TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO POLLUTION PROBE

UNDERTAKING NO. JT2.1:

Reference(s): **1B-PP-11**

To provide the outputs of the model on a gross and a net basis.

RESPONSE:

For a graph of gross peak, please refer to Exhibit 2B, Section D4, Appendix A, page 11. For a graph of net peak, please see Figure 1 below. Summer and winter gross and net peaks are broken down by driver in Tables 1-12. Please note that all peaks are coincident.

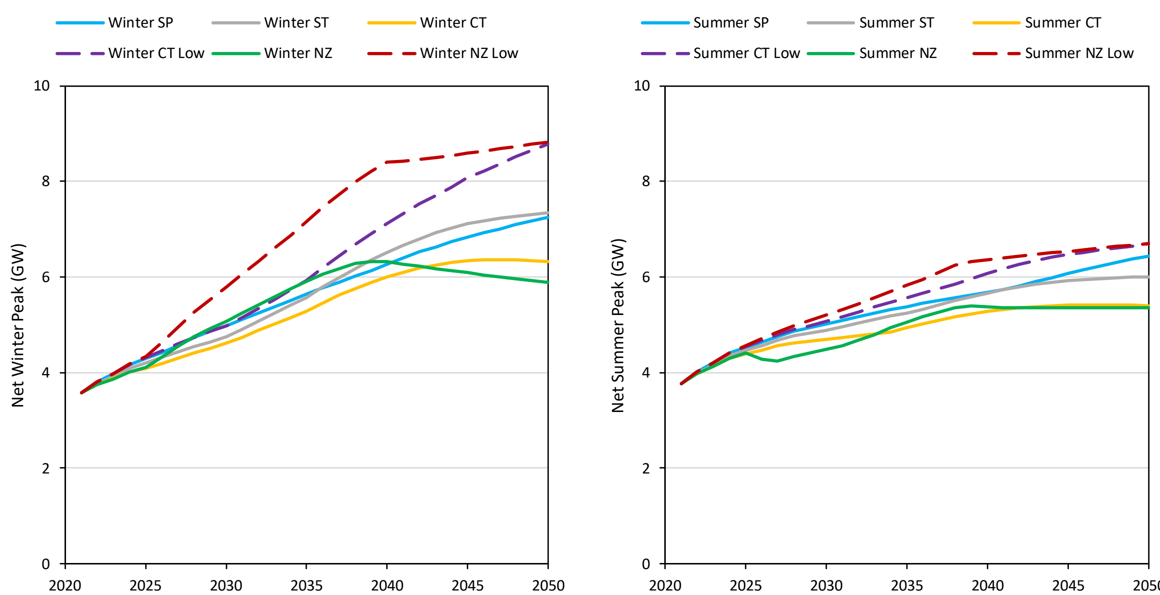


Figure 1. Net Winter (left) and Summer (right) Peak (GW)

Table 1: Steady Progression Summer Net Peak (left) and Gross Peak (right)

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,883	23	6	3,912	-	148	3,764
2022	4,139	25	7	4,170	-	159	4,010
2023	4,330	26	10	4,366	-	171	4,196
2024	4,533	27	14	4,574	(0)	172	4,402
2025	4,657	28	20	4,706	(0)	173	4,533
2026	4,755	30	32	4,817	(0)	175	4,642
2027	4,849	31	55	4,936	(0)	177	4,758
2028	4,923	35	84	5,042	(0)	180	4,862
2029	4,970	38	115	5,123	(0)	185	4,939
2030	5,014	41	146	5,201	(0)	189	5,012
2031	5,054	44	183	5,281	(0)	195	5,087
2032	5,094	47	219	5,361	(0)	200	5,161
2033	5,131	49	264	5,445	(0)	210	5,235
2034	5,172	52	301	5,526	(1)	217	5,310
2035	5,211	55	338	5,604	(1)	224	5,380
2036	5,240	60	375	5,674	(1)	232	5,443
2037	5,266	63	410	5,740	(1)	241	5,500
2038	5,293	66	449	5,809	(1)	251	5,559
2039	5,320	70	487	5,877	(1)	261	5,618
2040	5,347	74	527	5,948	(1)	272	5,678
2041	5,373	78	569	6,021	(2)	284	5,739
2042	4,871	81	980	5,933	2	121	5,810
2043	4,896	83	1,046	6,024	2	124	5,897
2044	4,859	80	1,153	6,091	2	101	5,988
2045	4,883	81	1,215	6,179	3	103	6,074
2046	4,908	82	1,275	6,264	3	105	6,157
2047	4,933	83	1,325	6,341	3	107	6,231
2048	4,960	84	1,377	6,421	3	110	6,307
2049	4,985	85	1,419	6,488	4	113	6,372
2050	5,010	86	1,454	6,550	4	116	6,430

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,883	23	6	3,912
2022	4,139	25	7	4,170
2023	4,330	26	10	4,366
2024	4,533	27	14	4,574
2025	4,657	28	20	4,706
2026	4,755	30	32	4,817
2027	4,849	31	55	4,936
2028	4,923	35	84	5,042
2029	4,970	38	115	5,123
2030	5,014	41	146	5,201
2031	5,050	43	189	5,282
2032	5,090	46	227	5,363
2033	5,131	49	264	5,445
2034	5,172	52	301	5,526
2035	5,211	55	338	5,604
2036	5,240	60	375	5,674
2037	5,266	63	410	5,740
2038	5,293	66	449	5,809
2039	5,320	70	487	5,877
2040	5,347	74	527	5,948
2041	5,373	78	569	6,021
2042	5,400	82	612	6,094
2043	5,427	84	655	6,166
2044	5,455	86	696	6,237
2045	5,482	88	734	6,305
2046	5,510	91	771	6,371
2047	5,538	93	802	6,433
2048	5,567	95	835	6,497
2049	5,596	97	861	6,553
2050	5,624	99	882	6,606

1 **Table 2: Steady Progression Winter Net Peak (left) and Gross Peak (right)**

	Baseload *(A)* *(MW)*	De-carbonised Heating *(B)* *(MW)*	Electric Vehicles *(C)* *(MW)*	Gross Demand (at time of Net Peak) *(D)=(A+B+C)* *(MW)*	Storage *(E)* *(MW)*	Generation *(F)* *(MW)*	Net Peak *(G)=(D-E-F)* *(MW)*
2021	3,367	291	8	3,666	36	55	3,575
2022	3,589	313	9	3,911	50	64	3,797
2023	3,754	336	14	4,104	63	73	3,967
2024	3,928	359	19	4,306	71	73	4,161
2025	4,034	378	30	4,442	76	74	4,292
2026	4,121	402	47	4,570	82	74	4,414
2027	4,213	433	81	4,726	87	74	4,565
2028	4,282	488	121	4,890	93	74	4,723
2029	4,323	542	164	5,028	99	74	4,855
2030	4,360	592	210	5,163	106	74	4,983
2031	4,395	645	263	5,303	112	75	5,116
2032	4,430	696	315	5,441	119	75	5,247
2033	4,465	747	366	5,578	126	75	5,378
2034	4,500	798	415	5,713	132	76	5,505
2035	4,380	767	553	5,700	0	69	5,630
2036	4,404	824	611	5,839	1	69	5,770
2037	4,426	864	667	5,957	1	69	5,887
2038	4,448	903	727	6,078	1	69	6,008
2039	4,470	943	787	6,200	1	69	6,130
2040	4,492	990	850	6,332	1	69	6,262
2041	4,514	1,036	915	6,465	1	69	6,395
2042	4,537	1,075	980	6,592	1	69	6,522
2043	4,559	1,093	1,046	6,698	1	69	6,627
2044	4,582	1,111	1,108	6,800	1	69	6,730
2045	4,604	1,128	1,166	6,898	1	69	6,828
2046	4,627	1,145	1,222	6,993	2	69	6,922
2047	4,650	1,161	1,269	7,080	2	69	7,009
2048	4,674	1,176	1,316	7,167	2	69	7,096
2049	4,698	1,192	1,355	7,244	2	69	7,173
2050	4,721	1,208	1,388	7,317	2	70	7,245

	Baseload *(A)* *(MW)*	De-carbonised Heating *(B)* *(MW)*	Electric Vehicles *(C)* *(MW)*	Gross Peak *(D)=(A+B+C)* *(MW)*
2021	3,312	353	7	3,671
2022	3,536	377	7	3,920
2023	3,702	401	11	4,114
2024	3,877	426	15	4,318
2025	3,984	444	23	4,451
2026	4,071	469	37	4,577
2027	4,163	502	64	4,730
2028	4,282	488	121	4,890
2029	4,323	542	164	5,028
2030	4,360	592	210	5,163
2031	4,395	645	263	5,303
2032	4,430	696	315	5,441
2033	4,465	747	366	5,578
2034	4,500	798	415	5,713
2035	4,534	847	462	5,843
2036	4,559	912	508	5,979
2037	4,582	958	552	6,091
2038	4,605	1,004	597	6,206
2039	4,628	1,051	642	6,322
2040	4,651	1,106	688	6,446
2041	4,674	1,161	735	6,570
2042	4,698	1,208	782	6,687
2043	4,721	1,232	827	6,781
2044	4,698	1,201	974	6,874
2045	4,721	1,223	1,021	6,966
2046	4,745	1,244	1,065	7,054
2047	4,769	1,265	1,103	7,137
2048	4,794	1,284	1,140	7,218
2049	4,818	1,304	1,170	7,292
2050	4,842	1,324	1,197	7,363

1 **Table 3: System Transformation Summer Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,883	23	6	3,912	-	148	3,764
2022	4,113	25	7	4,144	-	159	3,986
2023	4,286	26	11	4,323	(0)	169	4,153
2024	4,468	27	18	4,514	(0)	168	4,345
2025	4,572	28	33	4,632	(0)	168	4,465
2026	4,651	29	57	4,737	(0)	168	4,569
2027	4,725	30	86	4,842	(0)	169	4,673
2028	4,779	32	120	4,931	(0)	171	4,760
2029	4,806	33	159	4,999	(0)	175	4,824
2030	4,829	35	205	5,068	(1)	180	4,889
2031	4,848	39	260	5,147	(1)	187	4,961
2032	4,865	43	321	5,230	(1)	195	5,036
2033	4,884	47	385	5,315	(1)	204	5,112
2034	4,901	51	449	5,401	(1)	217	5,185
2035	4,913	54	519	5,486	(2)	237	5,250
2036	4,918	66	582	5,565	(2)	257	5,310
2037	4,375	67	1,028	5,470	2	59	5,408
2038	4,376	74	1,115	5,565	3	61	5,501
2039	4,375	81	1,198	5,655	3	64	5,588
2040	4,375	88	1,272	5,735	3	66	5,666
2041	4,375	94	1,343	5,812	4	69	5,740
2042	4,375	100	1,400	5,874	4	71	5,799
2043	4,375	105	1,446	5,925	5	75	5,846
2044	4,375	110	1,485	5,970	5	78	5,886
2045	4,378	114	1,516	6,008	6	82	5,920
2046	4,380	116	1,540	6,036	6	87	5,943
2047	4,383	118	1,559	6,060	7	91	5,962
2048	4,386	119	1,575	6,081	7	96	5,978
2049	4,390	121	1,589	6,100	8	100	5,992
2050	4,394	122	1,601	6,118	8	105	6,005

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,883	23	6	3,912
2022	4,113	25	7	4,144
2023	4,286	26	11	4,323
2024	4,468	27	18	4,514
2025	4,572	28	33	4,632
2026	4,651	29	57	4,737
2027	4,725	30	86	4,842
2028	4,779	32	120	4,931
2029	4,806	33	159	4,999
2030	4,825	34	210	5,069
2031	4,843	38	266	5,148
2032	4,861	42	328	5,232
2033	4,880	46	393	5,318
2034	4,897	50	458	5,405
2035	4,913	54	519	5,486
2036	4,918	66	582	5,565
2037	4,914	75	647	5,637
2038	4,914	86	704	5,704
2039	4,914	96	757	5,766
2040	4,914	105	804	5,823
2041	4,914	114	850	5,878
2042	4,913	123	887	5,922
2043	4,913	131	917	5,960
2044	4,913	139	942	5,994
2045	4,915	146	963	6,024
2046	4,917	150	978	6,045
2047	4,919	155	991	6,065
2048	4,922	159	1,002	6,082
2049	4,390	121	1,589	6,100
2050	4,394	122	1,601	6,118

1 **Table 4: System Transformation Winter Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,367	291	8	3,667	36	55	3,575
2022	3,567	312	9	3,888	57	63	3,768
2023	3,715	333	15	4,062	77	71	3,914
2024	3,871	353	24	4,249	95	68	4,086
2025	3,960	368	43	4,371	105	65	4,201
2026	4,030	388	72	4,490	115	63	4,313
2027	4,105	409	109	4,622	125	60	4,438
2028	4,157	430	152	4,739	136	57	4,547
2029	4,039	390	254	4,683	0	48	4,635
2030	4,057	416	326	4,799	0	45	4,754
2031	4,073	469	413	4,954	0	43	4,911
2032	4,088	521	506	5,114	1	40	5,073
2033	4,103	572	604	5,278	1	38	5,240
2034	4,117	622	701	5,441	1	36	5,404
2035	4,130	671	794	5,595	1	34	5,560
2036	4,134	799	888	5,822	1	32	5,789
2037	4,134	907	978	6,019	1	31	5,987
2038	4,135	1,010	1,061	6,206	2	29	6,175
2039	4,134	1,109	1,139	6,382	2	28	6,352
2040	4,134	1,201	1,209	6,543	2	26	6,515
2041	4,133	1,286	1,275	6,694	2	24	6,668
2042	4,133	1,366	1,329	6,827	2	22	6,802
2043	4,132	1,441	1,372	6,945	3	21	6,922
2044	4,132	1,511	1,409	7,052	3	20	7,030
2045	4,134	1,571	1,439	7,145	3	18	7,123
2046	4,136	1,602	1,462	7,199	3	18	7,178
2047	4,138	1,630	1,481	7,248	4	17	7,228
2048	4,140	1,654	1,497	7,291	4	16	7,271
2049	4,143	1,676	1,510	7,329	4	15	7,310
2050	4,146	1,698	1,522	7,366	5	13	7,348

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,312	353	7	3,672
2022	3,514	375	7	3,896
2023	3,663	397	12	4,072
2024	3,822	418	20	4,260
2025	3,911	433	34	4,378
2026	3,982	454	58	4,494
2027	4,105	409	109	4,622
2028	4,157	430	152	4,739
2029	4,180	452	202	4,834
2030	4,199	477	258	4,934
2031	4,215	535	325	5,075
2032	4,230	593	395	5,218
2033	4,246	650	468	5,364
2034	4,261	706	541	5,508
2035	4,233	726	686	5,646
2036	4,278	915	680	5,874
2037	4,279	1,046	746	6,072
2038	4,279	1,172	808	6,259
2039	4,279	1,294	864	6,436
2040	4,279	1,408	914	6,601
2041	4,278	1,515	959	6,753
2042	4,278	1,616	997	6,891
2043	4,228	2,008	790	7,027
2044	4,228	2,120	809	7,157
2045	4,230	2,222	823	7,275
2046	4,231	2,279	834	7,345
2047	4,233	2,335	843	7,411
2048	4,235	2,386	849	7,470
2049	4,237	2,432	854	7,523
2050	4,241	2,477	858	7,577

Table 5: Consumer Transformation Summer Net Peak (left) and Gross Peak (right)

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,883	23	6	3,912	-	148	3,764
2022	4,104	24	7	4,135	(0)	160	3,975
2023	4,261	25	11	4,298	(0)	172	4,126
2024	4,428	26	18	4,472	(0)	177	4,296
2025	4,515	27	32	4,575	(0)	182	4,392
2026	4,580	28	56	4,664	(0)	189	4,476
2027	4,639	29	85	4,753	(1)	197	4,557
2028	4,678	30	119	4,827	(1)	207	4,621
2029	4,689	31	157	4,878	(1)	220	4,659
2030	4,696	33	203	4,932	(1)	239	4,694
2031	4,698	36	258	4,992	(2)	262	4,732
2032	4,700	40	318	5,057	(2)	290	4,770
2033	4,701	43	381	5,125	(2)	323	4,804
2034	4,569	50	489	5,108	(3)	270	4,841
2035	4,168	44	810	5,021	3	88	4,930
2036	4,154	51	906	5,111	4	90	5,016
2037	4,137	56	998	5,190	4	94	5,092
2038	4,119	61	1,083	5,263	5	98	5,160
2039	4,100	65	1,164	5,329	6	102	5,222
2040	4,082	70	1,236	5,387	6	106	5,275
2041	4,063	73	1,306	5,442	7	110	5,325
2042	4,045	76	1,361	5,481	7	114	5,360
2043	4,026	78	1,406	5,511	8	119	5,384
2044	4,009	80	1,444	5,533	9	124	5,401
2045	3,997	82	1,475	5,553	9	129	5,415
2046	3,983	81	1,498	5,562	10	135	5,418
2047	3,970	81	1,517	5,568	11	141	5,416
2048	3,958	80	1,533	5,570	11	147	5,412
2049	3,945	79	1,546	5,570	12	153	5,406
2050	3,934	78	1,558	5,571	13	158	5,399

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,883	23	6	3,912
2022	4,104	24	7	4,135
2023	4,261	25	11	4,298
2024	4,428	26	18	4,472
2025	4,515	27	32	4,575
2026	4,580	28	56	4,664
2027	4,639	29	85	4,753
2028	4,678	30	119	4,827
2029	4,689	31	157	4,878
2030	4,692	32	208	4,932
2031	4,694	36	264	4,994
2032	4,695	39	326	5,060
2033	4,696	42	390	5,128
2034	4,697	45	454	5,196
2035	4,695	48	515	5,258
2036	4,680	58	578	5,316
2037	4,661	67	637	5,365
2038	4,637	74	699	5,409
2039	4,616	81	752	5,449
2040	4,596	89	799	5,483
2041	4,575	95	844	5,515
2042	4,555	101	881	5,537
2043	4,535	107	911	5,552
2044	4,515	112	936	5,563
2045	4,501	116	957	5,573
2046	4,484	118	972	5,574
2047	4,468	120	985	5,573
2048	3,958	80	1,533	5,570
2049	3,945	79	1,546	5,570
2050	3,934	78	1,558	5,571

1 **Table 6: Consumer Transformation Winter Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,367	291	8	3,667	36	55	3,575
2022	3,559	310	9	3,878	61	63	3,753
2023	3,693	329	15	4,036	86	71	3,879
2024	3,835	347	24	4,206	125	72	4,010
2025	3,910	362	41	4,313	146	71	4,096
2026	3,835	324	88	4,247	0	65	4,182
2027	3,893	343	133	4,369	0	63	4,305
2028	3,929	364	185	4,478	0	62	4,416
2029	3,939	386	244	4,568	1	60	4,508
2030	3,944	412	312	4,668	1	58	4,609
2031	3,945	457	395	4,797	1	56	4,740
2032	3,946	499	485	4,930	1	53	4,876
2033	3,946	540	579	5,065	1	50	5,014
2034	3,946	579	674	5,199	2	48	5,149
2035	3,944	615	763	5,323	2	46	5,275
2036	3,931	720	855	5,505	2	44	5,459
2037	3,915	802	941	5,658	3	43	5,613
2038	3,898	878	1,021	5,798	3	41	5,754
2039	3,880	948	1,097	5,925	3	40	5,882
2040	3,863	1,011	1,165	6,039	4	38	5,998
2041	3,846	1,063	1,229	6,139	4	36	6,099
2042	3,828	1,110	1,281	6,219	4	34	6,181
2043	3,811	1,149	1,324	6,284	5	33	6,247
2044	3,795	1,182	1,359	6,336	5	31	6,300
2045	3,783	1,207	1,388	6,378	5	30	6,342
2046	3,769	1,207	1,410	6,386	6	29	6,351
2047	3,756	1,204	1,429	6,389	6	28	6,355
2048	3,744	1,197	1,444	6,384	7	27	6,350
2049	3,731	1,185	1,457	6,374	7	26	6,341
2050	3,720	1,172	1,469	6,361	7	25	6,329

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,312	353	7	3,671
2022	3,506	373	7	3,886
2023	3,642	392	12	4,046
2024	3,787	411	19	4,217
2025	3,863	425	32	4,320
2026	3,921	445	54	4,420
2027	4,028	401	102	4,531
2028	4,066	421	143	4,631
2029	4,076	443	188	4,707
2030	4,081	468	239	4,788
2031	4,082	517	301	4,901
2032	4,083	565	367	5,014
2033	4,084	610	436	5,129
2034	4,083	654	503	5,241
2035	4,042	665	646	5,353
2036	4,029	784	723	5,535
2037	4,012	880	795	5,686
2038	3,995	969	861	5,825
2039	3,977	1,052	923	5,951
2040	3,959	1,128	978	6,065
2041	3,941	1,192	1,029	6,163
2042	3,924	1,250	1,071	6,245
2043	3,906	1,301	1,105	6,312
2044	3,797	1,577	1,011	6,385
2045	3,784	1,637	1,032	6,453
2046	3,769	1,661	1,048	6,478
2047	3,754	1,684	1,061	6,499
2048	3,740	1,700	1,071	6,511
2049	3,726	1,710	1,080	6,516
2050	3,712	1,718	1,088	6,518

1 **Table 7: Consumer Transformation Low Summer Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,883	23	6	3,912	-	148	3,764
2022	4,139	25	7	4,170	-	159	4,011
2023	4,330	26	11	4,368	-	171	4,197
2024	4,533	27	18	4,579	(0)	172	4,407
2025	4,657	28	33	4,718	(0)	173	4,545
2026	4,755	30	57	4,842	(0)	175	4,667
2027	4,849	31	86	4,967	(0)	177	4,789
2028	4,923	33	121	5,077	(0)	180	4,897
2029	4,970	35	160	5,166	(0)	185	4,981
2030	5,014	37	207	5,257	(0)	189	5,068
2031	5,054	42	263	5,359	(0)	195	5,164
2032	5,094	46	324	5,465	(0)	200	5,265
2033	5,135	51	388	5,575	(0)	207	5,368
2034	5,172	55	461	5,688	(1)	217	5,472
2035	5,211	60	523	5,793	(1)	224	5,570
2036	5,240	73	586	5,899	(1)	232	5,668
2037	5,266	86	646	5,998	(1)	241	5,758
2038	4,714	84	1,143	5,940	1	93	5,846
2039	4,737	92	1,227	6,057	1	94	5,962
2040	4,761	100	1,303	6,165	2	95	6,068
2041	4,786	108	1,376	6,269	2	97	6,171
2042	4,810	116	1,434	6,359	2	98	6,259
2043	4,834	123	1,481	6,438	2	100	6,337
2044	4,859	130	1,521	6,510	2	101	6,407
2045	4,883	137	1,553	6,573	3	103	6,468
2046	4,908	141	1,578	6,627	3	105	6,519
2047	4,933	146	1,598	6,676	3	107	6,566
2048	4,960	150	1,614	6,724	3	110	6,611
2049	4,985	154	1,628	6,768	4	113	6,651
2050	5,010	158	1,641	6,810	4	116	6,690

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,883	23	6	3,912
2022	4,139	25	7	4,170
2023	4,330	26	11	4,368
2024	4,533	27	18	4,579
2025	4,657	28	33	4,718
2026	4,755	30	57	4,842
2027	4,849	31	86	4,967
2028	4,923	33	121	5,077
2029	4,970	35	160	5,166
2030	5,014	37	207	5,257
2031	5,050	41	269	5,360
2032	5,090	45	331	5,467
2033	5,131	50	396	5,577
2034	5,172	55	461	5,688
2035	5,211	60	523	5,793
2036	5,240	73	586	5,899
2037	5,266	86	646	5,998
2038	5,289	96	708	6,093
2039	5,316	107	761	6,185
2040	5,343	119	809	6,271
2041	5,370	130	855	6,355
2042	5,397	141	892	6,430
2043	5,424	152	922	6,498
2044	5,455	165	941	6,562
2045	5,482	176	962	6,620
2046	5,510	183	978	6,670
2047	5,538	191	991	6,719
2048	5,567	198	1,001	6,766
2049	5,596	205	1,010	6,810
2050	5,624	212	1,018	6,854

1 **Table 8: Consumer Transformation Low Winter Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,367	291	8	3,667	36	55	3,575
2022	3,589	314	9	3,912	50	64	3,798
2023	3,754	337	15	4,106	63	73	3,970
2024	3,928	361	25	4,313	71	73	4,168
2025	4,034	381	44	4,459	76	74	4,309
2026	4,121	407	74	4,602	82	74	4,446
2027	4,213	435	112	4,760	87	74	4,599
2028	4,282	465	158	4,905	93	74	4,738
2029	4,323	497	210	5,030	99	74	4,856
2030	4,360	534	269	5,163	106	74	4,982
2031	4,395	602	338	5,335	112	75	5,148
2032	4,280	598	523	5,401	0	69	5,331
2033	4,314	662	623	5,599	0	69	5,529
2034	4,348	726	724	5,797	0	69	5,727
2035	4,380	789	819	5,988	0	69	5,918
2036	4,404	943	916	6,263	1	69	6,193
2037	4,426	1,074	1,008	6,508	1	69	6,438
2038	4,448	1,204	1,094	6,745	1	69	6,675
2039	4,470	1,330	1,174	6,974	1	69	6,904
2040	4,492	1,454	1,246	7,192	1	69	7,122
2041	4,514	1,573	1,314	7,402	1	69	7,332
2042	4,537	1,690	1,370	7,596	1	69	7,525
2043	4,559	1,803	1,415	7,777	1	69	7,706
2044	4,653	2,627	864	8,144	162	103	7,879
2045	4,675	2,785	882	8,342	163	105	8,074
2046	4,698	2,898	897	8,493	164	108	8,221
2047	4,722	3,012	909	8,643	166	110	8,367
2048	4,747	3,123	919	8,788	167	114	8,508
2049	4,770	3,229	927	8,927	169	117	8,641
2050	4,794	3,339	935	9,067	170	121	8,776

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,312	353	7	3,671
2022	3,536	377	7	3,920
2023	3,702	402	12	4,116
2024	3,877	427	20	4,324
2025	3,984	446	35	4,465
2026	4,071	473	59	4,603
2027	4,213	435	112	4,760
2028	4,282	465	158	4,905
2029	4,323	497	210	5,030
2030	4,360	534	269	5,163
2031	4,395	602	338	5,335
2032	4,430	671	411	5,512
2033	4,465	741	488	5,694
2034	4,500	811	564	5,876
2035	4,534	882	637	6,052
2036	4,559	1,064	711	6,334
2037	4,582	1,224	781	6,587
2038	4,605	1,381	846	6,832
2039	4,628	1,535	906	7,069
2040	4,651	1,687	960	7,298
2041	4,617	2,120	784	7,521
2042	4,640	2,293	815	7,748
2043	4,663	2,463	842	7,967
2044	4,686	2,627	864	8,177
2045	4,709	2,785	882	8,375
2046	4,732	2,898	897	8,526
2047	4,755	3,012	909	8,676
2048	4,780	3,123	919	8,822
2049	4,804	3,229	927	8,960
2050	4,827	3,339	935	9,101

1 **Table 9: Net Zero 2040 Summer Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,883	23	6	3,912	-	148	3,764
2022	4,104	24	7	4,135	(0)	157	3,977
2023	4,261	24	13	4,298	(0)	166	4,132
2024	4,428	24	29	4,481	(0)	175	4,306
2025	4,515	24	51	4,591	(0)	186	4,405
2026	4,542	35	82	4,659	(0)	387	4,273
2027	4,123	34	193	4,351	1	107	4,243
2028	4,155	40	270	4,465	2	128	4,335
2029	4,164	45	352	4,562	3	151	4,408
2030	4,169	50	442	4,661	4	173	4,484
2031	4,170	53	546	4,770	6	197	4,567
2032	4,170	57	671	4,898	7	221	4,670
2033	3,971	45	850	4,866	8	61	4,797
2034	3,971	47	991	5,008	10	65	4,933
2035	3,969	48	1,123	5,141	11	70	5,060
2036	3,955	51	1,242	5,249	13	74	5,162
2037	3,939	53	1,367	5,358	14	79	5,265
2038	3,922	54	1,488	5,464	16	83	5,365
2039	3,903	55	1,533	5,492	17	88	5,386
2040	3,886	56	1,543	5,485	19	92	5,374
2041	3,868	53	1,555	5,476	20	96	5,360
2042	3,850	51	1,567	5,468	22	99	5,347
2043	3,275	24	1,660	4,959	(413)	23	5,349
2044	3,260	23	1,675	4,958	(416)	24	5,350
2045	3,249	22	1,688	4,959	(419)	24	5,354
2046	3,236	21	1,701	4,959	(422)	24	5,356
2047	3,223	20	1,714	4,958	(425)	25	5,358
2048	3,211	19	1,727	4,957	(427)	25	5,360
2049	3,199	18	1,739	4,956	(430)	25	5,361
2050	3,187	18	1,751	4,956	(433)	25	5,364

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,883	23	6	3,912
2022	4,104	24	7	4,135
2023	4,261	24	13	4,298
2024	4,428	24	29	4,481
2025	4,515	24	51	4,591
2026	4,580	34	81	4,695
2027	4,639	43	119	4,801
2028	4,678	51	167	4,896
2029	4,689	58	219	4,966
2030	4,696	64	276	5,036
2031	4,694	68	347	5,109
2032	4,695	72	426	5,194
2033	4,696	76	517	5,290
2034	4,697	79	604	5,380
2035	4,695	82	686	5,463
2036	4,680	85	760	5,525
2037	4,656	86	844	5,586
2038	4,637	87	924	5,648
2039	4,616	88	953	5,657
2040	4,596	89	959	5,644
2041	4,575	85	965	5,625
2042	4,555	81	972	5,608
2043	4,026	65	1,505	5,596
2044	4,009	62	1,515	5,586
2045	3,997	60	1,524	5,581
2046	3,983	58	1,532	5,573
2047	3,970	55	1,541	5,566
2048	3,958	53	1,549	5,559
2049	3,945	51	1,557	5,553
2050	3,934	48	1,564	5,547

1 **Table 10: Net Zero 2040 Winter Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,367	291	8	3,667	36	55	3,575
2022	3,559	302	9	3,870	61	61	3,748
2023	3,693	314	16	4,023	86	66	3,871
2024	3,835	324	34	4,194	125	58	4,011
2025	3,910	332	60	4,302	146	51	4,105
2026	3,835	398	124	4,357	0	39	4,318
2027	3,893	500	182	4,575	1	34	4,540
2028	3,929	590	254	4,773	1	29	4,743
2029	3,939	670	332	4,940	2	25	4,913
2030	3,944	739	416	5,098	3	19	5,077
2031	3,945	800	513	5,259	3	19	5,236
2032	3,946	854	630	5,430	4	20	5,406
2033	3,946	901	763	5,610	5	20	5,585
2034	3,946	941	889	5,776	6	20	5,750
2035	3,944	980	1,008	5,932	7	20	5,905
2036	3,931	1,029	1,115	6,076	8	21	6,047
2037	3,915	1,059	1,228	6,202	9	21	6,172
2038	3,898	1,083	1,339	6,320	10	21	6,289
2039	3,880	1,100	1,380	6,360	11	22	6,328
2040	3,863	1,111	1,389	6,363	12	22	6,329
2041	3,846	1,061	1,398	6,305	12	22	6,270
2042	3,772	986	1,494	6,252	13	22	6,217
2043	3,755	946	1,505	6,206	14	23	6,170
2044	3,738	909	1,515	6,162	15	23	6,124
2045	3,727	873	1,524	6,124	15	23	6,085
2046	3,713	837	1,532	6,083	16	23	6,043
2047	3,701	802	1,541	6,043	17	24	6,002
2048	3,688	766	1,549	6,002	18	24	5,961
2049	3,676	730	1,557	5,962	18	24	5,919
2050	3,664	692	1,564	5,921	19	25	5,878

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,312	353	7	3,671
2022	3,506	363	7	3,876
2023	3,642	373	13	4,029
2024	3,787	383	27	4,197
2025	3,910	332	60	4,302
2026	3,921	545	75	4,541
2027	3,984	684	110	4,778
2028	4,022	807	151	4,981
2029	4,032	915	196	5,143
2030	4,038	1,007	244	5,288
2031	4,040	1,088	296	5,424
2032	4,040	1,159	360	5,559
2033	4,084	1,054	560	5,697
2034	4,083	1,099	652	5,834
2035	4,042	1,076	846	5,963
2036	4,029	1,128	935	6,092
2037	3,973	1,091	1,143	6,208
2038	3,898	1,083	1,339	6,320
2039	3,880	1,100	1,380	6,360
2040	3,863	1,111	1,389	6,363
2041	3,846	1,061	1,398	6,305
2042	3,828	1,016	1,408	6,252
2043	3,755	946	1,505	6,206
2044	3,738	909	1,515	6,162
2045	3,727	873	1,524	6,124
2046	3,713	837	1,532	6,083
2047	3,701	802	1,541	6,043
2048	3,688	766	1,549	6,002
2049	3,676	730	1,557	5,962
2050	3,664	692	1,564	5,921

1 **Table 11: Net Zero 2040 Low Summer Net Peak (left) and Gross Peak (right)**

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Demand (at time of Net Peak) (D)=(A+B+C) (MW)	Storage (E) (MW)	Generation (F) (MW)	Net Peak (G)=(D-E-F) (MW)
2021	3,883	23	6	3,912	-	148	3,764
2022	4,139	25	7	4,170	-	159	4,011
2023	4,330	26	13	4,369	-	171	4,199
2024	4,533	27	29	4,589	(0)	172	4,418
2025	4,657	28	51	4,737	(0)	173	4,564
2026	4,755	42	82	4,879	(0)	175	4,704
2027	4,849	54	121	5,024	(0)	177	4,847
2028	4,923	67	169	5,159	(0)	180	4,979
2029	4,970	79	222	5,272	(0)	185	5,088
2030	5,014	91	281	5,385	(0)	189	5,196
2031	5,054	103	347	5,504	(0)	195	5,309
2032	5,094	114	425	5,634	(0)	200	5,434
2033	5,135	126	517	5,778	(0)	207	5,571
2034	5,176	137	603	5,916	(1)	213	5,703
2035	5,211	146	695	6,051	(1)	224	5,828
2036	4,665	116	1,247	6,029	1	91	5,937
2037	4,689	125	1,374	6,187	1	92	6,094
2038	4,714	133	1,498	6,345	1	93	6,251
2039	4,737	141	1,543	6,421	1	94	6,326
2040	4,761	149	1,553	6,463	2	95	6,367
2041	4,786	149	1,564	6,498	2	97	6,400
2042	4,810	150	1,575	6,534	2	98	6,434
2043	4,834	151	1,586	6,570	2	100	6,469
2044	4,859	152	1,596	6,607	2	101	6,503
2045	4,883	153	1,606	6,642	3	103	6,536
2046	4,908	155	1,614	6,677	3	105	6,569
2047	4,933	156	1,623	6,712	3	107	6,602
2048	4,960	158	1,631	6,749	3	110	6,636
2049	4,985	160	1,639	6,784	4	113	6,668
2050	5,010	161	1,647	6,819	4	116	6,699

	Baseload (A) (MW)	De-carbonised Heating (B) (MW)	Electric Vehicles (C) (MW)	Gross Peak (D)=(A+B+C) (MW)
2021	3,883	23	6	3,912
2022	4,139	25	7	4,170
2023	4,330	26	13	4,369
2024	4,533	27	29	4,589
2025	4,657	28	51	4,737
2026	4,755	42	82	4,879
2027	4,849	54	121	5,024
2028	4,923	67	169	5,159
2029	4,970	79	222	5,272
2030	5,014	91	281	5,385
2031	5,054	103	347	5,504
2032	5,090	112	432	5,635
2033	5,131	124	524	5,779
2034	5,172	134	612	5,919
2035	5,211	146	695	6,051
2036	5,240	159	770	6,169
2037	5,266	170	849	6,286
2038	5,289	179	936	6,405
2039	5,316	190	965	6,471
2040	5,343	201	971	6,515
2041	5,370	201	977	6,548
2042	5,397	201	984	6,582
2043	5,424	202	991	6,616
2044	5,451	203	997	6,651
2045	5,479	204	1,003	6,685
2046	5,510	208	1,001	6,719
2047	5,538	210	1,007	6,754
2048	5,567	211	1,012	6,790
2049	5,596	213	1,017	6,825
2050	5,624	214	1,022	6,859

1 **Table 12: Net Zero 2040 Low Winter Net Peak (left) and Gross Peak (right)**

	Baseload *(A)* *(MW)*	De-carbonised Heating *(B)* *(MW)*	Electric Vehicles *(C)* *(MW)*	Gross Demand (at time of Net Peak) *(D)=(A+B+C)* *(MW)*	Storage *(E)* *(MW)*	Generation *(F)* *(MW)*	Net Peak *(G)=(D-E-F)* *(MW)*
2021	3,367	291	8	3,667	36	55	3,575
2022	3,589	314	9	3,912	50	64	3,798
2023	3,754	337	17	4,108	63	73	3,971
2024	3,928	360	36	4,324	71	73	4,179
2025	4,034	381	64	4,479	76	74	4,329
2026	4,071	652	81	4,804	82	97	4,626
2027	4,163	851	119	5,134	87	98	4,949
2028	4,233	1,046	165	5,443	93	98	5,252
2029	4,273	1,236	216	5,724	99	100	5,525
2030	4,310	1,415	271	5,996	106	101	5,789
2031	4,344	1,594	328	6,266	112	103	6,051
2032	4,378	1,768	399	6,546	119	104	6,322
2033	4,413	1,941	480	6,834	126	106	6,603
2034	4,448	2,110	559	7,117	132	108	6,877
2035	4,481	2,284	636	7,401	139	110	7,152
2036	4,505	2,492	705	7,702	143	112	7,448
2037	4,527	2,673	779	7,980	146	115	7,719
2038	4,550	2,854	855	8,260	150	117	7,993
2039	4,573	3,030	880	8,482	153	120	8,209
2040	4,595	3,202	885	8,682	155	123	8,404
2041	4,617	3,202	891	8,711	157	127	8,428
2042	4,640	3,209	898	8,747	159	130	8,458
2043	4,630	3,224	904	8,758	160	101	8,497
2044	4,653	3,239	910	8,802	162	103	8,538
2045	4,675	3,263	915	8,854	163	105	8,586
2046	4,698	3,282	920	8,901	164	108	8,629
2047	4,722	3,308	925	8,955	166	110	8,679
2048	4,747	3,334	930	9,010	167	114	8,729
2049	4,770	3,358	935	9,063	169	117	8,777
2050	4,794	3,378	939	9,111	170	121	8,819

	Baseload *(A)* *(MW)*	De-carbonised Heating *(B)* *(MW)*	Electric Vehicles *(C)* *(MW)*	Gross Peak *(D)=(A+B+C)* *(MW)*
2021	3,312	353	7	3,671
2022	3,536	377	7	3,920
2023	3,702	402	14	4,117
2024	3,877	426	29	4,332
2025	3,984	446	51	4,481
2026	4,071	652	81	4,804
2027	4,163	851	119	5,134
2028	4,233	1,046	165	5,443
2029	4,273	1,236	216	5,724
2030	4,310	1,415	271	5,996
2031	4,344	1,594	328	6,266
2032	4,378	1,768	399	6,546
2033	4,413	1,941	480	6,834
2034	4,448	2,110	559	7,117
2035	4,481	2,284	636	7,401
2036	4,505	2,492	705	7,702
2037	4,527	2,673	779	7,980
2038	4,550	2,854	855	8,260
2039	4,573	3,030	880	8,482
2040	4,595	3,202	885	8,682
2041	4,617	3,202	891	8,711
2042	4,640	3,209	898	8,747
2043	4,663	3,224	904	8,790
2044	4,686	3,239	910	8,835
2045	4,709	3,263	915	8,887
2046	4,732	3,282	920	8,934
2047	4,755	3,308	925	8,989
2048	4,780	3,334	930	9,044
2049	4,804	3,358	935	9,096
2050	4,827	3,378	939	9,144

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.2:

Reference(s): 1B-ED-6

To provide the number of customers who have the ability to connect a DER to the system, versus those who do not have the ability to connect.

RESPONSE:

At the time of the original submission (November 17, 2023), 5.44 percent of Toronto Hydro's customers (42,717 out of 785,027) were serviced by a restricted feeder (see Exhibit 2B, Section E3, Table 1 on pages 9-11 for the list of feeders). It is important to note that this percentage assumes customers who don't currently have DER on the feeder have the intent, means and capability to install one.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.3:
Reference(s): 1B-ED-06

To provide the result of calculation of taking the customer base today in terms of the DER population, and extrapolate that against the investments to be made according to the plan, and provide the impact of reduction and constraints on that population we have today.

RESPONSE:
Due to technical restrictions, the utility has not proposed to alleviate the restricted feeders at Leaside TS and install a bus-tie reactor. As such, in 2029, Toronto Hydro estimates that all customers connected to Leaside TS which represent 1.39 percent of the total customer base (10,892 out of 785,027) will be constrained.

This estimate is subject to the following assumptions:

- The restricted feeder list in Exhibit 2B, Section E3, Table 1 at pages 9-11 and the utility's customer base remain constant.
- The proposed 2025-2029 renewable enabling improvement ("REI") investments are approved and executed; and
- All technical proposals have been successfully reviewed, approved and executed by all stakeholders. It should be noted that the technical feasibility of solutions at each station are subject to a detailed technical study by multiple stakeholders.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.4:

Reference(s): **N/A**

To advise the feasibility of tracking capacity driven future premature retirements, listing the reasons for premature placements, de-recognition expenses, to the extent there are further reasons than those already cited.

RESPONSE:

Below is a list of capital work considerations that contribute to derecognition expenses:

- **Assets with capacity constraints**: System growth and customer connections can trigger the need to upgrade assets, such as overloading transformers or undersized cables.
- **Functional obsolescence of assets or system configurations:** Legacy system configurations such as Rear Lot and Box Conversion trigger asset replacements driven by functionally obsolete distribution system designs and increased safety and failure risks. Furthermore, legacy equipment may be replaced in accordance with latest standards and operating practices when replacement and maintenance supplies are unavailable, when required skill set is in short supply, evolving work practices result in excessively time-consuming or arduous work practices for legacy assets, or when introducing modernization (e.g. enhancing assets to enable automation or SCADA monitoring).
- **Reactive replacements**: Unplanned asset replacements due to events such as equipment failures or foreign interference.

- **Assets causing situational, environmental, or safety risks:** Examples include assets causing encroachment and clearance issues (e.g. new developments closer than safe limits of approach), assets not suited for their conditions (e.g. non-submersible equipment in underground locations), and assets required to be removed by legislation (e.g. PCB contaminated transformers, asbestos materials).
- **Externally Initiated Plant Relocation**: Third-party relocation requests may trigger asset replacement and/or upgrade as part of the relocation. Toronto Hydro must undertake to relocate its infrastructure in response to these requests to resolve conflicts between existing utility infrastructure and third-party capital construction projects.
- **Asset replacements to support other Toronto Hydro projects**: Examples include relocating or rebuilding civil infrastructure in order to permit the construction of new cable chambers or vaults where needed, or upsizing transformers and reconfiguring assets to permit continuity of service to customers while their existing supplies are taken out of service to support work like rebuilds and relocations.
- **Operational efficiency:** When conducting large scale work, such as area rebuilds, it may be more efficient to renew all assets in the area, instead of returning a short period of time later and disrupting the area again to renew other assets that were not targeted originally. In these cases, it is possible that some assets in a renewal project are not past useful life.

Currently there is limited data availability to identify, at an asset-by-asset basis, the driver of replacement within the current information systems. The linkages between the specific asset replaced and the project drivers are not available when the replaced asset is removed from source information systems. To track the requested information, Toronto Hydro would have to develop, administer and monitor new processes for identifying and mapping asset removals in a consistent and verifiable manner. Given the large volume of distribution system capital projects (e.g. Planned Capital programs alone can constitute approximately 290 projects per year) that the utility undertakes in a given year, and the dynamic nature of Toronto Hydro's capital work program, tracking asset removals at this level would be burdensome.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.5:

Reference(s): **TBC**

To advise on tracking and targeting total distribution costs per megawatt-hour delivered.

RESPONSE:

In the first stage of the energy transition that is set to unfold over the 2025-2029 rate period, Toronto Hydro does not view total distribution costs per MWh delivered as a metric conducive to assessing performance in the 2025-2029 rate period. The reasons for this view include:

- **The impact of energy conservation and demand management (CDM) activities** continue in Toronto Hydro's service territory, and it remains to be seen exactly how they will evolve to support energy transition objectives. Historically, the impact of these activities deteriorates the utility's perceived performance in a $/MWh assessment because at the same time that these CDM activities have been undertaken to generate bulk-system value (i.e., avoided generation and transmission level investments), the utility has been investing significant capital in the local distribution grid to renew its aging and deteriorating infrastructure to continue to provide safe and reliable electricity to its customers.

- **The impact of policy, technology and consumer-behaviour changes:** Changes in policy requirements, technology and consumer-behaviour often drive the need for investment in new distribution capabilities and capacity (e.g., new systems, field technology and human capital) that can impact and distort the perceived value of total distribution cost per MWh. For example, some emerging technologies (e.g., more powerful and rapid electric vehicle chargers in residential or commercial contexts) may have a more pronounced impact on the grid and investment needs due to their localized demand impact (i.e., MW), as opposed to their consumption impact (i.e., MWh). Similarly, regulatory policies and consumer needs with respect to DER enablement and integration require utilities to develop new capabilities across a broad range of utility functions.

- **The need for comprehensive assessment of utility performance in the near-and long-term:** Investments in infrastructure upgrades and modernization (including investments in human capital) may initially increase distribution costs but also lead to long-term benefits in reliability, resilience and efficiency. When assessing total distribution cost per MWh, it is important to ensure that other key outcomes such as service quality, reliability, and customer satisfaction are not compromised in the near-and long term.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.6:

Reference(s): 2B-ED-17

To describe how transformers are sized, whether that is based on individual analysis of demand or through other means.

RESPONSE:

Transformer sizing depends on a number of factors such as location, density, area landscape, geography, existing and future developments, historical customer load, and other relevant considerations.

Where the transformer is supplying a single customer, Toronto Hydro determines its size based on the customer’s requested load. Where the transformer is supplying multiple customers, the utility determines its size by aggregating the requested load from the requesting customer, the aggregate historical loads recorded of existing customers on the transformer (if available), and anticipated future growth in the area.

Consider the following example to illustrate a typical scenario: Twenty customers are connected to a 100kVA pole-top transformer with a coincident peak load of 80 kVA (loaded at 80%). A residential customer connected to this transformer has increased their panel size from 100A to 200A and is requesting an upgrade to their service to accommodate an incremental load of 8 kVA. When factoring in the additional load and applying coincidence factors to adjust for load usage patterns on the transformer, the existing transformer is found to exceed the recommended 80% loading to maintain safety and reliability of operation. Therefore, to ensure sufficient capacity for this customer and facilitate future growth in the area, the transformer is upgraded to 167kVA.

Toronto Hydro's investments in system observability technologies as part of its Intelligent Grid Strategy for 2025-2029 will enhance its decision-making in right-sizing its assets. For more details please refer to Exhibit 2B, Section D5.2.1.1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.7:

Reference(s): **2B-ED-18**

To describe the basis for the $600 fee and its justification; the average time it takes and the actual labour costs connected to it.

RESPONSE:

As specified in Toronto Hydro's Conditions of Service, when a customer requests a disconnection and a reconnection of its supply of electricity, Toronto Hydro requires the customer to pay a fair and reasonable charge based on cost recovery principles or pay the applicable OEB-approved fees in accordance with the charges presented in the Standard Service Charges listing, as available on Toronto Hydro's website.[1]

Depending upon the type of disconnection, the OEB-approved specific service charges for disconnections during regular business hours are $120 at the meter and $300 at the pole. The type of disconnection required depends upon various customer- and site-specific factors such as access, physical configuration, the customer's needs, etc. Each charge is applied once for disconnection and once for reconnection. These specific service charges were set and approved by the OEB in Toronto Hydro's 2015 Custom Incentive Rate application, according to the utility's prevailing labour and vehicle costs.

[1] Toronto Hydro Conditions of Service (Revision #23, effective January 1, 2024), s. 2.2.1 at p. 29; available at torontohydro.com/conditions-of-service.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.8:

Reference(s): 2B-ED-18

To confirm whether the connection is occurring on the customer property or at the pole level, and speak in more detail to whether Toronto Hydro would be open to considering an arrangement whether the customer's electrician can do that.

RESPONSE:

When a customer requests a temporary service shut-off for purposes of electrical work on their panel, the type of disconnection/reconnection required depends upon various customer- and site-specific factors such as access, physical configuration, the customer's needs, whether the work is happening at the panel or around the meter base, etc.

Toronto Hydro would not be open to an arrangement where a customer's electrician could conduct the temporary service shut-off. There are several reasons for this including, but not limited to, public and worker safety, compliance with applicable legislation, regulations, and technical standards, asset reliability, and to ensure billing accuracy.

Under Ontario Regulation 22/04,[1] which is overseen by the Electrical Safety Authority ("ESA"), Toronto Hydro carries the ultimate responsibility for public, worker, operation and equipment safety of the distribution system. Therefore, as the licensed distributor of electricity within the City of Toronto, Toronto Hydro retains control over any work on the

[1] Under the *Electricity Act, 1998*, SO 1998, c 15, Sched A.

distribution system to promote electrical safety and ensure compliance with O. Reg. 22/04 and all other applicable legislative, regulatory, and technical authorities. In the utility's assessment, the delegation of temporary service shut-offs to customer-retained electricians would create too many unpredictable variables with respect to safety and the reliability of the distribution system and the resulting risks would not be worth any potential efficiency benefits.

Toronto Hydro also notes that this position is aligned with restrictions upon the use of customer-retained electricians/contractors in distinct but similar contexts. For example, although the Distribution System Code ("DSC") contemplates the use of customer-retained qualified contractors for expansion work (known as "alternative bids"),[2] and Toronto Hydro's Conditions of Service[3] allows such arrangements for customer connections and expansion work, work that makes physical contact with Toronto Hydro's existing distribution system is not eligible for such arrangements.[4] In the same context, the DSC also assigns sole responsibility for decisions related to the temporary de-energization of any portion of the existing distribution system to the distributor.

[2] Distribution System Code ("DSC", last revised March 27, 2024), s. 3.2.14
[3] Toronto Hydro Conditions of Service ("CoS", Revision #23, effective January 1, 2024), s. 2.1.2.1 at p. 15; available at torontohydro.com/conditions-of-service.
[4] DSC s. 3.2.15A.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.9:

Reference(s): **2B-ED-26**

To advise the total typical cost for all connection charges for a micro-gen connection, including baseline, replacing a meter.

RESPONSE:

As noted in interrogatory responses 2B-ED-26(a) and (c), for the connection of micro-embedded generation facilities, where a site assessment is required, Toronto Hydro charges a $500 connection deposit plus HST,[1] which is applied towards any connection costs that may arise under the offer to connect. Toronto Hydro also collects a variable connection charge[2] to recover any costs above and beyond those covered by the $500 connection deposit, including the meter replacement costs, which may vary depending upon the size and complexity of the connection project and site conditions. The variable connection charge is typically under $1,200.

[1] In accordance with section 5.3.6 of the OEB's Distributed Energy Resource Connection Procedures.
[2] In accordance with section 3.1.6 of the Distribution System Code.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.10:

Reference(s): N/A

To justify the fees the connection charge in terms of the actual costs incurred by Toronto Hydro.

RESPONSE:

Please refer to undertaking JT2.9.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENVIRONMENTAL DEFENCE

UNDERTAKING NO. JT2.11:

Reference(s): 2B-ED-26

To provide a document where Toronto Hydro defines a basic connection with respect to micro-generate facilities and provide that except in that document; or if it isn't indicated in a public-facing document, to explain why.

RESPONSE:

Toronto Hydro's Distributed Energy Resource Application and Connection Guidelines, available on the utility's website,[1] show estimated connection application costs on page 3 for projects of varying nameplate capacity, which is $500 for micro-embedded generation facilities, i.e. those with a nameplate rated capacity of 10 kW or less.

[1] Toronto Hydro Distributed Energy Resource Application and Connection Guidelines, online: https://www.torontohydro.com/documents/d/guest/2023-distributed-energy-resource-application-and-connection-guidelines.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

UNDERTAKING NO. JT2.12:

Reference(s): **2B-ED-43**

Referencing 2B-ED-43, to confirm if the figures include upstream losses and both transmission and distribution losses.

RESPONSE:

In reviewing transcript, Toronto Hydro notes that this undertaking does not capture the request by Coalition of Concerned Manufactures and Businesses of Canada. The scope of the undertaking is to confirm that the comparison of distribution line losses provided in Figure 1 is a direct "apples to apples" comparison, particularly in relation to Hydro Ottawa, including only distribution losses and not also distribution and transmission losses.

Toronto Hydro confirms that the comparison of distribution line losses provided in Figure 1 is a direct “apples to apples” comparison using published RRR data. Toronto Hydro further confirms that the line losses provided in Figure 1 include only distribution losses.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

UNDERTAKING NO. JT2.13:

Reference(s): **2B-ED-43**

To advise how the value of losses are quantified, whether it includes the all-in price of electricity, or just the HOEP, or otherwise.

RESPONSE:

When evaluating transformers for procurement, Toronto Hydro calculates the present value of the proposed transformer losses and adds it to the respective proposed prices using the formula below. This approach consistent with the methodology set out in CSA Standard C802.1 – Minimum efficiency values for liquid-filled distribution transformers:

Present Value of cost of losses in dollars = XN + YL

where N = no-load losses in watts
L = total-losses in watts
X = cost of no-load losses per watt in dollars
Y = cost of full-load losses per watt in dollars

The values for N and L are provided by the manufacturer. The values for X and Y factor are derived from a number of variables including but not limited to electricity price, load factor, and useful life. HOEP + GA (Global Adjustment) is used as the electricity price.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

UNDERTAKING NO. JT2.14:

Reference(s): Technical Conference Transcript, Day 1, Pages 43-47

To provide the figures behind the Alteryx model for each year 2023-2029.

RESPONSE:

The table below provides the output of the Alteryx model used for Defective Equipment modelling for SAIFI and SAIDI. Please note that the outputs of the model reflect the annual projected values for SAIFI and SAIDI, however a 5-year rolling average projection of these results are used within the reliability forecast presented for Outage Duration and Outage Frequency in Exhibit 1B, Tab 3, Schedule 1, at pages 10 and 17, and the updated projections shown in Figures 1 and 2 provided in response to interrogatory 2B-SEC-42 part (c).

Measure	2023F[1]	2024P	2025P	2026P	2027P	2028P	2029P
Defective Equipment – SAIFI	0.38	0.44	0.45	0.44	0.42	0.42	0.43
Defective Equipment – SAIDI	15.91	21.68	21.94	21.58	21.01	20.95	21.34

[1] Year-end forecast as of October 15, 2023

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

UNDERTAKING NO. JT2.15:

Reference(s): 2B-CCMBC-06

Referring to 2-CCMBC-6e, to make best efforts to inquire of Stantec whether low temperature would have been selected as a climate parameter.

RESPONSE PROVIDED BY STANTEC:

In more recent studies conducted by Stantec for other utilities, we have included a low temperature parameter to reflect potential impacts on health and safety of personnel (working in cold conditions) as well as potential for increased load demand in extreme winter conditions. In most cases, this is reflected by cold snap (multiple days below a relevant temperature threshold) or extreme cold days (a very cold temperature for the region). Based on the decreasing likelihood of cold events in the future and data from similar studies, it is not likely that the addition of the low temperature parameter would materially change the risks determined in this study as the likelihood of cold events drops off in all future climate scenarios.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COALITION OF CONCERNED MANUFACTURERS AND BUSINESSES OF CANADA

UNDERTAKING NO. JT2.16:

Reference(s): 2B-CCMBC-8

To confirm whether the region described in 2B-CCMBC-8 is only the Toronto Hydro service area or is southern Ontario.

RESPONSE PROVIDED BY STANTEC:

Confirmed that the region described is only the Toronto Hydro service area.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENERGY PROBE

UNDERTAKING NO. JT2.17:

Reference(s): **1B-EP-5**

To respond to 1B-EP-5(b), and describe how Toronto Hydro applies the Distribution System Code.

RESPONSE:

Toronto Hydro recovers from individual customers the costs of connecting distributed energy resource ("DER") to the distribution system, including capital contributions where applicable, in accordance with the applicable authorities such as the Distribution System Code ("DSC") and the DER Connection Procedures ("DERCP"). Since customers' DER projects vary in size and complexity, the costs incurred and recovered by the utility to enable such projects are not uniform and depend upon the particular circumstances of each connection request. Below is a non-exhaustive list of the provisions that authorize Toronto Hydro to recover DER connection costs in a range of connection scenarios:

- **Basic Connection Charge for Micro-Embedded Generation Facilities:** Recovery of the basic connection charge including the supply and installation of any new or modified metering in accordance with section 3.1.5A of the DSC;
- **Connection Deposit for Preparation of Offers to Connect with Site Assessment:** $500 connection deposit in accordance with section 5.3.6 of the DERCP;
- **Preparation Fee for Detailed Cost Estimates for Mid-Sized or Large Generation Facilities**: Fees for preparing detailed cost estimates in accordance with section 6.2.16 of the DSC and section 5.1.4 of the DERCP;

- **Capital Contribution for Constructing Expansions to Connect a Generation Facility:** The generator's share of the present value of projected capital costs and ongoing maintenance costs for new/modified distribution facilities to accommodate the connection, where projected revenue and avoided costs are assumed to be zero, in accordance with section 3.2.5 and Appendix B of the DSC.[1] Toronto Hydro also notes that the cost recovery rules in Chapter 3 of the DSC apply to all generation facilities, including storage facilities, connecting to the distribution system, in accordance with section 6.2.31 of the DSC;
- **Preparation Costs for More than 3 Preliminary Consultation Reports Per Year:** Recovery of the reasonable costs incurred in preparing a Preliminary Consultation Report beyond the initial 3 reports provided free of charge per person in a calendar year, in accordance with subsection 6.2.9.1(a) of the DSC;
- **Passthrough of Transmitter's Costs:** Recovery of costs paid to a transmitter under a Capital Cost Recovery Agreement with the transmitter, in accordance with section 6.2 of the DERCP.

[1] Subject to exceptions laid out in sections 3.2.5B and 3.2.5C of the DSC.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.18:

Reference(s): 1B-Staff-89

To complete the OEB's BCA calculator, named the Draft Phase 1 BCA reporting template, with the inputs included in THESL's BCA calculator

RESPONSE:

Please see JT2.18 Appendix A for the BCA calculator spreadsheet.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.19:

Reference(s): Exhibit 2B, Section D4.1.1.4, Figure 1

To provide reference to the data input sources used to forecast EV update.

RESPONSE:

The following inputs were used to forecast the volume of EVs in Toronto Hydro's system.

Table 1: Inputs Used to Forecast EV Volume

Input	Source	Purpose
Table 20-10-0024-01 New motor vehicle registrations, quarterly	Statistics Canada	Annual total vehicle purchases and annual EV purchases for Ontario
EVs Registered in the City of Toronto	Ontario Ministry of Transportation	Annual total EV population in the City of Toronto
City of Toronto Electric Vehicle Strategy	City of Toronto	Estimate total vehicles registered in the City of Toronto in 2018
TransformTO Net Zero Strategy	City of Toronto	Inform forecasted adoption
2030 Emissions Reduction Plan	Government of Canada	Inform forecasted adoption
TTC Green Bus Program	Toronto Transit Commission	Inform forecasted HDEV adoption, and historical actuals

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.20:

Reference(s): Exhibit 2B, Section D4.1.1.4, Figure 1 [Updated Jan 29, 2024]

Please provide the references used for vehicle charging profiles, and insurance data regarding EV driving habits locally.

RESPONSE:

To understand typical light-duty electric vehicle charging, Toronto Hydro referenced charging profiles provided in:

- the *Summary Report on EVs at Scale and the U.S. Electric Power System* by the U.S. DRIVE Grid Integration Tech Team and Integrated Systems Analysis Tech Team, available here: https://www.energy.gov/eere/vehicles/articles/summary-report-evs-scale-and-us-electric-power-system-2019; and
- the *National Plug-In Electric Vehicle Infrastructure Analysis* by the National Renewable Energy Laboratory, available here: https://www.nrel.gov/docs/fy17osti/69031.pdf.

For typical medium-duty electric vehicle and heavy-duty electric vehicle charging, Toronto Hydro engaged METSCO Energy Solutions Inc., who worked with Lawrence Berkeley National Laboratory (“Berkeley Lab”). Berkeley Lab modelled charging profiles for several MDEV and HDEV fleets, and METSCO aggregated these profiles into system-level averages for each of MDEVs and HDEVs, based on fleets applicable to Toronto’s environment.

For light-duty electric vehicles, the referenced charging profiles were modelled for US cities or states. Toronto Hydro adjusted these by scaling the hourly charging profiles such that the energy consumed by the profile equals the estimated average daily energy consumed by a light-duty EV in Toronto. The estimated average daily energy was produced by considering the average distance driven by Ontario drivers in 2019 (2020 excluded due to COVID considerations), available here: https://www.insurancehotline.com/resources/did-ontario-motorists-drive-fewer-kilometres2020#:~:text=According%20to%20InsuranceHotline.com's%20data,14%2C725%20kilometres%20driven%20in%202019.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.21:

Reference(s): **2B-ED-7**

To review and provide any customer end use surveys or any analysis of data or trends related to energy efficiency retrofit projects or publicly available energy consumption data that have been used to inform its understanding of consumer behaviour with respect to building electrification, on a best-efforts basis.

RESPONSE:

Toronto Hydro did not consider end-use surveys or specific energy efficiency retrofit models related to building electrification in the preparation of its plans. However, the utility considered the potential impacts of building electrification in preparing a system peak demand scenario as part of the IESO's Integrated Regional Resource Plan ("IRRP") process. To inform its input to the 25-year IRRP Forecast, Toronto Hydro considered four space and water heating electrification scenarios. The rate of adoption in each scenario was developed using the City of Toronto's TransformTO Net Zero Strategy targets. The assumptions used in each scenario are provided in Table 1, and the adoption rates estimated from these assumptions in Table 2. The adoption rates are provided relative to the total building stock in a given year (please note that building stock is forecasted to grow).

Table 1: Pacing assumptions for building electrification

Scenario	Pacing Assumptions
High	Achieve TransformTO Net Zero Strategy targets for buildings by 2040

Scenario	**Pacing Assumptions**
Medium	Achieve TransformTO Net Zero Strategy targets for buildings by 2050
Low	Achieve TransformTO Net Zero Strategy targets for buildings by 2060
Business as Usual	Model building retrofits based on Business as Planned targets for buildings in TransformTO Net Zero Strategy Technical Report

Table 2: Building electrification adoption rates, in percentage of total building stock

Year	Residential (Dwellings)				Commercial & Industrial (GFA)			
	High	Med	Low	BAU[1]	High	Med	Low	BAU[1]
2023	31%	29%	28%	27%	3%	2%	1%	2%
2029	60%	49%	44%	35%	22%	13%	10%	12%
2034	79%	63%	55%	40%	55%	23%	17%	20%
2039	97%	76%	65%	44%	92%	45%	24%	28%
2044	100%	87%	74%	48%	100%	70%	40%	35%

Toronto Hydro referenced the Transform TO Net Zero Strategy Technical Report[2] in developing its assumptions with regards to how consumer behaviour scenarios could affect building electrification.

[1] Business as Usual
[2] https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173759.pdf

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.22:

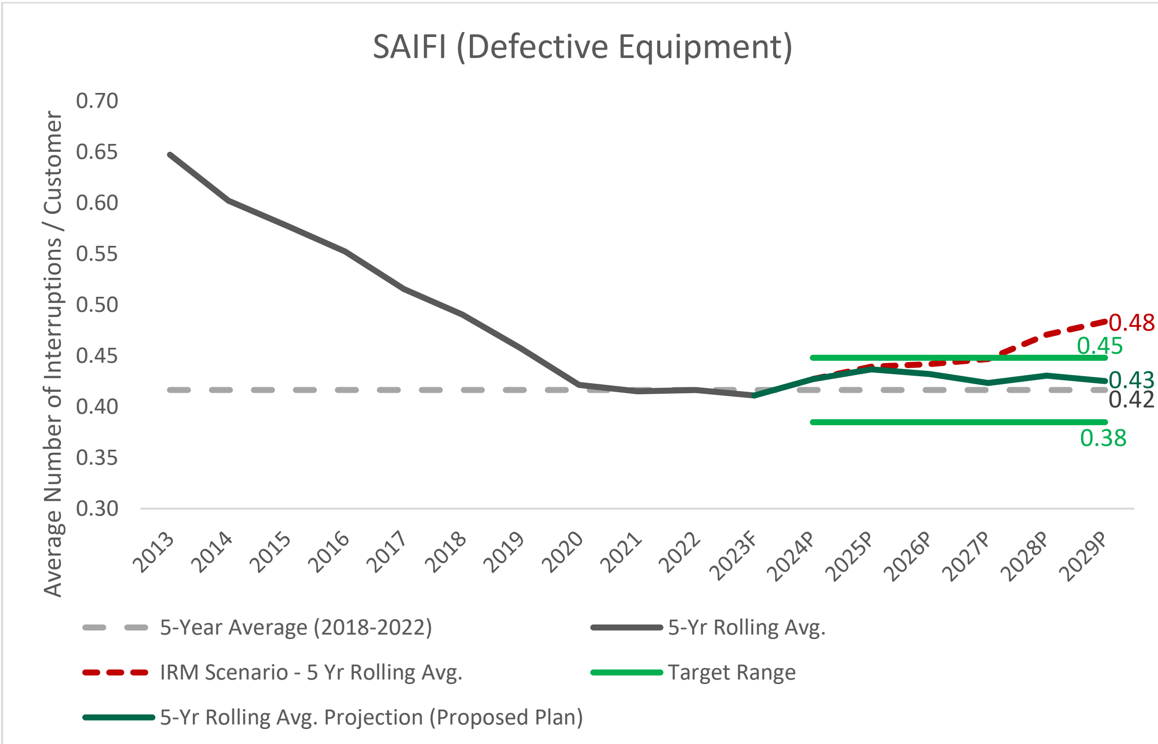
Reference(s): 1B-Staff-91

To update the graph in 1B-Staff-91 to include the five-year rolling average back to 2013.

RESPONSE:

In reviewing transcript, Toronto Hydro notes that this undertaking does not capture the request made by OEB Staff. The scope of the undertaking is to provide Figure 2 from 1B-Staff-91 using a 5-year average over the 2013-2023 period.

The utility also notes that the data underpinning the original Figure which was provided in Exhibit 1B, Tab 3, Schedule 1, at page 17 was corrected in Figure 2 in the response to 2B-SEC-42 part (c). The chart provided below aligns with the updated data. Appendix A to this response provides the supporting tabular data.


SAIFI (Defective Equipment)
Average Number of Interruptions / Customer
0.70
0.65
0.60
0.55
0.50
0.45
0.40
0.35
0.30
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023F
2024P
2025P
2026P
2027P
2028P
2029P
0.48
0.45
0.43
0.42
0.38
5-Year Average (2018-2022)
5-Yr Rolling Avg.
IRM Scenario - 5 Yr Rolling Avg.
Target Range
5-Yr Rolling Avg. Projection (Proposed Plan)

SAIFI (Defective Equipment)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023F	2024P	2025P	2026P	2027P	2028P	2029P
5-Yr Rolling Avg.	0.65	0.60	0.58	0.55	0.52	0.49	0.46	0.42	0.42	0.42	0.41						
5-Yr Rolling Avg. Projection (Proposed Plan)												0.43	0.44	0.43	0.42	0.43	0.43
Target (Lower Bound)												0.38	0.38	0.38	0.38	0.38	0.38
Target (Upper Bound)												0.45	0.45	0.45	0.45	0.45	0.45
IRM Scenario - 5 Yr Rolling Avg.												0.43	0.44	0.44	0.45	0.47	0.48

5-Year Average (2018-2022)	**0.42**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.23:

Reference(s): 2A-Staff-108

To confirm the actual numbers of MCS and antenna installation programs and MCS buyback programs that are included this the RGCRP funding requested for clearance from 2020 through 2022.

RESPONSE:

Over the 2020-2022 period, 40 Monitoring and Control Systems (SCADA enclosure with Meter and RTU) were issued by Toronto Hydro and 110 antennas were installed. Please see the Table 1 below for the annual breakdown.

Table 1: MCS Issued and Antennas Installed in 2020-2022 Period

	2020	2021	2022	Total
Monitoring and Control Systems	16	11	13	**40**
Antenna Installations	19	91	0	**110**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.24:

Reference(s): 2A-Staff-109

To provide a breakdown of the calculation of the 27.5-year depreciation period shown in 2A-Staff-109, Appendix B; to redo the calculation using the updated depreciation rates from the Concentric study proposed in this application.

RESPONSE:

The 27.5 useful life is based on the average[1] of the assets identified in Table 1. Toronto Hydro notes that the asset classes used for the calculation are based on the potential distribution assets originally included in the 2-FB templates in the 2020-2024[2] and the 2015-2019[3] models as noted in the response to 2A-Staff-109, Appendix B for the purposes of simplifying the approach to calculating DVA balances. This excludes Energy Monitoring and Control software which are IT related assets.

Table 1: Useful Life used in 2A-Staff-104- Appendix A

Asset Class Description	Useful Life in 2-FB	Updated Useful Life	
SCADA Assets	15	20	**A**
Bus Tie Reactor[4]	40	40	**B**
Simple Average	**27.5**	**30**	**(A+B)/2**

[1] Technical Conference Transcript Day 2 (April 9, 2024) page 157, lines 18-19
[2] EB-2018-0165, Exhibit 2A, Tab 6, Schedule 5
[3] EB-2014-0116, Exhibit 2A, Tab 8. Schedule 1
[4] Bus Tie reactor assets did not exist in Toronto Hydro's asset base at the time of the Concentric Depreciation Useful life study

Appendix A to this response provides an updated schedule to reflect the change in the useful life as of 2023.

Toronto Hydro notes that the actual depreciation expense for the assets, such as the amounts reflected in Appendix 2-BA, follows the specific useful life of the assets put in-service each year, such as SCADA assets, IT software assets, etc.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.25:

Reference(s): 2B-Staff-135

To break out the costs for decommissioning of MSs in the forecast period where they are included in the DSP (ref: 2B-Staff-135).

RESPONSE:

Please see Table 1 below for the breakdown of the costs estimated to decommission the Municipal Stations from 2025-2029. Toronto Hydro notes that depending on the nature of the station egress, or the drivers of the conversion projects, costs to convert these assets may be incurred in the Overhead System Renewal (Exhibit 2B, Section E6.5), Underground System Renewal – Horseshoe (2B, E6.2), Underground System Renewal – Downtown (2B, E6.3) and Area Conversions (2B, E6.1) programs.

Table 1: Estimated Costs to Decommission Municipal Stations (2025-2029)

	2025	2026	2027	2028	2029
Planned Units	3	5	1	2	6
Planned Cost 2025-2029	$365K	$850K	$115K	$420K	$680K

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.26:

Reference(s): 2B-Staff-188

To describe any agreement between Toronto Hydro and Metrolinx regarding the apportionment of relocation costs under the Building Transit Faster Act, part IV, Section 51 (ref: 2B-Staff-188).

RESPONSE:

Please refer to Exhibit 2B, Section E5.2, at page 6, lines 16-17 and Toronto Hydro's subsequent testimony from Day 3 of the Technical Conference.[1]

[1] Technical Conference Day 3 Transcript (April 10, 2024), at p. 126, lines 2-8.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. JT2.27:

Reference(s): 2B-Staff-162(c)

To provide an approximate value for how much of the Horseshoe system has overhead feeders, versus underground.

RESPONSE:

As of the end of Q1 2024, 45% of the Horseshoe system is underground with the remaining 55% being overhead. These estimates are based on the length of linear assets (i.e. cables and wires) within the horseshoe system.