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July 15, 2005

Ms. Raquel Rodriguez
California Energy Commission
Docket Unit, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Docket No. 02-AFC-1

Dear Ms. Rodriguez:

Enclosed for filing with the California Energy Commission are one original and 12 (Twelve) copies of the **Caithness Blythe II, LLC's Testimony, for the Blythe Energy Project Phase II. (02-AFC-1).**

Sincerely,

Valerie J. Decker

Valerie J. Decker
Receptionist

/vjd
Enclosures

...\Blythe II\Cover Docket 07-15-05

PROJECT DESCRIPTION

PROJECT DESCRIPTION

Testimony of Thomas Cameron, Robert Looper and Robert E. Gavahan

I. Name: Thomas Cameron
Robert Looper
Robert E. Gavahan

II. Purpose:

The purpose of our testimony is to provide a complete Project Description of the Blythe Energy Project, Phase II (BEP II).

III. Qualifications:

Thomas Cameron: I am a Project Manager retained by Caithness Blythe II. I hold a B.S. degree in engineering. I have 25 years experience in the energy field. I am responsible for managing the permitting activities for development of the BEP II. I am a principal and Vice President of Mountain View Power, Inc., LLC, Project Manager of Summit Power NW LLC, and President/Managing Director of Cameron & Associates, a power industry consulting firm. I was Project Director for the Blythe Energy Project and am also currently Project Director for the Summit Westward Project, a 520 MW Combined Cycle facility using the Siemens V84.3a technology; Vice President and Project Manager for the Bennett Mountain Power Plant, a 160 MW Simple Cycle facility using Siemens 501F technology; Vice President and Project Manager for the Lake Side Power Plant, a 535 MW Combined Cycle facility using Siemens 501 F technology. I have held assignments as Project Manager for Siemens Power Corporation in charge of design, procurement, equipment manufacturing, construction, and commissioning of several large gas turbine power projects, including the 520 MW Bridgeport Energy Project, using the Siemens V84.3a technology. This was the first project of its type using the new Siemens technology in the world. During execution of these projects, my responsibilities included project management, cost and schedule control, technical and commercial contract negotiations, selection and coordination of vendors, engineering firms, and erection contractors, supervision of engineering and site staff, preparation of bid specifications, coordination of construction management, startup coordination and customer interfaces. A more detailed resume is included in Appendix A.

Robert Looper: I am a Professional Engineer and the Project Director for the 520 MW Phase II - Blythe Energy Project. I have been the principal developer for the Blythe Energy projects dating to the initial filings with the California Energy Commission in 1998. I have developed energy projects in partnership with companies that include Duke Energy, PP&L Global, Florida Power & Light, Oglethorpe Power Co., Caithness Energy and others. Affiliated companies have been directly involved in the development and construction of over 6,000 MW of new power plants in the past 7 years. I have over 28 years experience working principally with private industries involved in the development and operation of water, power and general civil projects.

Robert E. Gavahan: I am a Project Engineer employed by Power Engineers Collaborative, LLC. I hold a B.S. degree in mechanical engineering from the University of Minnesota. I have 15 years experience in the energy field. I am responsible for the plant engineering related to the development of the BEP II. My qualifications are more completely detailed in the resume attached in Appendix A.

IV. To the best of our knowledge all referenced documents and all of the facts contained in this testimony are true and correct. To the extent this testimony contains opinions, such opinions are our own. We make these statements and provide these opinions freely and under oath for the purpose of constituting sworn testimony in this proceeding.

V. Summary:

INTRODUCTION

The Blythe Energy Project Phase II (BEP II) is a nominally rated 520 MW combined-cycle power plant and is owned by Caithness Blythe II, LLC (CBII). The proposed project is adjacent to the approved and operating Blythe Energy Project (BEP), which is owned by Florida Power & Light. BEP was approved by the Commission in March 2001 and is described in 99-AFC-8. BEP II consists of two Siemens Westinghouse V84.3a 170 MW combustion turbine generators (CTGs), one (1) 180 MW steam turbine generator and supporting equipment. The project Owner, Caithness Blythe II (CB II) owns the CTGs, STG and Heat Recovery Steam Generators (HRSGs) and this equipment is stored in Kingman Arizona. This equipment was configured for "wet cooling" and assigned to the BEP II since it represents the same design and technology as was licensed for the BEP.

BEP II will be essentially the same design as the BEP. The majority of the design details from BEP will be applied to the design and construction of BEP II. This includes the major equipment, facility arrangement, compliance with LORs, fire protection, etc.

BEP was originally approved to be constructed on a 76-acre parcel of land. Amendment 1A to the Commission Decision allowed for the addition of a 10 acre parcel adjacent to the northwestern portion of the BEP site. The 10-acre parcel was utilized for equipment lay down/storage space during the construction of BEP. Amendment 1B to the Commission Decision provided for the addition of another 66 acre parcel adjacent to the western boundary of the approved BEP Site. Approximately 10 acres of this parcel was fenced to avoid trash mounds that were created during the military occupation of the Blythe airfield during and post WW II. The remaining 56 acres of land was utilized to place approximately 200,000 cubic yards of excess fill material, which was excavated to construct the BEP evaporation ponds and storm water retention basin. The final BEP site therefore encompasses approximately 152 acres.

PROJECT SETTING

The BEP II site is located within the City of Blythe, approximately five miles west of the center of the City. The overall site is located east of the Blythe Airport, which is currently owned by Riverside County and operated by the City of Blythe. The Project site is on an intermediate plateau, about 70 feet in elevation above and west of the Colorado River Valley and the City of Blythe and about 60 feet below the elevation and east of the Blythe Airport. The topography of the project site is flat.

The BEP II site is the western 76 acres of the 152-acre BEP site. The BEP II site is bounded on the south by Hobsonway and on the east by the BEP. Hobsonway is a paved highway running east/west parallel to and one-quarter mile north of Interstate 10 (I-10). The permanent plant entrance for BEP II will be via the BEP entrance off Buck Boulevard. Buck Boulevard runs along the eastern side of the approved BEP property line and runs north from Hobsonway. The north boundary of the BEP II property is on an easement dedicated for extending Riverside Drive. The construction entrance for BEP II will be from Riverside Drive. The entire 152-acre site is fenced with desert tortoise exclusion fence, which was approved during the BEP compliance phase.

All BEP II features and interconnections are located within the "fenced" 152-acre parcel that was approved for the BEP. This includes the plant facilities/equipment, natural gas and transmission interconnections and water supply. There are no project features that are outside the existing 152-acre "fenced" site.

The closest residence is over 3000 feet from the project. Although certain types of farming have occurred at one time in the vicinity of the project, no active farming is taking place adjacent to the BEP II. Citrus trees were growing on the eastern boundary of BEP, however the Owner - Sun World has removed them as they were old growth trees and not producing fruit economically. Sun World has not announced any plans to re-plant this property in the near future. Properties to the North and West are desert sands with sparse creosote bush.

Water to operate the facility will be supplied by two (2) additional groundwater wells having the capability to pump up to 3000 gpm. The wells will be located on the BEP II site.

Natural gas will be supplied to BEP II via the existing 20-inch pipeline, which was constructed as part of the BEP. Connection to this existing pipeline for BEP II will be made within the 152-acre parcel. The line size and operating pressure is sufficient to support both the BEP and BEP II.

BEP II will be electrically interconnected to the Buck Blvd. Substation, located at the northeastern corner of the approved BEP site. Electrical power generated by the combustion turbine generators (CTGs) and steam turbine generator (STG) will be routed to the 8 acre Buck Blvd. switchyard located at the northeast portion of the BEP site between BEP and Buck Boulevard. Buck Boulevard switchyard will be modified by Western to interface with the BEP II and the 500 kV Desert Southwest Transmission Project.

AIR QUALITY

CB II received a Final Determination of Compliance (FDOC) from the Mohave Desert Air Quality Management District (MDAQMD) in May of 2004. With the exception of slightly lower NOx and CO permit levels, the FDOC for BEP II is consistent with the FDOC for the BEP.

BIOLOGICAL RESOURCES

In January 2005, CB II received a consistency determination from US Fish & Wildlife Services regarding the BEP II. This determination recognized the BEP II is within the existing approved BEP site, is essentially the same as BEP, all compensation to mitigate loss of habitat associated with the use of the 152 acre parcel had been made, and required the terms and conditions of the BEP Biological Opinion be met. Subsequently, Staff has presented a potentially significant issue associated with selenium and sodium concentrations, which have been measured in the BEP evaporation ponds and the potential to cause bird deaths. Staff is requiring the implementation of brine crystallizer technology to eliminate the need for evaporation ponds to retain solids resulting from the blowdown from the cooling tower. Although CBII disagrees with Staff's position, CBII has agreed to implement the brine crystallizer technology but requests Committee to approve use of the proposed ponds for backup in the event the zero liquid discharge equipment experiences a forced outage.

It is also important to note the City's approval of the project by the Planning Review Committee did not require any off site improvement be made by CB II.

CULTURAL RESOURCES

During the permitting of the BEP, several World War II vintage trash mounds located on the western 76 acres were investigated. Blythe Energy elected to completely fence the trash mounds as if they were determined to be of cultural significance. During the construction of the BEP, this 10-acre parcel was avoided. This area will also be avoided during the construction of BEP II.

Blythe Energy has placed approximately 200,000 cubic yards of excess material from the construction of the BEP evaporation ponds and retention basin on the BEP II site.

This material averages approximately 5 feet thick and was compacted as it was placed. The BEP II site has therefore been disturbed by the construction of BEP. .

SOCIOECONOMICS

The City of Blythe established a Re-Development Agency and as a result received the use of all property tax dollars originating from the BEP. CB II provided legal support and funds to establish the RDA. Approximately 16 million in bonds were issued to fund several improvement projects within the City. One of these projects is the construction of a water line to the Mesa Verde community.

Although it may not be possible to extend the RDA to the property tax revenue resulting from BEP II, the City will still receive significant new income from the property tax payments. These funds will provide a new source of badly needed funding for additional City projects.

TRANSMISSION SYSTEM ENGINEERING

The new power plant will be connected to a new 500kV Integration Switchyard in the form of a collector bus. One 500kV transmission line from the Integration Switchyard will connect to the existing Buck Boulevard Switchyard owned by the Western Area Power Administration (Western). The BEP II scope of transmission facilities shall terminate at the Buck Blvd. Substation, the first point of interconnection with the high voltage electrical grid.

The Integration Switchyard will be connected to each of the plant unit GSU transformers, which will include all materials to make connections to the high side bushings. All three generator positions will include a high side 500kV breaker and disconnect switch that will be used for isolation and protection. The plant will have close/sync control of the STG position breaker. All three positions will combine into one single bus, then through a disconnect switch and leave via one 500kV line to Buck Blvd. Substation.

The Integration Switchyard will be connected to Buck Blvd via a single circuit 500kV Transmission Line. It will be constructed of single pole steel towers using double-bundle Blue Bird conductor. There will be a total of six structures, with the highest tower 125 feet tall.

Western has completed their System Impact Study, which confirms the ability of Western to modify their facilities inside the fence line of the existing Buck Blvd. Substation to accommodate the proposed BEP II interconnection. A copy of this document has been provided to the CEC staff for their information. There are no significant impacts identified in the Western study.

WATER, DRAINAGE AND WASTE

BEP II proposes to utilize ground water from on site wells to supply water to the project. Testing of the water used by BEP indicates a TDS over 1000. CB II proposes to use this same source of water as was approved for the BEP. This water supply is the poorest quality water available.

The existing retention basin that was constructed for the BEP is designed to provide retention of the storm water originating from the entire 152 acre parcel as well as a significant portion of lands to the north of BEP. BEP II will utilize this same retention basin for storm water retention. There are no required changes to the retention basin as a result the construction of BEP II. The incremental runoff from the paved and roof surfaces in insignificant in proportion to the capacity of the basin.

CB II has based the design of water supply, use and discharge systems for BEP II on the same concept as was approved by the Commission for BEP. This includes two 3000 gpm water supply wells and water storage facilities. It also includes a zero liquid discharge system utilizing a brine concentrator system to return water to process. Blowdown from the cooling tower averages about 400 gallons per minute. As a water savings measure, the system returns all but approximately 10 gallons to plant process for reuse. In the BEP design the 10 gpm waste stream from the brine concentrator is sent to the evaporation ponds in order to contain the concentrated ground water solids.

For BEP II, Staff is requiring elimination of the evaporation ponds and implementation of a brine crystallizer. This recommendation is made due to the potential for chemicals present in the ground water to reach concentrations, which can be harmful to aquatic and migratory birds as described in Biology above. This system will add approximately 3 million to the project capital costs and will consume approximately 1 MW. The remainder of the BEP II water treatment facility will be the same as constructed for the BEP. CB II has requested however, approval of the proposed evaporation ponds for emergency back up storage in the event the water treatment system is out of service.

A primary concern for the CEC regarding BEP use of groundwater from the Mesa, and proposed use by BEP II, were the potential impacts to the water supply for the community of Mesa Verde. BEP II pledged to work with the City of Blythe and Riverside County to solve an existing water quality problem with the drinking water supply for Mesa Verde. CB II, working with the City of Blythe, initiated and funded a study of extending water supply lines to the Mesa Verde from the City of Blythe water supply system. As a result of tax revenues to be received from the BEP, the City has secured funding for the new water project and is now in the process of extending the City water lines to the airport and the community of Mesa Verde. This new service will greatly improve the water quality for the residents of Mesa Verde, who for years were relying on a water well on the mesa, which was providing inferior quality water with limited storage and emergency back-up capability. CB II may tie plant fire protection systems to this new water line as backup to the normal plant systems.

WORKER SAFETY AND FIRE PROTECTION

CB II has agreed to fund the City of Blythe $1.3 million dollars for improvements the City desires to make. As a result of the fire needs assessment performed by the City for BEP II, a portion of these funds will be utilized to fund additional training and equipment identified in the fire needs assessment.

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of:	DOCKET NO. 02-AFC-1
Application for Certification for the Blythe Energy Project, Phase II	**DECLARATION OF THOMAS CAMERON**

I, Thomas Cameron, declare as follows:

1. I am presently retained by Caithness Blythe II as the Project Manager for the Blythe Energy Project, Phase II.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to the **Project Description** for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Las Vegas, NV on July 14, 2005.

Thomas Cameron

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of:	**DOCKET NO. 02-AFC-1**
Application for Certification for the Blythe Energy Project, Phase II	**DECLARATION OF** ROBERT E. GAVAHAN

I, Robert Gavahan, declare as follows:

1. I am presently employed by Power Engineers Collaborative, a provider of engineering services to Caithness Blythe II as the project engineer for the provision of owners engineer services.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to Project Description for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at West Allis, WI on June 14, 2005.

Robert E. Gavahan

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of: Application for Certification for the Blythe Energy Project, Phase II	**DOCKET NO. 02-AFC-1** **DECLARATION OF ROBERT LOOPER**

I, **ROBERT LOOPER**, declare as follows:

1. I am presently employed by Caithness Blythe II, LLC as Project Director.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to Project Description for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Boise, Idaho on July 14, 2005.

Robert Looper

ROBERT LOOPER

TRANSMISSION SYSTEM ENGINEERING

Transmission System Engineering

I. Introduction

A. Name

Robert Looper, Robert Mooney, Mark L. Etherton, P.E. and Chuck Cadiente, P.E.

B. Purpose

This testimony addresses the Transmission System Engineering (TSE) issues associated with the Blythe II Project.

C. Qualifications

Mr. Looper has 28 years of electric utility experience with an extensive background in transmission system planning and operations engineering. He has worked as Project Director for the Blythe Energy Project Phase 1 (1998-2003) and subsequently for Blythe Energy Project - Phase II. His qualifications are summarized more completely in the attached resume included in Appendix A.

Mr. Mooney is the Project Director for the Desert Southwest Transmission Project ("DSWTP"). In addition, he has over 30 years of electric utility experience with an extensive background in transmission system planning and operations engineering. His qualifications are summarized more completely in the attached resume included in Appendix A.

Mr. Etherton has 21 years of electric utility experience with an extensive background in transmission system planning and operations engineering. His qualifications are summarized more completely in the attached resume included in Appendix A.

Mr. Cadiente has 16 years of electric utility experience with an extensive background in transmission system design and operations engineering. He has worked for Power Engineers, Inc and Cadiente Consulting, LLC. His qualifications are summarized more completely in the attached resume included in Appendix A.

D. Prior Filings

In addition to the statements herein, this testimony is based upon all the documents previously docketed in this proceeding that are pertinent to transmission system engineering. Applicant understands that all documents that have been docketed and are part of the administrative record will be incorporated into the evidentiary record of this hearing. Accordingly, this testimony will not specifically identify these prior filings for the purpose of evidentiary identification and admission.

To the best of our knowledge, all of the facts contained in this testimony (including all referenced documents relied upon) are true and correct. To the extent this testimony contains opinions; such opinions are consistent with our own. We make these statements, and render these opinions, freely and under oath for the purpose of constituting sworn testimony in this proceeding.

II. Summary of Testimony

This testimony addresses four topics. First, in Section II.A, we describe the electric transmission facilities that are proposed for licensing as part of this Project. Second, in Section II.B, we assess the compliance of the project with all applicable laws, ordinances, regulations and standards ("LORS") pertinent to transmission system engineering. Our conclusion is that the project will comply with all applicable LORS. Third, in Section II.C, we assess whether the transmission facilities caused by the proposed project will have any significant, adverse impacts on the environment within the meaning of the California Environmental Quality Act, the National Environmental Policy Act and the Warren-Alquist Act. Our conclusion is that the transmission facilities caused by the project will not have any such impacts. Fourth, in Section II.D, we comment upon the Staff's proposed transmission system engineering Conditions of Certification. There we offer certain relatively minor amendments to the Staff proposed conditions primarily intended to reflect the Commission's licensing jurisdiction.

A. Project Descript ion

A complete description of the transmission facilities associated with the Blythe II Project can be found in the Project Description testimony being submitted concurrently with this testimony. In brief, however, Caithness Blythe II, LLC proposes to construct a nominal 520-megawatt (MW) natural gas-fired combined cycle generating facility to be located about 5 miles west of the City of Blythe near Interstate 10 and the Blythe Airport (BEP II, 2002a, Application for Certification, 2-20-02). Caithness Blythe II, LLC proposes to connect the BEP II project to Western's existing Buck Boulevard Substation where the Blythe Energy Project Phase I (BEP I) is presently interconnected.

1. Electrical Interconnection

a. 500KV Integration Switchyard

The new power plant will be connected to a new 500kV Integration Switchyard in the form of a collector bus. One 500kV transmission line will be constructed from the Integration Switchyard to the existing Buck Boulevard Switchyard.

The Integration Switchyard will be connected to each of the plant unit GSU transformers, which will include all materials to make connections to the high side bushings. All three generator positions will include a high side 500kV breaker and disconnect switch that will be used for isolation and protection. The plant will have close/sync control of the STG position breaker. All three positions will combine into one single bus, then through a disconnect switch and leave via one 500kV line to Buck Blvd.

The Integration Switchyard will include the following:

- Three 500kV Power Circuit Breakers
- Four 500kV Group Operated Disconnect Switches
- 3 Metering Class CTs/VTs for revenue class metering.
- 3 Relaying Class VTs for relaying and synchronization
- All structures, foundations and buswork to connect from the high side bushings on the GSUs to the outgoing 500kV line, including deadend structures.
- Control Building
- Control/Communication Cable for interface signals
- Relay Protection and control equipment.
- Communication Equipment to transmit information and control to Buck Blvd.

b. 500kV Transmission Line To Buck Blvd.

A single circuit 500kV Transmission Line approximately 2,290 feet long will be constructed from the Integration Switchyard to connect to the Buck Blvd substation. The line will be located on the project site and will cross the Blythe I plant site. It will be constructed on single steel poles using double-bundle Blue Bird conductor. There will be a total of six poles, with the highest pole being 125 feet tall.

B. Compliance with Applicable Laws, Ordinances, Regulations and Standards

The Final Staff Assessment (FSA) for the project filed by the CEC Staff sets forth the applicable LORS for this project.[1] The applicable LORS are the reliability standards of the North American Electric Reliability Council ("NERC"); the reliability standards of the Western Electric Coordinating Council ("WECC"); the interconnection standards of the Western Area Power Administration ("Western" or "WAPA"); the National Electric Safety Code 1999; and California Public Utilities Commission General Order 95.

Having considered all the documents submitted in this proceeding, our conclusion is that the Project will comply with all applicable LORS. This conclusion is based on our engineering judgment in light of all the documents we have reviewed. However, to briefly summarize the bases for our conclusion, we highlight three key factors: 1) the BART Study; 2) the Western System Impact Study; and 3) the fact that federal laws not pre-empted by the Energy Commission will require compliance independent of any conditions of certification. We briefly discuss each of these factors below.

1. Blythe Area Regional Transmission ("BART") Study

The BART Study was conducted in response to a California Energy Commission ("CEC") requirement to seek input from the regional transmission owners and operator to develop a common base case that would allow assessment of the regional impacts of the transmission system under various transmission options for the Blythe Energy Project Phase II ("BEPII"). The primary participants of the study included Western, the

[1] Staff's list of applicable LORS also includes tariffs of the California Independent System Operator ("CAISO") that are applicable only to the DSWTP, which is a separate project not being licensed by the Commission in this proceeding.

Imperial Irrigation District ("IID"), Southern California Edison ("SCE"), Metropolitan Water District of Southern California ("MWD"), and the CEC Transmission System Engineering Staff. The BART Study was kicked off by the CEC at the first workshop (ref. September 10, 2002 meeting notes) and concluded following the final work group meeting (ref. April 2, 2004 meeting notes) documented in a "Work Group Consensus" memo dated April 30, 2004. The 20 month long Study process was not intended to fulfill each transmission owner's tariff requirements for a system impact study. However, the Study did include power flow, transient stability, short circuit, and post-transient analysis to assess the impacts of BEPII interconnected at the Western Buck 500kV substation and the Desert Southwest Transmission Project ("DSWTP") connected between the Buck and Devers 500kV substations.

There were three primary conclusions from the BART Study (ref. BART Exec Summary August 14, 2003, page 3):

1. For the loss of the DSWTP 500kV line from Buck to Devers, the mitigation requirement will be to prevent no more than 520MW total from BEPI and BEP2II from being delivered into the existing Blythe 161kV area system, the WALC Operating Procedure will be used to limit the flow into the underlying 230kV and 161kV as required. BART assumed that all of BEPII would be tripped for the loss of the 500kV line to Devers. This was also tested via transient stability (ref. General Electric Final Report Dated May 18, 2004) and determined to be the best solution to limit the flow into the existing Blythe 161kV system.

2. For the loss of the Devers - Valley 500kV line, a "Devers Import Nomogram" should be developed to mitigate the overloads on the Devers 500/230kV transformer and the Devers - San Bernardino 230kV #1. Curtailments would be based on a maximum import limit (BART concluded 2200MW) and the criteria established by SCE and the CAISO.

3. With the DSWTP and the interconnection to the Buck 161kV system, the existing Blythe area 161kV system is relieved of many of the existing overloads under N-0, N-1 and N-2 conditions.

The BART Study short circuit analysis concluded that the highest three phase incremental fault current with both the BEPII and DSWTP facilities in service was at the Buck and Blythe substations with approximately 6,000 amps of incremental fault current (ref General Electric Report Table 4-1). The incremental fault current at Devers 230kV with both of the new facilities was found to be 1,100 amps. The respective owners of these facilities (Western and SCE) were to evaluate these incremental levels with their respective system impact studies to determine if additional mitigation would be required (e.g. replacement of breakers).

The Work Group Consensus memo addresses the two major outages related to the above conclusions and related mitigations:

1. Loss of the Buck to Devers 500kV Line - Subsequent to the interconnection of BEPI, Western has developed a Blythe area Remedial Action scheme to protect

the 161kV system from overloads under certain system conditions (now known as WALC RAS#3, ref Western SIS pgs 288-301). The WALC RAS#3 will be used to limit the flow into the underlying 230kV and 161kV system as required. This includes the loss of the Buck to Devers 500kV line to limit no more than 520MW of flow from BEPI and BEPII to the Blythe area 230kV and 161kV system. The WALC RAS#3 has also been reviewed and approved by WECC RAS Subcommittee.

2. Loss of the Devers to Valley 500kV Line - The existing CAISO Operating Procedure T-103, V6.1, Section 5 is the currently defined procedure to deal with any potential Devers area overloads for the loss of the Devers to Valley 500kV line (ref. T-103). The CAISO had also stated that with the addition of the second Devers 500/230kV transformer (proposed for mid-2006), the immediate need for this mitigation (i.e. Devers Import Nomogram) will not be required. However, as a "back-up", and if a single Devers 500/230kV transformer is out of service, the CAISO T-103 procedure will be used to limit flow into the Devers area as required (ref. Consensus Memo, page 2, third paragraph).

Overall, the BART Study concluded that the BEPII interconnected to the Buck substation and with a new 500KV line between Buck and Devers would have little impact to the interconnected system. The impacts can be addressed with the modification of existing procedures (ref. CAISO T103 and WALC RAS #3).

Historically, with the requirements under the transmission owners Open Access Transmission Tariff ("OATT") processes, studies had been done only behind closed doors with little coordination among the regional utilities to develop joint planning cases. Since BART, the Southwest Transmission Expansion Planning ("STEP") and Southwest Area Transmission ("SWAT") regional planning organizations have started to review regional planning in a very similar process to BART, with open meetings to review ideas and to build consensus of conclusions for expansion of the transmission system to meet the requirements of load serving entities, generation developers, and other interested stakeholders. The "open" planning process is not intended to replace the required OATT interconnection process required under the FERC tariffs. The BART efforts led to the conclusions that a new 500kV line between Buck and Devers was the best regional solution for the transmission of the BEPII generation interconnected at the Buck substation to the Edison system. Subsequently, Western is completing the OATT requirements for the interconnection of the BEPII facility at Buck substation, and SCE is completing the OATT requirements for the interconnection of the DSWTP facility at the Devers substation. When these two facilities are completed, they will provide much needed resources and transmission to serve the growing needs of southern California.

2. Western Area Power Administration System Impact Study (ref. May 28, 2005 Western Study Report)

On May 28, 2005, Western completed a System Impact Study ("SIS") for the interconnection of the Blythe II project at the Buck Boulevard substation. The purpose of this portion of the testimony is to provide our opinion of the Western SIS and to compare the analysis to that of the BART Study and to applicable LORS.

The Western SIS was conducted in accordance with Western's OATT in response to the requests of Caithness Blythe II, LLC ("BEPII") together with the DSWTP for the interconnection at the Western Buck substation in the 2008-2009 time-frames. The Western SIS examined various scenarios of the facilities that are in Western's queue for interconnecting to the Buck substation based on Autumn conditions with higher East of the River ("EOR") flows to stress the system from Palo Verde towards Devers. The initial base case was initiated from the approved Western Arizona Transmission Study ("WATS") group case to upgrade the EOR system to 8055MW (including the associated upgrades). The Western SIS included power flow, transient stability, post-transient and short circuit analysis to assess the impacts of the proposed interconnections. Analysis also included the assessment of the second Palo Verde-Devers 500kV line and related facilities.

The conclusion of the SIS is set forth in the last paragraph from the Executive Summary at p. 1:

"In summary, study results demonstrate that the proposed BEPII power plant with a new associated 500kV transmission line as proposed by DSWTP presents ***no adverse impacts*** (emphasis added) on Western's Desert Southwest Region (DSW) transmission system in accordance with WECC, NERC Reliability Criteria and Western's Requirements for Interconnection. As part of project facility improvements Western will expand the Blythe area remedial Action Scheme and the Blythe Substation Operating Procedures to protect the 161kV transmission system from induced power flows through the BEPII connection with the Expanded Buck Boulevard Substation."

The Western SIS also addresses the concerns regarding the applicability of the other projects in the Western queue. Western describes the "plan-of-service" to interconnect the BEPII facilities with the other queue upgrades (ref. page 16). Western includes a Buck Boulevard Substation general arrangement and one-line diagram (ref. page 17 and 18) in the SIS that includes the expansion facilities for the BEPII interconnection, the proposed 230kV line from Buck to Julian Hinds, the proposed 161kV line from Buck to the proposed MidPoint substation, and the proposed Buck 230/161kV phase shifting transformer terminations. These facilities can all be accommodated within the fence line of the existing Buck Substation.

While the Western SIS developed eighteen conclusions (ref. page 6 of Western SIS) as a result of the study, there are some very similar correlations with the conclusions of the BART Study. The following is our executive summary of the relevant conclusions and findings;

- BEPII and the DSWTP 500kV line interconnected to the Buck substation presents no negative impact to Western's system, provided that Remedial Action Schemes ("RAS") are implemented to prevent no more than 520MW of generation from BEPI and BEPII to flow into the existing 161kV system for the loss of the DSWTP 500kV line (ref. power flow and transient stability analysis sections). Additionally the SIS states: "This conclusion is true if the project was connected to the existing system without the additions of the proposed Western queue projects (specifically FPL proposed projects). Similarly, there is no negative impact to Western's system if the project is connected after the implementation of the Buck-Julian Hinds interconnection or after the implementation of the Buck Blvd Midpoint interconnection or if both of these projects are connected to Western's system."

- New transmission facilities interconnected to Buck were found to relieve the existing Blythe area 161kV transmission system under continuous and emergency conditions.

- High simultaneous flows into the Devers substation will need to be reviewed by SCE as part of the interconnection of the DSWTP 500kV line at Devers.

- No new stability or post-transient stability issues were found with the BEPII and DSWTP interconnections.

- The incremental three phase fault current levels noted by Western were approximately 6,200 amps at the Buck 161kV bus, and approximately 1,000 amps at the Devers 230kV bus.

The Western SIS, which has been completed in response to their OATT, comes to nearly identical conclusions as the BART Study. That is, that the existing Blythe area 161kV transmission system (without, for example, the DSWTP) can accommodate no more than 520MW total of Blythe area generation. New 230kV or 500kV transmission line(s) interconnected to Buck may be used to deliver BEPII generation output and, under certain scenarios, has the effect of unloading the existing Western 161kV transmission system. This is also one of the major findings of the BART Study. Western noted that for transient stability, a minimum of two units of BEPII should be tripped via a RAS to maintain system stability for loss of the DSWTP 500kV line. The BART Study examined the transient stability for loss of the DSWTP line and recommended that all of the BEPII generation be tripped to have a significant damping of the system following this disturbance. The Western SIS noted that the incremental fault currents at Buck and Devers were 6,200 amps and 1,000 amps, respectively. These findings are virtually identical to the BART Study, which found that the incremental fault currents at Buck and Devers were 6,000 amps and 1,100 amps, respectively.[2]

In conclusion, the Western SIS is a very thorough and complete impact study examining all of the recent Western interconnection requests to the Buck substation and closely follows the feasibility analysis completed with the BART Study. The interconnection of the BEPII and DSWTP facilities were determined to have no negative impacts to the interconnected transmission system. Western will be proceeding with the required System Facilities Study to determine the specific interconnection requirements and costs for the interconnection to the Buck substation.

[2] The congruence of these two studies refutes Staff's claims that the BART Study is outdated and no longer valid because of alleged changes in the queue positions of the DSWTP and BEPTL. The just completed Western SIS, which fully considered the interactions of these two lines as well as others, confirms almost perfectly the prior conclusions of the BART Study.

Thus, the Western SIS supports the conclusion that the Blythe II project as proposed to the Energy Commission can meet all applicable LORS with appropriate operational mitigation schemes identified in these studies.

3. Compliance with LORS Is Required By Non-Preempted Federal Law

In addition to the two major studies described above, our conclusion regarding compliance with applicable LORS is also based on the simple fact that Western will not allow the project to interconnect if it does not comply. Western's authority to require such compliance resides in its transmission interconnection and open-access tariffs, which are federal laws not pre-empted by the Warren-Alquist Act. Accordingly, even if the Energy Commission imposed no transmission conditions as part of its certification, as a matter of law the project will comply with applicable transmission LORS because federal tariffs administered by Western require it. These requirements are not pre-empted by the Warren-Alquist Act and the Commission must assume that these laws will be fully enforced. For this reason alone, there can be no legitimate question regarding compliance with these requirements.

4. Conclusion as to LORS

In summary, we conclude that Blythe II project will meet all applicable LORS related to transmission system engineering because, among other things: 1) the BART Study concludes that it can be interconnected in compliance with these standards with some mitigation; 2) the Western SIS independently reaches the same conclusion; and 3) Western will enforce its federal tariffs to ensure that project meets all such requirements as a condition of interconnection. To further ensure that the project meets these requirements, Applicant proposes to accept with some amendments various Conditions of Certification described in Section II.D that will make compliance a certification requirement. Moreover, to specifically enforce the mitigation identified by the Western SIS, Applicant will also accept the following proposed condition:

> TSE-__ The Project Owner shall not commence construction until the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) has received all necessary permits. The Project Owner shall not deliver to the grid more than 520 megawatts combined from BEP and BEP II until the Desert Southwest Transmission Project (or an equivalent transmission upgrade as determined by the CPM) has been constructed and is in operation. The Project Owner shall implement a remedial action scheme as described in the Western Area Power Administration System Impact Study to curtail total generation from the BEP and BEP II projects to no greater than 520 megawatts in the event of an outage of the Desert Southwest Transmission Project (or equivalent transmission upgrade as determined by the CPM).

C. Enviro nmental Impacts of Transmission Facilities

This portion of the testimony addresses whether the transmission facilities caused by the Blythe II Project may have significant, adverse and unmitigated environmental impacts. For the reasons set forth below, we conclude that there will be no such impacts. The transmission facilities that the Commission is being asked to license in this proceeding are the new integration switchyard, the approximately 2,290 foot long "generation tie" transmission line from the integration switchyard to the Buck Boulevard substation and certain changes within the substation needed to accommodate the interconnection. In addition, the Blythe II project proposes to rely upon the DSWTP for the transmission of its power from Buck Boulevard to the Southern California Edison system at the Devers substation. While this project is while beyond the Commission's licensing jurisdiction, Applicant has nonetheless provided information regarding its environmental impacts for the Commission's consideration. This testimony discusses the potential environmental impacts of each of these facilities below.

a. The Integration Switchyard and the Generation Tie Line

These facilities are proposed to be built almost entirely upon the Blythe I project site which the Commission assumed would be disturbed and was therefore fully mitigated as part of the Blythe I proceeding. The potential impacts of these linear facilities have been reviewed by the Staff under each of the environmental disciplines and Staff has identified no unmitigated significant, adverse environmental impacts from these facilities in the FSA. Applicant reached the same conclusion based upon its studies done for the application.

b. The Substation Changes

These are relatively minor equipment changes entirely within the fence-line of the existing Buck Boulevard substation. Staff has identified no potential significant, adverse environmental impacts from these facilities in the various environmental sections of the FSA nor were any identified in the studies done for the application.

c. The Desert Southwest Transmission Project (DSWTP)

The DSWTP is a separate project from the Blythe II facility intended to serve multiple purposes including, but not limited to, transmission of power from the Blythe II facility to Edison's Devers substation. It is a new 118-mile 500 kV transmission line from the Blythe area to the Devers Substation of Southern California Edison ("SCE") near Palm Springs, CA. It is not part of the Blythe II project for licensing and is being reviewed and licensed separately. Nonetheless, because the Blythe II project proposes to contribute significantly to the power transmitted across this new facility, Applicant has submitted to the Commission the draft environmental impact statement/report ("DEIS/DEIR") prepared for this project.

The DEIS/DEIR evaluated four primary routing alternatives between the Blythe, Ca area and the Coachella Valley.. Three of these primary routes were along the utility corridor abutting Interstate highway 10 to terminate at SCE's Devers Substation. The fourth primary route traversed the Chocolate Mountains adjacent to an existing IID transmission line to terminate at IID's Midway Substation.

The preferred alternative identified in the DEIS/DEIR extends from the Blythe area along the I10 corridor adjacent to the existing DPV1 transmission line for most of its 118 mile length. This preferred alternative, incorporating comments on the draft, will be put forth in the FEIS/FEIR.

The DSWTP is nearing completion of a joint NEPA/CEQA environmental analysis process that has addressed its potential effects. This environmental process included scoping with agencies and the public, including the CEC. The DEIS/DEIR was published and comments were received via public hearings and written comments. The Final EIS/EIR is being reviewed during July, 2005 by the Bureau of Land Management ("BLM") and IID, the lead NEPA and CEQA agencies, and is expected to be noticed for publication in September, 2005 or before. Comments received regarding the DEIS/DEIR will be incorporated in the final document.

The DEIS/DEIR concludes that all potential adverse impacts of the DSWTP can be mitigated with reasonable and feasible measures. Based upon our review of the DEIS/DEIR, we conclude that the DSWTP will not have any unmitigated, significant adverse impacts on the environment. Thus, to the extent the DSWTP impacts can be considered "downstream" impacts of the BEPII project, there is ample evidence that these impacts can be mitigated to insignificance.

D. Appl icant's Changes to Proposed Conditions of Certification

The Staff's supplement to the FSA proposes various conditions of certification that we have reviewed carefully. Notwithstanding the Applicant's disagreement with Staff regarding the schedule of this proceeding and the submission of additional information, issues that the Committee has ruled upon twice, we do not have major disagreements with the Staff's proposed conditions.

Set forth below are our proposed changes to the Staff's conditions. These changes clarify that the conditions apply only to the facilities that are part of the BEPII Project and are within the Commission's jurisdiction. Said differently, these changes clarify that the conditions do not apply to facilities such as Western's or the DSWTP that are not part of this project and not within the control of the Project Owner.

Thus, we have amended Table 1 of Condition of TSE-1 that describes the "major equipment" to which the conditions apply. These changes make clear that the references to equipment (e.g. buses or breakers) refer only to such equipment within the integration switchyard as opposed to similar equipment that may be installed by Western or others elsewhere on the grid. We have also proposed amendments to other conditions, notably Condition TSE-5, to implement this same concept either by reference this Table or by referring to the first point of interconnection with the grid. Our proposed changes to Staff's recommended conditions are as follows:

TSE-1 The project owner shall furnish to the CPM and to the CBO a schedule of transmission facility design submittals, a Master Drawing List, a Master Specifications List, and a Major Equipment and Structure List <u>for the BEP II transmission facilities to the first point of interconnection at the Buck Blvd Substation</u>. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide designated packages to the CPM when requested.

Verification: At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction of any transmission facility, the project owner shall submit the schedule, an updated Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in **Table 1: Major Equipment List** below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Equipment List
Integration Switchyard Equipment:
3- Power Circuit Breakers, 550kV, 1800kV BIL, 3000A, 40KAIC
3 - Step-up Transformers, 16-500kV
~~Busses~~ 3 - Capacitive Voltage Transformers, 525kV, 1800kV BIL, 400VA, 2500/4500:1 DR
3 - Metering Class CTs/VTs for revenue class metering.
3 - Surge Arrestors, 525kV, 335kV MCOV, 420kV Duty Cycle
4 – Disconnects Switches, 525kV, 1800kV BIL, 3000A, 63KAIC, Motor Operated
All structures, foundations and buswork to connect from the high side bushings on the GSUs to the outgoing 500kV transmission tie line, including deadend structures. ~~Take off facilities~~
Switchyard Control Building
Relay/Control/Communication System
Station Service/Battery System
Transmission Tie Line Equipment:~~Pole/Tower~~
7,000 ft - Double Bundled 2156 kcmil Bluebird Conductor and associated fittings 2,400 ft - Overhead Shieldwire 6 - Tubular Steel Pole Structures 27 sets - Insulator and Hardware Assemblies 6 - Foundations and Grounding Systems
The transmission tie line extends from the Integration deadend structure to the fence line at Buck

TSE-2 Prior to the start of construction of any transmission facility <u>to the first point of interconnection at Buck Boulevard</u>, the project owner shall assign an electrical engineer and at least one of each of the following to the project: A) a civil engineer; B) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; C) a design engineer, who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; or D) a mechanical engineer. (Business and Professions Code Sections 6704 et seq., require state registration to practice as a civil engineer or structural engineer in California.)

The tasks performed by the civil, mechanical, electrical or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer. The civil, geotechnical or civil and design engineer assigned in conformance with Facility Design condition **GEN-5**, may be responsible for design and review of the TSE facilities.

The project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all engineers assigned to the project. If any one of the designated engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer. This engineer shall be authorized to halt earthwork and to require changes; if site conditions are unsafe or do not conform with predicted conditions used as a basis for design of earthwork or foundations.

The electrical engineer shall:

1. Be responsible for the electrical design of the power plant switchyard, outlet and termination facilities; and
2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

<u>Verification:</u> At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading <u>for transmission related facilities to the first point of interconnection at Buck</u>

Boulevard, the project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

TSE-3 If any discrepancy in design and/or construction is discovered in any transmission facility engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend corrective action. (1998 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval and shall reference this condition of certification.

Verification: The project owner shall submit a copy of the CBO's approval or disapproval of any corrective action taken to resolve a discrepancy to the CPM within 15 days of receipt. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action required to obtain the CBO's approval.

TSE-4 For the power plant Integration Switchyard, outlet line and termination, the project owner shall not begin any increment of construction until plans for that increment have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. The following activities shall be reported in the Monthly Compliance Report:

a) receipt or delay of major electrical equipment;
b) testing or energization of major electrical equipment; and
c) the number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant switchyard, outlet line and termination, including a copy of the signed and stamped statement from the responsible electrical engineer attesting to compliance with the applicable LORS, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

TSE-5 The project owner shall ensure that the design, construction and operation of the proposed power plant integration switchyard~~,~~ and transmission line facilities to the first point of interconnection at Buck Boulevard ~~and Buck Blvd. Substation~~ will conform to all applicable LORS, including the requirements and description listed below. No increment of construction of these facilities shall commence until the CPM approves the documents required in the Verification for TSE-5. The project owner shall submit the required number of copies of the design drawings and calculations as determined by the CBO.

The BEP II 500 kV integration switchyard shall have four switchbays with 500 kV circuit breakers. The high voltage transformer terminals of two CTGs and one STG unit shall be connected by overhead conductors to three switch bays. The fourth bay shall be connected to a 500 kV 2-2156 Aluminum Conductor Steel Reinforced (ACSR) interconnecting line to a new 500 kV substation to be built as an expansion of the existing Buck Boulevard Substation.

The integration switchyard shall be connected to the Buck Blvd. 500 kV Bus~~Substation~~ via a 500 kV single circuit ~~lattice tower~~ transmission line.

~~The expansion of the Buck Blvd. 500 kV substation shall include three switch bays with 500 kV circuit breakers. The 500 kV facilities shall be connected to the existing Buck Blvd. 161/230 kV Substation by installing a 400 MVA 500/230/161 kV step-down dual voltage transformer to transfer power to the DSWTP Line which shall be connected to the third 500 kV switch bay.~~

a) The power plant Integration Switchyard and outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", Western Interconnection standards, IEEE grounding standards, National Electric Code (NEC) and related industry standards.

b) Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

c) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards.

d) The project conductors shall be sized to accommodate the full output from the project.

e) Termination facilities shall comply with applicable Western interconnection standards.

f) The project owner shall provide to the CPM:

i) A System Impact Study and a final Detailed Facility Study (DFS) conducted by Western which includes, with respect to the major equipment listed in Table 1 of TSE-1, the following~~:~~

(1) a description of all interconnection facilities with a one-line diagram including BEP II integration switchyard and the new Buck Boulevard 500 kV substation showing major equipment and their ratings.

(2) ~~a description, including a one-line diagram, of all modifications to the existing Buck Boulevard Substation .~~

~~(3)~~ descriptions of any mitigation measures selected by project owner (to offset reliability criteria violations) and letters or reports of acceptance from the affected transmission owners and where applicable, the CA ISO.

ii) Executed project owner and Western BEP II Facility Interconnection Agreement. ~~A System Impact Study and a final Detailed Facility Study conducted by SCE and coordinated with the CA ISO for termination of the 500 kV DSWTP at Devers including:~~

~~(1) a description of all modifications in the Dever's Su bstation,~~

~~(2) new downstream linear facilities or linear facility upgrades,~~

~~(3) descriptions of any mitigation measures selected by project owner (to offset reliability criteria violations) and letters or reports of acceptance from the affected transmission owners and where applicable, the CA ISO.~~

~~iii) A final Interconnection Approval by the CA ISO for termination of the DSWTP at Devers.~~

~~iv) Executed DSWTP project owner and CA ISO Interconnection Agreement.~~

~~v) Executed project owner and Western BEP II Facility Interconnection Agreement.~~

~~vi) Executed DSWTP project owner and Western Interconnection Agreement.~~

~~vii) Should new downstream linear facilities or downstream linear facility modifications be required due to interconnection and/or operation of BEP II or the DSWTP, the project owner shall~~

~~provide an environmental assessment conducted at~~
~~a level of analysis approved by the CPM.~~

Verification: At least 90 days prior to the start of construction of transmission facilities to the first point of interconnection at the Buck Blvd. Substation (or a ~~lessor~~ lesser number of days mutually agreed to by the project owner and CBO), the project owner shall submit to the CBO and where applicable the CPM for approval:

a) Design drawings, specifications and calculations conforming with CPUC General Order 95 or NESC, Title 8, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", NEC, applicable interconnection standards and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment listed in Table 1 of Condition TSE-1.

b) For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on "worst case conditions"[8] and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", IEEE grounding standards, NEC, applicable interconnection standards, and related industry standards.

c) Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements **TSE-5** a) through f) above.

d) Item f) above submitted to the CPM for approval.

TSE-6 The project owner shall inform the CPM and CBO of any impending changes, which may not conform to the requirements **TSE-5** a) through f), and have not received CPM and CBO approval, and request approval to implement such changes. A detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change shall accompany the request. Construction involving changed equipment ~~or substation configurations~~ shall not begin without prior written approval of the changes by the CBO and the CPM.

Verification: At least 60 days prior to the construction of transmission facilities to the first point of interconnection at the Buck Blvd. Substation, the project owner shall inform the CBO and the CPM of any impending changes which may not conform to requirements of **TSE-5** and request approval to implement such changes.

TSE-7 The project owner shall provide the following Notice to the Western Area Power Administration, Desert Southwest Region (Western, DSR) and the California Independent System Operator (Cal-ISO) prior to synchronizing the facility with the Western transmission ~~California Transmission~~ system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the Western, DSR and Cal-ISO a letter stating the proposed date of synchronization; and
2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the Western, DSR and Cal-ISO Outage Coordination Department.

Verification: The project owner shall provide copies of the Western, DSR and Cal-ISO letters to the CPM when they are sent to the Western, DSRand Cal-ISO one week prior to initial synchronization with the grid. The project owner shall contact the Western,DSR and Cal-ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the Western, DSR and Cal-ISO shall be provided electronically to the CPM one day before synchronizing the facility with the Western, DSR California transmission system for the first time.

TSE-8 The project owner shall be responsible for the inspection of the transmission facilities to the first point of interconnection at the Buck Blvd. Substation during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", applicable interconnection standards, IEEE grounding standards, NEC and related industry standards. In case of non-conformance, the project owner shall inform the CPM and CBO in writing, within 10 days of discovering such non-conformance and describe the corrective action(s) to be taken.

Verification: Within 60 days after first synchronization of the project, the project owner shall transmit to the CPM and CBO:

"As built" engineering description(s) and one-line drawings of the Integration Switchyard~~,~~ and the 500 kV line to the Buck Blvd. Substation ~~, and termination facilities including all new and modified facilities inside Buck Blvd. Substation~~ signed and sealed by the registered electrical engineer in responsible charge. A statement attesting to conformance with CPUC GO-95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders IEEE grounding standards, and applicable interconnection standards, NEC, related industry standards, and these conditions shall be provided concurrently.

a) An "as built" engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. "As built" drawings of the electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the "Compliance Monitoring Plan".

b) A summary of inspections of the completed transmission facilities, and identification of any nonconforming work and corrective actions taken, signed and sealed by the registered engineer in charge.

E. Proposed Interconnection Alternatives

The BART Study, the DEIS/DEIR for the DSWTP present information for the Commission's consideration regarding possible alternatives to the network transmission configurations assumed in this application. However, Caithness-Blythe II does not propose that the Commission license any of these alternatives. Based on our review of these studies, we conclude that there is no alternative configuration that is preferable to the proposed configuration in terms of potential environmental impacts or other factors. Specifically with regard to the interconnection facilities to the Buck Boulevard substation that are within the Commission's licensing jurisdiction, there are no alternatives that are substantially different from or potentially superior to that proposed in this application.

F. Mitigation and Compliance with Laws, Ordinances, Regulations, and Standards

With the implementation of the mitigation measures and the proposed Conditions of Certification discussed in this testimony, the project will comply with the applicable federal, state, and local laws, ordinances, regulations, and standards, and potential impacts, if any, will be mitigated to a level of less than significant

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of:	DOCKET NO. 02-AFC-1
Application for Certification for the Blythe Energy Project, Phase II	**DECLARATION OF ROBERT LOOPER**

I, **ROBERT LOOPER**, declare as follows:

1. I am presently employed by Caithness Blythe II, LLC as Project Director.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to Transmission System Engineering for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Boise, Idaho on July 14, 2005.

Robert Looper

ROBERT LOOPER

BIOLOGICAL RESOURCES

BIOLOGICAL RESOURCES
Testimony of Thomas Cameron

I. Name: Thomas Cameron

II. Purpose:

My testimony addresses the Biological Resources issues related to the construction and operation of the Blythe Energy Project, Phase II (BEP II).

III. Qualifications:

I am a Project Manager retained by Caithness Blythe II. I hold a B.S. degree in engineering. I have 25 years experience in the energy field. I am responsible for managing the permitting activities for development of the BEP II. I am a principal and Vice President of Mountain View Power, Inc., LLC, Project Manager of Summit Power NW LLC, and President/Managing Director of Cameron & Associates, a power industry consulting firm. I was Project Director for the Blythe Energy Project and am also currently Project Director for the Summit Westward Project, a 520 MW Combined Cycle facility using the Siemens V84.3a technology; Vice President and Project Manager for the Bennett Mountain Power Plant, a 160 MW Simple Cycle facility using Siemens 501F technology; Vice President and Project Manager for the Lake Side Power Plant, a 535 MW Combined Cycle facility using Siemens 501 F technology. I have held assignments as Project Manager for Siemens Power Corporation in charge of design, procurement, equipment manufacturing, construction, and commissioning of several large gas turbine power projects, including the 520 MW Bridgeport Energy Project, using the Siemens V84.3a technology. This was the first project of its type using the new Siemens technology in the world. During execution of these projects, my responsibilities included project management, cost and schedule control, technical and commercial contract negotiations, selection and coordination of vendors, engineering firms, and erection contractors, supervision of engineering and site staff, preparation of bid specifications, coordination of construction management, startup coordination and customer interfaces

IV. To the best of my knowledge all referenced documents and all of the facts contained in this testimony are true and correct. To the extent this testimony contains opinions, such opinions are my own. I make these statements and provide these opinions freely and under oath for the purpose of constituting sworn testimony in this proceeding.

V. Summary:

In January 2005, CB II received a consistency determination from US Fish & Wildlife Services regarding the BEP II. This determination recognized the BEP II is within the existing approved BEP site, is essentially the same as BEP, all compensation to mitigate loss of habitat associated with the use of the 152 acre parcel had been made, and required the terms and conditions of the BEP Biological Opinion be met. Subsequently, Staff in its Final Staff Assessment (FSA) has presented a potentially significant issue associated with selenium and sodium concentrations, which have been measured in the BEP evaporation ponds and the potential to cause bird deaths. Staff is requiring the implementation of brine crystallizer technology to eliminate the need for evaporation ponds to retain solids resulting from the blowdown from the cooling tower. Although CBII disagrees with Staff's position, CB II has agreed to implement the brine crystallizer technology but requests Committee to approve use of the proposed ponds for backup in the event the zero liquid discharge equipment experiences a forced outage.

I have reviewed and agree with the Proposed Conditions of Certification contained in the Biological Resources Sections of the FSA except Condition of Certification **BIO-2** and **BIO-7**. CBII proposed modifications to these two conditions in its Prehearing Conference Statement dated June 24, 2005. Staff agreed to CBII's modification to **BIO-2** and proposed additional modifications to **BIO-7**. CBII agrees to Staff's additional modifications to **BIO-7.** These modifications are reproduced here for the Committee's use.

Designated Biologist and Biological Monitor Duties

BIO-2 The project owner shall ensure that the Designated Biologist and Biological Monitor(s) shall perform the following ~~during any site (or related facilities) mobilization, ground disturbance, grading, construction, operation, and closure activities~~:

1. Advise the project owner's Construction and Operation Managers on the implementation of the biological resources Conditions of Certification;
2. Be available to supervise or conduct mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as wetlands and special status species or their habitat;
3. Clearly mark sensitive biological resource areas and inspect these areas at appropriate intervals for compliance with regulatory terms and conditions;

~~4. Inspect active construction areas where animals may have become trapped prior to construction commencing each day. At the end of the day, inspect for the installation of structures that prevent entrapment or allow escape during periods of construction inactivity. Periodically inspect areas with high vehicle activity (parking lots) for animals in harms way;~~

5. Notify the project owner and the CPM of any non-compliance with any biological resources Condition of Certification; and

6. Respond directly to inquiries of the CPM regarding biological resource issues.

Verification: The project owner shall ensure that the Designated Biologist and Biological Monitor(s) maintain written records of the tasks described above, and summaries of these records shall be submitted in the Monthly Compliance Reports (MCR).

During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report.

BIO-7 ~~During the interim period between the Commission Decision on the project, and the CPM authorization to start construction, the project owner shall follow a weed control program modeled on the "Interim Weed and Erosion Control Prevention Program" adopted for the site by the Blythe Energy Project Phase I.~~

During construction and operations, a comprehensive exotic weed control program for California Department of Agriculture List A, List B, and Red Alert weeds, shall be implemented at the 66-acre power plant site. This program shall be implemented until such time that the adjacent land use on the north and west sides in no longer a natural community or agriculture, or until the plant is permanently closed. The natural vegetation adjacent to the BEP II site shall be monitored to determine if it has been modified or degraded. Any seed mixture applied following ground disturbance shall be certified as weed-free.

Verification: ~~The project owner shall submit an "Interim Weed and Erosion Control Prevention Program" for CPM review and approval within 90 days of the Commission Decision. The project owner shall be responsible for implementing an approved "Interim Weed and Erosion Control Prevention Program" until they have requested authorization to mobilize at the power plant site from the CPM~~. Thirty days prior to mobilization, the project owner shall submit a weed control report to the CPM for approval and to Western Area Power Administration for comment. The report shall include photos of the adjacent land or otherwise document any changes in an annual report until such time as the CPM approves cessation. The project owner shall submit the seed mixture to be used following ground disturbance.

With the implementation of the Conditions of Certification as modified above, I agree with Staff's conclusions that the project will not result in significant environmental impacts and will comply with all applicable laws, ordinances, regulations and standards.

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of: Application for Certification for the Blythe Energy Project, Phase II	**DOCKET NO. 02-AFC-1** **DECLARATION OF THOMAS CAMERON**

I, Thomas Cameron, declare as follows:

1. I am presently retained by Caithness Blythe II as the Project Manager for the Blythe Energy Project, Phase II.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to **Biology** for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Las Vegas, NV on July 14, 2005.

WATER RESOURCES

WATER RESOURCES
Testimony of Jeffrey G. Harvey and Ed Smith

I. Name: Jeffrey G. Harvey, Ph.D.
Ed Smith

II. Purpose: Our testimony addresses water resources issues associated with the Blythe Energy Project II.

III. Qualifications:

Jeffrey G. Harvey: I am self-employed as the Principal and Senior Scientist for the Harvey Consulting Group, LLC, (HCG, LLC), and was previously the California General Manager for Greystone Environmental Consultants, Inc., in Sacramento, California. I have 24 years of professional experience as a consultant in project planning and environmental reporting for local, state, and federal government agencies, nonprofit environmental groups, and private resource developers. In that time I have organized and managed more than 250 projects, leading multi-disciplinary teams of scientists, engineers, lawyers, economists, and planners. Projects have included environmental reports and assessments, and special resource analyses for a variety of proposals including water transfers, water conservation, energy development, mining, policy analysis of state-wide water resources and energy systems management problems, large mixed land use developments, public infrastructure projects, aggregate mining, and recreation resorts.

I hold degrees in Geography, including a B.A. (emphasis in physical geography), and M.A. (emphases in environmental planning, water resources development, and impact analysis) from CSU Chico, and a Ph.D. from UCLA, (emphases in environmental and policy, natural resources management, western water resources, and impact analysis.

I have worked on western water, energy and related natural resources policy issues since 1983, including power plant and hydroelectric power development, water development, management, and planning, and analyses of land and agricultural water use practices and conservation. For the past 6 years I have been the Transfer Program Consultant to the San Diego County Water Authority (SDCWA) for the agricultural water transfer of up to 200,000 acre-feet of Colorado River water between SDCWA and the Imperial Irrigation District. This work also includes SDCWA representation for the Colorado River Quantification Settlement Agreement Joint Powers Authority (QSA JPA); the Lower Colorado River Multi-Species Conservation Program, and monitoring of policy development and environmental impact assessment for the California

Department of Water Resources Salton Sea Restoration Program.

In the late 1980s and early 1990s I worked on the San Joaquin Valley Drainage Program conducting water resource management and policy studies of irrigated agriculture for the purpose of reducing toxic levels of selenium in drainage water, and to improve water use efficiency and water supply through improved on-farm water conservation and management. As a consultant to the Natural Heritage Institute in 1993-1994 I also prepared initial hydrological investigations and inventory of groundwater basins and resources for development of a statewide conjunctive water use plan. I served as Project Manager for preparation of the Environmental Report for the California Public Utilities Commission to address statewide policy and environmental issues related to restructuring the electric utility industry. I was also Project Manager for the preparation of an environmental report on the Sand Hollow Reservoir Project in southwest Utah, including comprehensive analysis of hydrology, conjunctive groundwater and surface water management, and aquatic habitat effects on the Virgin River, a tributary to the lower Colorado River. A detailed resume is included in Appendix A.

I was the Project Manager for environmental planning for the Blythe Energy Project beginning in 1998. I have been responsible for preparation of environmental documentation including the AFC, permitting documents, and related submittals to the CEC. I prepared the water resources analyses for the AFC, and the subsequent response to Data Requests.

<u>Ed Smith:</u> I am the General Manager of the Palo Verde Irrigation District (PVID) since 2000. I have lived and worked in the Palo Verde Region since 1971, and have been involved in irrigated agriculture since my childhood in Yuma Arizona. I have dealt with Colorado River management and agricultural water uses for my entire career. Prior to taking the lead at PVID, I was managing partner in a fertilizer and farm chemical wholesale and retail business for 28 years. I hold a B.S> in Agronomy from the University of Arizona, have served on the Board of Directors of the 54th District Agricultural Association (Colorado River Fair, 25 years) and on the Board of Directors of the California Fertilizer Association (8 years).

IV. To the best of our knowledge all referenced documents and all of the facts contained in this testimony are true and correct. To the extent this testimony contains opinions, such opinions are our own. We make these statements and provide these opinions freely and under oath for the purpose of constituting sworn testimony in this proceeding.

V. <u>Summary</u>:

A. <u>Project Description</u>: The project will utilize groundwater for cooling and other purposes. Up to two (2) wells will be developed on-site, approximately 500-600 feet deep, and capable of pumping up to 2,500 gpm; maximum water use is estimated to total 3,300 acre-feet per year (af/yr). Groundwater underlying the Mesa is considered to be brackish water (TDS levels approximately 1,000 mg/l or more) under definition of State Policy 75-58 regarding cooling water for inland power plants. Groundwater aquifer characteristics were modeled at the regional and local levels to determine potential for impacts on groundwater levels and surrounding wells.

B. We contest substantial portions of staff testimony regarding water issues as presented in the FSA, particularly with regard to staff's unsupported assertion that California groundwater is actually Colorado River surface water, and staff's unsupported claim that legal use of California groundwater has the potential to impact downstream surface water users. We also disagree with staff's positions regarding the efficacy of the proposed Water Conservation Offset Program (WCOP), and with staff's contradictory claims that total water drawn from BEP II's well(s) will simultaneously deplete the Colorado River and the regional aquifer, leading to degradation of water quality in the aquifer. Therefore the following testimony will focus primarily on two areas:

1) water supply issues identified in the staff FSA testimony related to the distinction between California groundwater and Colorado River surface water, including related misunderstandings or disputes regarding the Water Conservation Offset Program; and

2) groundwater depletion and attendant water quality impacts.

CBII has also filed additional testimony in this proceeding relating to Staff's recommendations for Dry Cooling (Water Resources, Testimony of Thomas Cameron, Robert E. Gavahan and Philip G. Deen) and Staff's analysis of groundwater effects of BEP II pumping (Water Resources, Testimony of Oliver Page)

The body of staff's testimony regarding water supply and groundwater quality is based entirely upon false premises regarding the source of water proposed to be used, the applicable LORS that govern the use of that water, and the physical effects of groundwater pumping on surrounding waters. Impacts identified on the basis of these false premises are then used to support their conclusion that dry-cooling is needed as mitigation. If surface water will be used, staff has attempted to condition the Water

Conservation Offset Program (WCOP) in ways that make it extremely and unnecessarily cumbersome and costly.

1. Groundwater is distinct from surface water, geologically, hydrologically, and legally. Groundwater is not surface water, and surface water is not groundwater.

Groundwater and surface water are distinct water systems physically, in practice and in law. They are universally related in the hydrologic cycle, and virtually all groundwater in unconfined and confined aquifers is derived from recharge by seepage and deep percolation of surface waters. That the groundwater body under the Palo Verde Mesa is ultimately and predominantly recharged by the surface waters of the Colorado River, other local surface sources (McCoy Wash and stormwater detention ponds), and percolation losses of applied irrigation water is not disputed. Simply having identified the source of recharge does not change the fact that the recharged groundwater is groundwater – distinct from surface water – and governed by California water law pertaining to groundwater.

Staff's primary assertion, and fundamental error throughout their technical report, is that groundwater drawn from a well located more than nine (9+) miles from the Colorado River and 500-600 feet below the surface, is actually surface water. Staff also asserts that this use of California groundwater should be, and will be, accounted for by the federal Water Master for the Lower Colorado River (the Bureau of Reclamation) as surface water. Since the Lower Colorado River is fully allocated, staff concludes that this accounting of groundwater as surface water will harm downstream water rights holders.

As we have testified consistently in the first Blythe Energy Project case, and in numerous responses to data requests for the BEP II case, each of these premises is false, and staff has failed to cite any LORS or provide any supporting evidence from the very agencies whose jurisdiction and interests they claim to represent. The facts remain unchanged, as follows:

- In California, property owners are allowed to pump groundwater from beneath their property for beneficial uses on their property without obtaining a formal water right. Shallow wells in close proximity (up to about one-half mile) to a surface water body and within a well defined subsurface bed and banks, have been found to be directly linked to surface water, requiring a surface water right. In no case in California is a deep well located miles from a stream channel considered to be directly linked to, or classified as surface water.

- The Blythe Energy Project, Phase II, proposes to utilize groundwater, extracted from on-site wells approximately 550 to 600 feet deep, and more than nine miles west of the Colorado River. Under California water law, a landowner may pump groundwater from beneath their own lands for use on their property. No other LORS apply to this project.

- All aquifers – unconfined and confined – are recharged over time from a surface water source. Staff's assertion that *groundwater is surface water* simply because the groundwater in this region is primarily recharged by the Colorado River negates all of California water law (and that of most western states) which clearly distinguishes between groundwater and surface water. Staff's position could be applied anywhere in the State to claim that all wells ultimately are connected to surface water for groundwater recharge, and therefore all wells should be regulated as surface water. For example, according to staff's position, this fundamental geologic relationship would claim all wells in the Sacramento Valley, or San Joaquin Valley as surface water diversions from those rivers. This is in distinct contrast to more than a century of State water management, water rights law, and water use practice.

- There are some adjudicated groundwater basins in California subject to special rules, however, this exception does not apply to the Palo Verde region, and none of the hundreds of wells - either on the valley floor or on the Mesa – are regulated by either the State or federal governments.

- Blythe II will utilize groundwater, not Colorado River water, as has been consistently reported and confirmed. Mesa groundwater use is not regulated by any State, Federal or local agency at present, and the Project's use of groundwater derived from wells does not present any LORS issues.

- As determined by the Commission during the Blythe I deliberations, Mesa groundwater use does not constitute a LORS issue, and does not pose a significant environmental effect (page 208, Final Decision). The WCOP has been developed as a voluntary response to the speculative future possibility that the Bureau will implement a formal policy to regulate ALL well users sometime during the life of the Project.

- As for the Phase I project, the applicant recognizes that Reclamation has discussed for many years the possibility of developing a policy to regulate groundwater users drawing water from a modeled "accounting surface". At this time no such policy exists, nor is such policy pending for the foreseeable future, and under negotiated terms of the Quantification Settlement Agreement (QSA) there appears to a be disincentive to pursue such a policy.

- No groundwater use in the Palo Verde Valley or Palo Verde Mesa is regulated by the Bureau of Reclamation or PVID, nor is any Mesa groundwater accounted for in PVID's Colorado River surface water entitlement accounting. If such policy is ever implemented, it must be equally applied to all well water users, and cannot be applied arbitrarily or capriciously to selected wells. It should particularly not be applied unilaterally – without consensus of the agencies that have water rights jurisdiction and without basis in LORS – by the California Energy Commission. It is unlikely that such a policy can ever be implemented without harming substantial users of groundwater. In fact, such a policy would require existing irrigators pumping groundwater to account for their use against the Palo Verde Irrigation District water rights. This would reduce the amount of water that can be diverted for use by IID, Coachella Valley, and MWD.

2. Having no other legitimate basis in laws, ordinances, regulations or standards (LORS), CEC staff has erroneously claimed that the 1964 Supreme Court decision in Arizona v. California provides a legal basis for their unilateral assertion that California groundwater is Colorado River surface water.

- The 1964 Supreme Court Case *Arizona V. California* is misinterpreted by staff (p. 4.9-42) as the basis in law supporting their claim that groundwater under the Mesa is surface water. The Decision does not declare that groundwater is surface water, and does not compel any regulation of groundwater use. Rather, it allows the Bureau, as Water Master for the Lower Colorado River, to determine whether some wells may be pumped underflow from the river, and if so, to regulate the well withdrawals as a part of the surface water use accounting.

- In more than four decades of application of that legal guidance, the Bureau has imposed rules to account for one well in California (Needles) and two or more wells in Arizona, all of which are located in very close proximity to the active River channel (measured in hundreds of yards, not miles). For more than two decades they have studied the feasibility of accounting for more wells, or all wells, drawing groundwater from the Colorado River aquifer as a part of surface water accounting. The accounting surface model was developed as a part of those policy investigations.

- Over the course of all this time, the Bureau has not developed an accounting surface policy pertaining to use of groundwater, and does not regulate any wells in the Palo Verde region. Groundwater use is not accounted for in the Bureau's accounting of Colorado River volumes. The development of a groundwater accounting policy has been deterred by physical, legal, and political realities, and may be negated at this time since water disputes between the California agencies with entitlements to the Colorado River have been settled in the Quantification Settlement Agreement (QSA).

- PVID, in a letter to the Commission dated September 16, 2003, made it abundantly clear that BEP II's use of groundwater is not an illegal diversion of Colorado River Water as follows:

  "Setting aside the question of whether or not a particular well produces water "drawn from the mainstream," there is a practical answer to whether or not a well is unauthorized. There are hundreds, perhaps thousands, of wells in the Palo Verde Valley, Imperial Valley and Coachella Valley which draw water from below the Bureau of Reclamation's accounting surface. These wells are in districts which have water delivery contracts with the United States. No one, including the United States, has assumed that these wells are unauthorized. There is no reason whatever why wells on the lower Palo Verde Mesa should be treated differently than wells in the Palo Verde, Imperial or Coachella Valleys. In fact, if the Bureau's presumption that they are drawing from the river is correct, then wells in the Palo Verde Valley and the lower Palo Verde Mesa are drawing from the same underground pool. The only difference is that the water would be used on the Mesa, not in the valley. Other wells are operating on the Mesa and the United States issued patents based on the water supply from such wells.

  It should not be assumed or concluded that the Blythe Energy Project's wells are unauthorized or that, even if they are actually diverting water from the river, there is no right to do so. The water delivery agreements give no support to such arguments and where wells are within districts authorized to use water, it is assumed that the wells within the district are not additional diversions from the river, and that such wells are not unauthorized diversions.

  You should not assume that Blythe Energy has no right to use well water on the lower Palo Verde Mesa. Such use would be indistinguishable from wells already on the Mesa or in the PVID and PVID has the right to provide water to additional lands on the Mesa under its water delivery agreement."

- If the groundwater were in fact hydrologically connected in real-time to the Colorado River surface water as alleged by Staff, clearly the downstream users would be extremely concerned about the accounting for every well using this groundwater. The groundwater use would in essence need to be accounted for and "charged" against PVID's water right. Yet, unexplained by Staff, there are hundreds of wells including agricultural wells, the well at the community of Mesa Verde, and the City of Blythe municipal wells, none of which are "charged" against PVID's allocation. According to Staff's logic every one of these wells are violating federal law by using Colorado River water without the legal authorization to do so.

- The very downstream users that Staff claims the BEP II will impact do not object to every other well user within PVID's boundaries. In fact, the largest downstream user, MWD, supported the WCOP by BEP and BEP II as providing a benefit to it. In other words, MWD has not objected to the BEP or BEP II proposed uses because the voluntary WCOPs of both projects results in reducing the amount of water that PVID is able to divert by taking land that PVID had the legal right to irrigate with Colorado River surface water and removing it from PVID's total acreage Priority 1 water right. This improves MWD's inferior water right by in effect placing additional limits on PVID. Without objection of the largest downstream user, the Committee should find Staff's arguments that BEP II's use of groundwater negatively affects downstream water rights holders to be less than credible.

- CEC staff has systematically ignored these facts, and has instead tried to apply a LORS standard that simply does not exist, and that is not applied by any of the agencies with jurisdiction and responsibility for water resources in this region.

3. Staff's groundwater quality assessment is predicated on contradictory and unsupported premises, and based upon extremely limited and outdated data that has been misinterpreted.

Water Resources Testimony of Oliver Page address primary issues related to staff's groundwater quality analysis. I note here that in my review of these sections of the FSA, staff completely contradicts its previous assessment claiming that all project well water will be directly derived from fresh surface water (primarily the Rannells Drain).

Staff asserts in one section (p. 4.9-49) that the project will deplete the Colorado River directly in an amount equal to total water use (3,300 AF/yr), and that the well will simultaneously deplete the same amount of water from aquifer storage, not only drawing down the water table for miles around, but causing more brackish water from depth to contaminate the general aquifer. (pp.4.9-31 through 39, and 4.9-54). (As PVID has noted, if a significant portion of replacement water is derived from surface water, improvement of local aquifer water quality conditions should occur over time.)

In addition to this contradiction, staff ignores the fact that any draw of high salinity brine from depth will be pulled directly into the project well, ensuring that the project <u>does</u> use the lowest quality water available in the region. There is no physical mechanism by which brine drawn from depth under the influence of project well pumping can be dispersed throughout the surrounding aquifer, or transmitted to other wells. At closure of the power plant and termination of pumping, the cone will close in on itself, and does not get dispersed throughout the aquifer.

Staff also bases it conclusions regarding potential water quality impacts on 5 data points from each of 4 wells on the Mesa, taken between 1959 and 1964 (pp. 4.9-38 through 41). This data set is obviously too limited to have any value for drawing analytical conclusions, and is more than 40 years out of date. Over those 40 years substantial changes have occurred in groundwater pumping for 1) agriculture (increased during 1970s and 1980s, declining since early 1990s, and increasing again in recent years); and 2) municipal and industrial uses including the City's airport well, Mesa Verde community wells, the Community College well, other residential wells, and the Blythe Energy Project well.

In addition, we note that staff misinterpreted those limited data points to make their impact findings, claiming the data indicate a general trend for increasing TDS (declining water quality) when in fact three of the four wells showed reductions in TDS over time (improving water quality). (See FSA, Figure 4, p. 4.9-40)

4. The project's use of groundwater will have no measurable affect on surface waters of the PVID or the Colorado River, will not reduce supplies available to Colorado River surface water users.

Groundwater is distinct from surface water. Its movement is measured in feet per day, rather than feet per second as for surface water, and it is recharged by surface water sources over a period of weeks, months, years, and decades. As it percolates slowly through pervious sediments, it dissolves salts and minerals, and changes its chemical character from the original source water. In general, the longer the water has been in groundwater storage, the higher its content of dissolved solids (TDS), which explains the brine quality of the groundwater proposed to be used from depth in the aquifer underlying the Mesa.

As groundwater is pumped, it creates a cone of depression and flow pattern from surrounding waters into the well. Water in the surrounding aquifer – laterally, and vertically – is thus induced to flow following that pattern towards the well and from all directions around the well. Only a portion of the induced flow will come from east of the well in the direction of the Rannells Drain and irrigated lands of the Palo Verde Valley – and that portion will come as subsurface recharge water moving at rates of feet per day, not feet per second. The 1) rate of movement, 2) low volume of water (relative to the millions of acre-feet of the groundwater and surface water systems involved), and 3) dynamics of the surface water system above, make it impossible to detect the groundwater withdrawals in any measurable way.

PVID confirms that there is no way that groundwater drawn from the proposed project well could have any measurable affect on the Rannells Drain or any other part of its surface water system (Ed Smith, PVID General Manager, pers.comm. to Jeff Harvey, 07/14/05). They also noted that the total of the proposed BEP II water use is not even within the range of measurement accuracy for their water system – for diversions, drain discharges, or delivery of water at major headgates within the system.

5. Staff has systematically misunderstood and/or misrepresented PVIDs statements and positions in an attempt to support their arguments.

Counter to what staff claims in their FSA, supplemental testimony, and in various docketed records of telephone conversations:

- PVID <u>does not</u> account for groundwater use as a part of its surface water accounting, does not monitor or measure any well user in the region, and has no means to account for groundwater use even if it wanted to.

- PVID confirms that there is no way that groundwater drawn from the proposed project well could have any measurable affect on the Rannells Drain or any other part of its surface water system.

- Groundwater use within PVID has no measurable impact on downstream surface water supplies (p. 4.9-41 last para., and 4.9-51), and cannot be accounted for in PVID's "diversion less returns" method in any meaningful way. The level of accuracy for water measurement in the Valley is approximately 5% for the diversion, and 10% for the return flow (Ed Smith, PVID General Manager, and Roger Henning, PVID Chief Engineer, pers.comm. to Jeff Harvey, 07/14/05). With diversions of up to 1,000,000 acre-feet, and return flows up to 500,000 acre-feet, the limit of accuracy (margin for error) is therefore within 50,000 acre-feet.

- Under most flow conditions, surface water in the Rannells Drain is substantially higher quality water (lower TDS) than groundwater pumped from below the Mesa, and Mesa groundwater is the lowest quality water available to the power plant.

- Surface water flowing in the Rannells Drain ultimately discharges to the Colorado River and is accounted for as a part of the District's Colorado River water supply.

- Implementation of the Quantification Settlement Agreement by the California water agencies negates potential issues pertaining to groundwater use, and CEC staff references and claims regarding the accounting surface model, and pre-QSA statements by the Colorado River Board, CVWD, MWD, and others are out of date and invalid.

- PVID does not claim that California groundwater is Colorado River water – they do assert that it does not matter to them whether it is classified one way or another – if classified as California groundwater, individuals have a right to use it under California water law, and if classified as Colorado River water individuals within the PVID boundaries have a right to use it as a part of the District's legitimate water supply under first and third priority water rights.

- PVID disagrees with CEC staff's claims that groundwater pumping will degrade the water quality in the aquifer. Rather, they cite past experience that groundwater quality may improve slightly with higher quality groundwater recharge water replacing pumped water.

- Finally, PVID believes it is improper and poor policy for the CEC to insert itself in complex regional water policies based upon staff findings and conclusions that are made in direct contradiction to all of the agencies with jurisdiction and decades of experience in dealing with water in this region, including PVID, the Bureau of Reclamation, the Colorado River Board, and other parties to the Quantification Settlement Agreement (MWD, IID, CVWD).

6. BEP II proposes to use brine quality water from deep in the underlying groundwater aquifer, which is the lowest quality water available to the power plant and which should not be classified as fresh water for application of the policies identified in the Commission's Integrated Energy Policy Report 2003 (IEPR 2003).

Based upon a very few data points at one location staff claims that water in the Rannells Drain is of lower quality than the deep groundwater proposed for use, and should therefore be used as an alternative if the power plant will not be dry-cooled.

Salinity of the Rannells drain varies significantly depending upon volume of diversions from the Colorado River, total applied water for irrigation, which varies with crop cycles, and operational spillage (surplus diverted river water that is not taken by farmers for irrigation) from one of their main canals (the "B Canal"). At very low flow periods the drains consist predominately of agricultural tailwater (surface runoff) and draining soil water (shallow subsurface throughflow), which is higher in salinity (approximately 800 to 1,600 TDS). At average and high flows the drain water has salinity levels that are about the same as the source water from the Colorado River (500 to 600 TDS).

Salinities of groundwater at the depth proposed for pumping for BEP II well are in the 1,000+ TDS range, and do not vary significantly over time. This is the lower end of water defined as "brackish" and is considered very low quality water, and undesirable for drinking. Shallower groundwater, particularly under the Palo

Verde Valley, has lower TDS, and surface waters are substantially higher quality. The BEP II applicants have proposed to use the lowest quality brackish water available for use in the power plant, and selecting the Rannells Drain as an alternative would result in use of higher quality water.

The State Water Resources Control Board (SWRCB) adopted Policy 75-58 recognizes that brackish water from natural sources should be used for cooling purposes before inland wastewaters of low total dissolved solids and other inland waters. While the IEPR 2003 states a policy that is not, in exact terms identical to Policy 75-58, the concepts were its underpinnings. Therefore, the Committee should recognize that the guidance in 75-58, which is designed to reduce the use of "fresh" water for cooling purposes, gives preference to the use of brackish water and therefore the Commission should not treat the groundwater as "fresh" water.

Staff goes so far as to assert that since some people are drinking or irrigating with this high TDS water, staff does not classify the groundwater (at 1,000 TDS and above) as brackish (p. 4.9-37). The one community that uses this water as its primary source is Mesa Verde, and its water is considered unhealthful. Riverside County has sited Mesa Verde water supply as not meeting EPA drinking water standards and requiring alternative clean drinking water source. The City considers this community to be impacted by this poor water supply, and is in the process of extending a pipeline to the Mesa Verde Community to replace the Mesa well with higher quality water from the City's main system. In addition to drinking water issues, growers on the Mesa are forced to blend the groundwater with diversions directly from the Colorado River to maintain water quality suitable for citrus and other crops. In any case, it is simply wrong to reclassify brackish water as fresh potable water just because some unfortunate individuals have no alternative water sources to use.

With regard to the Mesa Verde well, the BEP II team has worked diligently with the City providing free legal and engineering services to assist the City of Blythe in developing a project to deliver City water to the community of Mesa Verde. Mesa Verde's wells have been of extremely poor quality, unrelated to BEP. However, after hearing the complaints of the Mesa Verde community, the City of Blythe and members of the CB II team initiated an engineering study sufficient to support bonding to develop a project to deliver much needed City water to the community of Mesa Verde. While we disagree with Staff that BEP II pumping could further degrade the quality of the Mesa Verde well, actions to replace the source of water to this community are already underway and should be in place in 2006..

Finally, we note that the Rannells Drain is an integral part of the water district's return flow system that is ultimately discharged to the Colorado River, and that is a part of the Colorado River accounting system for PVID. Use of this water would raise all of the water allocation issues that staff has erroneously attempted to attribute to the proposed use of California groundwater.

7. The Water Conservation Offset Program (WCOP)

A. Introduction

In recognition of the issues regarding water use in general, *and in the absence of governing LORS*, the Blythe Phase II project has proposed a **voluntary** Water Conservation Offset Program more stringent than that adopted by the Blythe Energy Project and accepted by the Commission in its March 2001 decision to approve the original Blythe Energy Project.

Criteria for eligible lands has been more narrowly defined to include retirement or rotational fallowing of irrigated lands (within the past five years) for the life of the power plant; and as agreed with the Bureau of Reclamation (and disputed as too low a figure) a consumptive water use volume of 4.2 acre-feet per acre will be used as an accounting basis for retired or fallowed lands. The WCOP will be implemented concurrent with commercial operation of the power plant.

B. Overview of Regional Surface Water Use of the Colorado River for Purposes of Understanding the Proposed WCOP

The majority of water use in the Palo Verde Valley is surface water diverted from the Colorado River by PVID for irrigation of up to 104,500 acres of farm land. Surface water is also pumped up to the Palo Verde Mesa for blending with poor quality groundwater for irrigation use. Uses of groundwater from the aquifer include the City of Blythe's municipal wells, and multiple uses on the Mesa including irrigated agriculture, a well that supports the City's industrial and domestic uses at the airport, a residential well, and other wells more than two miles north of the project area and across the McCoy Wash to supply water to a golf course, the new Community College, and several residential communities.

Reclamation is responsible for delivery of California's allocation of Colorado River surface flows, divided in seven priority levels. The Palo Verde Irrigation District holds the Priority 1 rights, and a shared portion of the Priority 3 rights, and they have an unquantified right to water. They divert water at the Palo Verde Dam at the north end of the Palo Verde Valley; agricultural drainage, operational spillage, and the City's treated wastewater flow back to the river at the south end of the Valley.

Accounting for PVID's water use is done by a simple formula of diversion volume, less return volume. Priority 1 water is used on up to 104,500 acres on the valley floor; up to an additional 16,000 acres on the Mesa may be served by Priority 3 water. (PVID also has a Priority 6 entitlement to irrigate an additional 16,000 acres on the Mesa, however, under fully allocated conditions, there is no expectation that any Priority 6 water will be available for the foreseeable future.)

The Bureau of Reclamation, in conjunction with the USGS, has developed a model, referred to as the "Accounting Surface", in an attempt to determine the relationship of regional groundwater to surface water in the Colorado River. This model is the basis of Reclamation's potential future policy, which has been a source of contention with PVID, Mesa groundwater users, and other water users on the river for more than a decade now. In addition, the Bureau of Reclamation has never consulted the State Water Resources Control Board (SWRCB) about the Accounting Surface Model, or about any proposed policy that would assert federal jurisdiction over millions of acre-feet of California groundwater in this region, and the State does not recognize any such claim to its groundwater.

With adoption of the Quantification Settlement Agreement allocating fixed amounts of surface water to the California water agencies involved in the Colorado River (but not including the PVID and its Priority 1 water rights), such a policy may be to the detriment of lower priority entitlements, which are therefore not inclined to support the policy. Reclamation has no firm timetable for actually developing a policy whereby they would regulate groundwater users relative to the PVID surface water entitlement, and we note that the policy is no closer to being developed and implemented than it was five years ago during the first BEP proceeding.

Since groundwater pumping for the Blythe Energy Project will encounter the Accounting Surface as defined by Reclamation, Reclamation has suggested that this use of water, and all other Mesa groundwater users, <u>**may be**</u> accounted for <u>**at some undefined time in the future**</u> as a part of PVID's Priority 3 surface water entitlement. For that reason, BEP II has voluntarily agreed to implement the Water Conservation Offset Program.

C. The Water Conservation Offset Program

The BEP II proposed Water Conservation Offset Program relies upon the fact that both the Bureau of Reclamation (Bureau) and Palo Verde Irrigation District (PVID) have affirmed the adequacy of the WCOP to address water concerns relative to a potential, but speculative and perhaps unlikely future Colorado River accounting system that could account for all regional well water users as part of PVID's Colorado River surface water entitlement.

Staff claims that the WCOP is incomplete mitigation for the project's water use to the extent that staff is unable to determine if it is capable of providing for the conservation of the same amount of water the BEP II will consume. We note however that the Bureau of Reclamation has sole jurisdiction over Colorado River water use in this region, and together with PVID, they are the agencies responsible for making the determination as to whether the WCOP is capable of providing conservation of the same amount of water as the Blythe Energy Project will consume. The Water Conservation Offset Program was developed in close coordination with both agencies. The Bureau has reviewed the Final WCOP and determined that it does satisfy all of their criteria for accounting for project water use, as stated for the first BEP in their letter to Robert Therkelsen (August 9, 2000, with July 17, 2000 Final Water Conservation Offset Program referenced and attached to their letter), and for the BEP II case in their June 14, 2002 letter. On these bases, I believe there is conclusive evidence in the record that this question has been reviewed by the agencies with legal jurisdiction and expertise. Both agencies have determined that the WCOP complies with existing and potential future LORS.

C. 1. Target Acreage for WCOP

The target acreage for the WCOP includes a total of 786 acres, to be acquired and confirmed prior to commercial operation, selected from any of the eligible acreage on the Palo Verde Valley floor (104,500 total acres) or the Palo Verde Mesa (total of about 4,000 acres of 16,000 total within PVID). This approach has been taken intentionally to provide flexibility and maintain economic neutrality for this market-based transaction.

As noted in the Bureau's letter to the CEC (June 14, 2002):

> *The Water Conservation Offset Program voluntarily developed by BEP II addresses Reclamation's objectives for selection and management of lands to account for water use, and prevents increased Colorado River water demands in the Lower Basin.*

C. 2. History of Crop and Water Use

The need for crop and water use history of selected lands is negated by use of the very conservatively low, average consumptive water use rate of 4.2 acre-feet per acre, as agreed in consultation with the Bureau and MWD in development of the final WCOP. PVID has expressed its opinion that the figure is too low, and that actual average water consumption within the District ranges from 4.6 to 5.0 acre-feet per acre, substantially higher than the 4.2 AF/Ac/year value to be used for BEP II.

C. 3. Erosion Control

Retirement and/or fallowing of eligible land does not pose erosion issues. In fact, the larger program which fallows 25,000 acres in the PVID to provide water to MWD is in place and is exactly what CB II proposes for the WCOP. Under the fallowing option, 786 acres of irrigated farmlands would not be actively farmed at any one time during the life of the power plant, and PM_{10} emissions associated with tilling, planting and harvesting those farmlands, and transporting produce would be eliminated. In its analysis of the wind and dust issue for the MWD water transfer program, the Palo Verde Irrigation District (PVID) estimates these PM_{10} emissions can reach 25 pounds per acre annually for crops such as cotton that involve fairly substantial tilling and harvesting activities. Farm vehicles tailpipe emissions also would be reduced as a result of decreased farming activity. (Source: PVID, *Draft EIR for the Proposed Palo Verde Irrigation District Land management, Crop Rotation, and Water Supply Program, May 2002*, section 4.3.1)

- The applicant has agreed to implement clod tillage and stubble maintenance on fallowed lands, identified by PVID a standard practices employed for decades throughout the region for soil stabilization.

- The two farming practices, which produce the greatest windblown material, pre-planting plowing, and harvest, will be eliminated on fallowed (and retired) lands.

BEP II proposes to include the following land management measures to control wind erosion as a condition of any lease agreement for fallowing farmlands as part of the proposed Water Conservation Offset Program.

1. For crops that leave adequate stubble residue (alfalfa, wheat, barley and similar crops) pre-fallowing harvesting methods will include retention of crop stubble to leave the non-irrigated fields with a root system to help hold soil in place and minimize wind erosion.

2. For crops that would not leave an adequate stubble residue (such as many vegetable or melon crops), clod plowing would be implemented. The term 'clod plowing' refers to the practice of tilling a field when it is wet so that large, damp clumps of soil are produced. These wet clumps break down into clods of soil that have a low susceptibility to wind erosion. For soil types classified as Highly Erodible Land (HEL) soils by the Natural Resource Conservation Service, mulch or similar material would be integrated into the clods to further strengthen their resistance to wind erosion.

3. Fallowed lands will be rotated on a two to three year cycle.

C. 4. Farmland Use Issues

The voluntary Water Conservation Offset Program (WCOP) developed for the project and described in Section 7.13, includes retirement or rotational fallowing of farmland. The Program will include about 786 acres within the Palo Verde Valley and/or Palo Verde Mesa to offset annual water use for the life of the project.

If the rotational fallowing option is employed, no farmlands will be permanently retired or converted from agricultural use, and no adverse impacts to farmlands will occur. The WCOP does include a criterion that retired lands may not be converted to any use that relies upon Colorado River water during the life of the project. However, if lands are permanently retired, the program will have potential impacts associated with loss of productive farmlands.

The applicant has committed to accept a condition of certification to mitigate this potential impact. One of several mitigation strategies may be used, including:

1) Obtaining permanent conservation easements of Transfer of Development Rights (TDRs) for an equal number of irrigated farmland acreage within the Palo Verde Valley or Mesa.

2) Payment of endowment funds to a special fund to be managed by the City of Blythe, or alternatively, to a recognized farmland trust organization such as the American Farmland Trust.

3) Equivalent participation in an established County farmland conservation program.

Such mitigation, imposed in a binding Condition of Certification, would adequately mitigate potential farmland impacts associated with permanent retirement of irrigated lands for the WCOP.

D. Conclusions

The issue of water supply and use of groundwater in Blythe was thoroughly litigated for the original Blythe Energy Project proposal. The CEC staff assessments do not reflect the results of that litigation. The Commission's Decision (March 22, 2001, pages 200 through 208) summarizes the keys issues, and concludes that: "*<u>The need for a Water Conservation Offset Program is not driven by a finding of adverse environmental impact, or need to mitigate under existing LORS</u>. Therefore, the WCOP, in this case, is sufficient to satisfy the Commission's concerns.*" (page 208). (underline emphasis added)

- The Water Conservation Offset Program voluntarily developed by BEP II addresses Reclamation's objectives for selection and management of lands to account for water use, and prevent increased Colorado River water demands in the Lower Basin.

- With implementation of the Final WCOP (which was developed in consultation with the Bureau and MWD, and was attached to Reclamation's June 14, 2002 letter), the project will have no impacts on the Colorado River system or junior water rights holders within that system

It is important to reiterate that adoption of a voluntary Water Conservation Offset Program is not required in response to any finding of environmental impact, or any requirement under existing LORS. Finally, with regards to the voluntary WCOP, we note that no other groundwater user in the region has taken such extraordinary measures to provide long term offset as has been done voluntarily and at considerable expense for this project.

E. Conditions of Certification

CB II requests that the Committee reject Staff's proposed Condition of Certification **SOIL & WATER-7**, which requires CPM approval of the WCOP. CB II requests the Committee to base its rejection on the same reasons the Commission rejected Staff's arguments in BEP. Since BEP II's proposed use of groundwater does not result in a significant impact, a WCOP is not necessary for mitigation. The voluntary WCOP should be acknowledged in the Commission Decision but not made to be mandatory and subject to CPM jurisdiction because its purpose is only to comply with the speculative uncertain future Bureau policy.

CB II believes Staff's Proposed Conditions of Certification **SOIL & WATER-8** and **9** should be rejected because they are not necessary to mitigate any identifiable impact, are not required by any LORS and may actually result in the use of Colorado River surface water.

CB II requests that the Committee reject Staff proposed Condition of Certification **SOIL & WATER-11** and replace it with the exact same well interference conditions imposed on BEP (BEP Conditions of Certification **SOIL & WATER-6** and **7**). Staff has provided no support for modifying the BEP conditions.

CB II requests that Staff's proposed Condition of Certification **SOIL & WATER-12** be replaced with the groundwater quality monitoring requirements imposed on BEP (BEP Condition of Certification **SOIL & WATER-10**). Staff has not demonstrated sufficient changed circumstances to warrant modification of the BEP monitoring strategy.

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of: Soil and Water Resources Application for Certification for the Blythe Energy Project, Phase II	**DOCKET NO. 02-AFC-1** **DECLARATION OF** Ed Smith, General Manager, PVID

I, Ed Smith, declare as follows:

1. I am presently employed by the Palo Verde Irrigation District. as the General Manager.

2. A copy of my professional qualifications and experience is included with the attached Soil and Water Resources testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I reviewed portions of the attached testimony relating to Soil and Water Resources for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony referring to my input is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Blythe, CA on July 14, 2005.

Ed Smith, General Manager
Palo Verde Irrigation District

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of:	DOCKET NO. 02-AFC-1
Application for Certification for the Blythe Energy Project, Phase II	**DECLARATION OF** Jeffrey G. Harvey, Ph.D.

I, Jeffrey G. Harvey, Ph.D., declare as follows:

1. I am presently self-employed as the Principal and Senior Scientist.
2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.
3. I prepared the attached testimony relating to Water Resources for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).
4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.
5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Sacramento, CA on July 12, 2005.

Jeffrey G. Harvey, Ph.D.

WATER RESOURCES
Testimony of Thomas Cameron, Robert E. Gavahan, and Philip G. Deen

I. Name: Thomas Cameron
Robert E. Gavahan
Philip G. Deen

II. Purpose: Our testimony addresses alternative cooling technology issues associated with the Blythe Energy Project II.

III. Qualifications:

Thomas Cameron: I am a Project Manager retained by Caithness Blythe II. I hold a B.S. degree in engineering. I have 25 years experience in the energy field. I am responsible for managing the permitting activities for development of the BEP II. I am a principal and Vice President of Mountain View Power, Inc., LLC, Project Manager of Summit Power NW LLC, and President/Managing Director of Cameron & Associates, a power industry consulting firm. I was Project Director for the Blythe Energy Project and am also currently Project Director for the Summit Westward Project, a 520 MW Combined Cycle facility using the Siemens V84.3a technology; Vice President and Project Manager for the Bennett Mountain Power Plant, a 160 MW Simple Cycle facility using Siemens 501F technology; Vice President and Project Manager for the Lake Side Power Plant, a 535 MW Combined Cycle facility using Siemens 501 F technology. I have held assignments as Project Manager for Siemens Power Corporation in charge of design, procurement, equipment manufacturing, construction, and commissioning of several large gas turbine power projects, including the 520 MW Bridgeport Energy Project, using the Siemens V84.3a technology. This was the first project of its type using the new Siemens technology in the world. During execution of these projects, my responsibilities included project management, cost and schedule control, technical and commercial contract negotiations, selection and coordination of vendors, engineering firms, and erection contractors, supervision of engineering and site staff, preparation of bid specifications, coordination of construction management, startup coordination and customer interfaces. A detailed resume is included in Appendix A.

Robert E. Gavahan: I am a Project Engineer employed by Power Engineers Collaborative, LLC. I hold a B.S. degree in mechanical engineering from the University of Minnesota. I have 15 years experience in the energy field. I am responsible for the plant engineering related to the development of the BEP II. My qualifications are more completely detailed in the resume attached in Appendix A.

Philip G. Deen: I am an Electrical Engineer employed by Siemens Westinghouse Power Corporation and currently act as the Manager of Thermal Cycle Engineering. I am currently responsible for cycle design and performance acceptance testing of all combined cycle plants in the Americas region for Siemens Power Generation.

IV. To the best of our knowledge all referenced documents and all of the facts contained in this testimony are true and correct. To the extent this testimony contains opinions, such opinions are our own. We make these statements and provide these opinions freely and under oath for the purpose of constituting sworn testimony in this proceeding.

V. Summary

Staff has continued to provide in the FSA economic analysis of dry cooling economic assumptions that underestimate the true cost to CB II to implement dry cooling for the Blythe II facility, especially the economic impact at high ambient temperature conditions. Appendix A – Water Supply and Cooling Options of the FSA Soils and Water section does little to acknowledge CB II's efforts to quantify the cost of dry cooling at BEP II as provided in the Dry Cooling Economic Analysis submitted on 15MAR05, which presented higher costs for implementation than those estimated by Staff.

As well as underestimating the economic impact of dry cooling, Staff includes statements in the FSA Soils and Water Appendix A – Water Supply &Cooling Options that CB II believes merit comment. Staff writes that "the minimal increase in production costs would not compromise the project owner's ability to recover its investment and earn a return (profit) considering power values from sales are typically ranging from 100% to 300% of the cost of production".

This comment by staff shows a complete lack of understanding of the current California power market. New power plant starts were almost non-existent over the past two years with no credible power purchase off-take agreements offered in southern California. Yet the State of California is again facing power shortages projected for the summer of 2006. Last week, Southern California was again dangerously close to forced curtailments as reserve margins dropped below 5%. Staff is cavalier with their attitude that dry-cooling will not have a material impact on the project economics. Independent power producers are now targeting investment returns in the 10-13% range as the best the market can offer. Dry-cooling represents a potential 30% hit to the plant return on investment.

If staff can provide a 300% cost of production opportunity to sell power, BEP II will endorse the dry-cooling option. The reality is that utilities are looking to purchase power from, and own the most efficient generating assets the market can offer. Although staff has advocated dry-cooling, in fact over 90% of the CEC plant licenses in the last 5 years have been issued for wet cooled systems. BEP II would be placed at a serious market disadvantage with no grey water sources and a forced dry-cooling option.

In Section 1.0 of the Appendix Staff presents the currently operating Crocket and Sutter power plants as examples of potential competitors for BEP II that rely on dry cooling. CB II does not consider these to be relevant competitors commercially. Sutter has a 10 year contract with DWR and operates under commercial terms that 1) are no longer available and 2)were the subject of substantial controversy in the State. The DWR Contracts led California to the brink of bankruptcy and certainly forced a political change in leadership. This is hardly a good example where a dry cooled power plant resulted in a market based power contract. Crocket is a 240 MW cogeneration facility operating under completely different commercial conditions than the proposed BEP II. Crocket is a must run plant to meet steam load and serve native loads at the complex.

The FSA notes in several locations the inclusion of brine evaporation ponds in the BEP II design. CB II has decided that the BEP II facility will include a crystallizer instead of evaporation ponds for processing the brine produced by the brine concentrator and the description of the facility with brine evaporation ponds is no longer correct. (The facility will include retention ponds for temporary storage of cooling tower blowdown during times when the brine concentrator or crystallizer are not operable.)

Section 3.1 of Appendix A describes several pieces of equipment that can be eliminated when using an ACC including storage tanks and waste discharge piping. CB II notes that the raw water storage tank is required for storage of water for fire suppression at Blythe (300,000 gallons reserved for fire suppression in the 600,000 gallon tank) and the storage tank is not used for makeup to the cooling tower; a large storage tank would remain as part of the BEP II design in the event the facility used dry cooling. Also, a small waste water treatment system would be required for treatment of blowdown from the HRSGs; some process waste treatment equipment and piping would still be required at the site.

Staff concludes in section 4 of Appendix A that the costs to implement wet cooling and dry cooling are reasonably equivalent. As stated above, CB II will not provide a detailed critique of Staff's estimate; however, CB II believes that the costs provided in the March 15th dry cooling economic analysis more accurately represent the costs to the project than Staff's estimates. Additionally, CB II has recently received installed costs for an ACC at Blythe II from the potential EPC contractor for the facility. These show an estimated installed cost of an ACC could be as much as $52 million for an ACC that reduces some of the limitations on plant start up on hot days; both Staff and CB II had previously estimated approximately $32 million for purchase and erection of an ACC.

Staff's discussion of profit margin effects from the higher cost of production as presented in the Supplementary Testimony notes that BEP II could sell balance energy, capacity, and ancillary services to the ISO to supplement its electricity income. Power that has been designated to be available for these "supplements" is generally not available to be put into the marketplace. CB II does not view these items as supplements to income but as a redefinition of the power available for marketing and a potential encumbrance on the ability to market the full capacity of the plant.

Impact of Implementing Dry Cooling on Existing Design and Equipment

CB II emphasizes that, because much of the major equipment for the BEP II facility has been manufactured and is in storage, the cost to implement dry cooling for the BEP II project is greater than Staff recognized. Additionally, the design for the plant facilities for a plant using wet cooling, as proposed by CB II, will substantially duplicate the existing design from the BEP facility.

CB II requested that Siemens Westinghouse provide a description of the equipment that will be affected by use of dry cooling at BEP II. Some of the significant components are:

- the steam turbine,
- steam turbine condenser,
- circulating water pumps,
- condensate extraction pumps,
- closed cooling water pumps,
- closed cooling water heat exchangers,

- unit auxiliary transformers, and
- cooling tower motor control center and transfomer

These components would either become unnecessary, as in the case of the steam turbine condenser, or require modifications or replacement, in the case of the unit auxiliary transformers. A more detailed description of the affected equipment is provided in the attachment to this exhibit. Some of the equipment modifications identified by Siemens Westinghouse are significant in scope, cost, and schedule impact. For example, modifications to the steam turbine will require shipping the low pressure turbine to the manufacturing facility in Germany.

In addition to the equipment affected by implementation of dry cooling, a significant amount of the existing balance of plant design would need to be revised. Siemens Westinghouse was the EPC contractor (as a member of a consortium) for the completed BEP facility. As such, they have available a substantially completed design for BEP II. The attachment to this exhibit provides Siemens Westinghouse's acknowledgement that existing designs would be affected by the implementation of dry cooling. Both engineering costs and material costs will be affected. Some of these design changes result in significant and costly deviations from the BEP. For instance, the steam turbine hall would not be able to use the existing BEP design because the BEP design has no accommodations for routing and support of an 18' diameter steam duct.

Impact of Dry Cooling on Plant Operations and Reliability

The implementation of dry cooling in an extreme temperature environment such as Blythe's would have a serious detrimental effect on plant operations and reliability. CB II has explained the operational limits related to dry cooling in Blythe's climate; Staff has not commented on these concerns in the FSA or Supplemental Testimony. The impacts on plant operations and reliability are described below and in the attachment.

Plant start-up times could increase by as much as one to two hours as the startup scenario for the plant becomes more complex. Start-up is critical for a plant to meet the current and near term market demand in Southern California. The SCE RFO is seeking plants that can meet daily peak loads and intends to turn these plants on and off on a daily basis. There are no ACC plants in the size class of BEP II that are subject to daily starts. ACC would place BEP II at a serious disadvantage to BEP, which is currently operating on a daily start basis to meet market demands.

The plant may not be able to operate in the 2x1 condition, depending on ACC design criteria. As ambient temperature increases, the plant will be more difficult to start; at some point the ambient temperature may be too high to allow the condenser vacuum to be maintained below the steam turbine limits when attempting to start the second combustion turbine.

Restart of the steam turbine after a trip on a hot day may not be possible, depending on ACC design criteria, or would require a complex procedure similar to initial start; that is, one combustion turbine would need to be shut down and the other one reduced in load as far as possible. Inability to restart the steam turbine could result in forced outage penalties for CB II.

Startup with a hot steam turbine rotor would be the most difficult as the minimum combustion turbine load to meet steam turbine steam temperature requirements would be higher than for a cold steam turbine. A cold steam turbine rotor (or ambient temperatures requiring startup with on combustion turbine at low load) may be difficult as well due to the need to balance minimum steam flow (setting minimum combustion turbine load) and steam temperature/backpressure limits (setting maximum combustion turbine load).

Start-ups at higher ambient temperatures (usually above ~70°F to 80°F) would require reducing combustion turbine load below emissions compliance loading to achieve required steam turbine backpressures. This would result in greater startup emissions, both from the reduced load and from the increased start-up times.

We have included as an attachment to this exhibit a climate summary for Blythe. It shows that the average mean monthly temperatures for April through October are greater than 70°F. The BEP II operations and reliability would be negatively impacted by dry cooling for approximately half of the year.

The limitations described above have a negative impact on the ability of BEP II to market its power as BEP II, being burdened with the operational and reliability limits of dry cooling, would be less able to respond quickly to power sales opportunities at those times when power sales are most profitable.

Visual and Noise Impact

Staff recognizes the undesirable noise and visual impact of an air cooled condenser as compared to a cooling tower.

With regards to noise, Staff offers "It is not known whether would be feasible to achieve the required noise level reduction for a power plant design including the use of an ACC" as well as "...the use of ACC or hybrid cooling would require substantial additional noise level reduction, at increased cost". CB II agrees with both of these statements. The attachment to this exhibit contains Siemens Westinghouse's estimate of the cost increases to attain noise reduction; they show additional costs ranging from $2 million to $6 million to reduce ACC noise levels. We would like to emphasize the uncertainty regarding the feasibility of even being able to achieve the required noise level reduction when using an ACC.

Staff describes the visual impact of an ACC as adverse because of its greater visual contrast, view blockage, and dominance but does not expect that detailed visual analysis would result in a finding of significant adverse impact. Staff offers no indication of additional mitigation that may be required if an ACC is used. CB II anticipates that visual mitigation would be substantial and expensive.

Impact on Project Costs and Revenues

Staff in their Supplemental Testimony does not dispute the predicted increase of 3.5% increase in production costs associated with implementing dry cooling. Staff does, however, discount the economic impact of dry cooling; writing "Implementation of an alternative water supply and/or cooling method would not affect BEP II's economic viability in relation to its ability to recover the cost of its investment and O&M costs". CB II disagrees. CB II's ability to recover its investment is directly related to its ability to market and sell power. A 3.5% cost of production penalty does affect CB II's ability to market its power at competitive rates and affects its economic viability. CB II calculated the 3.5% penalty based on an estimated erected cost for the ACC of $33 million. Siemens Westinghouse has recently provided information that the erected cost of an operationally optimized ACC is approximately $52 million. The annual average production penalty with this optimized ACC is 4.5%.

The increase of 4.5% of production costs is based on an average power penalty of 2% of plant capacity for dry cooling. As Staff correctly describes, the penalty is greater at high ambient temperatures. Attached to this exhibit is a graph of net power and heat rate penalties vs ambient temperature for the BEP II facility with wet and dry cooling (including wet and dry cooling for the inlet chilling system). The net power graph shows that the generation penalty at temperatures greater than 90°F averages approximately 3.5%. The production cost penalty for the facility is approximately 6% at those times when the ambient temperature is greater than 90°F (assuming the optimized ACC proposed by Siemens).

To demonstrate that the annual average production cost penalty of 4.5% underestimates the commercial impact of dry cooling in an extreme temperature environment, CB II has included a capacity price shape table below. This table does not provide actual selling prices but it does illustrate the relative value of power to a purchaser based on time of day and month of year. (It does not represent any actual prices for which CB II has negotiated to sell power; it is representative of the current Southern California market for power sales).

Monthly Capacity Price Shape Table

	Heat Rate at P-max (MMBtu/MWh)				
	7 to 9	**9 to 11**	**11 to 14**	**14 to 18**	**18 to 22**
Jan	90%	80%	60%	35%	15%
Feb	80%	60%	40%	25%	10%
Mar	70%	60%	40%	25%	10%
Apr	70%	70%	70%	70%	65%
May	80%	75%	75%	70%	70%
Jun	100%	100%	110%	110%	110%
Jul	160%	190%	220%	270%	310%
Aug	180%	210%	250%	310%	370%
Sep	130%	140%	160%	170%	180%
Oct	80%	70%	60%	40%	20%
Nov	80%	75%	60%	40%	20%
Dec	80%	70%	55%	35%	20%

Source: Southern California Edison RFO for New Generation Resources, April 22, 2005 (www.sce.com/AboutSCE/Regulatory/newGenRFO)

The capacity price shape table provided by SCE in their request for New Generation Resources heavily weights the performance of the plant to super on-peak summer load periods. This is an area in which ACC plants perform the worst. On July 13, 2005, the temperatures in the Blythe area exceeded 120°F. There is over a 30 MW difference between ACC and wet cooled technology for the BEP II plant at these temperatures. The SCE Power Purchase Agreement dictates that the power plant deliver at the declared summer contract capacity or face financial penalties. The penalties are tied to the market rate for energy during the hours where the plant failed to perform. In this case, CB II would have to declare a reduced capacity for the entire six month summer period. At contract rates of $10/kW-mo, the lost revenue to the project would be $1.8 million for the six month summer period or a net present value of approximately $11 million over the ten year contract life. (The table is not meant to imply that the sales price per kW at 1800 to 2200 in August is 3.7 times the sales price at 0700 to 0900 in June but that the price of power does have a relationship to ambient temperature and that this relationship penalizes BEP II beyond annual average 3.5% production cost penalty based on the average annual generation penalty of approximately 2% of plant capacity.)

SIEMENS
Westinghouse

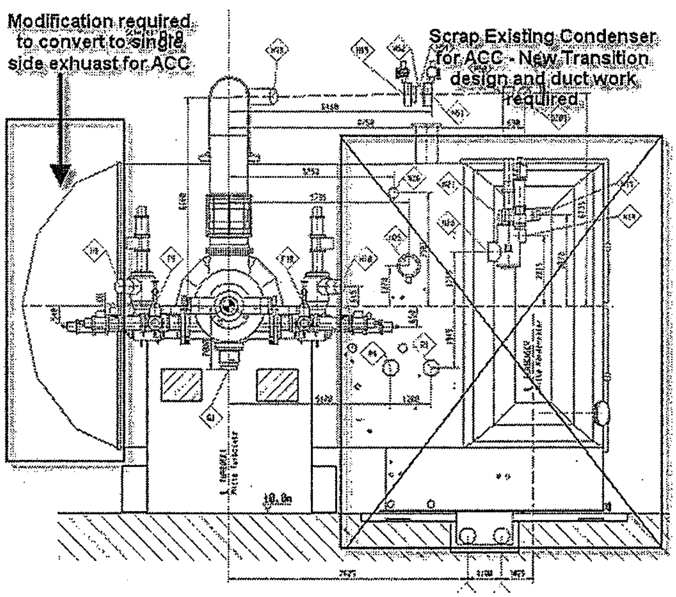
ACC IMPACT DOCUMENT

The purpose of this document is to capture the likely impacts to the proposed Blythe II (BEP II) project for the implementation of an Air Cooled Condenser (ACC) retrofit to the already designed and built equipment, currently in storage.

1. List of Impacts

   a. ST Modifications

   The current LP ST is in a double flow side exhaust arrangement. This will require an new LP outer cylinder for the LP ST and also will require shipping the ST to the factory in Mülheim Germany. Modifications will include, but may not be limited to, replacement of the outer cylinder with a design that effectively blanks off one side of the ST discharge and also provides a suitable interface for ACC duct work. At this time, it is not known if a blade redesign or blade modifications are required. The figure below illustrates the required changes. Schedule impacts are expected.



   b. Duct Work

   It will be necessary to design, manufacture and install a new interface duct from the ST discharge to the 18 ft. diameter main ACC inlet duct. The length of this duct will not be determined until a plant layout can be developed. California building and fire code requirements require at least 60 feet of separation between the steam turbine hall and ACC which can be considered a minimum practical length for the duct.

c. Cooling Tower (Currently 60% Complete)

The wet cooling tower is currently over 60% complete. Changing to ACC will necessitate the disposal of this equipment.

d. Fin Fan Auxiliary Cooler

In order to provide adequate auxiliary cooling for certain systems, such as lube oil and generators, it will be necessary to design, build and install an auxiliary fin fan closed loop cooler.

e. Circulating Water Pumps

The circulating water pumps are currently part of the existing equipment and will be scrapped in an ACC application.

f. Condensate Pumps

The condensate pumps will need to be redesigned to support an ACC layout as NPSH and pipe routing will be vastly different. The current existing pumps would be scrapped.

g. Zero Liquid Discharge Plant (ZLD)

The Zero Liquid Discharge Plant will become smaller as the need to treat cooling tower blow-down will be eliminated.

h. Titanium Wet Condenser (Currently 100% Complete)

The current existing condenser is of a titanium design and would not be required as it will be replaced by the ACC.

i. Blow-down

Handling of the blow-down streams would become less complex.

j. Engineering Replication

The Blythe II project is based on replication of an existing design. Retrofit of an ACC will drastically alter the existing plant design thereby increasing plant costs.

k. Motor Control Centers (MCC) and Mechanical Containers

The Cooling Tower MCC would either be scrapped or re-designed to work in some capacity with an ACC. Also, there most likely will be a need for additional MCCs and Mechanical Containers.

l. Vacuum Pumps / SJAE / Hogger

The current existing Vacuum Pump arrangement will be scrapped and replaced with a vacuum system that will support the needs of an ACC plant.

m. Auxiliary Transformers

Due to the increase auxiliary load associated with the ACC, it will be necessary to redesign the current auxiliary transformer(s) and to replace them with larger ones.

n. By-pass Systems

The current steam turbine by-pass systems will need to be redesigned and re-built for use with ACC. This includes by-pass stream conditioning station redesign and procurement of new equipment so as to support the maximum allowable inlet enthalpy to the ACC. The current existing by-pass design, with wet condenser, supports a much higher inlet enthalpy.

o. Control Systems Logic and Hardware

The current existing Distributed Control System is designed for a wet condenser. Modifications to the control system hardware and software will be necessary to support the ACC. Also, new control logic will need to be developed to support the operation of the plant with an ACC.

p. Environmental

Given that plant performance will be reduced with the application of an Air Cooled Condenser, emissions on pounds per megawatt basis will increase by the amount of performance reduction. That is to say that a 2% loss of plant output will result in an effective increase in emissions of 2%.

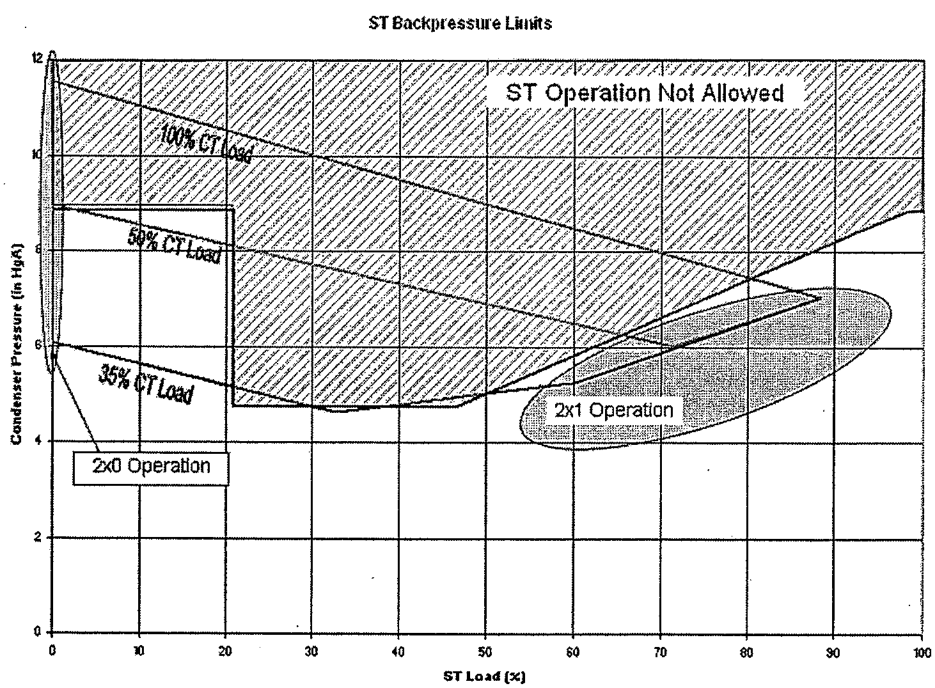
Additionally, the current far field guaranteed sound level for the cooling system, 60 dB at 400 ft., would be violated with an ACC unless special sound abatement measures were exercised. These measures will have a further negative impact on plant performance driving total plant costs higher.

q. Addition of ST Drains Tank

It will be necessary to design, build and install a new steam drain system and associated tankage to accommodate an ACC layout as the current existing equipment relies on the hot well of the condenser as a receiving and conditioning vessel.

2. Budgetary Pricing Costs Impacts for the ACC vs Cooling Tower Only

The current Wet Cooling Tower and Titanium Condenser would be scrapped and replaced with an ACC. Pricing represented below is based on an ACC sizing that maintains the capability of the plant to simultaneously load both GTs during plant startup at the site maximum design ambient temperature of 110F. ACC sizing is determined by selecting a condenser design that can reject the heat generated by two gas turbines operating in steam bypass (dumping steam to the condenser) so that during steam turbine loading, backpressure limits are not violated. The curve shown below indicates the GT load level and corresponding ST backpressure as well as the ST operation exclusion zone. From the curve, it is indicated that at a GT load of 35% and an ST load of 20%, the condenser backpressure will be slightly inside the exclusion zone. This slight incursion is generally acceptable for short periods of time.



Furthermore, it is necessary to provide the necessary engineering and equipment to ensure that the ACC does not violate any sound level requirements. The existing Wet Cooling Tower and the subject ACC will be required to meet a sound level guarantee of 60.0 dB(A) at 400 Ft.

A low noise configuration of an ACC capable of supporting the minimum ST starting needs was selected. Although this selection is not fully capable of matching the existing Wet Cooling Tower capabilities, it does provide a reasonable level of comparative operation. The ACC could be further optimized for size and cost at the expense of operational flexibility and plant performance or further optimized for operational flexibility and plant performance at the expense of size and cost.

The three sound level ACC options available from the GEA Quick Size calculation, with the corresponding estimated Siemens to customer equipment costs, are listed below. These ACC options are based on the selection criteria discussed above. Dimensions are in feet and reported in Length, Width, Height format.

Sound Option 1. Standard Noise

67.4 dB(A) at 400 Ft. = $28,224,000 (529X190X126)

Sound Option 2. Low Noise *(Used for this Evaluation)*

62.5 dB(A) at 400 Ft. = $30,384,000 (537X192X130)

Sound Option 3. Ultra Low Noise

56.5 dB(A) at 400 Ft. = $34,224,000 (541X193X132)

Installation cost = $23,824,734

3. Impact to Plant Start Times

Retrofit of an ACC will result in an increase to plant startup times. After an 8 hour shut down, the restart time is increased by 25% and after a 48 hour shut down the restart time is increased by 15%. This represents a direct impact on start up costs and ability of the plant to more quickly achieve AGC.

Impacts relative to emissions compliance:

After an 8 hour shut down, the time required to reach emissions compliance is increased by 55 minutes for the first GT and 35 minutes for the second GT. After a 48 hour shut down the time required to achieve emissions compliance is increased by 60 minutes of the first GT and 45 minutes for the second GT. This will result in higher emissions during this period of non compliance and could impact the number of allowed starts per year.

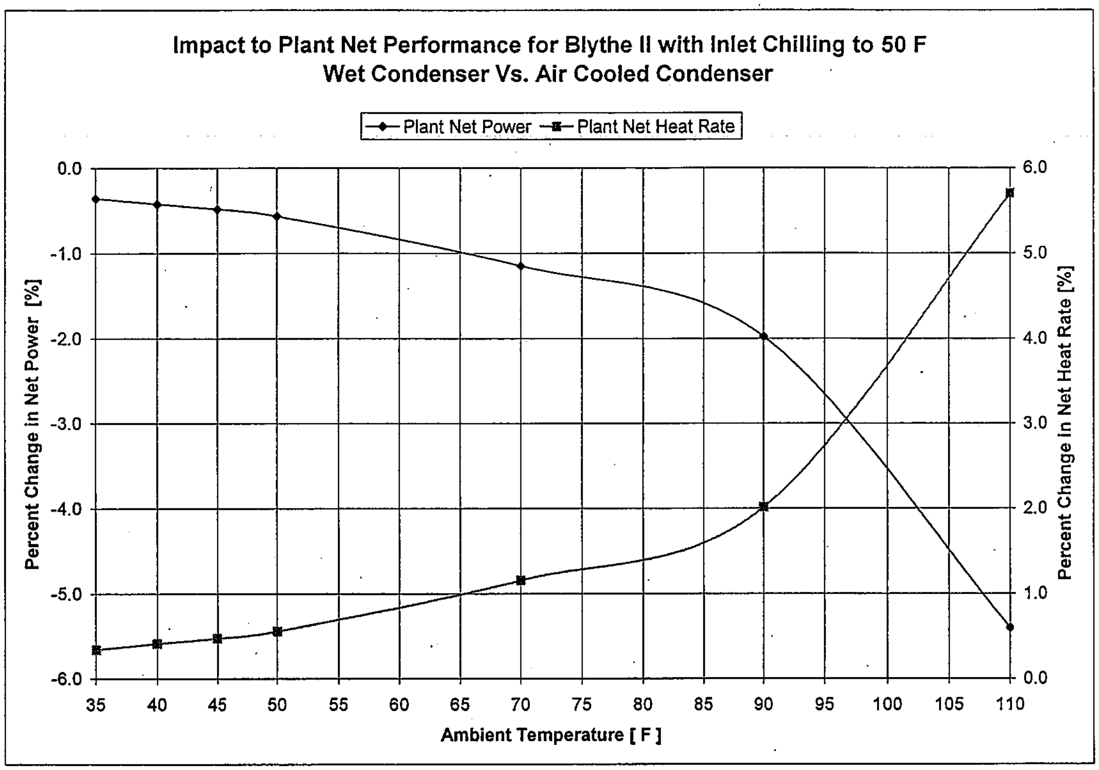
The main issues with the ACC are:

Steam Turbine limits during startup are in part governed by last row blade cooling requirements. Blade cooling is a function of backpressure and flow. Given that air cooled condensers utilize only the sensible heat of ambient air, it is their nature to operate at higher backpressures when compared to wet condenser / cooling tower designs. Because of this it is therefore necessary to limit duty to the ACC during startup by operating the GT at lower loads during thermal soak periods. Since this results in a less optimum match between steam and metal temperatures throughout the plant, longer start times with an air cooled condenser are to be expected. In summary, the impacts are:

- Higher emissions
- Difficulty matching steam temp requirements
- Difficulty attaining required steam mass flow (especially when starting with 1 GT)
- Increased time to warm-up steam piping due to low steam flow
- As ambient temperature increases, problem is worse. A hot ST rotor is worse due to steam temperature requirements (higher GT load). Operation in the operation exclusion zone of the above curve is limited to 5 min per event, 300 min per life of last row LP blades.

4. Power / HR over Ambient

As previously mentioned, an air cooled condenser relies only on sensible heat transfer and does not take advantage of the latent heat of vaporization (as is the case of an wet cooling tower). The net result is that it is not possible to achieve the same level of steam turbine performance since the backpressure of an air cooled condenser will be higher. Performance impacts from an air cooled condenser are further compounded by the fact that they have higher parasitic loads. The performance impacts from an ACC (based on the ACC performance assumptions of section 2) for the Blythe project are summarized below.


Impact to Plant Net Performance for Blythe II with Inlet Chilling to 50 F
Wet Condenser Vs. Air Cooled Condenser
Plant Net Power
Plant Net Heat Rate
0.0
-1.0
-2.0
-3.0
-4.0
-5.0
-6.0
Percent Change in Net Power [%]
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Percent Change in Net Heat Rate [%]
35
40
45
50
55
60
65
70
75
80
85
90
95
100
105
110
Ambient Temperature [F]

BLYTHE CAA AIRPORT, CALIFORNIA

Period of Record General Climate Summary - Temperature

Station:(040927) BLYTHE CAA AIRPORT

From Year=1948 To Year=2004

	Monthly Averages			Daily Extremes				Monthly Extremes				Max. Temp.		Min. Temp.	
	Max.	Min.	Mean	High	Date	Low	Date	Highest Mean	Year	Lowest Mean	Year	>= 90 F	<= 32 F	<= 32 F	<= 0 F
	F	F	F	F	dd/yyyy or yyyymmdd	F	dd/yyyy or yyyymmdd	F	-	F	-	# Days	# Days	# Days	# Days
January	66.7	41.5	54.1	89	25/1951	20	08/1971	61.1	81	44.1	***	0.0	0.0	2.7	0.0
February	72.0	45.4	58.7	93	18/1981	22	16/1990	64.9	63	52.8	***	0.2	0.0	0.9	0.0
March	78.4	50.2	64.3	100	30/1971	30	13/1956	72.9	104	58.9	***	3.1	0.0	0.1	0.0
April	86.4	56.6	71.5	107	08/1989	38	10/1975	77.8	89	62.7	***	11.7	0.0	0.0	0.0
May	95.1	64.3	79.7	114	27/1951	43	29/1971	87.4	97	72.7	77	23.6	0.0	0.0	0.0
June	104.5	72.6	88.6	123	28/1994	46	01/1980	95.0	81	82.9	65	28.9	0.0	0.0	0.0
July	108.3	80.9	94.6	123	28/1995	62	01/1982	98.2	80	90.0	87	30.9	0.0	0.0	0.0
August	106.6	80.1	93.4	120	01/1972	62	30/1957	98.8	69	88.8	76	30.6	0.0	0.0	0.0
September	101.4	73.1	87.2	121	01/1950	53	20/1971	91.2	56	80.1	86	28.4	0.0	0.0	0.0
October	89.8	60.9	75.4	111	01/1980	27	30/1971	81.3	103	66.4	71	17.8	0.0	0.0	0.0
November	75.7	48.5	62.1	95	01/1997	27	20/1994	67.0	95	55.6	71	0.7	0.0	0.1	0.0
December	66.7	41.3	54.0	87	29/1980	24	22/1968	60.5	80	47.2	71	0.0	0.0	1.7	0.0
Annual	87.6	59.6	73.6	123	19940628	20	19710108	75.5	97	70.2	71	175.9	0.0	5.5	0.0
Winter	68.5	42.7	55.6	93	19810218	20	19710108	61.2	81	49.2	49	0.2	0.0	5.3	0.0
Spring	86.7	57.1	71.9	114	19510527	30	19560313	76.7	97	66.6	75	38.4	0.0	0.1	0.0
Summer	106.5	77.9	92.2	123	19940628	46	19800601	96.3	81	89.4	76	90.4	0.0	0.0	0.0
Fall	89.0	60.8	74.9	121	19500901	27	19711030	78.0	101	68.9	71	46.9	0.0	0.1	0.0

Table updated on Mar 30, 2005
For monthly and annual means, thresholds, and sums:
Months with 5 or more missing days are not considered
Years with 1 or more missing months are not considered
Seasons are climatological not calendar seasons
Winter = Dec., Jan., and Feb. Spring = Mar., Apr., and May
Summer = Jun., Jul., and Aug. Fall = Sep., Oct., and Nov.

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of: Application for Certification for the Blythe Energy Project, Phase II	**DOCKET NO. 02-AFC-1** **DECLARATION OF THOMAS CAMERON**

I, Thomas Cameron, declare as follows:

1. I am presently retained by Caithness Blythe II as the Project Manager for the Blythe Energy Project, Phase II.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to **Water Resources** for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Las Vegas, NV on July 14, 2005.

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of: Application for Certification for the Blythe Energy Project, Phase II	**DOCKET NO. 02-AFC-1** **DECLARATION OF** ROBERT E. GAVAHAN

I, Robert Gavahan, declare as follows:

1. I am presently employed by Power Engineers Collaborative, a provider of engineering services to Caithness Blythe II as the project engineer for the provision of owners engineer services.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to Water Resources for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at West Allis, WI on June 14, 2005.

Robert E. Gavahan

STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of:	DOCKET NO. 02-AFC-1
Application for Certification for the Blythe Energy Project, Phase II	**DECLARATION OF Phil Deen**

I, Phil Deen, declare as follows:

1. I am presently employed by Siemens Westinghouse as the Manager of Thermal Cycle Engineering, Post Award.

2. A copy of my professional qualifications and experience is included with the attached testimony in Appendix A, and is incorporated by reference in this Declaration.

3. I prepared the attached testimony relating to Water Resources for the Blythe Energy Project, Phase II (California Energy Commission Docket Number 02-AFC-1).

4. It is my professional opinion that the attached prepared testimony is valid and accurate with respect to issues that it addresses.

5. I am personally familiar with the facts and conclusions related in the attached prepared testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge and that this declaration was executed at Orlando, FL on July 13, 2005.