SOUTH CAROLINA ELECTRIC & GAS COMPANY

COLUMBIA, SOUTH CAROLINA

SALUDA HYDROELECTRIC PROJECT

FERC PROJECT NO. 516

PROJECT OPERATION AND RESOURCE UTILIZATION

EXHIBIT B

AUGUST 2008

Prepared by:

Kleinschmidt

Energy & Water Resource Consultants

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PROJECT OPERATION AND RESOURCE UTILIZATION

1.0 PROJECT OPERATION

Historically, Saluda Hydro has operated as a baseload, peaking, load following, and reserve capacity facility. Currently, Saluda Hydro is operated primarily as a reserve generation facility in the Applicant's system. The plant normally operates with one unit on line at minimum gate to provide downstream flow in the Saluda River. In the event of a loss of generation, the remaining Saluda Hydroelectric Project units can be started and brought to full load within 15 minutes. This allows a rapid response to emergencies on the Applicant's system, and also fulfills the Applicant's reserve share obligation as a member of the Virginia-Carolinas Electric Reliability Council (VACAR) under the VACAR Reserve Sharing Arrangement (VRSA). It should be noted that, in order to be considered a reserve generation asset at any given time, Saluda Hydro units must remain on standby and cannot be providing generation for other purposes.

Saluda Hydro is also operated to manage the reservoir elevation on a seasonal basis. Under the current license, the Applicant has managed the reservoir using monthly target elevations, which are subject to revision by the Applicant's management based on climatic conditions, reservoir level at the time, dam and reservoir maintenance requirements, or operational considerations. Historically, the reservoir has been maintained between El. 348.5' NAVD88[1] (winter) and El. 356.5' (summer). Occasional reservoir drawdowns to El. 343.5' have occurred for project maintenance work or control of aquatic vegetation (primarily hydrilla) in the reservoir. The current license allows a maximum operating water surface elevation of 358.5'. Saluda Hydro units are occasionally dispatched on an economic basis when it is necessary to release water from the reservoir for seasonal or other drawdowns, or to pass inflow from precipitation in the drainage basin. During the relatively infrequent periods when Saluda Hydro is being utilized for reservoir management, the units being so utilized are not

[1] Unless otherwise noted, all elevation references in Exhibit B are given in North American Vertical Datum 1988 (NAVD 88); conversion to traditional plant datum (PD, used in numerous supporting studies for this license application and often erroneously referred to as MSL) requires the addition of 1.50 feet.

available for reserve generation, and other generation assets must be made available to meet the Applicant's obligation under the VRSA.

The Applicant proposes to continue to utilize Saluda Hydro primarily for reserve generation on an as-needed basis. Generation will also occur to provide downstream flow and for reservoir management when required. The main value of the Project to the Applicant's system is as a reserve generation asset, due to its rapid starting capability and overall excellent reliability.

1.1 Manual or Automatic Operation

The Saluda Hydroelectric Project units normally are dispatched remotely from SCE&G's System Control Center in Columbia. Once started, the units are under automatic control. Units can also be operated manually from the powerhouse. The plant is manned five days per week, eight hours per day, with plant checks conducted on weekends and holidays. Personnel are also available for call out should a problem arise after normal business hours.

1.2 Estimate of Annual Plant Factor

The annual plant factor (the ratio of the average load on the plant for a certain period of time to the capacity rating of the plant) for Saluda Hydro is estimated to be 10 percent, based on annual gross generation data from 1988 through 2006, shown in Exhibit B-1.

1.3 Proposed Operation During Adverse, Mean, and High Water Years

The proposed reservoir operation guide curve and table included as Exhibits B-17 and B-18 gives proposed target reservoir elevations and a proposed normal target operating range for Lake Murray. It should be noted here that the Applicant is using the term "guide curve" and not "rule curve", which was the term used in the application for the current license. A "rule curve" implies that the reservoir will be maintained at or very near a given elevation at certain times of the year, with little flexibility given to the Project operators to allow for conditions beyond their control. Use of the term "guide curve" reflects the intent of the Applicant to manage the reservoir in a more flexible manner, while attempting to balance the often competing demands on the Project's water resources. Because the Applicant must respond to widely varying conditions in the operation of the Project, that are largely beyond the Applicant's control, the seasonal target reservoir elevations are intended as a guideline to allow the Project to be operated in a flexible manner, within certain constraints as described below.

The Applicant proposes a normal target operating range between El. 352.5' (354' PD) and El. 356.5', (358.0' PD), with a maximum operating pool elevation of 358.5' (360.0' PD). The target operating pool elevation for March through August will be 356.5' (358.0' PD). As has been the practice under the current license, the Applicant proposes a minimum operating pool elevation of 343.5' (345.0' PD) for periodic maintenance conditions, which would include but not be limited to: control of aquatic vegetation in the reservoir, investigation, maintenance or repairs of the intake towers, spillway structure, and the upstream face of the original dam, in order to maintain the Project in a safe and reliable condition. Operation at el. 343.5' is anticipated to be infrequent.

The Applicant has no intention of routinely operating the Project at reservoir elevations at or below el. 343.5' (345.0' PD), due to concerns, among others, that one or more of the four municipal water intakes on Lake Murray begin to have difficulty maintaining their normal pumping rate below that water elevation. However, should the pool ever fall below el. 343.5', the Applicant proposes that the Project will remain available for reserve generation at any pool level consistent with the original design of the Project structures. For example, were it absolutely necessary to operate Saluda Hydro to preserve or restore the stability of the Applicant's electrical system during an emergency situation, the Applicant would expect to do so. The original Saluda Dam was provided with upstream riprap armor down to El. 298.5' (300' PD), and the Project has in the past operated at reservoir elevations as low as 321.26' (322.76' PD).

The proposed guide curve targets having the reservoir at its normal maximum operating elevation of El. 356.5' by March 1st, in order to have water in storage to provide higher seasonal minimum flow to enhance fish passage over shoals in the lower Saluda River during April and May, as recommended by the consulting resource agencies. Improvements in weather forecasting technology and the stream gauge network, and the Applicant's development of a computer based Flow Forecast Model (FFM) allows more accurate prediction of inflow than in the past. This allows the Applicant to anticipate most high inflow events and reduce the reservoir level in advance of the flood if necessary. This should mitigate the need to spill water in most cases, even though the reservoir would be maintained at El. 356.5' for a greater portion of the year than it was historically.

The six foot operating range between El. 352.5' at the end of December and full pool El. 358.5', provides adequate usable storage for reserve generation requirements in most years, and the normal maximum operating pool elevation of 356.5' provides approximately 99,000 acre-feet of storage below full pool el. 358.5' for higher than anticipated inflow during storm events. A gradual reduction in pool level to El. 352.5' during September through December is proposed in order to provide storage volume for the higher inflow to the reservoir typical in January through March. Public recreational access to the reservoir at El. 352.5' is excellent, since virtually all public boat ramps on the reservoir are usable well below this level.

The proposed guide curve differs from the reservoir rule curve included in the 1974 application for the current Project license, which provided a reservoir operating range between El. 348.5' (350' PD) during November and El. 356.5' (358.0' PD) during May. The proposed guide curve presented in this Application reflects the changes in utilization of the Project since 1974, when the Project served baseload, peaking and load following functions in the Applicant's system. Currently, baseload generation requirements are primarily met by fossil and nuclear units. Peaking and load following generation requirements are primarily met by combustion turbines and a pumped storage facility. Saluda Hydro is now primarily utilized for reserve generation as described in Section 1.0 of this Exhibit. Since the annual energy production of the Project is a secondary benefit to the Applicant, it is not usually necessary to allow the reservoir to fluctuate over as wide a range as was the practice in the past.

<u>Adverse Flow Years</u>: A proposed Maintenance, Emergency, and Low Inflow Protocol (MELIP) is being developed in consultation with the Project stakeholders that includes provisions for staged reductions in seasonal minimum flow and scheduled

downstream recreation flows, in order to conserve the remaining water stored in Lake Murray during periods of low inflow, in order to delay or prevent depletion of the usable storage (between el. 358.5' and el. 343.5') in the reservoir. The intent of the MELIP is to allow the Project to continue to fulfill its three primary critical functions for as long as possible during drought periods: Reserve electric generation, municipal water supply, and critical downstream flows. The MELIP will be provided as part of the final Settlement Agreement when that document is finalized with the stakeholders.

In adverse flow years, the reservoir may not reach the normal maximum target elevation of 356.5' (358.0' PD) during the spring and summer months, and may fall below the normal target operating range lower elevation of 352.5' (354.0' PD). Low inflow does not significantly limit the operation of Saluda Hydro for reserve generation, since these generation events are relatively brief and intermittent.

<u>Mean Flow Years</u>: Operation of Saluda Hydro in mean flow years will generally consist of continuous minimal generation to provide downstream flow; intermittent generation for reserve requirements and to provide downstream recreation flows throughout the year; occasional generation for reservoir level management; and some sustained generation in the fall if necessary to reduce the reservoir level to accommodate inflow from winter storms and spring runoff from the upper basin.

<u>High Flow Years</u>: In high flow years, the need to pass higher inflow may require that Saluda Hydro be dispatched on an economic basis for several hours per day or for several days during the week, in addition to the operations listed above for mean flow conditions. During these periods of extended generation, the units being so utilized are not available for reserve use, as described previously. Due to the relatively large hydraulic capacity through the powerhouse (approximately equal to the 1 percent exceeds flow), it is rarely necessary to use the spillway for reservoir level management. The proposed Maintenance, Emergency, and Low Inflow Protocol (MELIP) described above will include guidelines for Project operations during high inflow events.

2.0 ESTIMATE OF DEPENDABLE CAPABILITY

2.1 Gross Generation

Annual gross generation at Saluda Hydro for the years 1988 through 2007 is shown in Exhibit B-1. The average gross annual generation over this period was 180,069 MWH. Rated capacity of the plant is 207.3 MW, and dependable capability is estimated to be 206 MW.

2.2 Streamflow Data & Flow Duration Curves

The Saluda Hydroelectric Project is located on the Saluda River near Columbia, SC. The total contributing drainage area at the Saluda Dam is 2,420 square miles. The monthly and annual flow regime data was collected from two United States Geological Survey (USGS) gauges located along the lower Saluda River downstream of the dam. Gauge number 02169000 is located on the Saluda River near Columbia, about eight miles downstream from the Saluda Dam. It has remained in this location from the time it was first installed in 1925. The contributing drainage area for this gauge is 2,520 square miles and it has an average annual flow of 2,762 CFS (USGS 2007). A second gauge, number 02168504, was installed along the lower Saluda River by USGS in 1988. This gauge records data immediately downstream from the Lake Murray Dam. Data from this gauge have shown that from the time period of 1988 to 2007, flows from Lake Murray have varied from 185 CFS to a recorded high of 22,400 CFS. Annual mean flow from gauge number 02168504 is 2,386 CFS (USGS 2007). The contributing drainage area for this gauge is 2,420 square miles. Monthly and annual flow-duration curves were developed for the Project using the mean daily flow data from the respective gages. The data from the two gages were combined to develop the curves shown in Exhibits B-2 through B-14. The data from the gages was pro-rated to their respective contributing drainage areas to make the mean daily flow site-specific. The period of record for the data that is used in these graphs dates from 1979 through 2003. Since gage number 02168504, directly downstream from the dam, was installed in 1988, data from gage 02169000 was used and pro-rated to that particular drainage area.

The flood of record for the Saluda River near the Project location occurred during construction of the original Saluda Dam on October 2, 1929, and was recorded at USGS gauge 02169000 at 67,000 CFS. Summary statistics for these stations from the USGS 2007 Water Data Report for South Carolina appear below.

02169000 SALUDA RIVER NEAR COLUMBIA, SC—Continued

SUMMARY STATISTICS

	Calendar Year 2006		Water Year 2007		Water Years 1925 - 2007	
Annual total	452,339		564,618			
Annual mean	1,239		1,547		2,762	
Highest annual mean					5,431	1936
Lowest annual mean					815	1988
Highest daily mean	16,600	Jan 8	18,400	Mar 3[a]	62,300	Oct 2, 1929
Lowest daily mean	340	Jan 29	329	May 23	12	Jul 13, 1930
Annual seven-day minimum	473	Sep 30	416	May 23	21	Aug 28, 1930
Maximum peak flow			18,900	Mar 2[b]	[c]67,000	Oct 2, 1929
Maximum peak stage			7.96	Mar 2[b]	15.22	Oct 2, 1929
Instantaneous low flow			302	May 23	11	Jul 13, 1930
Annual runoff (cfsm)	0.492		0.614		1.10	
Annual runoff (inches)	6.68		8.33		14.89	
10 percent exceeds	2,150		3,110		6,200	
50 percent exceeds	626		630		1,860	
90 percent exceeds	501		501		426	

[a] Also occurred Mar. 4.
[b] Also occurred Mar. 3.
[c] From rating curve extended logarithmically above 36,000 cfs.

02168504 SALUDA RIVER BELOW LAKE MURRAY NEAR COLUMBIA, SC—Continued

SUMMARY STATISTICS

	Calendar Year 2006		Water Year 2007		Water Years 1988 - 2007	
Annual total	404,256		518,329			
Annual mean	1,108		1,420		2,386	
Highest annual mean					4,328	2003
Lowest annual mean					1,037	2002
Highest daily mean	15,800	Jan 8	18,100	Mar 3	21,800	Jan 16, 1995
Lowest daily mean	229	Jan 29	298	May 23	155	Sep 24, 1989[a]
Annual seven-day minimum	346	Aug 23	370	May 22	168	Jan 12, 1989
Maximum peak flow			18,400	Sep 26	22,400	Jan 16, 1995
Maximum peak stage			15.11	Sep 26	[b]16.01	Feb 21, 1990
Annual runoff (cfsm)	0.458		0.587		0.986	
Annual runoff (inches)	6.21		7.97		13.39	
10 percent exceeds	2,160		2,720		5,530	
50 percent exceeds	497		547		1,420	
90 percent exceeds	401		441		441	

[a] Also occurred Sep. 25, 29, 1989.
[b] Caused by backwater from spillway floodgates.

Inflow to Lake Murray is measured at three USGS gauge stations:

Saluda River at Chappells, USGS No. 02167000, located downstream of the Buzzards Roost Hydroelectric Project (FERC Project No. 1267): This gauge station has been in operation since 1926, and has a contributing drainage area of 1,360 square miles.

Little River near Silverstreet, USGS No. 02167450, located on a tributary to Lake Murray: This gauge station has been in operation since 1990, and has a contributing drainage area of 230 square miles.

Bush River near Prosperity, USGS No. 02167582, located on a tributary to Lake Murray: This gauge station has been in operation since 1990, and has a contributing drainage area of 115 square miles.

Summary statistics for these stations from the USGS 2007 Water Data Report for South Carolina appear below.

An additional gauge station, Little Saluda River at Saluda, USGS No. 021677037, measures discharge values above about 160 CFS due to backwater effects. This gauge station has been in operation since 1992, and has a contributing drainage area of 90 square miles. No summary statistics are available for this station due to the intermittent nature of its data.

02167000 SALUDA RIVER AT CHAPPELLS, SC—Continued

SUMMARY STATISTICS

	Calendar Year 2006		Water Year 2007		Water Years 1927 - 2007	
Annual total	368,898		432,671			
Annual mean	1,011		1,185		1,869	
Highest annual mean					3,110	1929
Lowest annual mean					732	1988
Highest daily mean	4,500	Dec 26	12,300	Mar 3	56,700	Oct 3, 1929
Lowest daily mean	493	Jul 16	228	Aug 19[a]	8.0	Oct 29, 1939
Annual seven-day minimum	503	Jul 14	241	Aug 16	23	Jun 29, 1940
Maximum peak flow			14,200	Mar 3	[b]63,700	Oct 2, 1929
Maximum peak stage			19.73	Mar 3	[c]32.50	Oct 2, 1929
Annual runoff (cfsm)	0.743		0.872		1.37	
Annual runoff (inches)	10.09		11.83		18.67	
10 percent exceeds	1,970		3,090		3,730	
50 percent exceeds	756		752		1,370	
90 percent exceeds	534		256		518	

[a] Also occurred Aug. 20.
[b] From rating curve extended logarithmically above 29,000 cfs.
[c] Adjusted to present datum.

02167450 LITTLE RIVER NEAR SILVERSTREET, SC—Continued

SUMMARY STATISTICS

	Calendar Year 2006		Water Year 2007		Water Years 1990 - 2007	
Annual total	35,971		42,180.9			
Annual mean	98.6		116		178	
Highest annual mean					304	1993
Lowest annual mean					77.7	2002
Highest daily mean	1,150	Nov 23	3,060	Mar 3	5,600	Feb 3, 1996
Lowest daily mean	16	Oct 16	3.2	Aug 22	0.71	Aug 14, 2002
Annual seven-day minimum	19	Oct 11	3.7	Aug 18	1.2	Aug 9, 2002
Maximum peak flow			3,500	Mar 3	Unknown	Apr 19, 2003
Maximum peak stage			13.03	Mar 3	15.73	Apr 19, 2003
Annual runoff (cfsm)	0.428		0.502		0.774	
Annual runoff (inches)	5.82		6.82		10.52	
10 percent exceeds	212		211		317	
50 percent exceeds	61		60		87	
90 percent exceeds	24		7.0		27	

02167582 BUSH RIVER NEAR PROSPERITY, SC—Continued

SUMMARY STATISTICS

	Calendar Year 2006		Water Year 2007		Water Years 1990 - 2007	
Annual total	24,004		27,771.1			
Annual mean	65.8		76.1		102	
Highest annual mean					178	1993
Lowest annual mean					43.6	2002
Highest daily mean	984	Nov 22	2,200	Mar 2	4,330	Jan 15, 1995
Lowest daily mean	10	Jun 12	4.4	Sep 30	3.2	Aug 12, 2002
Annual seven-day minimum	11	Oct 2	5.3	Aug 17	3.9	Aug 7, 2002
Maximum peak flow			3,100	Mar 2	5,570	Jan 15, 1995
Maximum peak stage			13.62	Mar 2	16.06	Jan 15, 1995
Annual runoff (cfsm)	0.572		0.662		0.887	
Annual runoff (inches)	7.76		8.98		12.04	
10 percent exceeds	142		152		192	
50 percent exceeds	33		30		44	
90 percent exceeds	13		6.8		14	

2.3 Area Capacity Curve

Area-capacity curves are given in Exhibit B-15, with a corresponding table presented as Exhibit B-16. The reservoir has gross storage of approximately 2,000,000 acre feet at full pool elevation 358.5’, and usable storage of approximately 635,000 acre feet between elevation 358.5’ (full pool) and elevation 343.5’. The reservoir area is approximately 50,900 acres at full pool elevation 358.5’, and is approximately 35,600 acres at an elevation of 343.5’. At maximum normal operating pool elevation 356.5’, the reservoir area is approximately 48,000 acres, with gross storage of about 1,909,000 acre feet. Previous stage–storage data included in the 1976 application for the current license represented active storage above El. 298.5’ (300.0’ PD), which was the extreme low water elevation for operation of the Project when it was originally designed, and the elevation above which the original earth embankment dam had upstream rip-rap armor provided. To obtain gross storage values, an estimated storage value below El. 298.5’ of 394,000 acre feet was added to the previously published active storage values.

2.4 Reservoir Guide Curve

The proposed guide curve for reservoir operation (discussed previously in this Exhibit) is included as Exhibit B-17, and a guide curve table is given in Exhibit B-18.

2.5 Estimated Hydraulic Capacity

The estimated hydraulic capacity of the plant is 18,000 CFS at 180 feet of head and optimum gate opening.

2.6 Spillway Rating Curve

A spillway rating curve is given in Exhibit B-19.

2.7 Tailwater Rating Curve

A tailwater rating curve is given in Exhibit B-20.

2.8 Elevation – Capacity Curve

Elevation-capacity table and curve are given in Exhibits B-21 and B-22. These represent the Applicant’s estimate of the Project generating capacity based on operating experience and the installed turbine and generator nameplate ratings.

2.9 Generation Analysis

A Resource Utilization Study was conducted in 2005 to compare historical generation at Saluda Hydro with optimal generation based on available flow.

Monthly generation data were examined for the period 1988 to the present. Annual data were provided going back to 1931. An analysis of a sample period (10 years) was considered to be representative of Project operations and generation. For this analysis, the period used ran from 1989-1998, inclusive. Data prior to 1988 was not used as only annual values were reported. Generation data for 1988 was not considered because it was a severe drought year. Data after 1998 was not used due to extraordinary reductions of the reservoir levels due to the backup dam construction and drought periods. The data for the period of consideration indicated an average annual Project generation of 248,474 MWH. Exhibit B-30 summarizes the historical average data by month and year for the noted period. The minimum and maximum annual generation for the period was determined to be 209,182 MWHs in 1989 and 332,152 MWHs in 1998. The highest recorded generation since 1931 occurred in 1964 with an annual generation of 499,074 MWHs.

An energy model was developed to determine the optimal output of the station. To verify the model's accuracy and calibrate it to site conditions, the model was run using existing conditions and compared to the historical generation for years where both head pond levels and annual generation data were available. These years were 1993-1998, with the exception of 1997 which had incomplete head pond level data. Inputs to the model consisted of the average monthly flow, the average monthly head pond level, tailwater rating curve, head loss data and overall efficiency.

The results of the analysis comparing actual generation to computed generation for the years noted indicated close agreement of the model to actual values. This would indicate that the model accurately represented Project generation. The results of the generation analysis are summarized in Exhibit B-23. Individual curves depicting computed vs. actual generation for 1993-1996 and 1998 are provided in Exhibits B-24 – B-28, and a curve showing the average computed vs. actual generation for the study period is included as Exhibit B-29.

The energy model was then re-run using the 10 year average conditions both in regards to head pond level and flow, and the results were compared to the 10-year average generation. The model results indicated that the station output matches modeled output closely. The only variations occur during the summer period, May through September. The net computed values are within 3 percent of the historical average values. Note that the net values allow for a 5 percent reduction in generation to account for scheduled and unscheduled outages, station service, transformer and other minor losses. Because during typical operations no flow is lost due to spillage, there is not much that can be done to change flow utilization. Changes in impoundment and/or Project operation potentially could result in some increases in Project revenues due to time of day generation. This potential would need to be examined as part of another analysis. Further, some potential gains in equipment performance could also increase Project generation. These however, would be relatively small. Exhibit B-30 presents the 10 year historical generation and a graph showing a comparison with the energy model analysis results.

3.0 POWER UTILIZATION

3.1 Generation for Reservoir Management

When Saluda Hydro is utilized to pass inflow from the drainage basin, or to reduce the reservoir level for maintenance or as part of normal seasonal operation, the power produced is used in the Applicant's system to serve customer demand, and thereby balance the Applicant's system load.

3.2 Generation for Applicant's System Reserve

When Saluda Hydro is utilized to replace the sudden loss of power from another generation asset on the Applicant's own system, the power produced is used in the Applicant's system to serve customer demand, usually for periods of several minutes to several hours, until such time as other generation assets can be brought on line, or purchased off-system power becomes available to balance the Applicant's system load.

3.3 Generation for Regional Reserve Sharing Obligations

When Saluda Hydro is utilized in fulfillment of all or a portion of the Applicant's reserve sharing obligation under the VRSA, the power produced by Saluda Hydro represents excess generation above the requirements of the Applicant's own customer demand. The excess power is made available through the interconnected regional transmission system (the "grid"), to balance generation and load over the interconnected system. Compensation to the Applicant for reserve generation provided to other VRSA member systems is made according to the terms of the VRSA.

4.0 FUTURE DEVELOPMENT

4.1 Potential for Future Development

A Resource Utilization Study was conducted in 2005 was performed to evaluate the potential for future development of the Saluda Project. The study concluded that the existing hydraulic capacity of the Project corresponds to approximately the 1 percent exceeds flow at the Project location, and greatly exceeds the average annual flow at the Project location. This indicates that the Project is fully developed hydraulically, and that no additional generating capacity is necessary to fully utilize the available flow.

Economically feasible future development will likely be limited to upgrading the turbines and/or generators in order to enhance efficiency, maintain reliability, and provide ancillary benefits such as enhancement of downstream dissolved oxygen levels. Some increase in rated capacity or energy may be realized, depending on the actual upgrades performed and the final operating regime for the Project with regard to minimum flow, and reservoir operating range.

4.2 Potential Equipment Upgrades

The Applicant commissioned a Saluda Hydroelectric Project Upgrade Study (Kleinschmidt 2007) to evaluate the potential for upgrading the existing, original generating equipment. The upgrade study determined that significant increases in turbine performance could be obtained with modern runner designs.

For the purposes of the upgrade study, the following alternatives were selected for detailed analysis:

Alternative 0: (Base Case) Existing equipment Rehabilitated/Replaced In-Kind

Alternative 0 represents the Base Case for rehabilitating the existing, original equipment. This option consists of installing in-kind replacement runners and restoring the original machine clearances to achieve the initial performance characteristics and reliability. This alternative would provide no increase in capacity over existing conditions.

Alternative 1: Maximum Capacity, No Wheel Case or Generator Modifications

Alternative 1 would maximize the installed capacity by installing new runners of modern design that offer higher efficiencies, output and DO uptake, and rewinding the generators. This alternative would increase the rated capacity of the Project from 207.3 MW to about 247 MW.

Alternative 2: Maximum Capacity, No Wheel Case or Generator Modifications

Alternative 2 would include the upgrades described in Alternative 1, with additional capacity achieved by also modifying the water passages and generators. This alternative would increase the rated capacity of the Project from 207.3 MW to about 259 MW.

Alternative 3: Alternative 1 with a Minimum Flow Optimized Runner in One Unit

Alternative 3 would include the upgrades described in Alternative 1, with the exception that one of the four smaller turbines would receive a runner optimized for highest efficiency at low flow (less than 1,200 CFS). This alternative would increase the rated capacity of the Project from 207.3 MW to about 227 MW.

Alternative 4: Alternative 2 with a New Minimum Flow Optimized Turbine in One Unit Bay

Alternative 4 would include the upgrades described in Alternative 2, with the exception that one of the four smaller turbines would be replaced by a new turbine optimized for highest efficiency at low flow (less than 1,200 CFS). This alternative would increase the rated capacity of the Project from 207.3 MW to about 227 MW.

Comparison of Upgrade Alternatives

Alternative 0, replacing the existing runners in-kind, represents the least cost option. No increase in rated capacity or energy is realized.

Alternative 1, which maximizes rated capacity without modifications to the wheel cases and generators, would cost approximately 10 percent more than Alternative 0, would have an installed capacity of 247 MW and would produce approximately 3 to 8 percent more energy on an annual basis than the existing equipment, depending on downstream minimum flow requirements.

Alternative 2, which results in the highest rated capacity (259 MW), would cost 45 percent more than Alternative 1, and adds only 6 percent more rated capacity. Alternative 3 would cost slightly more than Alternative 1 due to the modifications required to install a minimum flow optimized runner, and adds 10 percent less rated capacity than Alternative 1. Alternative 4, the most expensive option (75 percent more than Alternative 1), reflects the additional costs for a complete new minimum flow turbine/generator along with the costs for generator and pressure case modifications to the remaining units, and also adds 10 percent less rated capacity than Alternative 1.

In the initial Upgrade Study, water allocations and prioritizations yielded a decisive preferred upgrade option (Alternative 1, maximize capacity with runner replacements) for all minimum flow scenarios. The initial study used an extremely large reserve allocation (ten - 4 hour reserve calls per month) coupled with low priority for minimum flows, which affected the balance of economics against options capable of generating with minimum flows. Based on historical averages of reserve allocation (two – 2 hour reserve calls a month), additional energy model runs and economic evaluations with the same average flow year (calendar year 1996) were made. The revised results suggest that Alternative 3 (rather than Alternative 1) is the economically preferred option for all minimum flow scenarios. However, the overall benefit of Alternative 1 remained an attractive option, due to the projected need for increased reserve generation capacity. Furthermore, there appears to be limited potential for a full size turbine (no wheel case modifications) to generate measurable energy with a minimum flow of 700 CFS. Based on these considerations, the Applicant has selected Alternative 1 as the preferred upgrade alternative.

These upgrades are being proposed to support the South Carolina Department of Health and Environmental Control (SCDHEC) in-stream water quality standard for dissolved oxygen (DO) within the lower Saluda River and to provide increased assurance of the reliability of the equipment to meet Licensee’s generation obligations. Based on recent testing preformed as part of the existing license, the lower Saluda River already meets the SCDHEC DO standard approximately 98% of the time. The Applicant proposes a schedule for equipment upgrades that should improve the water quality characteristics of the lower Saluda River such that a 100% maintenance of the in-stream DO standard may be assured as early as within three years after the license is issued but no later than 11 years after the license is issued. The Applicant proposes to develop an adaptive management program in which, after each unit upgrade, the Project will be evaluated to determine if it is achieving the in-stream water quality goal. At the point at which the DO standard is consistently maintained through all operating scenarios, whether it occur after the first unit upgrade, the second one, or the third one, the remaining unit upgrades (if any remain to be done) will be implemented in a purely economics-driven manner that could extend the upgrade period to 25 years after the issuance of the license. The Applicant proposes to perform the equipment upgrades according to the following protocol:

Unit 5 will be the first unit to be modified. Upgrade of Unit 5 will be completed within three years from issuance of the license. The upgrade of that unit is expected to take as long as three years to accommodate the design and testing necessary to assure the new runner meets the performance objectives.

After completing the upgrade of Unit 5, Applicant proposes to evaluate the effectiveness of the Project based on the adaptive management program. Should it be necessary to upgrade another unit to assure maintenance of the SCDHEC in-stream DO standard, the Applicant will upgrade one of the smaller units (preferably Unit 3) within two years after the completion of the upgrade to Unit 5. This process will be repeated with the sequential upgrades of Units 4, 1, and 2 each being achieved within two years after the completion of the previous unit upgrade should the effects of that prior upgrade not achieve the water quality goals. The adaptive management program could be performed after each unit upgrade simultaneously with the ordering and preparation of installation of the next unit upgrade. If maintenance of the SCDHEC in-stream DO standard has been achieved, the Applicant will have the option to proceed with the installation of the next unit or reschedule the installation based on economics or reliability concerns.

This iterative process produces a schedule of a maximum of eleven years from the issuance of the license until all five units are upgraded should all five unit upgrades be necessary to assure maintenance of the SCDHEC in-stream DO standard for the lower Saluda River. However, should the SCDHEC in-stream DO standard be assured with installation of Unit 5 the Applicant will perform the upgrades on the following schedule:

1. Unit 3 will be upgraded within five years after license issuance;
2. Two units (preferably Units 4 and 1) will be upgraded within 15 years of license issuance; and
3. The last unit (preferably Unit 2) will be upgraded within 25 years after license issuance.
4. Should reliability or other issues require the upgrade of one or more of the units sooner than proposed, the schedule will be accelerated to meet the identified need.

The Applicant proposes to use other hydro/pumped storage facilities and/or gas turbines as alternatives to meet our reserve obligations during the time each unit is out of service for the upgrade modification.

Estimated costs associated with the proposed upgrade option are presented in Exhibit D.