36]

3.3 Conversions to Load Impact and Installation Volume

- ICF developed calculations for the net load impact to the grid based on the storage system sizes and charge/discharge cycles by customer use case. For storage (as opposed to solar) the net energy impact from a system perspective is an increase in load from assumed roundtrip efficiency losses of 10%. ICF assumed an annual storage energy capacity degradation of 3% for all customer classes, while recognizing that this number depends heavily on the number of daily battery cycles, the depth of discharge, environmental conditions, and other factors.
- ICF based the number of installed storage systems on the annual aggregated capacity estimates divided by average system sizes by customer class to provide the potential volume of connection activity annually and the number of systems over time that will be connected to the grid.

[35] The IESO provided ICF with the aggregate storage capacity (45.05 MW) currently registered in the IAMs.
[36] The 400 MW value is from a presentation by Energy Storage Canada to the IESO's Energy Storage Advisory Group on May 21, 2019. Available online (Appendix C, slide 20): http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esag/esag-20190621-energy-storage-canada.pdf?la=en

IV. Appendix D – References

- Aird and Berlis LLP, 2020: Energy Storage Developments in the Last Twelve Months, August 28, 2020
- Alectra Utilities, Connecting Generation. Available online: https://alectrautilities.com/connecting-generation
- Alectra Utilities, POWER.HOUSE Feasibility Study. Available online: TABLE OF CONTENTS - Alectra Inc.
- Alectra Utilities, Distribution System Plan 2020 – 2024, May 2019. Available online: https://alectrautilities.com/sites/default/files/assets/pdf/AlectraUtilities_APPL_Ex-4-Apx-A_PUBLIC-VERSION_-v.-2-of-7.pdf
- Argonne National Laboratory, Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids, August 2015
- Asano, Marc and Rodney Chong, Modern Grids of Hawaii, T&D World, November 1, 2018. Available online: https://www.tdworld.com/grid-innovations/distribution/article/20971882/modern-grids-of-hawaii
- Brian Rivard, Don't leave me stranded: What to do with Ontario's Global Adjustment?, July 2019
- Burger, et al., Restructuring Revisited: Competition and Coordination in Electricity Distribution Systems, March 2018
- C. Baldus-Jeursen, Y. Poissant, Wes Johnston, National Survey Report of PV Power Applications in Canada, 2018
- CAISO, Business Practice Manual for Direct Telemetry, March 3, 2019. Available online: https://bpmcm.caiso.com/BPM%20Document%20Library/Direct%20Telemetry/BPM_for_Direct_Telemetry_V12%20Clean.docx
- CAISO, Local Resource Adequacy with Availability-Limited Resources and Slow Demand Response, Draft Final Proposal, October 3, 2019. Available online: DraftFinalProposal-LocalResourceAdequacy-AvailabilityLimitedResources-SlowDemandResponse.pdf (caiso.com)
- California IOUs, Enabling Smart Inverters for Distribution Grid Services, October 2018
- Carkner, Sarah, ESR Bidding Rules for ICAP Suppliers with an Energy Duration Limitation, ICAPWG/MIWG, July 14, 2020. Available online: https://www.nyiso.com/documents/20142/13769834/ESR%20Bidding%20for%20ICAP%20Suppliers%20with%20Energy%20Duration%20Limitations.pdf/.
- Changgui Dong, Benjamin Sigrin, Gregory Brinkman, Forecasting Residential Solar Photovoltaic Deployment in California, 2016
- Consolidated Edison, Distributed System Implementation Plan, June 30, 2020. Available online: https://jointutilitiesofny.org/sites/default/files/CONED_2020_DSIP.pdf
- Compass Renewable Energy Consulting, Market Analysis of Ontario's Renewable Energy Sector, June 30, 2017. Available online: COMPLETE FINAL_MOE Ontario Market Assessment July 20, 2017.pdf (ontarioenergyreport.ca)

- Cooke, Alan, Juliet Homer, and Lisa Schwartz, Distribution System Planning – State Example by Topic, 2018. Available online: https://eta-publications.lbl.gov/sites/default/files/dsp_state_examples.pdf.
- CPUC. Proposed Decision of Commissioner Peterman: Decision on Multiple-Use Application Issues, January 11, 2018. Available online: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K234/202234451.pdf
- CPUC, Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process), February 8, 2018
- Dalton, Patrick and Bob Mack, Why utilities need to proactively guide standard DER bulk system response, May 12, 2020. Available online: https://www.icf.com/insights/energy/guide-standard-der-bulk-system-responses.
- Digka G. Paschalia, The Non-Linear Bass Diffusion Model on Renewable Energy Technologies in European Countries, October 2012
- DOE, On the Path to SunShot: Emerging Issues and Challenges in Integrating Solar with the Distribution System, May 2016. Available online: https://www.nrel.gov/docs/fy16osti/65331.pdf.
- Elia, Deployment of a Datahub Shared by All System Operators to Support Electrical Flexibility", March 8, 2018. Available online: http://www.elia.be/~/media/files/Elia/PressReleases/2018/20180308_SYN_Persbericht_Datahub_EN.pdf.
- ERCOT, Distributed Energy Resources: Reliability Impacts & Recommended Changes, March 2017. Available online: http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf
- Energy Storage Canada/ Power Advisory LLC, Unlocking Potential: An Economic Valuation of Energy Storage in Ontario, July 2020. Available online: https://energystoragecanada.org/unlocking-potential
- Energy Storage Canada, Energy Storage Roadmap, Presented at the IESO's Energy Storage Advisory Group Meeting, June 21, 2019
- EPRI, The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources. Available online: https://www.energy.gov/sites/prod/files/2015/03/f20/EPRI%20Integrated%20Grid021014.pdf
- EPRI and NREL, Innovation in the Interconnection Application Process, Distributed Generation Interconnection Collaborative (DGIC), April 2, 2014. Available online: https://www.nrel.gov/dgic/assets/pdfs/2014-04-02_innovation-in-the-interconnection-application-process.pdf
- EPRI and NREL, Evaluating Dynamic, Flexible Interconnection Options for Distributed Photovoltaic Resources, Distributed Generation Integration Collaborative (DGIC) Webinar, February 27, 2020. Available online: https://www.nrel.gov/dgic/assets/pdfs/dgic-webinar-flexible-interconnection.pdf
- Essex Energy Corporation, The Study of Energy Storage in Ontario Distribution Systems, May 2017. Available online: The Study of Energy Storage in Ontario Distribution Systems (ontarioenergyreport.ca)

- FERC, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. Docket Nos. RM16-23-001; AD-20-001; Order No. 841-A. May 16, 2019. https://www.ferc.gov/whats-new/comm-meet/2019/051619/E-1.pdf.
- FERC, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators. Docket No. RM18-9-000l Oder No. 2222. September 17, 2020. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf
- F. Sultan, J.U. Farley, D.R. Lehmann, A meta-analysis of diffusion models, Journal of Marketing Research, 1990
- Government of Ontario, 2020 Ontario Budget. Available online: https://budget.ontario.ca/2020/pdf/2020-ontario-budget-en.pdf
- Greentech Media, Where Are All the Non-Wires Alternatives?, August 27, 2020. Available online: https://www.greentechmedia.com/articles/read/where-are-all-the-non-wires-alternatives
- GridWorks, Chapter Seven: Next Steps and Future Challenges, October 10, 2019. Available online: https://gridworks.org/2019/10/chapter-seven-next-steps-and-future-challenges/
- Hawaiian Electric Companies, Modernizing Hawai'i's Grid For Our Customers, August 29, 2017. Available online: https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf
- Heather Shirley Smith, Deputy General Counsel, Duke Energy, Duke Energy Progress, LLC's Establishment of Net Energy Metering Tariff in Compliance with H. 3659 and Duke Energy Carolinas, LLC's Establishment of Net Energy Metering Tariff in Compliance with H. 3659 Docket Number: 2019-169-E & 2019-170-E, filed September 21, 2020.
- Hydro One, Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50 kV and Below. Available online: https://www.hydroone.com/businessservices_/generators_/Documents/Distributed%20Generation%20Technical%20Interconnection%20Requirements.pdf
- ICF, Development of a Transmission-Distribution Interoperability Framework, May 2020. Available online: Transmission-distribution interoperability: Laying the foundation for decision-making (ieso.ca)
- ICF, Integrated Distribution Planning – Prepared for the Minnesota Public Utilities Commission, August 2016. Available online: https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf
- IEEE, A Compilation of IEEE Standard Computer Glossaries, 1990
- IESO, A Progress Report on Contracted Electricity Supply, Second Quarter 2020
- IESO's Active Contracted Generation List. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/power-data/supply/IESO-Active-Contracted-Generation-List.ashx
- IESO, Annual Planning Outlook, January 2020. Available online: Annual Planning Outlook (ieso.ca)

- IESO Data Directory. Available online: Data Directory - Independent Electricity System Operator (ieso.ca)
- IESO, Exploring Expanded DER Participation in the IESO-Administered Markets, Part I – Conceptual Models for DER Participation, Innovation and Sector Evolution White Paper Series, 2020. Available online: Distributed Energy Resources: Models for Expanded Participation in Wholesale Markets (ieso.ca)
- IESO, Exploring Expanded DER Participation in the IESO-Administered Markets, Part II – Options to Enhance DER Participation, Draft White Paper, Innovation and Sector Evolution White Paper Series, 2020. Available online: https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-Paper-Series-Part-2-Options-to-Enhance-DER-Participation-20201110.ashx
- IESO, Global Adjustment Class A Eligibility. Available online: https://www.ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-Class-A-Eligibility
- IESO, Market Renewal Program. Available online: http://www.ieso.ca/en/Market-Renewal
- IESO, Market Rule Amendment Proposal MR-00445-R00.
- IESO, Ontario Generation Resources Database. Available online: Transmission-Connected Generation (ieso.ca)
- IESO York Region NWA Project. Available online: https://www.ieso.ca/Corporate-IESO/Media/News-Releases/2020/11/IESO-York-Region-NWA-Project
- Interstate Renewable Energy Council, Inc. (IREC), Model Interconnection Procedures (2019), available at https://irecusa.org/publications/irec-model-interconnection-procedures-2019.
- IREC, Making the Grid Smarter: Primer on Adopting the New IEEE 1547-2018 Standard for Distributed Energy Resources, January 2019
- IRENA, Innovation landscape for a renewable-powered future, February 2019
- Joint Utilities of New York, Supplemental Distributed System Implementation Plan. Case 16-M-0411, In the Matter of Distributed System Implementation Plans, November 1, 2016. Available online: https://jointutilitiesofny.org/sites/default/files/Supplemental%20distributed%20system%20implementation%20plan%20nov%202016.pdf
- K.D. Lawrence and W.H, Lawton, Applications of diffusion models: Some empirical results, in Y. Wind et al., eds., New Product Forecasting, Lexington Books, Lexington, MA, USA, 1981
- Lavilloti, Michael and Zachary T Smith, DER Energy & Capacity Market Design, Business Issues Committee, April 17, 2019. Available online: https://www.nyiso.com/documents/20142/6006612/BIC%20DER%20Market%20Design%20Presentation.pdf/9cdc8700-ab90-d741-c28d-0c29b3468807.
- Lyons, Cristin, Non-Wires Alternatives: Non-Traditional Solutions to Grid Needs, T&D World, June 6, 2019. Available online: https://www.tdworld.com/overhead-distribution/article/20972703/nonwires-alternatives-nontraditional-solutions-to-grid-needs.
- Makhyoun, M., B. Campbell, and M. Taylor. 2014. Distributed Solar Interconnection Challenges and Best Practices. Washington, DC: Solar Electric Power Association.

Available online: https://www.growsolar.org/wp-content/uploads/2014/10/SEPA-Interconnection-Report-1014- email.pdf.

- More Than Smart, Data and the Electricity Grid – A Roadmap for Using System Data to Build a Plug and Play Grid. Available online: http://gridworks.org/wp-content/uploads/2016/10/MTS-System-Data-Paper.pdf
- National Energy Screening Project (NESP), National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, August 2020. Available online: NSPM-DERs_08-24-2020.pdf (nationalenergyscreeningproject.org)
- National Grid. 2017. National Grid DG Interconnection REV Demo Project. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV). Niagara Mohawk Power Corporation d/b/a National Grid. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b6B0377EF-F949-4DAA-A164-AB8ABB019E5B%7d
- NREL, Annual Technology Baseline 2020. Available online: ATB | NREL
- NREL, An Overview of DER Interconnection: Current Practices and Emerging Solutions, April 2019. Available online: https://www.nrel.gov/docs/fy19osti/72102.pdf
- NREL, Maximum Photovoltaic Penetration on Typical Distribution Feeders, July 2012. Available online: https://www.nrel.gov/docs/fy12osti/55094.pdf
- NREL, New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues, February 2019. Available online: https://www.nrel.gov/docs/fy19osti/72038.pdf
- NREL PVWatts Calculator. Available online: PVWatts Calculator (nrel.gov)
- NREL, The Future of Energy Storage: A Pathway to 100+ GW of Deployment, October 16, 2019. Available online: https://www.energy.gov/sites/prod/files/2019/10/f68/EAC_Storage_Denholm.pdf
- NYISO, DER Real-Time Telemetry and Alternate Telemetry Approach for Small DER, Market Issues Working Group, September 28, 2018. Available online: https://www.nyiso.com/documents/20142/2549675/DER%206-Second%20Telemetry%20-%20MIWG%2020180928%20MIWG.pdf/e4309d38-8f57-2dc8-7328-5c2dc519b198
- NYISO, Manual 4: Installed Capacity Manual, June 2020. Available online: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.
- Nieminski, Joe, Resource Capability Testing: Amount of Capacity Available, Intermediate ICAP Course, June 18-19, 2019. Available online: https://www.nyiso.com/documents/20142/3036383/3_Resource+Capability_Amt+of+Capacity+Available.pdf/ee932c12-61bd-f38e-bfa6-f6e873e5c2af?version=1.1&t=1560190368938&download=true.
- NYPSC, BCA Order: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016). Available online: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7D
- NYPSC, Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings, January 25, 2017. Available online:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={22BEAB22-7F9F-45B8-89FD-0E8AD84692B4}

- NYPSC, Case 18-E-0130 – In the Matter of Energy Storage Deployment Program. Order Establishing Energy Storage Goal and Deployment Policy, December 13, 2018. Available online: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bFDE2C318-277F-4701-B7D6-C70FCE0C6266%7d
- OEB, A New Distribution Rate Design for Residential Electricity Customers, EB-2012-0410 Board Policy. Available online: OEB_Distribution_Rate_Design_Policy_20150402.pdf
- OEB, Choosing your electricity price plan. Available online: Choosing your electricity price plan | Ontario Energy Board (oeb.ca)
- OEB, Electricity Distribution Rates, 2019. Available online: https://www.oeb.ca/sites/default/files/2019-Distribution-Rates-Database.xlsx
- OEB, Historical Electricity Rates, 2020. Available online: https://www.oeb.ca/rates-and-your-bill/electricity-rates/historical-electricity-rates
- OEB Market Surveillance Panel, The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches, December 2018. Available online: MSP Report - The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches (Dec 18, 2018) (oeb.ca)
- OEB, Net Metering and Renewable Energy Generation Data, 2020
- OEB, Regulated Price Plan Roadmap, Report of the Board, EB-2014-0319, November 16, 2015. Available online: RPP Roadmap - Report of the Board - November 16, 2015 (oeb.ca)
- OEB, Responding to Distributed Energy Resources (DERs). Available online: Responding to Distributed Energy Resources (DERs) | Ontario Energy Board (oeb.ca)
- OEB Staff Presentation, Sector Evolution: Renumeration & Responding to DERs, Defining the Scope & Approach to Work Based on Stakeholder Input", February 20, 2020. Available online: https://www.rds.oeb.ca/CMWebDrawer/Record/667330/File/document
- OEB Staff Research Paper, Evaluation of Alternative Price Designs for the Recovery of Global Adjustment Costs from Class B Consumers in Ontario, March 21, 2019. Available online: Examination of Alternative Price Designs - Technical Meeting for Stakeholders – Presentation Slides - March 21, 2019 (oeb.ca)
- OEB, ED-2019-0207 Information and Template Forms for Preliminary Consultations on DER Connections, November 26, 2020. Available online: https://www.oeb.ca/sites/default/files/OEB-Staff-Ltr-DER-Connections-Preliminary-Consultation-Forms-20201126.pdf.
- OEB, EB-2019-0207 Guidance – Protection Philosophy for DER Connections, November 26, 2020. Available online: https://www.oeb.ca/sites/default/files/OEB-Staff-Ltr-DER-Connections-Protection-Philosophy-20201126.pdf.
- Ontario Ministry of Energy, Ontario's Long-Term Energy Plan 2017. Available online: Archived - 2017 Long-Term Energy Plan: Delivering fairness and choice (ontario.ca)
- Pacific Gas & Electric, Advice Letter 5435-E, February 5, 2019. Available online: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5435-E.pdf

- Pacific Gas and Electric Company, EPIC 2.02 – Distributed Energy Resource Management System, January 18, 2019. Available online: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf
- Peterson, Zachary, Alternative Methods for Interconnection Cost Allocation, August 2018. Available online: https://www.nrel.gov/dgic/interconnection-insights-2018-08-31.html.
- PNNL, Electricity Distribution System Baseline Report, July 2016. Available online: https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf
- Rylander et. al, Alternatives to the 15% rule, November 2015. Available online: https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/1510099.pdf
- St. John, Jeff, California Struggles to Find Path for Solar and Batteries to Take Place of Traditional Grid Investments, GTM Squared, February 6, 2020
- Taft, Jeff, Grid Architecture 2, Pacific Northwest National Laboratory, 2016. Available online: https://gridmod.labworks.org/sites/default/files/resources/Grid%20Architecture%202%20final_GMLC.pdf.
- The Ontario EBT Working Group, Electric Business Transactions (EBT) Standards Document for Retail Settlement in the Electric Retail Open Access Industry, January 21, 2008. Available online: https://www.oeb.ca/oeb/_Documents/Regulatory/Ontario_EBT_Standards_v4.pdf
- Toronto Hydro, Grid Connection Process. Available online: https://www.torontohydro.com/grid-connections/connection-process
- U.S. Department of Energy Global Energy Storage Database. Available online: Energy Storage Database | Energy Storage Systems (sandia.gov)
- Walton, Robert, New York utilities increasingly embrace non-wires alternatives as ConEd forges the path, Utility Dive, May 31, 2019. Available online: https://www.utilitydive.com/news/new-york-utilities-increasingly-embrace-non-wires-alternatives-as-coned-for/555762/.