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Integrated Resource Plan, Addendum I: Losses Considerations

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Siemens Industry

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Siemens Industry, Inc.
Siemens Power Technologies International
400 State Street • P.O. Box 1058
Schenectady, New York 12301-1058 USA
Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777
www.siemens.com/power-technologies

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Section
1

Addendum 1

1.1 Introduction

The objective of this Addendum is to provide background information on the consideration and impact of losses in the IRP.

PREPA's losses as a percentage of the gross generation have been in the order of 12.5% to 14.2% as shown the table below. PREPA also historically estimates its technical losses and the balance are attributed to non-technical losses. As can be observed in Table 1-1 the non-technical losses show an increasing trend as the overall demand is reduced. For the demand projection we reversed this trend and maintained the non-technical losses at 5.8%.

For the demand projection we used values for the technical losses in line with PREPA's estimation, also shown below. However, in this addendum, we cover the expected impact that the IRP once implemented is expected to have on the technical losses.

Table 1-1: Technical and Non-Technical Losses 12 month Period

	Jul-13	Jan-14	Aug-14	Jan-15	Projection
Transmission Loss	2.9%	2.9%	2.9%	2.9%	2.7%
Distribution losses	5.0%	5.0%	5.0%	5.0%	5.0%
Non-Technical Losses	4.6%	5.2%	6.3%	6.0%	5.8%
Total Losses	12.5%	13.1%	14.2%	13.9%	13.5%

1.2 Transmission Technical Losses

Although PROMOD®IV can consider the impact of losses in its cost optimization decisions, for the case of Puerto Rico transmission losses have negligible effect on the dispatch. This fact can be appreciated considering that for the most likely Futures where there is only natural gas in the South and not in the North, the cost differential between the generation in the North with respect of the South is in the order of $90 / MWh (estimated based on Portfolio 3 considering the new combined cycles at Aguirre and Palo Seco). Thus considering that the transmission losses are in the order of 3% or less of the delivered power, its cost avoidance can never justify higher generation in the North (closer to the load) at the expense of reducing cheaper generation in the South.

In fact, detailed study of the hourly generation demonstrates that the North-South cost differential drives the dispatch and if it were not for security constraints imposed by the contingency loadings of the transmission system, all the generation would be dispatched in the South irrespective of the losses. In other words, the dispatch is given by the maximum flows acceptable on the transmission system and not by changes in losses.

To gain insight on the effect of losses in the transmission system we modeled, in PSS®E, three system conditions.

Condition 1: corresponds to the short term conditions after the Aguirre CC has been repowered and Aguirre Steam 1&2 has been converted to gas. In the North the smaller combined cycle at Palo Seco has been installed and PSSP and SJSP has been retired or designated limited use.

Condition 2: corresponds to the same condition above but in the long term 2035, when Aguirre 1&2 and Costa Sur 5&6 have been replaced by new efficient combined cycles.

Condition 3: corresponds to a situation where due to gas availability there is more generation installed in the North and the use of transmission is limited. This condition also represents the 2035 situation.

The table below shows the generation sources and location for the three conditions above.

Table 1-2: Evaluated Generation Conditions for Loss Estimation

	Condition	1	2	3
	Year	2022	2035	2035
North	Palo Seco SCC-800 (Duct Fired)	210	210	
	Palo Seco 1x1 F-class			359
	S J Repowering	400	400	400
	San Juan 1x1 F-class or H Class			359
South	Aguirre 1&2	900		
	Costa Sur 5&6	820		
	Aguirre 1&2 CC Unit Gas Repower	263	263	255
	Aguirre 1x 1x1 F-class or H Class		369	359
	Aguirre 2x 1x1 F-class or H Class		738	
	Costa Sur 2x 1x1 F-class or H Class		738	787
	AES & EcoElectrica	961	961	961
	Total North	610	610	1117
	Total South	2944	3070	2361
	Grand Total	3555	3681	3478

We modeled the dispatches from PROMOD corresponding to the peak night and day time peak for the conditions above and estimated the transmission losses. The resulting values are reported in the table below, where we observe that the losses do not vary significantly between night and day time conditions or in the dispatches and this further confirm the little weight that losses have on dispatch decisions.

Table 1-3: Losses Results By Condition

		Condition 1	Condition 2	Condition 3
	Year:	2022	2035	2035
Night Peak	Generation MW	2884.5	2840.8	2852.6
	Load MW	2809.8	2759.9	2782.3
	Losses	2.6%	2.8%	2.5%
Day Peak	Generation MW	2789.1	2666.1	2666.1
	Load MW	2724.7	2605.4	2599.9
	Losses	2.3%	2.3%	2.5%

In conclusion, the implementation of the IRP is expected to modestly affect the transmission technical losses and this fact has negligible impact on dispatch or Portfolio selection decisions, which are driven by fuel availability, generation efficiency and its location on the system.

1.3 Distribution Losses

One possible impact of the IRP is the impact of the distributed generation (DG) on the losses. This impact is direct as DG results of reduction on the end consumption. However, it is expected to be relatively small as shown below.

To estimate the impact of DG we considered that the Power Losses (also known as the peak capacity losses), i.e. those corresponding to the active power losses at the time of the system peak, will not be affected by DG, as the system peak occurs during night hours. However, the energy losses can be affected.

The relation between energy and capacity losses can be estimated using the following approximate relationship:

$$\%E_l = (0.3 + 0.7 * LF) * \%P_{\ l} = Loss\ Factor * \%P_l$$

Where:

$\%E_l = Energy\ Losses\ in\ \%\ of\ delivered\ energy$

$\%P_l = Power\ Losses\ in\ \%\ of\ delivered\ power$

$LF = Load\ Factor$

So even if the Losses during the system peak are the same, the energy losses will be lower if the load factor (LF) is reduced, as will be the case when distributed generation is considered[1]

[1] The Load Factor (LF) is the annual energy delivered divided by the product of the peak power times the number of hours in the year; thus while with DG the peak power stays the same (the peak occurs at night) the energy delivered will be less and the LF is lower.

Based in the formula above the reduction in energy losses can be estimated with the formula below:

$$\% \, Loss \; Reduction = 1 - \frac{(0.3 + 0.7 * LF_{DG})}{(0.3 + 0.7 * LF_{o})} = \frac{Loss \; Factor_{DG}}{Loss \; Factor_{0}}$$

Where:

$LF_{DG} = Load \; Factor \; after \; DG \; is \; considered$

$LF_{0} = Load \; Factor \; before \; DG$

To assess the impact, the table below shows for the 20 years of the IRP the Maximum Demand, the energy delivered before and after DG, the corresponding Load Factors and Loss Factors, and the expected reduction in energy losses. As can be observed, DG will result in a very small reduction of technical losses in the order of 1.7% by the end of the period, which is an added benefit but not a significant driver behind this generation.

Table 1-4: Estimated Technical Loss Reduction Impact for Futures 1 to 3.

Year	Peak Demand MW	Energy Before DG MWH	DG Production MWH	Energy after DG MWh	LF Before DG	LF After DG	Loss Factor Before DG	Loss Factor After DG	% Loss Reduction
2015	2,995	10,404,546	52,064	10,352,482	79.32%	78.92%	0.855	0.852	0.3%
2016	2,936	20,491,568	125,268	20,366,285	79.67%	79.18%	0.858	0.854	0.4%
2017	2,933	20,483,246	152,350	20,330,883	79.72%	79.12%	0.858	0.854	0.5%
2018	2,930	20,463,915	177,393	20,286,516	79.72%	79.03%	0.858	0.853	0.6%
2019	2,934	20,487,830	198,429	20,289,399	79.72%	78.95%	0.858	0.853	0.6%
2020	2,899	20,209,436	219,140	19,990,278	79.59%	78.73%	0.857	0.851	0.7%
2021	2,886	20,119,729	240,122	19,879,599	79.57%	78.62%	0.857	0.850	0.8%
2022	2,874	20,029,971	260,705	19,769,267	79.57%	78.53%	0.857	0.850	0.8%
2023	2,850	19,826,540	280,984	19,545,561	79.41%	78.29%	0.856	0.848	0.9%
2024	2,828	19,624,532	301,046	19,323,477	79.23%	78.01%	0.855	0.846	1.0%
2025	2,804	19,413,705	320,716	19,092,995	79.03%	77.72%	0.853	0.844	1.1%
2026	2,807	19,424,786	340,760	19,084,025	79.00%	77.61%	0.853	0.843	1.1%
2027	2,809	19,435,617	361,256	19,074,364	78.99%	77.52%	0.853	0.843	1.2%
2028	2,810	19,446,210	381,869	19,064,331	78.99%	77.44%	0.853	0.842	1.3%
2029	2,812	19,456,575	402,293	19,054,276	78.99%	77.36%	0.853	0.842	1.3%
2030	2,813	19,466,722	422,443	19,044,279	78.99%	77.28%	0.853	0.841	1.4%
2031	2,815	19,476,660	442,569	19,034,097	78.99%	77.20%	0.853	0.840	1.5%
2032	2,816	19,486,397	463,186	19,023,199	78.99%	77.11%	0.853	0.840	1.5%
2033	2,817	19,495,941	484,048	19,011,902	78.99%	77.03%	0.853	0.839	1.6%
2034	2,819	19,505,300	504,606	19,000,683	78.99%	76.95%	0.853	0.839	1.7%
2035	2,820	19,514,481	525,102	18,989,395	78.99%	76.87%	0.853	0.838	1.7%

Even if we consider Future 4 where DG is close to duplicated there would be a reduction of the technical losses in the order of 3.5%.

Table 1-5: Estimated Technical Loss Reduction Impact Future 4.

Year	Peak Demand MW	Energy Before DG MWH	DG Production MWH	Energy after DG MWh	LF Before DG	LF After DG	Loss Factor Before DG	Loss Factor After DG	% Loss Reduction
2015	2,995	10,404,546	60,059	10,344,487	79.32%	78.86%	0.855	0.852	0.4%
2016	2,936	20,491,568	144,527	20,347,041	79.67%	79.10%	0.858	0.854	0.5%
2017	2,933	20,483,246	175,696	20,307,551	79.72%	79.03%	0.858	0.853	0.6%
2018	2,930	20,463,915	215,303	20,248,612	79.72%	78.88%	0.858	0.852	0.7%
2019	2,934	20,487,830	264,916	20,222,914	79.72%	78.69%	0.858	0.851	0.8%
2020	2,899	20,209,436	314,573	19,894,863	79.59%	78.35%	0.857	0.848	1.0%
2021	2,886	20,119,729	364,255	19,755,474	79.57%	78.13%	0.857	0.847	1.2%
2022	2,874	20,029,971	413,882	19,616,089	79.57%	77.93%	0.857	0.845	1.3%
2023	2,850	19,826,540	463,361	19,363,179	79.41%	77.56%	0.856	0.843	1.5%
2024	2,828	19,624,532	513,084	19,111,448	79.23%	77.16%	0.855	0.840	1.7%
2025	2,804	19,413,705	562,144	18,851,562	79.03%	76.74%	0.853	0.837	1.9%
2026	2,807	19,424,786	611,624	18,813,162	79.00%	76.51%	0.853	0.836	2.0%
2027	2,809	19,435,617	661,218	18,774,399	78.99%	76.30%	0.853	0.834	2.2%
2028	2,810	19,446,210	711,056	18,735,154	78.99%	76.10%	0.853	0.833	2.4%
2029	2,812	19,456,575	760,387	18,696,189	78.99%	75.90%	0.853	0.831	2.5%
2030	2,813	19,466,722	809,775	18,656,947	78.99%	75.71%	0.853	0.830	2.7%
2031	2,815	19,476,660	858,869	18,617,791	78.99%	75.51%	0.853	0.829	2.9%
2032	2,816	19,486,397	908,966	18,577,431	78.99%	75.31%	0.853	0.827	3.0%
2033	2,817	19,495,941	958,398	18,537,543	78.99%	75.11%	0.853	0.826	3.2%
2034	2,819	19,505,300	1,007,704	18,497,597	78.99%	74.91%	0.853	0.824	3.3%
2035	2,820	19,514,481	1,057,094	18,457,386	78.99%	74.71%	0.853	0.823	3.5%

Siemens Industry, Inc.
Siemens Power Technologies International
400 State Street • P.O. Box 1058
Schenectady, New York 12301-1058 USA
Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777

www.siemens.com/power-technologies