PRITCHARD & ABBOTT, INC.
VALUATION CONSULTANTS

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December 16, 2008

LaDonna Castañuela, Chief Clerk
Texas Commission on Environmental Quality
Office of the Chief Clerk - MC 105
PO Box 13087
Austin, Texas 78711-3087

Re: TCEQ Docket Numbers
2008-0830-MIS-U (UD 07-11914/Tenaska Gateway Partners, Ltd. – Rusk County)
2008-0831-MIS-U (UD 07-11966/Freestone Power Generation, L.P. – Freestone County)
2008-0832-MIS-U (UD 07-11971/Borger Energy Associates, L.P. – Hutchinson County)
Pritchard & Abbott, Inc., Appellant's Reply Brief

Dear Ms. Castañuela:

Enclosed for filing is an original and seven copies of the Appellant's Reply Brief to the TCEQ Executive Directors Response Brief for Rusk, Freestone, and Hutchinson County Appraisal Districts' Appeals of the Executive Director's Use Determination.

Sincerely,

C. Wayne Frazell

C. Wayne Frazell, P.E., CEM
Engineer/Appraiser

CWF/

Enclosures

copy to: (see enclosed Mailing List)

Mailing List
Tenaska Gateway Partners, Ltd.
TCEQ Docket No. 2008-0830-MIS-U
Freestone Power Generation LP
TCEQ Docket No. 2008-0831-MIS-U
Borger Energy Associates, LP
TCEQ Docket No. 2008-0832-MIS-U

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Texas Commission on Environmental Quality (TCEQ)

Docket Numbers

2008-0830-MIS-U (UD 07-11914/Tenaska Gateway Partners, Ltd. – Rusk County)
2008-0831-MIS-U (UD 07-11966/Freestone Power Generation, L.P. – Freestone County)
2008-0832-MIS-U (UD 07-11971/Borger Energy Associates, L.P. – Hutchinson County)

APPEAL OF THE EXECUTIVE	§	BEFORE THE
DIRECTOR'S USE DETERMINATIONS	§	
ISSUED TO	§	TEXAS COMMISSION ON
TENASKA GATEWAY PARTNERS, LTD;	§	
FREESTONE POWER GENERATION, L.P.; and	§	
BORGER ENERGY ASSOCIATES, L.P.	§	ENVIRONMENTAL QUALITY

PRITCHARD & ABBOTT, INC. (P&A)
FOR RUSK COUNTY, FREESTONE COUNTY, AND HUTCHINSON COUNTY
APPRAISAL DISTRICT'S
APPELLANT'S REPLY BRIEF

I. Property Description

The Tenaska Gateway Partners, Ltd. and the Freestone Power Generation, L.P. facilities are combined-cycle generation plants and the Borger Energy Associates, L.P. facility is a cogeneration plant. These plants all have one or more generators powered by industrial size jet engines. These engines can be fueled by most combustible gas or liquids, but currently, they are fueled by natural gas. The hot exhaust from these engines is passed through a heat recovery steam generator (HRSG). A HRSG is essentially a boiler without the burners. In a combined-cycle plant this boiler creates steam that is used to turn an electric generator(s) just like nuclear, coal and older natural gas fired power plants. In the case of a cogeneration facility the steam from the HRSG is sold directly. In the case of Borger Energy the steam is sold directly to the adjacent oil refinery.

II. Rule Change

The TCEQ rules were changed in response to the 2007 Texas Legislature HB 3732. The modified rules created the Part B List which includes Exhaust Heat Recovery Boilers (B-7) and Heat Recovery Steam Generators (B-8).

A HRSG is often added to recover exhaust gases to preheat water entering the boiler of a conventional electric generating plant to improve efficiency, but, they are not the driving force behind the plant production. We believe that these auxiliary boilers are the type of application that was intended by the inclusion of B-7 and B-8 in the TCEQ Part B List as opposed to boilers in the production stream.

III. Compliance

To some it will appear that the boiler that recovers the exhaust heat from the turbine engines qualifies as a pollution control item. This of course ignores the fact that this boiler is a major component of production. It was installed to produce more electricity or steam to sell and not to reduce pollution. If the jet engines were not ducted to the boiler and burners were added, the HRSG side of the plant would operate as a conventional steam driven plant. It is not the boiler that reduces the pollution. Ducting the hot gases from the jet engine(s) reduces the pollution by reducing the need for an additional heat source (burners).

As a general rule when a component for pollution control is removed, there is little or no loss in production. For example, when a catalytic converter is removed from an engine it still produces the same horsepower. If electronic precipitators are removed from the exhaust of a coal-burning power plant, it still produces the same amount of electricity.

If the boiler is removed from a combined-cycle/cogeneration power plant, production is greatly reduced. Removal of this component significantly reduces the amount of product (electricity and/or steam) produced. Therefore, this boiler is production equipment and is not a pollution control device.

On September 28, 2005 the Texas Commission on Environmental Quality heard the case docket number 2005-1008-AIR-U Appeal of Use Determination No. 04-8353. This case was between XTO Energy and Freestone County Appraisal District concerning a plant that removes sulfur and CO_2 from natural gas. In this case the TCEQ ruled that those components used directly in production were not pollution control equipment. We believe that these boilers are for production and should be treated in the same way as this previous ruling. This is particularly true in the case of Borger Energy that sells the steam from the HRSG directly to a customer.

Duff and Phelps in their briefs point out that the federal government recognizes that these types of plants are more efficient and produce less pollution than conventional power plants. In fact, the federal government has done much to encourage their development and construction. It is our understanding however that the federal government does not mandate this type of plant nor do they specifically specify that a HRSG is a pollution control device.

Before now, there were no environmental tax exemptions granted for the HRSG in a combined-cycle power plant. Few, if any, gas-fired steam-powered electric generators have been built since the late 1970s because of the economic advantages of building a combined-cycle power plant. Some simple-cycle gas turbines have been built for peaking purposes; but, economics has driven the construction of combined-cycle generation.

In 1992 the people of Texas voted and approved Proposition 2 creating the current environmental tax exemption. The ballot read "The constitutional amendment to promote the reduction and encourage the preservation of jobs by authorizing the exemption from ad valorem taxation of real and personal property **used for the control of air, water, or land pollution**." These boilers are used for production and not to control pollution. We believe the majority of the people would have voted **"NO"** on this proposition, if they thought it would include production equipment that produces INCOME and is not MANDATED by law!

IV. Tier III Calculation

We agree with the Public Interest Counsel Response Brief that the Executive Director should review their calculation method and we strongly suggest using the existing Tier III equations. In the Tier III section of the TCEQ Rules there are equations for calculating a Partial Use Determination (PUD). The Tier III calculations reduce the amount of exemption based on the sale of any byproduct sold setting the precedent that the economic benefit of any devise can influence the amount of exemption.

The Tier III terms and equations read as follows:

1. PCF - Production Capacity Factor
2. CCN - Capital Cost New
3. CCO - Capital Cost Old
4. BP - Byproduct
5. BPV – Byproduct Value
6. S&T – Storage and Transport
7. t - Time in Years

$$(1)\quad PCF = \frac{\text{Production Capacity of Existing Equipment}}{\text{Production Capacity of New Equipment}}$$

$$(2)\quad BP = \sum \frac{(\mathit{Byproduct\ Value}) - (\mathit{Storage\ \&\ Transport})}{(1 + \mathit{Interest\ Rate})^t}$$

$$(3)\quad PUD = \frac{[(PCF \times CCN) - CCO - BP]}{CCN} \times 100\%$$

Equation (3) yields the final result. This result is the percentage of equipment analyzed that qualifies for a pollution control tax exemption. The subtraction of BPV in this equation accounts for the additional revenue from a byproduct that is produced. This equation establishes the precedent that economic benefit created by equipment should be evaluated. In the case of a HRSG in a power plant this economic benefit is the additional revenue from electricity and/or steam sales.

We have done a generic Tier III calculation comparing combustion turbines and a combined cycle power plant. In order to have a non-biased source for data, the original cost, efficiency and maintenance cost are from DOE data published in 2007 (P&A Exhibit 1). This Tier III calculation (P&A Exhibit 2) uses the operating cost savings as a byproduct of the equipment. The result is a high negative percentage with any reasonable inputs. A negative result proves that this production equipment is used to produce INCOME. Therefore, this is not pollution control equipment.

We also completed a Tier III calculation for the Borger Energy cogeneration plant (P&A Exhibit 3). In addition to the DOE data, a conservative estimate of $40 million for the annual steam sales was used as the byproduct in this calculation. The actual sales cannot be used due to confidentiality agreements. The turbine costs are the same for both cases. Since the maintenance costs for the HRSGs only are not known, an estimate of maintenance values based on the EIA data was made to account for this equipment. The costs for the HRSGs are those in the Blackhawk plant exemption application indexed up to a 2007 value of over $18.8 million using the Chemical Engineering Index.

The result of these inputs is a NEGATIVE partial use determination. A negative result proves that this is production equipment used to produce **INCOME and is not** pollution control equipment. In fact, the simple payback for the added investment appears to be less than two years in both of our Tier III calculations. Why should other property taxpayers be required to subsidize equipment that already pays for itself?

We provided the TCEQ Executive Director's Staff a spreadsheet that makes these type calculations. This was done more than a month before their brief. It makes no sense for the TCEQ Executive Director to come up with a new way to make this calculation for these cases. We respectfully request that the TCEQ follow its own published and established Tier III equations to determine if equipment is for production or pollution control. Based on the result of our calculations, we believe the HRSGs at these plants do not qualify for any exemption. If some other factors need to be included in this analysis, then it should be the responsibility of the applicants rather than the appraisal districts to acquire the necessary data to perform these calculations. Any exemption should be based on the Tier III method with the inputs vetted by all parties.

The TCEQ Executive Director's Response Brief and exhibits did not include a copy of the new modified calculation. Therefore, it is difficult to make comments regarding this method. The

Executive Director's Response Brief mentions that the evaluation is now based upon the avoided emissions when compared to other fuels and other ways of producing the same products (electricity and/or steam). We agree that reducing pollution is a good thing; but, no law mandated that these HRSGs be installed. The Tier III calculations prove that these HRSGs were installed for economic reasons and not to reduce pollution. Again, why should other property taxpayers be required to subsidize equipment that was installed for economic reasons and not pollution control?

V. Limitations

If these HRSGs are found to be exempted, then a detailed description of what will be exempted needs to be provided to all parties. For example, do we also include the deaerator, the condenser, the pumps, all of the steam piping and other equipment installed to produce INCOME? If any exemption is granted in this case, then the TCEQ should provide direction to the applicants and the appraisal districts as to what does and does not qualify.

Just to point out how ridiculous an applicant request can become - if common sense is not exercised - please consider the following example. A case can be made to exempt plant lighting since this yields fewer emissions than gas lamps. Although there are safety and convenience reasons for electric lighting, the primary reason for this type installation is economics - not pollution control. If you say this is not a valid argument because electric lighting is the accepted technology, then we submit that HRSGs in these plants are also the accepted technology used for many years.

The primary reason for building combined-cycle and cogeneration power plants is economics and not pollution control. If the gas turbine(s) is removed, then all you need is a set of burners and an intake fan to have the same production on the steam side. Since this type of boiler is a major component of production, it is not pollution control equipment.

VI. Conclusions

The Texas Commission on Environmental Quality rule changes in response to the 2007 Texas Legislature HB 3732 that created the new Part B non-exclusive list was intended to clarify pollution control devices not previously recognized. These rule changes did not address exempting equipment used for producing a product.

The boilers in these power plants are installed to produce steam and/or electricity for sale rather than to reduce pollution and do not qualify for a tax exemption. **Therefore, we respectfully request that a Negative Use Determination be granted for the primary boiler (HRSG) of any cogeneration or combined-cycle power plant**. Thank you for your favorable consideration.

Pritchard & Abbott, Inc., Exhibit 1

DOE/EIA Data

Table 39. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2006 ($2005/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2006[3] (2005 $/kW)	Variable O&M[5] ($2005 mills/kWh)	Fixed O&M[5] ($2005/kW)	Heatrate in 2006 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2010	600	4	1,206	1.07	1.00	1,290	4.32	25.91	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2010	550	4	1,394	1.07	1.00	1,491	2.75	36.38	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,936	1.07	1.03	2,134	4.18	42.82	9,713	7,920
Conv Gas/Oil Comb Cycle	2009	250	3	574	1.05	1.00	603	1.94	11.75	7,163	6,800
Adv Gas/Oil Comb Cycle (CC)	2009	400	3	550	1.08	1.00	594	1.88	11.01	6,717	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,055	1.08	1.04	1,185	2.77	18.72	8,547	7,493
Conv Combustion Turbine[5]	2008	160	2	400	1.05	1.00	420	3.36	11.40	10,807	10,450
Adv Combustion Turbine	2008	230	2	379	1.05	1.00	398	2.98	9.91	9,166	8,550
Fuel Cells	2009	10	3	3,913	1.05	1.10	4,520	45.09	5.32	7,873	6,960
Advanced Nuclear	2014	1350	6	1,802	1.10	1.05	2,081	0.47	63.88	10,400	10,400
Distributed Generation -Base	2009	2	3	818	1.05	1.00	859	6.70	15.08	9,500	8,900
Distributed Generation -Peak	2008	1	2	983	1.05	1.00	1,032	6.70	15.08	10,634	9,880
Biomass	2010	80	4	1,714	1.07	1.02	1,869	2.96	50.18	8,911	8,911
MSW - Landfill Gas	2009	30	3	1,491	1.07	1.00	1,595	0.01	107.50	13,648	13,648
Geothermal [6,7]	2010	50	4	1,790	1.05	1.00	1,880	0.00	154.92	36,025	30,641
Conventional Hydropower[6]	2010	500	4	1,364	1.10	1.00	1,500	3.30	13.14	10,107	10,107
Wind	2009	50	3	1,127	1.07	1.00	1,206	0.00	28.51	10,280	10,280
Solar Thermal[7]	2009	100	3	2,675	1.07	1.10	3,149	0.00	53.43	10,280	10,280
Photovoltaic[7]	2008	5	2	4,114	1.05	1.10	4,751	0.00	10.99	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2006.

[2]The technological optimism factor is applied to the first four units of a new, unproven design, or regulatory structure. It reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[3]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2006.

[4]O&M = Operations and maintenance.

[5]Combustion turbine units can be built by the model prior to 2008 if necessary to meet a given region's reserve margin.

[6]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[7]Capital costs are shown before investment tax credits are applied.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed in the 'Notes and Sources' section at the end of the chapter.

Pritchard & Abbott, Inc., Exhibit 2

Tier III Combined-Cycle Calculation

TIER III Calculation of Partial Use
Comparing Combined Cycle and Combustion Turbine Power Plants
(Byproduct Defined as Operating Cost Savings)
Generic Example Calculation

Description			Combustion Turbines Existing Equipment	Unit		Combined Cycle New Equipment	Unit
(a)	Plant Capacity	(PCE)	500	MW	(PCN)	500	MW
(b)	Plant Unit Cost Generation		$420.00	/kW		$603.00	/kW
(c)	Total Generation Plant Cost (a * b * 1,000 [kW/MW])		$ 210,000,000			$ 301,500,000	
(d)	Other Cost (Boiler for steam sales etc.)		$ -			$ -	
(e)	Pollution Control (Low NOx,SCR,etc.) ((c + d) * *X*%)	10.00%	$ 21,000,000		6.00%	$ 18,090,000	
(f)	**Plant Cost Less Pollution equip. (c + d - e)**	(CCO)	$ 189,000,000		(CCN)	$ 283,410,000	
Revenue Projection							
(g)	Projected Utilization		60%			60%	
(h)	Factor for Annual Rate (hr/yr)		8,760	hr/yr		8,760	hr/yr
(i)	Annual Production (a * g * h)		2,628,000	MWh		2,628,000	MWh
(j)	Wholesale rate		$ 0.07000	$/kWh		$ 0.07000	$/kWh
(k)	Electric Revenue (j * 1,000 [kW/MW])		$ 70.00000	$/MWh		$ 70.00000	$/MWh
(l)	Other Income (Steam sales etc.)		$ -	/yr		$ -	/yr
(m)	Gross Revenue ((i x k) + l)		$ 183,960,000	/yr		$ 183,960,000	/yr
Operating Expense Projection							
(n)	Projected Fixed Operating Cost		$11.40	$/kW		$11.75	$/kW
(o)	Total Fixed Cost (a x n x 1,000 [kW/MW])		$ 5,700,000	/yr		$ 5,875,000	/yr
(p)	Heat Rate		10,450	Btu/kWh		6,800	Btu/kWh
	Plant Efficiency		32.65%			50.18%	
(q)	Generation Fuel Quantity (i *p * {1,000 [kW/MW] /1,000,000 [Btu/MMBtu]})		27,462,600	MMBtu		17,870,400	MMBtu
(r)	Boiler burner annual fuel consumption		$ -	MMBtu		$ -	MMBtu
(s)	Fuel Quantity (r + s)		27,462,600	MMBtu		17,870,400	MMBtu
(t)	Projected Fuel Value		$6.00	$/MMBtu		$6.00	$/MMBtu
(u)	Fuel Cost (s * t)		$ 164,775,600	/yr		$ 107,222,400	/yr
(v)	O&M Unit Variable Cost		$ 3.36	$/MWh		$ 1.94	$/MWh
(x)	Total O&M Cost (I * v)		$ 8,830,080	/yr		$ 5,098,320	/yr
(y)	Sustaining Capital (a * X%)	1.00%	$ 2,100,000	/yr	1.00%	$ 3,015,000	/yr
(z)	Projected Total Operating Cost (o + u + x + y)		$ 181,405,680	/yr		$ 121,210,720	/yr
Net Operating Income (m - z)		(NIE)	$ 2,554,320	/yr	(NIN)	$ 62,749,280	/yr

	Year	Income Changes		Cost Savings
Cost Savings (CS) = (NIN) - (NIE)	1	0.00%		$ 60,194,960
	2	0.00%		$ 60,194,960
	3	0.00%		$ 60,194,960
	4	0.00%		$ 60,194,960
	5	0.00%		$ 60,194,960
	6	0.00%		$ 60,194,960
	7	0.00%		$ 60,194,960
	8	0.00%		$ 60,194,960
	9	0.00%		$ 60,194,960
	10	0.00%		$ 60,194,960
		Total		$ 601,949,600
Interest Rate	11.00%	Net Present Value	(BP)	$ 354,502,085

Additional First Cost (AFC) = (CCN - CCO) = $ 94,410,000.00 Simple Payback = (AFC)/(CS) = 1.57 Years

PCF = Production Capacity of Existing Equipment (PCE) / Production Capacity of NEW Equipment (PCN)

PCF = 500 MW / 500 MW = 100.00%

Partial Use Determination = [(PCF * CCN) - CCO - BP] *100% / CNN

Partial Use Determination = $ (260,092,085) / $ 283,410,000 * 100% = **-91.77%**

Note: All above values are estimates - not actual.

Pritchard & Abbott, Inc., Exhibit 3

Tier III Borger Energy Calculation

TIER III Calculation of Partial Use
Comparing Cogeneration and Combustion Turbine Power Plants
(Byproduct Defined as Operating Cost Savings)
Borger Energy (Blackhawk) Built 1998

	Description			**(E) Combustion Turbines Existing Equipment**	**Unit**			**(N) Co-generation New Equipment**	**Unit**
(a)	Plant Capacity	(PCE)		225	MW	(PCN)		225	MW
(b)	Plant Unit Cost Generation			$420.00	/kW			$420.00	/kW
(c)	Total Generation Plant Cost (a * b * 1,000 [kW/MW])		$	94,416,000			$	94,416,000	
(d)	(1) Other Cost (Boiler for steam sales etc.)		$	-				$13,906,514.00	
	(2) CE Index to convert 1998 to 2007 Cost							1.3497	
	(3) Current indexed value (d1 * d2)							$18,769,330.96	
(e)	Pollution Control (Low NOx,SCR,etc.) (c *X%)	10.00%	$	9,441,600		10.00%	$	9,441,600	
(f)	**Plant Cost Less Pollution equip. (c + d3 - e)**	(CCO)	$	84,974,400		(CCN)	$	103,743,731	
	Revenue Projection								
(g)	Projected Utilization			80%				80%	
(h)	Factor for Annual Rate (hr/yr)			8,760	hr/yr			8,760	hr/yr
(i)	Annual Production (a * g * h)			1,575,398	MWh			1,575,398	MWh
(j)	Wholesale rate		$	0.05350	$/kWh		$	0.05350	$/kWh
(k)	Electric Revenue (j * 1,000 [kW/MW])		$	53.50000	$/MWh		$	53.50000	$/MWh
(l)	Other Income (Steam sales etc.)		$	-	/yr		$	40,000,000.00	/yr
(m)	**Gross Revenue ((i x k) + l)**		$	84,283,814	/yr		$	124,283,814	/yr
	Operating Expense Projection								
(n)	Projected Fixed Operating Cost			$11.40	$/kW			$11.75	$/kW
(o)	Total Fixed Cost (a x n x 1,000 [kW/MW])		$	2,562,720	/yr		$	2,641,400	/yr
(p)	Heat Rate			11,588	Btu/kWh			11,588	Btu/kWh
	Plant Efficiency			29.44%				29.44%	
(q)	Generation Fuel Quantity (i *p * {1,000 [kW/MW] /1,000,000 [Btu/MMBtu]})			18,255,764	MMBtu			18,255,764	MMBtu
(r)	Boiler burner annual fuel consumption			-	MMBtu			135,375	MMBtu
(s)	Fuel Quantity (r + s)			18,255,764	MMBtu			18,391,139	MMBtu
(t)	Projected Fuel Value			$6.00	$/MMBtu			$6.00	$/MMBtu
(u)	Fuel Cost (s * t)		$	109,534,584	/yr		$	110,346,831	/yr
(v)	O&M Unit Variable Cost		$	3.36	$/MWh		$	4.00	$/MWh
(x)	Total O&M Cost (i* v)		$	5,293,339	/yr		$	6,301,594	/yr
(y)	Sustaining Capital (f+e) * X%)	1.00%	$	944,160	/yr	1.00%	$	1,131,853	/yr
(z)	Projected Total Operating Cost (o + u + x + y)		$	118,334,802	/yr		$	120,421,678	/yr
	Net Operating Income (m - z)	(NIE)	$	-	/yr	(NIN)	$	3,862,136	/yr

	Year	Income Changes			Cost Savings
Cost Savings (CS) = (NIN) - (NIE)	1	0.00%		$	3,862,136
	2	0.00%		$	3,862,136
	3	0.00%		$	3,862,136
	4	0.00%		$	3,862,136
	5	0.00%		$	3,862,136
	6	0.00%		$	3,862,136
	7	0.00%		$	3,862,136
	8	0.00%		$	3,862,136
	9	0.00%		$	3,862,136
	10	0.00%		$	3,862,136
		Total		$	38,621,362
Interest Rate	11.00%	Net Present Value	(BP)	$	22,745,016

Additional First Cost (AFC) = (CCN - CCO) = $ 18,769,330.96 Simple Payback = (AFC)/(CS) = 4.86 Years

$$\text{PCF} = \frac{\text{Production Capacity of Existing Equipment (PCE)}}{\text{Production Capacity of NEW Equipment (PCN)}}$$

$$\text{PCF} = \frac{225 \text{ MW}}{225 \text{ MW}} = \boxed{100.00\%}$$

$$\text{Partial Use Determination} = \frac{[(\text{PCF} * \text{CCN}) - \text{CCO} - \text{BP}] * 100\%}{\text{CNN}}$$

$$\text{Partial Use Determination} = \frac{\$ \ (3,975,685)}{\$ \ 103,743,731} * 100\% = \boxed{-3.83\%}$$

Note: All above values are estimates - not actual.