EXHIBIT NO. _______ (EMM-26)
DOCKET NO.____________
2003 POWER COST ONLY RATE CASE
WITNESS: ERIC M. MARKELL

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. ____________

DIRECT TESTIMONY OF
ERIC M. MARKELL
ON BEHALF OF PUGET SOUND ENERGY, INC.

TENASKA Memorandum

TO: Charlie Black – Puget Sound Energy

DATE: September 24, 2003

RE: **LM 6000 4X1 Configuration at Frederickson**

FROM: Doug Lauver

Per your request, this note extends Tenaska's work in support of PSE's Least Cost Plan with the addition of a cost estimate for a 4 X 1 LM 6000 configuration located at the Frederickson site. For comparability, the costing and economic methodology are identical to that used in the *Assessment and Report on Self-Build Generation Alternative For Puget Sound Energy's 2002-2003 Least Cost Plan* (December 2002 draft, March 2003 final). As was the case with the other equipment configurations contemplated for the Frederickson site, we have assumed a 1/1/06 COD for the LM configuration. The actual timeline will depend on a number of factors, particularly permitting requirements.

Table 1 summarizes our estimated findings for a 4 X 1 LM 6000 configuration. Direct capital costs (the EPC contract, the major equipment components and interconnect costs) would be about $195.9 million. Adding "soft" costs (mostly related to project finance and start up), total installed capital cost is $268.6 million, or $1,083/kW. Given this capital requirement, the capacity cost becomes $11.93/kW-month (2006$). Recall "capacity cost" is the revenue requirement (expressed in $/kW-month starting in the COD year, escalated annually over the project's life) needed to cover fixed costs, service debt and earn a minimum return to equity. Adding variable operating costs ($3.32/MWh) and fuel ($3.77/MMB delivered with an average heat rate of 7,435) suggest all-in costs at the busbar of $51.80/MWh at a load factor of 90%. All-in costs increase as load factor decreases (the capacity cost is applied to fewer and fewer annual hours). For comparability, Table 1 uses a fuel cost for the LM 6000 plant equal to that used in our original costing work (i.e. $3.77/MMB). Results are also provided for current gas prices.

Table 1 reproduces the format of Table 10.1 in our original self-build report. Notice that the results for the three 7FA-based projects have been restated to correct an error. The LTSA fired hour charge did not properly reflect changes in load factor. This resulted in a slight under-recovery of costs at high load factors (hence the revised prices are about $.20/MWh higher at 90%) and an over-recovery at low load factors (hence the revised prices are $.50 to $.80/MWh lower at 60%). The mid-range load factor all-in prices recovered the proper LTSA amount and therefore are approximately equal to the original all-in prices. We apologize for the error and any confusion that may have arisen as a result.

The capital and operating costs, in $/kW and $/MWh, for an LM-based configuration (4 X 1 at 248 MW) are both somewhat higher than for a 7FA-based configuration of about the same size (a 1 X 1 at 294 MW). The following points highlight some of the differences:

> Capital Costs – EPC man hours and materials are higher since four GT's and four HRSG's need to be installed. A smaller steam turbine and less duct firing also impact the cost per kW comparison.
>
> Operating Costs – Refer to Table 2. Fixed costs (those costs which are generally independent of hours of operation) are about $925,000/year and $5.90/kW-year higher. Staffing is greater by three persons and we have assumed the facility will participate in GE's leased engine program (which costs about $850,000/year). The leased engine program has associated with it lower fired-hour fees for GT maintenance and certain guarantees relative to engine availability during both scheduled and forced outages. A project owner would need to analyze the expected economics of such a program based on annual operating hours as well as the owner's willingness to accept maintenance and availability risk. Non-fuel variable operating costs are greater by $.54/MWh. With LM 6000's GT maintenance, per unit of output, is higher than for 7FA's. Balance of plant maintenance is also somewhat higher (four HRSG's require maintenance versus one). Consumables are modestly higher as well (NOx emissions are higher which requires more ammonia consumption and system water use/discharge are a bit higher per unit of output).

In practice, the "best" or optimum equipment type and plant configuration depend on the owner's needs and the nature of the plant's duty. While areo-derivative machines (e.g. the LM 6000's) show higher costs in base load applications (which generally cover the range of load factors on Table 1) than FA frame-type machines, they can have important advantages: the number of annual GT starts has little or no impact on maintenance costs; ramp rates tend to be faster; and turn-down can occur in "GT increments" with only very little degradation in heat rate.

As indicated above, the LM 6000 economic methodology was identical to the 7FA methodology; Table 3 summarizes the key economic assumptions. Under separate cover, we will also send several tables which detail, for the LM 6000 project:

- Project scope assumptions,
- EPC cost estimates,

- Interconnect cost estimates,
- O&M cost estimates, and
- A summary of the technical characteristics covering all of the EA, FA and LM 6000 configurations that Tenaska evaluated.

Please call if any questions arise or if we can provide additional information.

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