Exhibit VIII, All Generation Source RFP – Avoided Cost Schedules

Pursuant to WAC 480-107-050, PSE is required to file an avoided cost schedule with its RFP; such filed avoided costs are subject to Commission review. The annual and monthly prices shown below constitute PSE's "avoided cost schedule" for purposes of WAC 480-107-050 at this time. The assumptions used in calculating this avoided cost schedule are consistent with PSE's Least Cost Plan This avoided cost schedule is intended to provide general information to potential respondents about the cost of new power supplies absent non-utility resources. The amounts contained in such schedule should not be viewed as the price at which PSE would purchase power from any resource. This Exhibit also includes levelized cost information regarding a wind project selected by PSE in the RFP process immediately preceding the present one, as indicative of a recent PSE avoided cost.

Avoided Cost Schedules

Table E7.1 provides an annual schedule for 2006 – 2025 of forecasted electricity prices from the April 2005 Least Cost Plan, Appendix C. The forecasts are based on assumptions about natural gas prices, regional demand, new resource cost and development, as used and discussed in the April 2005 Least Cost Plan. The prices provided are part of PSE's "Business As Usual" scenario from the April 2005 Least Cost Plan. The estimated prices are derived using the AURORA model and do not include system integration, shaping, or transmission costs. Table E7.2 provides the nominal price forecast on a monthly basis for flat load. Following the annual price table and the monthly price table is a description of the Business As Usual scenario, the AURORA model and key input assumptions. Lastly, PSE provides levelized cost information on its most recent purchase, the Hopkins Ridge wind project.

Table E7.1 Annual Prices for Mid-C Market (Nominal $/MWH)

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Nominal $/MWH	41.69	42.19	38.71	33.82	31.05	35.42	38.87	43.10	46.29	48.59
Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Nominal $/MWH	44.55	46.02	50.62	51.94	51.18	53.95	55.55	59.22	62.51	65.51

Table E7.2 Monthly Prices for Mid-C Market (Nominal $/MWH)

Business As Usual												
$/MWH	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2006	53.73	41.33	46.03	37.42	33.08	28.01	34.00	41.60	43.31	44.67	47.94	48.75
2007	48.79	41.32	42.45	38.84	34.27	29.08	35.92	45.49	49.00	47.28	46.97	46.62
2008	46.61	37.10	40.26	34.44	31.37	28.42	34.47	42.22	44.35	43.15	41.33	40.45
2009	37.69	33.32	36.27	30.73	27.80	23.07	29.10	36.31	39.75	38.60	37.00	36.02
2010	35.85	29.39	31.69	27.10	24.73	20.88	26.06	31.89	35.09	33.74	37.95	37.96
2011	36.89	34.12	36.88	31.10	27.50	22.95	30.98	38.62	42.82	39.99	41.56	41.37
2012	41.73	36.38	38.81	32.50	29.51	25.02	33.52	42.66	51.26	42.53	45.82	46.43
2013	44.91	40.93	43.35	36.04	31.51	26.33	37.02	46.73	59.18	47.48	51.65	51.95
2014	48.40	44.59	47.75	38.27	33.16	25.88	37.46	48.64	68.78	51.86	55.51	55.14
2015	54.22	46.43	49.66	40.56	35.35	28.48	41.28	52.81	73.23	53.88	54.61	52.47
2016	51.30	39.28	43.11	35.61	32.31	27.73	36.21	48.70	74.09	49.16	48.44	48.34
2017	46.64	42.09	42.99	36.70	34.21	29.79	38.98	51.99	73.43	52.40	51.73	51.21
2018	49.97	45.68	48.37	42.18	38.56	33.42	44.68	57.74	78.00	55.74	56.35	56.56
2019	54.47	49.55	52.36	45.24	40.57	30.70	43.89	55.86	71.99	57.30	60.44	60.69
2020	56.89	51.68	56.21	46.23	40.12	28.97	40.60	52.47	64.36	59.30	58.04	59.11
2021	58.13	53.46	57.12	48.32	41.91	31.06	42.78	55.50	74.43	61.33	61.66	61.63
2022	59.57	54.49	58.90	49.64	44.35	33.07	44.42	58.73	75.90	61.99	62.24	63.19
2023	62.50	56.91	60.73	53.46	49.70	37.10	49.55	64.99	81.74	63.75	64.76	65.27
2024	66.21	66.96	64.36	54.82	50.71	38.52	51.96	68.46	86.85	67.19	67.74	66.65
2025	66.16	64.21	65.98	60.86	52.20	42.19	56.45	77.82	90.52	70.13	70.51	69.03

Exhibit VIII, All Generation Source RFP – Avoided Cost Schedules

Business as Usual

The Business as Usual (BAU) scenario represents an Aurora Model forecast of power prices based upon the CERA Rearview Mirror gas price forecast as its foundation. The growth in demand for PSE and the western United States is "normal." The scenario considers only proven technologies for generation.

PSE uses the AURORA model to estimate the market price of power. AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources, regional demand for power, and transmission, which drive the electric energy market. AURORA models the competitive electric market and prices are determined from the clearing price of marginal resources. Marginal resources are determined by "dispatching" all of the resources in the system to meet loads in a least cost manner subject to transmission constraints. This process occurs for each hour that resources are dispatched. Resulting monthly or annual hourly prices are derived from that hourly dispatch.

Cost Information from the Hopkins Ridge Wind Project

The capital cost for the 149.4 MW Hopkins Ridge Project is expected to be approximately $200 million. Like other generating facilities, there will also be ongoing O&M and transmission expenses. The annual levelized cost of Hopkins Ridge is estimated at $46/MWh over the 20-year projected life.