APPENDIX J
GREENHOUSE GAS EMISSION CHANGES FROM PROPOSED OPERATIONAL MEASURES

Upper North Fork Feather River Hydroelectric Project

Revised Draft
Environmental Impact Report

State Water Resources Control Board
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Greenhouse Gas Emission Changes from Proposed Operational Measures

Aspen Environmental Group

Executive Summary

The Upper North Fork Feather River Federal Energy Regulatory Commission (FERC) Project No. 2105 is a 362 megawatt (MW) generation system. It provides important electric power services for the Pacific Gas and Electric Co. (PG&E) service area, including meeting peak capacity needs and providing reserves and load-following services.

As part of the environmental review under the California Environmental Quality Act (CEQA), the State Water Resources Control Board (SWRCB) is considering the potential indirect changes in greenhouse gas (GHG) emissions that might arise from changes in operations at the hydropower facilities. While changes in operations at the project will not directly cause changes in GHG emissions, those operational changes can induce compensating changes elsewhere in the interconnected Western power grid. Those changes in turn can cause indirect changes in GHG emissions from other power plants. The analysis presented here examines potential impacts under a range of scenarios, both with regard to hydrologic conditions and future electricity generation system situations.

The analysis indicated that the reasonably expected increase in indirect GHG emissions would be less than 4,000 tonnes CO_2 equivalent (CO_2e) for all of the alternative measures considered. Table ES-1 summarizes the results for the alternatives under consideration. This is less than the 7,000 tonnes threshold currently under consideration at the California Air Resources Board as a measure of significance under CEQA. For the specific measures, the installation of thermal curtains without changes in release requirements or preferential operations would not change GHG emissions.

Table ES-1
Annual Change in GHG Emissions in 2020 (Tonnes CO_2e)

	CEC SCENARIO 1B	CEC SCENARIO 1B @ $100/$CO_2e$ T	CEC SCENARIO 4	20% RPS	33% RPS
Baseline conditions	0	0	0	0	0
PG&E proposed Settlement Agreement Conditions	261	280	332	68	0
Prattville & Caribou Thermal Curtains	261	280	332	68	0
Thermal Curtains & 250 CFS @ Canyon Dam	1,120	1,165	1,454	265	0

When Canyon Dam bypass releases are increased to 600 cubic feet per second (CFS) and/or Caribou #1 is operated preferentially over Caribou #2, significant operational changes could occur. In these situations, PG&E would lose the capacity and ancillary services value of at least Caribou #2 and perhaps Caribou #1. As a result, PG&E likely would acquire 120 to 170 MW of new generating capacity to replace the lost capacity.

Introduction

The State Water Resources Control Board (SWRCB) is considering several operational measures to relicense Pacific Gas and Electric Company's (PG&E) Upper North Fork Feather River (UNFFR) Federal Energy Regulatory Commission (FERC) Project No. 2105. These measures may allow the UNFFR Project to comply with Section 401 of the Clean Water Act. As part of the environmental review under the California Environmental Quality Act (CEQA), the SWRCB is considering the potential indirect changes in greenhouse gas (GHG) emissions that might arise from changes in operations at the hydropower facilities. The question to be addressed in this report is whether any of the measures under consideration potentially reduce generation sufficiently that an increase in GHG emissions from replacement power could cause a significant environmental impact under CEQA. The analysis presented here examines potential impacts under a range of scenarios, both with regard to hydrologic conditions and future electricity generation system situations. These scenarios provide reasonably expected bounding cases on potential impacts to GHG emissions.

Description of the UNFFR System and Its Relationship to the PG&E System

The North Fork Feather River (NFFR) system upstream of Lake Oroville accounts for the second largest portion of PG&E's hydroelectric generation (after the McCloud-Pit basin) with 729.3 megawatts (MW) rated capacity (CPUC 2000) The UNFFR capacity under FERC Project No. 2105 is 362.3 MW or about half of this capacity. This system has both large inflows and very large amounts of storage, giving considerable ability to control levels of generation and water release on a seasonal as well as daily basis. Besides permitting winter-spring runoff to be stored for use in the summer, the considerable storage provided by Lake Almanor and other PG&E reservoirs can be used to coordinate generation with high electricity load (high market price) periods on a daily and hourly basis. During off-peak hours with low market prices, storable water flows used for hydro generation are reduced, usually to minimum levels, to preserve water for release during high load periods. When water is used to generate above minimum levels during off-peak periods, this is generally because so much water is available that the most economic option is to use some of it for generation even during off-peak hours. The UNFFR contains little generating capacity that is fully run-of-river or that has substantial minimum required flows through powerhouses.

The NFFR system benefits from the most reservoir storage of any PG&E basin. Large storage reservoirs are filled and drawn down on a seasonal basis. A reservoir that supplies water directly to the conveyance facilities leading to powerhouses is called a "forebay." Many of PG&E's powerhouses also have "afterbay" reservoirs downstream of the tailrace. Afterbays serve to smooth out rapid changes in discharge flow and dampen surges in stream flows that could endanger people or damage environmental resources. In many cases, the afterbay of one powerhouse is also the forebay for the next powerhouse in a series of reservoirs and powerhouses along a stream. On the NFFR system, water flow released from Mountain Meadows Reservoir produces electricity repeatedly through seven PG&E powerhouses and reservoirs as it flows to Lake Oroville, and then produces electricity two more times at the Department of Water Resource's Edward Hyatt and Thermalito powerhouses prior to being diverted in the Sacramento-San Joaquin Rivers Delta for the State Water Project. PG&E owns eleven reservoirs on the Feather River system with a combined capacity of 1,340,486 acre-feet. Important reservoirs and their total storage capacity in acre-feet are Lake Almanor (1,142,964), Bucks Lake (105,605), and Butt Valley Reservoir (49,897). Almanor and Butt Valley supply the UNFFR powerhouses. PG&E has an obligation to release 145,000 acre-feet annually from its reservoirs upstream of the State Water Project's Thermalito Afterbay for delivery to Western Canal Water District.

The Importance of Hydropower Generally, and the North Fork Feather River System, to Operating the State's Utility Network

Operation of a large electric power grid requires several "ancillary services" from generators in addition to basic energy production. In a large interconnected system such as supplies most of California, the load is constantly changing throughout the day as loads at factories, commercial buildings, farms, and homes are turned on and off at various times. In addition, generators are coming on line, changing output and going off line at various times for various reasons. But despite the complexity of the integrated system, one simple operating rule prevails: Generation output must match the load at all times since there is no reserve storage of electricity in the system. Therefore, adjustment of the total generator output to match the load demand is a continuous process. If the system load is greater than the generation, voltage starts dropping and the system loses speed. If the generators pump more energy into the system than the loads demand, the voltage and the speed of the system will increase. These changes are normally very small for a well operated system and go unnoticed. Daily variances in system speed might put electric clocks a few seconds off at the end of the day. That error is corrected by running the system slightly faster through the night. Provision of generation capability to match system output to load is generally referred to as "ancillary services."

California Independent System Operator (CAISO) grid operations involve dispatching generation to meet loads at every point in time, taking into account the physical properties of the transmission grid. The California system accomplishes this task through two instruments. First, the CAISO directly controls substantial generation within its control area that has been placed under Automatic Generation Control (AGC) through awards in the CAISO's Regulation auctions.[1] Second, the ISO operates a real-time balancing-energy auction, which produces both dispatch instructions to change the generation levels of participating resources, and price signals to participants in the informal, price-taking real-time market.

To maintain reliable grid operations, the CAISO must (1) place sufficient (and appropriately located) generation on AGC, and (2) ensure that there is sufficient participation in the real-time markets to meet the likely contingencies. The two tasks are accomplished jointly through the operation of the CAISO's Ancillary Services (A/S) auctions.

The Ancillary Services Markets have been established by the CAISO to ensure that necessary capacity and operational flexibility are available to maintain reliability of the electric system. The PX and, for the most part, the CAISO, procure energy or ancillary services through auctions. There are five Ancillary Services Markets (both day-ahead and hour-ahead) into which energy producers may bid their generation:

- Regulation “up” — generation that is already up and running (synchronized with the power grid) and can be moved via direct electronic commands by the ISO above the unit’s scheduled output level, to keep system-wide energy supply and energy use in balance (Automatic Generation Control [AGC], or market).

- Regulation “down” — generation that is already up and running (synchronized with the power grid) and can be moved via direct electronic commands by the ISO below the unit’s scheduled output level, to keep system-wide energy supply and energy use in balance (AGC, or market).

- Spinning reserves — unloaded online generation that can be dispatched within ten minutes.

- Non-spinning reserves — unloaded offline generation that can be dispatched within ten minutes.

- Replacement reserves — generation that can begin contributing to the grid within an hour.

PG&E generally has an incentive to bid hydroelectric generation into the market in a way that results in the highest value. The characteristics of a particular facility and the amount of water available at a given time may dictate which, if any, ancillary services can be provided. The ability to provide AGC market services (regulation up/down) is subject to having the specific hardware and control systems that enable remote control of output by the CAISO.

[1] Automatic generation control allows a unit’s power level to be altered every four seconds to follow momentary changes in system load. Electricity supply and demand must be balanced every instant within narrow tolerances to prevent system collapse.

Regulation

The CAISO procures enough upward and downward Regulation to respond to real-time disturbances. Capacity selected in the two auctions (one for each direction, up and down) are paid the market-clearing price, which can vary from zone to zone. In addition, the net energy delivered from Regulation action settled at the relevant real-time ex-post price. The CAISO's initial response to a system imbalance is a balancing set of AGC signals to generators providing Regulation.

Reserves

The CAISO sets its purchases of reserves to secure sufficient real-time supplies to both meet expected loads and to provide an adequate margin for unplanned contingencies. Spinning and Non-Spinning requirements are set in accordance with the WECC Minimum Operating Reserve Criteria, to five percent of expected demand (net that met by firm imports) served by hydro resources, and seven percent of net expected demand served by non-hydro resources, or the largest single contingency. At least half of these reserves must be Spinning. Replacement reserves are purchased based on the CAISO's forecasts of unplanned outages and on the expected draw on the real-time market (taking into account the expected output of unscheduled RMR operations and other sources of uninstructed deviations).

The three A/S reserve services are arrayed in decreasing order of quality based on their technical requirements. Spinning Reserves must be provided by generators that are synchronized to the grid; a unit's Spinning Reserve capacity is limited to that which may be delivered within ten minutes of the CAISO's dispatch instruction. Non-spinning Reserves have the same delivery requirement, but need not be provided by generators that are synchronized to the grid. Replacement Reserve capacity is limited to that which may deliver energy within 60 minutes of dispatch.

Providing ancillary services requires operational flexibility and agility to respond quickly to changes in load either up or down, and to come on line and to full load in a very short time. Spinning reserve requires the capability to economically operate a unit at a very low load synchronized on the system ready to crank-up to full power in a matter of minutes. Non-spinning reserve service may require a unit to come from a cold start to full power in a matter of 10 minutes.

Hydropower Provision of Ancillary Services

Hydroelectric resources have always provided a portion of PG&E’s reserve and load-following needs. Up to 75 percent of the Northern California spinning reserves market is served by PG&E’s hydropower assets. The current market structure also provides opportunities for hydroelectric facilities to sell products and services other than just energy. In the current market, PG&E has the opportunity to bid and schedule its generation into the energy markets, then to bid and schedule any unloaded capacity into the subsequent Ancillary Services Markets and the Imbalance Energy Market run by the California Independent System Operator (CAISO).

Balancing generation and load is a challenge because most thermal power plants operate best at constant loads and do not respond quickly to changes in demand. To increase load, a conventional steam plant must first increase the fuel flow and the size of the fire in the furnace to make additional steam for delivery to the turbine. This takes time, especially for older steam-drum type units that have a lot of thermal inertia due to the greater mass of their components. Nuclear plants are even less responsive and are generally operated base-loaded at full capacity. Frequent changes in loads in thermal plants also increases thermal stresses in the equipment and may lead to more frequent equipment failures. Bringing a thermal plant from a cold start to full load may take several hours. Nuclear plants may take a day or more to bring to full capacity after a cold shutdown.

Hydro generating units are especially well suited for providing ancillary services because they can change levels of output very rapidly and move from no-load condition to full power in a matter of a very few minutes. There is no warm-up time and changes in load levels do not thermally stress components to cause equipment failures. The proven reliability of hydro assures that the ancillary service needed will be available when called for by the CAISO.

The new generation of combustion turbine (CT) driven thermal power plants have faster start-up and response times than conventional steam plants and may compete with hydro in the ancillary services market. However, many of these CTs are combined cycle plants coupled with steam turbines for topping cycles. The steam cycles may slow the response time of these units.

Environmental Setting

Greenhouse gas (GHG) emissions are not criteria pollutants, but are described as contributing to global climate change. In December 2009, the U.S. Environmental Protection Agency (EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the American people (the endangerment finding), and this became effective on January 14, 2010. Regulating GHG at the federal level may be furthered by the Prevention of Significant Deterioration (PSD) program and New Source Review (NSR) rule changes proposed by U.S. EPA on September 30, 2009. These requirements could eventually apply to new facilities whose carbon dioxide-equivalent emissions exceed 25,000 tons per year (U.S.EPA2009c). Federal rules that became effective December 29, 2009 (40 CFR 98) already require reporting of GHG. As federal rulemaking evolves, this analysis focuses on analyzing the ability of the proposed measures to comply with existing state-level policies and programs for GHG. The state has demonstrated its intent to address global climate change though research, adaptation,[2] and GHG inventory reductions. In that context, this analysis evaluates the indirect GHG emissions from the proposed measures, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

California law provides that climate change is an environmental effect subject to the California Environmental Quality Act (CEQA) (Public Resources Code, § 21083.05). Lead agencies therefore are obligated to determine whether a project's climate change-related effects may be significant, requiring preparation of an Environmental Impact Report (California Code of Regulations, Title 14, § 15064, subdivision (f)(1)) and to impose feasible mitigation to substantially lessen any significant effects (California Code of Regulations, Title 14, § 15021, subdivision (a)(2)). the Governor's Office of Planning and Research in its June 2008 Technical Advisory, "CEQA and Climate Change," asked the Air Resources Board (ARB) to make recommendations for GHG-related thresholds of significance – identifiable benchmarks or standards that assist lead agencies in the significance determination (California Code of Regulations, Title 14, § 15064.7, subd. (a)). ARB has issued a preliminary interim

[2] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state's climate (for example, changing rainfall patterns).

recommendation for significance for any change exceeding 7,000 metric tonnes CO_2e per year, with caveats. (ARB 2008d)

Laws, Ordinances, Regulations, and Standards

The following federal, state, and local laws and policies in **Table 1** pertain to the control and mitigation of greenhouse gas emissions. Staff's analysis examines the proposed operation of the project under several different scenarios and its compliance with these requirements.

Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

APPLICABLE LAW	DESCRIPTION
Federal	
Mandatory Reporting of Greenhouse Gases (40 CFR 98, Subpart D)	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	California Global Warming Solutions Act of 2006. This act requires the California Air Resources Board (ARB) to enact standards that will reduce GHG emissions to 1990 levels. Electricity production facilities will be regulated by the ARB.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	ARB regulations implementing mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
Title 20, California Code of Regulations, section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2$/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lb CO_2/MWh)

Global Climate Change and California

General scientific consensus exists that climate change is occurring and that human activity contributes in some measure (perhaps substantially) to that change. When enacting the California Global Warming

Solutions Act of 2006 (AB 32), the California Legislature found that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Health & Safety Code, sec. 38500). It requires the California Air Resources Board (ARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020.[3] To achieve this, ARB has a mandate to define the 1990 emissions levels and achieve "the maximum technologically feasible and cost-effective" GHG emission reductions.

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December 2007, and adopted a statewide scoping plan in December 2008 to identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB staff is developing regulatory language to implement its plan and holds ongoing public workshops on key elements of the recommended GHG reduction measures, including market mechanisms (ARB 2006). The regulations must be effective by January 1, 2011, and mandatory compliance commences on January 1, 2012. The mandatory reporting requirements are effective for electric generating facilities over 1 megawatt (MW) capacity, and the due date for initial reports by existing facilities this first year was June 1, 2009.

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), were identified in the California Climate Action Team's Report to the Governor (CalEPA 2006). The scoping plan approved by the ARB in December 2008 builds upon the overall climate policies of the Climate Action Team report and shows the recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33 percent Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008c).

It is possible that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest effect for the least cost). For example, the ARB proposes up to 50 percent reduction in GHG from the electricity sector in its Scoping Plan, even though the sector currently only produces about 25 percent of the state's GHG emissions. In response, in September 2008 the CEC and the CPUC provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified points of regulation within the sector should ARB decide that a multi-sector cap and trade system is warranted.

The CEC's *2007 Integrated Energy Policy Report* (IEPR) also addresses climate change within the electricity, natural gas, and transportation sectors (CEC 2007a). For the electricity sector, it recommends such approaches as pursuing all cost-effective energy efficiency measures and meeting the Governor's stated goal of a 33 percent Renewables Portfolio Standard.

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[3] Governor Schwarzenegger has also issued Executive Order S-3-05 establishing a goal of 80 percent below 1990 levels by 2050.

SB 1368, also enacted in 2006, and regulations adopted by the CEC and the CPUC pursuant to the bill, prohibit California utilities from entering into long-term commitments with any base load facilities that exceed the Greenhouse Gas Emission Performance Standard of 0.499 metric tonnes CO_2 per megawatt-hour[4] (1,100 pounds CO_2/MWh).[5] *Base load* units are defined as those designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent. Specifically, the SB 1368 Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California. If a project, instate or out of state, plans to sell base load electricity to California utilities, the utilities will have to demonstrate that the project complies with the EPS. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant and not on full load heat rates [20 CCR §2093(a)].

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap and trade market to reduce greenhouse gas emissions in the western United States and the Western Electricity Coordinating Council (WECC). The timelines for the implementation of this program are similar to those of AB 32, with full roll-out beginning in 2012. As with AB 32, the electricity sector has been a major focus of attention.

Greenhouse gas emissions

Generation of electricity using any fossil fuel can produce greenhouse gases with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. For fossil fuel-fired power plants, the GHG emissions include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused or recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials. Global warming potential is a relative measure, compared to carbon dioxide, of a compound's residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO_2E) metric tonnes (MT) for ease of comparison.

Assessment of Impacts and Discussion of Mitigation

The impacts on GHG emissions caused by proposed UNFFR operational scenarios (alternatives) are characterized by considering how operating the project with different measures would affect the overall

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[4] The Emission Performance Standard only applies to carbon dioxide and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[5] California Code of Regulations, Title 20 § 2900 and Public Utilities Code § 8340 et seq.

electricity system. The integrated electricity system depends on generation resources to provide energy and satisfy local capacity needs. Electricity is produced by operation of inter-connected generation resources and, by knowing the fuel used by the generation sector, the resulting GHG emissions can be known. The operation of UNFFR affect the overall electricity system operation and GHG emissions in several ways:

- UNFFR provides flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.
- UNFFR displaces some less efficient local generation in the dispatch order of gas-fired facilities that are required to provide electricity reliability in the TID system.
- UNFFR facilitates to some degree the replacement of out-of-state coal electricity generation that must be phased out in conformance with the State's new Emissions Performance Standard.

In other system roles, as described in **Table 2**, UNFFR provides other services as well:

Table 2
Summary of Role in Providing Energy and Capacity Resources

SERVICES PROVIDED BY GENERATING RESOURCES	DISCUSSION, UNFFR
Integration of Renewable Energy	Provides fast startup capability (within 2 hours). Provides rapid ramping capability. Has ability to provide regulation and reserves, and energy when renewable resources are unavailable.
Local Generation Displacement	Is able to satisfy/partially satisfy local capacity area (LCA) resource requirements. Provides voltage support.
Ancillary Services, Grid System, and Emergency Support	Provides fast start-up capability (within 2 hours). Intermittently has low minimum load levels. Provides rapid ramping capability. Has ability to provide regulation and reserves.
General Energy Support	Provides general energy support. Provides cost-competitive energy. Is able to help a load-serving entity (LSE) meet resource adequacy (RA) requirements.

Source: CEC staff; based on: Expected Roles for Gas-Fired Generation (CEC2009b, p. 7).

The Role of UNFFR in the Integration of Renewable Energy

Electricity use can be as simple as turning on a switch to operate a light or fan. The system to deliver the adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to meet demand, such that the dispatch of a new source of generation unavoidably curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). *Ancillary services*[6] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. In this context, and because fossil-fueled resources produce GHG emissions, it is important to consider the role and necessity of hydropower and fossil-fuel resources. A report prepared as a response to the CEC's greenhouse gas Order Instituting Investigation (GHG OII) (CEC 2009a) defines five roles that gas-fired power plants are likely to fulfill in a high-renewables, low-GHG system (CEC 2009b, pp 93 and 94):

- Intermittent generation support
- Local capacity requirements
- Grid operations support
- Extreme load and system emergency
- General energy support.

CEC staff-sponsored report reasonably assumes that non-renewable power plants added to the system would almost exclusively be natural gas-fueled. Nuclear, geothermal, and biomass plants are generally base load and not dispatchable. Solid fueled projects are also generally base load, not dispatchable and carbon sequestration technologies needed to reduce the GHG emission rates to meet the EPS are not yet developed (CEC 2009b, p. 92). Further, California has almost no sites available to add highly dispatchable hydroelectric generation.

As California moves towards an increased reliance on renewable energy, the bulk of renewable generation available to, and used in California, will be intermittent wind generation with some intermittent solar (CEC 2009b, p.3). To accommodate the increased variability in generation due to increasing renewable penetration, compounded by increasing load variability, control authorities such as the California Independent System Operator (CAISO) need increased flexibility from other generation resources such as hydro generation, dispatchable pump loads, energy storage systems, and fast ramping and fast starting fossil fuel generation resources (CAISO 2007, p. 14).

[6] See page CEC 2009b, page 95.

Storage hydropower facilities such as UNFFR provide flexible, dispatchable and fast ramping[7] power consistent with the CAISO use of this term. UNFFR serve as an important firming source for intermittent renewable resources in support of PG&E's RPS and GHG goals.

The amount of dispatchable fossil fuel generation will have to be significantly increased to meet the statewide 20 percent RPS (CAISO 2007, p.113); the 33 percent RPS will require even more dispatchable resources to integrate the renewables. However, this does not suggest the existing and new fossil fuel capacity will operate more. **Table 3** shows how the build-out of either the 20 percent or the 33 percent statewide RPS goal will affect generation from new and existing non-renewable resources. Should California reach its goal of meeting 33 percent of its retail demand in 2020 with renewable energy, non-renewable, most likely fossil-fueled, energy needs will fall by over 36,000 GWh/year. In other words, all growth will need to come from renewable resources to achieve the 33 percent RPS. And some existing and new fossil units will generate less energy than they currently do, given the expected growth in retail sales.

These assumptions are conservative in that the forecasted growth in retail sales assumes that the impacts of planned increases in expenditures on (uncommitted) energy efficiency are already embodied in the retail sales forecast.[8] If, for example, forecasted retail sales in 2020 were lowered by 10,000 GWh due to the success of increased energy efficiency expenditures, non-renewable energy needs fall by an additional 6,700 to 8,000 GWh/year, depending on whether 20 percent or 33 percent RPS is assumed.

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[7] The CAISO categorizes *fast-ramping* as a generator capable of going from lowest power to highest in under 20 minutes, or greater than 10 MW per minute.

[8] The extent to which uncommitted energy efficiency savings are already represented in the current Energy Commission demand forecast is studied in the December 2009 IEPR (CEC 2009c).

Table 3
Estimated Changes in Non-Renewable Energy Potentially Needed to Meet California Loads, 2008-2020

CALIFORNIA ELECTRICITY SUPPLY	ANNUAL GWH	
Statewide Retail Sales, 2008, estimated [a]	265,185	
Statewide Retail Sales, 2020, forecast [a]	308,070	
Growth in Retail Sales, 2008-20	42,885	
Growth in Net Energy for Load [b]	46,316	
CALIFORNIA RENEWABLE ELECTRICITY	**GWH @ 20% RPS**	**GWH @ 33% RPS**
Renewable Energy Requirements, 2020 [c]	61,614	101,663
Current Renewable Energy, 2008	29,174	
Change in Renewable Energy-2008 to 2020 [c]	32,440	72,489
Resulting Change in Non-Renewable Energy [d]	13,876	(-36,173)

Source: CEC staff 2009.
Notes:
Not including eight percent transmission and distribution losses.
Based on eight percent transmission and distribution losses, or 42,885 GWh x 0.08 = 46,316 GWh.
Renewable standards are calculated on retail sales and not on total generation, which accounts for eight percent transmission and distribution losses.
Based on net energy (including eight percent transmission and distribution losses), not based on retail sales.

Replacement of Coal-Fired Generation

Coal-fired resources are effectively prohibited from entering into new long-term, base load contracts for California deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, more than 18,000 GWh of energy procured by California utilities under existing contracts will have to be replaced; these contracts are listed in **Table 4**.

This represents almost half of the energy associated with California utility contracts with coal-fired resources that will expire by 2030. If the State enacts a carbon adder[9], all the coal contracts (including those in **Table 4**, which expire by 2020, and other contracts that expire beyond 2020 and are not shown in the table) may be retired at an accelerated rate as coal-fired energy becomes uncompetitive. Also shown are the approximate 500 MW of in-state coal and petroleum coke-fired capacity that may not be able to contract with California utilities due to the SB 1368 Emission Performance Standard. As these contracts expire, new and existing generation resources will replace the lost energy and capacity. Some will come from renewable generation; some will come from new and existing natural gas fired generation. New generation resources generally will emit significantly less GHG than the coal and petroleum coke-fired generation, which average about 1.0 $MTCO_2$/MWh, or two times more than a typical combustion turbine that could replace the unique services of the UNFFR powerhouses.

[9] A carbon adder or carbon tax is a specific value added to the cost of a project per ton of associated carbon or carbon dioxide emissions. Because it is based on, but not limited to, actual operations and emission and can be trued up at year end, it is considered a simple mechanism to assign environmental costs to a project.

Table 4
Expiring Long-term Contracts with Coal-fired Generation 2009 – 2020

UTILITY	FACILITY [A]	CONTRACT EXPIRATION	ANNUAL GWH DELIVERED TO CA
PG&E, SCE	Misc In-state Qualifying Facilities [a]	2009-2019	4,086
LADWP	Intermountain	2009-2013	3,163 [b]
City of Riverside	Bonanza, Hunter	2010	385
Department of Water Resources	Reid Gardner	2013 [c]	1,211
SDG&E	Boardman	2013	555
SCE	Four Corners	2016	4,920
Turlock Irrigation District	Boardman	2018	370
LADWP	Navajo	2019	3,832
TOTAL			18,522

Source: CEC staff based on Quarterly Fuel and Energy Report (QFER) filings.
Notes:
a. All facilities are located out-of-state except for the Miscellaneous In-state Qualifying Facilities.
b. Estimated annual reduction in energy provided to LADWP by Utah utilities from their entitlement by 2013.
c. Contract not subject to Emissions Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.

As directed by the GHG OII (CEC 2009a), CEC staff is refining and implementing the concept of a "blueprint" that describes the long-term role of fossil-fueled power plants in California's electricity system. The five separate roles that gas-fired power plants are most likely to fulfill in the future of a high-renewables, low-GHG system include: 1) Intermittent generation support; 2) Local capacity requirements; 3) Grid operations support; 4) Extreme load and system emergencies support; and 5) general energy support (CEC 2009b, p. 93). As stated in the 2009 *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* (CEC 2009b, p.23):

> *When one resource is added to the system, all else being held equal, another resource will generate less power. If the new resource has a lower cost or fewer emissions than the existing resource mix, the aggregate system characteristics will change to reflect the cheaper power and lower GHG emissions rate.*

Net GHG emissions for the integrated electric system will decline when new gas-fired power plants are added to: 1) permit the penetration of renewable generation to the 33 percent target; 2) improve the overall efficiency of the electric system; or 3) serve load growth or capacity needs more efficiently than the existing fleet (CEC 2009b, p. 98).

Indirect Impacts of the Proposed Operational Measures

An EIR must identify and focus on the significant environmental effects of all phases of the proposed project, including planning, acquisition, development, and operation of the proposed project (CEQA Guidelines § 15126). *Indirect impacts,* also referred to as secondary effects, are those caused by a project that may occur either later in time or at some distance from the project site but that are still reasonably foreseeable (CEQA Guidelines § 15358). Put another way, an indirect impact is "a physical change in the environment…which is not immediately related to the project, but which is caused by the project" (CEQA Guidelines § 15064 (d)(2)). We are describing here how changes in operating a power plant in one location can induce compensating changes in other distant generators connected through the power grid.

Specifically, this assessment analyzes the operation of the UNFFR Project with the proposed measures, their commensurate effect in reducing power generation from the Project, and the potential indirect impacts of increasing GHG emissions by replacing the lost power with alternate sources. In addition, this analysis models how operation of the UNFFR Project with the proposed measures could affect PG&E's ability to meet State GHG emission requirements and policies.

Compliance With Laws, Ordinances, Regulations, and Standards

Ultimately, ARB's AB 32 regulations are likely to address both the degree of electricity generation sector emissions reductions (through cap-and-trade), and the method by which those reductions will be achieved (e.g., through command-and-control). However, the exact approach to be taken is currently under development. That regulatory approach may address emissions not only from the newer, more efficient, and lower emitting facilities that may be needed to replace UNFFR generation, but also from the older, higher-emitting facilities not subject to any GHG reduction standard that the SWRCB could presently impose. This programmatic approach is likely to be more effective in reducing GHG emissions overall from the electricity sector than one that merely relies on displacing out-of-state coal plants ("leakage") or older "dirtier" facilities.

The CEC and the CPUC provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified the regulation points should ARB decide that a multi-sector cap-and-trade system is warranted. As ARB codifies accurate GHG inventories and methods, it may become apparent that emission reductions from the generation sector are less cost-effective than other sectors, and that other sectors of sources can achieve reductions with relative ease and cost-effectiveness.

Any generation sources that PG&E might acquire to replace UNFFR generation would be subject to ARB's mandatory reporting requirements and potentially other future requirements mandating compliance with AB 32 that are being developed by ARB. How these sources would comply with these ARB requirements is speculative at this time, but compliance would be mandatory. The ARB's mandatory GHG emissions reporting requirements do not indicate whether these sources, as defined, would comply with the potential GHG emissions reduction regulations being formulated under AB 32. These sources may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB. Similarly, these sources would be subject to federal mandatory reporting of GHG.

Reporting of GHG emissions would enable these sources to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide the information to demonstrate compliance with any applicable EPS that could be enacted in the next few years. A simple-cycle CT power plant which is the most likely identifiable replacement resource discussed in two of the alternatives below is not designed or intended for base load generation, and the UNFFR project capacity factor averages 37 percent, which is less than the 60 percent threshold for baseload generation. Therefore, the SB 1368 limitation does not apply to these facilities.

The ARB also will rely on a yet-to-be-designed cap-and-trade program to allow electric utilities and other major emitters flexibility in complying with AB 32 requirements (ARB 2008c). Under this program, PG&E could acquire credits or allowances produced from other emission reduction efforts, e.g., improved power plant efficiency, to offset any increases in system-wide emissions indirectly created by changes in UNFFR operations. These reductions will meet ARB's predetermined criteria for being substantiated, thus guaranteeing that total emissions will not increase. However, it is not possible to identify beforehand what specific measures will be undertaken to create the necessary credits. The decisions about what actions are taken to produce emission reduction allowances are left to a decentralized process in which individual firms and organizations act. Thus, there is a fully-functioning compliance mechanism to ensure that offsetting emission reductions will be produced at a yet-to-be-determined economic cost.

Conceptual Analysis of Generation Impacts

Analysis of the potential impacts from operational changes on the UNFFR project must recognize the two valuable attributes of the generating assets—the abilities to shape energy production into the highest demand and value periods, and to rapidly respond to changes in demand so as to follow load and provide ready reserves. The alternative resources used to provide these services to the CAISO tend to come from higher emitting fossil-fueled plants, such as older natural-gas fired steam turbines and less efficient CTs. To answer whether these attributes are significantly diminished, the changes in generation were first qualitatively assessed and then quantitatively modeled.

Methodology

The first step in the analysis was to prepare a spreadsheet model that converts the monthly energy changes into hourly operational changes. The model translated the average daily flows developed by Stetson Engineering, described in Attachment A, into a model representing a typical week of hourly operations in the four monthly periods of interest, June to September, for three different water-year types. The analysis relied on the representation of current project operations presented in that report and reflects the operational constraints listed there and in the other FERC licensing conditions. The changes in hourly flows were computed for the six different operational measures being considered, as compared to baseline and proposed conditions under the Settlement Agreement.

The second step was to prepare an estimate of short-term and long-term incremental electricity system resource additions to 2020. That year was chosen due to its relevance and salience in resource planning for the CPUC in its Long Term Procurement Planning Proceeding (LTPP), and the ARB's AB 32 Scoping Plan for complying with mandated GHG reduction targets. We used results from the CEC's Scenarios Analysis prepared for the 2007 IEPR to estimate hourly emission rates. (CEC 2007a).   That project prepared five different scenarios for 2020 based on differing policies and forecast assumptions. We also reviewed the identified resource additions in those scenarios so as to be able to delineate what types of resources, including fossil and renewable generation, distributed generation (DG) and demand-side management (DSM) such as energy efficiency (EE), would be added to replace the reduced generation from the UNFFR Project.

The third step was to estimate the changes in incremental resources identified in the plans collected and analyzed in the second step from changes in operations estimated in the first step. A spreadsheet model was developed to facilitate ease of computation and transparency. The changes are segmented by resource plan case and hydrologic conditions. A weighted average based on historic hydrologic conditions of changes were computed for each resource plan.

Quantitative Analysis of Generation Impacts

Alternatives to be Compared

The Alternatives analyzed are listed in Table 5 below. The analysis focuses on the three powerhouses, Butt Valley and the Caribou #1 and #2, that are affected by the proposed alternatives. These total 247 MW in rated capacity. The important infrastructure and operational attributes that are being varied are:

- The installation of thermal curtains at Caribou to allow full operation of Caribou #1 and #2 and at Prattville Intake;
- Increase minimum Canyon Dam releases to 250 or 600 cfs when water is available; or
- Operate Caribou #1 preferentially over Caribou #2, diverting up to the maximum Caribou #1 throughput.

Table 5
Summary of Proposed Alternative Measures

Alternative	Measures
Baseline	Baseline conditions
PG&E Proposed Settlement Agreement	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to Those Given in the proposed Settlement Agreement
Alternative 3	Install Prattville Intake Thermal Curtain and Remove Submerged Levees
	Install Caribou Intake Thermal Curtain
	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 250 cfs
Alternative 3x	Install Prattville Intake Thermal Curtain and Remove Submerged Levees
	Operate Caribou #1 PH Preferentially
	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 600 cfs
Alternative 4a	Install Prattville Intake Thermal Curtain
	Install Caribou Intake Thermal Curtain
Alternative 4b	Install Prattville Intake Thermal Curtain
	Operate Caribou #1 PH Preferentially
Alternative 4c	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 600 cfs
	Operate Caribou #1 PH Preferentially
Alternative 4d	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 600 cfs
	Install Caribou Intake Thermal Curtain

Modeling Hourly Operation Changes

Stetson Engineering provided results of its hydrologic analysis of these alternatives described in Attachment A, as well as the hydrologic engineering operational parameters of Butt Valley, Caribou #1 and 2 powerhouses required to calculate the power output. **Table 6** lists the engineering parameters for each powerhouse.The results include actual average discharge rates in cubic feet per second (CFS) for Butt Valley, Caribou #1 and 2 powerhouses, covering June 15 through September 15 for 2002-2004. Stetson also provided results for several Alternatives with different changes in average discharge rates per month for each powerhouse, as shown in **Tables 7, 8 and 9** for each powerhouse.[10] These Alternatives reflected the proposed operational changes described in Table 5 and Attachment A. The discharge changes were converted to power output and a proportion of the change was allocated to weekdays and weekends, based on the proportion of those days in each month.

[10] Hourly discharge data for the week of July 18-25, 2003 for Caribou #2 was adjusted to fit more normal operations. Hourly flow for this week was replaced with an average of the previous and subsequent weeks, since PG&E conducted special tests (favoring Caribou #1 PH over Caribou #2), which may not reflect normal operations.

Table 6
Powerhouse Properties

POWERHOUSE	HEAD (FT)	EFFICIENCY	MAX DISCHARGE (CFS)	MAX OUTPUT (MW)
Butt Valley	362	80.6%	2118	52.3
Caribou #1	1151	69.1%	1114	75
Caribou #2	1150	84.2%	1464	119.9

Table 7
Change in Discharge of Butt Valley PH Relative to Baseline Condition for Different Alternatives

	ALTERNATIVE	CHANGE IN DISCHARGE (CFS)			
		JUN	JUL	AUG	SEP
Change in Discharge by Alternative (cfs)	PG&E proposed Settlement Agreement	-90	-55	-45	-25
	Alternative 3	-215	-215	-215	-215
	Alternative 3x	-565	-565	-565	-565
	Alternative 4a	-90	-55	-45	-25
	Alternative 4b	-90	-55	-45	-25
	Alternative 4c	-565	-565	-565	-565
	Alternative 4d	-565	-565	-565	-565

Table 8

Change in Discharge of Caribou #1 PH Relative to Baseline Condition for Different Alternatives

	ALTERNATIVE	CHANGE IN DISCHARGE (CFS)			
		JUN	JUL	AUG	SEP
Change in Discharge by Alternative (cfs)	PG&E proposed Settlement Agreement	-29	-18	-16	-8
	Alternative 3	-70	-69	-75	-70
	Alternative 3x	-22	+183	+296	+299
	Alternative 4a	-29	-18	-16	-8
	Alternative 4b	+453	+693	+655	+697
	Alternative 4c	-22	+183	+296	+299
	Alternative 4d	-184	-181	-196	-184

Note: The symbol "+" indicates an increase in discharge which results from preferential use of Caribou #1 over Caribou #2. The total discharge of Caribou #1 should not exceed its capacity of 1,114 cfs.

Table 9

Change in Discharge of Caribou #2 PH Relative to Baseline Condition for Different Alternatives

ALTERNATIVE		CHANGE IN DISCHARGE (CFS)			
		JUN	JUL	AUG	SEP
Change in Discharge by Alternative (cfs)	PG&E proposed Settlement Agreement	-61	-37	-29	-17
	Alternative 3	-145	-146	-140	-145
	Alternative 3x	-543	-748	-861	-864
	Alternative 4a	-61	-37	-29	-17
	Alternative 4b	-543	-748	-700	-722
	Alternative 4c	-543	-748	-861	-864
	Alternative 4d	-381	-384	-369	-381

Actual hourly hydro discharges for each month (i.e., 720 or 744 hours for each month) were averaged to obtain daily discharge profiles for each powerhouse, and aggregated by month, and day type (weekday or weekend). The average daily profiles were graphed and fitted with six-degree polynomial equations, which allowed for numerical approximations representing the average for each month for the baseline discharges.[11] "Apparent maximum" powerhouse flows were found averaging flows of all non-zero hours for each powerhouse, and taking the maximum value. The apparent maximums reflected the difference between the rated capacity and the average hourly output, with this difference presumably devoted to the A/S markets. These powerhouses almost never run at sustained rated generating capacity because they are used to provide the ancillary services described above. Using engineering parameters from Stetson, discharges were converted to power output in MWs for each hour.

Using an optimization algorithm, a dispatch flow level was used to produce an hourly power generation profile. For Alternatives that increased average discharges (positive changes), these changes were added to the hours during peak periods through the optimization routine when the powerhouses were operating

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[11] Numerical approximations were truncated to not go below zero or above the maximum capacity of each powerhouse

at less than full output under the assumption that PG&E would prefer to increase generation during the periods when such power is most valuable, and that the powerhouses could accommodate more peak output. The optimization routine used the historic hourly generation pattern as a proxy for the generation market power prices. That is, when historic generation levels were high within a single day, that reflected that power prices also were high and that hydropower was most valuable then. Changes from the baseline conditions were allocated to the least valuable unconstrained hours so as to maintain generation during the most valuable periods by choosing a historic power output level at which to dispatch the unit in an alternative regime. For alternatives that reduced discharge volume, hours below this dispatch level were reduced to the minimum discharge of that power house, and hours above this level were "turned on" using the baseline flow curve values. An iterative process in calculating the dispatch levels was done for each alternative such that the total flow met the change requirements.

Alternatives with relatively large reductions required minimum flows below the average power profile minimums to meet the requirements. If the alternative reduced generation below the historic minimum generation level, the model produced a flat 24-hour constant generation level. In some cases, the reduction changes were larger than the total flow of the average power profiles, in which case, the power house was reduced to zero. For alternatives that added volume, hours above the dispatch level were increased to the apparent maximum flow for that power house, and flows below the dispatch level used the baseline flow values.

In several of the proposed operational Alternatives, Alternatives 3x, 4b and 4c, flows are preferentially diverted from the more efficient Caribou #2 powerhouse to the less efficient Caribou #1 to meet downstream flow objectives. Where Caribou #1 has an increasing scenario change, negative scenario changes for Caribou #2 were subtracted from peak hours. This is due to water diversion from Caribou #2 to Caribou #1 and not necessarily a change in total average flow. In some alternatives for Caribou #1, the shift in flows from Caribou #2 required was beyond Caribou #1's maximum capacity. In these cases, the excess flow was retained by Caribou #2.

Attachment B contains graphs of the scenario changes and the baseline energy output (from the numerical approximation).

Hourly Emissions Factors

Changes in hydropower operations result in offsetting changes in other power plant operations throughout the Western U.S., in the larger transmission network known as the WECC. The CEC as part of its *2007 IEPR* prepared a Scenarios Analysis that examined several different potential resource plans (CEC 2007a). These ranged from a "business as usual" case in which California utilities complied with existing state laws and regulations and continued adding resources in historic patterns, to adopting aggressive policies to add renewables, energy efficiency and customer-side resources. We obtained three cases with hourly MarketAnalytics emissions data for all of 2020, from the CEC. These cases reflect a presumption that the changes in UNFFR operations are sufficiently *de minimis* so as not to induce additional resource acquisitions. In other words, only existing resources would be needed to accommodate these changes. Those cases reflect three bounding outcomes:

- **Case 1B** reflects "business as usual" (BAU) with significant reliance on fossil fuel and achieving the current 20 percent renewable portfolio standard (RPS).

- A second scenario uses the **Case 1B** resource plan but includes a carbon fee or allowance price set at **\$100 per tonne of carbon dioxide (CO_2)** emitted to reflect a potential outcome of meeting Assembly Bill 32 goals or a national cap and trade program. This fee or price would be levied on the carbon content of the fuel, with coal having a much larger carbon "footprint" than natural gas. Currently, natural gas is the last fuel used in the least-cost order of generation sources—it is the power source that is increased or decreased as loads increase or decrease, or correspondingly, other resources are reduced or added. At a carbon fee of \$100, coal becomes more expensive than natural gas, and coal-fired units instead become the swing generation resources. As a result, the emission impacts from changes in hydropower operations increase in this scenario because emissions per incremental MWH are higher.

- **Case 4** reflects the highest investment in renewables, achieving a 33 percent RPS by 2020.

The incremental generation for each hour of the forecast year (2020 in this case) is associated with a specific coal- or natural gas-fueled plant in MarketAnalytics. We used results reported for transmission area 15 in MarketAnalytics, where the UNFFR is located, to reflect any regional transmission congestion. **Table 10** shows the incremental emission rates for each fuel type. Hourly marginal incremental heat rates were multiplied by the corresponding facility type incremental emissions rates. Incremental CO_2 rates were aggregated and averaged for a 24 hour period by day type and month.

Table 10

Incremental CO_2 Emissions for Coal and Natural Gas

FACILITY TYPE	INCREMENTAL EMISSIONS (METRIC TONNES / MMBTU)
Natural Gas	0.0531
Coal	0.0965

Source: EIA - http://www.eia.doe.gov/oiaf/1605/coefficients.html

In addition, two other scenarios that reflect policy-based planning mandates are included. For these latter two, the assumption is that over the long-run, PG&E would plan on replacing the hydropower with a mix of new generating resources rather than responding in the short-term with operational changes in existing resources. For these two, the existing 20% renewable portfolio standard (RPS) and proposed 33% renewable energy standard (RES) effectively mandate that most (20%) or all (33%) new resources be zero-emitting renewables except when a new CT is required to provide peak capacity and ancillary services. In these cases, the CTs are assumed to run at a 5% capacity factor based on analysis of historic and projected operating conditions by the CEC with an average heat rate of 9,266 Btu/kWh or a CO_2 emission rate of 0.492 tonnes per MWH (CEC 2010). This amounts to an average operation of 6.87 hours per weekday for the June 16 to September 15 period.

Combining Hourly Operation Changes with Hourly Emission Factors

Incremental CO_2 rates for each case were multiplied by the hourly MWh scenario changes from part 1. Total emission changes were aggregated for all powerhouses, and broken down by month (June to September), hourly operation Alternatives and by emission cases, and for years 2002 to 2004. CO_2 rates for each year were combined and weighted by the occurrence of each water year type, represented by 2002, 2003 and 2004. Water year types for 1901-2009 were obtained from DWR, and aggregated to the categories below, each occurring in 2002-2004 (CDWR 2010). Weights were assigned to each year's incremental CO_2 rates based on the fraction of occurrences of those year types in the past (1901-2009) as shown in **Table 11**.

Table 11

Water Year Type Weight Factors for Representative Annual Impacts

DATA YEAR	WATER YEAR TYPE	WEIGHT % (1901-2009)
2002	Dry (dry)	33%
2003	AN (above normal)	16.5%
2004	BN (below normal)	50.5%

Based on the hourly operational changes multiplied by the hourly incremental emission rates, weighted by water year type, a range of forecasted average monthly and annual changes in GHG emissions are shown in Tables 12 to 16. These show the results of the analysis for five scenarios across PG&E proposed Settlement Agreement and the six Alternatives compared to the baseline conditions.

Table 12

Case 1B – CEC Scenario Analysis Business As Usual

PG&E PROPOSED SETTLEMENT AGREEMENT	3	3X	4A	4B	4C	4D
JUNE INCREMENTAL CO_2 (MT)						
97.3	229.9	547.5	97.3	75.3	547.5	497.7
JULY INCREMENTAL CO_2 (MT)						
72.6	314.7	667.3	72.6	73.7	667.3	797.9
AUGUST INCREMENTAL CO_2 (MT)						
60.8	279.0	745.1	60.8	165.0	745.1	786.3
SEPTEMBER INCREMENTAL CO_2 (MT)						
30.5	296.8	867.1	30.5	199.1	867.1	817.6
ANNUAL INCREMENTAL CO_2 (MT)						
261.1	1120.4	2827.1	261.1	513.1	2827.1	2899.5

Table 13

Case 1B_$100/Ton CO_2 - CEC Scenario Analysis BAU with CO_2 Allowance Price at $100 per Ton

PG&E PROPOSED SETTLEMENT AGREEMENT	3	3X	4A	4B	4C	4D
JUNE INCREMENTAL CO_2 (MT)						
108.9	260.0	672.0	108.9	147.7	672.0	631.4
JULY INCREMENTAL CO_2 (MT)						
75.4	317.9	726.9	75.4	133.5	726.9	801.0
AUGUST INCREMENTAL CO_2 (MT)						
63.7	292.9	814.5	63.7	186.5	814.5	790.3
SEPTEMBER INCREMENTAL CO_2 (MT)						
32.5	294.5	854.4	32.5	195.7	854.4	811.3
ANNUAL INCREMENTAL CO_2 (MT)						
280.4	1165.3	3067.8	280.4	663.4	3067.8	3034.0

Table 14

Case 4A – CEC Scenarios Analysis 33% RPS

PG&E PROPOSED SETTLEMENT AGREEMENT	3	3X	4A	4B	4C	4D
JUNE INCREMENTAL CO_2 (MT)						
125.9	305.1	758.2	125.9	135.5	758.2	702.9
JULY INCREMENTAL CO_2 (MT)						
88.1	393.3	870.5	88.1	151.3	870.5	1006.2
AUGUST INCREMENTAL CO_2 (MT)						
78.4	370.4	987.3	78.4	230.4	987.3	1018.9
SEPTEMBER INCREMENTAL CO_2 (MT)						
39.2	385.5	1120.3	39.2	259.3	1120.3	1055.7
ANNUAL INCREMENTAL CO_2 (MT)						
331.6	1454.3	3736.3	331.6	776.6	3736.3	3783.8

Table 15

Case Legislatively Mandate 20% RPS

PG&E PROPOSED SETTLEMENT AGREEMENT	3	3X	4A	4B	4C	4D
JUNE INCREMENTAL CO_2 (MT)						
25.7	57.6	271.2	25.7	68.7	271.2	241.2
JULY INCREMENTAL CO_2 (MT)						
18.2	70.7	274.6	18.2	80.5	274.6	320.9
AUGUST INCREMENTAL CO_2 (MT)						
15.8	68.4	339.3	15.8	116.2	339.3	282.7
SEPTEMBER INCREMENTAL CO_2 (MT)						
8.0	68.7	336.0	8.0	111.8	336.0	222.4
ANNUAL INCREMENTAL CO_2 (MT)						
67.8	265.4	1221.1	67.8	377.3	1221.1	1067.1

Table 16
Case Legislatively/Regulatorily Mandated 33% RPS/RES

PG&E PROPOSED SETTLEMENT AGREEMENT	3	3X	4A	4B	4C	4D
JUNE INCREMENTAL CO_2 (MT)						
0.0	0.0	181.8	0.0	65.1	181.8	154.5
JULY INCREMENTAL CO_2 (MT)						
0.0	0.0	160.9	0.0	91.8	160.9	196.1
AUGUST INCREMENTAL CO_2 (MT)						
0.0	0.0	229.1	0.0	118.6	229.1	138.9
SEPTEMBER INCREMENTAL CO_2 (MT)						
0.0	0.0	192.2	0.0	102.7	192.2	184.3
ANNUAL INCREMENTAL CO_2 (MT)						
0.0	0.0	764.0	0.0	378.3	764.0	673.8

Findings

The proposed operational changes fall into three general categories:

- ramping limitations,
- increased turbine bypass flows and
- preferential powerhouse operations.

Examining each of these in turn based on the analysis presented here:

- The peak period generation is likely to be affected by reducing the number of hours that the powerhouses can operate at maximum load because this operational approach preserves the most amount of energy for the use during the most valuable time periods.

- The ramping limitation occurs only at Canyon Dam and is non-binding on the hourly operations of the individual powerhouses. This avoids a key constraint on ancillary services provision by preserving flexibility for instantaneous responses to system demands and emergencies.

- The increased turbine bypass flows at Canyon Dam reduces the amount of energy available to produce power. So long as the remaining water can be stored and released at the most valuable time, the ability to provide ancillary services is not impacted. A/S provision requires little additional energy as it is the *option* to generate, not actual power production that is the embodied value. However, diverting 600 cfs in *Alternative 4d* does reduce the available storable or "pondage" water so as to impair the ability of the powerhouses to provide ancillary services. This means that the 247 MW of controllable project capacity would have to be replaced with alternative generation. Given the load-following and reserve characteristics of Caribou #1 and #2, this would almost certainly have to be a CT. Based on the cost of constructing CTs derived by the CEC from a survey of California power plants supplemented by estimates from other agencies, building a new replacement plants would cost $208 to $369 million (CEC 2010). Energy production could be replaced with the system incremental resources available from existing resources on the power grid.

- The preferred powerhouse operations shifts generation from the more efficient Caribou #2 to the less efficient Caribou #1 powerhouse in *Alternatives 3x, 4b and 4c*. The proposed shift completely diverts all water flows from Caribou #2 removing from both the ability to serve on-peak energy loads and to provide ancillary services. Given the load-following and reserve characteristics of Caribou #2, the replacement would almost certainly have to be a 120 MW CT. Installation costs would be $101 to $179 million (CEC 2010). Energy production could be replaced with the system incremental resources currently available from the grid.

The largest expected change is 3,783 metric tonnes of CO_2e per year for Alternative 4D under Case 4A. This change is 3,452 tonnes per year higher than the proposed conditions (Table 13). All of the other alternatives under the five scenarios show increases less than this amount. For each alternative and scenario shown, the increases in GHG emissions are less than the ARB's proposed interim threshold of 7,000 tonnes per year.

Table 17 summarizes the results for the alternative measures of interest, across a range of future scenarios. The change associated with PG&E's proposed Settlement Agreement will increase GHG emissions by an average of 0 to 332 tonnes per year. Adding only thermal curtains will not change the operations, and thus, the emissions also will remain unchanged from the Settlement Agreement proposed flow conditions. Adding a bypass requirement at Canyon Dam of 250 CFS increases the upper end of the range of potential average emission increases so that it extends from 0 to 1,454 tonnes.

Table 17
Annual Change in GHG Emissions in 2020 (Tonnes CO_2e)

	CEC SCENARIO 1B	CEC SCENARIO 1B @ $100/$CO_2e$ T	CEC SCENARIO 4	20% RPS	33% RPS
Baseline conditions	0	0	0	0	0
PG&E proposed Settlement Agreement Conditions	261	280	332	68	0
Prattville & Caribou Thermal Curtains	261	280	332	68	0
Thermal Curtains & 250 CFS @ Canyon Dam	1,120	1,165	1,454	265	0

Although a chosen Alternative may increase the range of potential average emissions, the ARB is proposing to achieve state-wide emission reductions through a cap-and-trade program that encompasses the electricity and large industrial stationary sources sectors. If adopted in its current form, the cap-and-trade program would require the offset of increases in emissions through compensating reductions from other sources. PG&E would be left with the discretion as to where to find these reductions, including acquiring allowances from other program participants. In this situation, the cap-and-trade program might mitigate any potential increases in GHG emissions created by a chosen Alternative.

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Attachment A

Analysis Results for the Additional Work
Requested by the State Water Board and NSR

Stetson Engineers Inc.
December 10, 2009

1. Investigate whether there would be any change in power capacity or ramping rates under each alternative scenario

The Partial Settlement has the following ramping rate requirements:

- Canyon Dam: 0.5 ft/hr up and down, in all months, as measured at NF-2; and
- Belden Dam: 0.5 ft/hr up and down, in all months, as measured at NF-70.

Of the Level 3 water temperature reduction alternatives, only the increased Canyon Dam release measure would need to be verified as to whether it can meet the requirement of the ramping rate for the Canyon Dam discharge. Alternatives 4a and 4b would not be applicable under the Canyon Dam ramping rate requirement because these two alternatives do not have the increased Canyon Dam release measure. In addition, the Level 3 water temperature reduction alternatives would not be applicable under the Belden Dam ramping rate requirement because these alternatives have no effect on Belden Dam releases.

Figure 1 shows the estimated stage vs. discharge rating curve of Seneca Reach below Canyon Dam (NF2). The rating curve was estimated using the Manning's Equation and the data/assumptions shown on Figure 1. Table 1 shows the estimated operational time needed to adjust to the next month's required dam release in compliance with the Canyon Dam ramping rate requirement. The analysis results show that Alternatives 3x, 4c, and 4d have the greatest flow changes from June to July and from August to September. These three alternatives require about 2.4 hours of operational time to adjust from the June to July release and 2.9 hours of operational time to adjust from the August to September release.

The Butt Valley, Caribou #1, and Caribou #2 powerhouses have reported capacities of 2,118 cfs, 1,114 cfs, and 1,464 cfs, respectively (FERC, 2005). The historical monthly discharge data shown in Figures 2 through 5 and the selected historical hourly discharge data shown in Figures 6 through 8 confirmed these capacity values. Alternatives 4a and 4b would not have any change in powerhouse operations and capacity. Increasing Canyon Dam releases under Alternatives 3, 3x, 4c, and 4d would require commensurately reducing the volume of discharges at the Butt Valley, Caribou #1, and Caribou #2 powerhouses in order to maintain water levels in Lake Almanor and Butt Valley Reservoir as agreed to in the Partial Settlement. These powerhouses have historically normally been operated in peaking mode (see Figures 6 though 8) and are expected to be operated in this same mode during the term of the next license. Note that the hourly operations data shown in Figures 6 through 8 indicate that the operations of these powerhouses were not in strict peaking mode. Depending on water availability and energy demand, the powerhouses sometimes were operated in relatively strict peaking mode (see Figures 6a, 6b, 7a, 7b, 7c, 8a, and 8b), sometimes were operated continuously (see Figure 6c), and sometimes were operated in peaking mode but with a base load component (see Figure 8c). The historical hourly operations data shown in Figures 6 through 8 also indicate that most of time the powerhouses were not operated at their full power capacities. The flexibility of historical operations suggests that there will be two general operating options for Alternatives 3, 3x, 4c, and 4d: (i) shorten the duration of peak operations to maintain the baseline hourly discharge rate or power capacity, and (ii) reduce the hourly discharge rate to maintain the duration of the baseline operations, which could result in a reduction in power capacity. Either way, the change in hourly operations can be estimated using a percentage of reduced discharge (due to increased Canyon Dam release under each alternative) relative to the baseline discharge. More detailed analysis about the change in hourly operations will be discussed in Section 3.

Table 1 Summary of Operations to Comply with the Canyon Dam Ramping Rate Requirement

	Alternative	**Jun**	**Jul**	**Aug**	**Sep**
Proposed Canyon Dam Release in a Normal Water Year (cfs)	Baseline	35	35	35	35
	"Present Day"	125	90	80	60
	Alternative 3	125	250	250	60
	Alternative 3x	125	600	600	60
	Alternative 4a	125	90	80	60
	Alternative 4b	125	90	80	60
	Alternative 4c	125	600	600	60
	Alternative 4d	125	600	600	60
Estimated Water Depth (ft) below Canyon Dam at the Proposed Dam Release (ft)	Baseline	0.26	0.26	0.26	0.26
	"Present Day"	0.60	0.48	0.44	0.36
	Alternative 3	0.60	1.01	1.01	0.36
	Alternative 3x	0.60	1.81	1.81	0.36
	Alternative 4a	0.60	0.48	0.44	0.36
	Alternative 4b	0.60	0.48	0.44	0.36
	Alternative 4c	0.60	1.81	1.81	0.36
	Alternative 4d	0.60	1.81	1.81	0.36
Estimated Operational Time Needed to Adjust to the Next Month's Release in Compliance with the Canyon Dam Ramping Rate Requirement (hours)	Baseline		0	0	0
	"Present Day"		0.3	0.1	0.2
	Alternative 3		0.8	0	1.3
	Alternative 3x		2.4	0	2.9
	Alternative 4a		0.3	0.1	0.2
	Alternative 4b		0.3	0.1	0.2
	Alternative 4c		2.4	0	2.9
	Alternative 4d		2.4	0	2.9

2. **Develop and add the June 15th to September 15th energy loss calculation to our existing assumptions for July & August, add calculation of total energy generation for the UNFFR Project under the baseline condition and compute the percentage of energy loss for each alternative**

Of the Level 3 water temperature reduction alternatives, Alternatives 3, 3x, 4c, and 4d have the increased Canyon Dam release measure which would be operated in July and August. Increasing Canyon Dam releases under these alternatives would require commensurately reducing the volume of discharges at the Butt Valley, Caribou #1, and Caribou #2 powerhouses in order to maintain water levels in Lake Almanor and Butt Valley Reservoir as agreed to in the Partial Settlement and, thereby, result in foregone energy generation loss at these powerhouses. The Level 3 Report estimated the foregone energy generation loss for July and August for each alternative. The foregone energy generation loss was estimated based on the potential commensurate flow reduction and/or turbine efficiency reduction in each respective powerhouse resulting from a particular measure, static head of the powerhouse, and normal operating efficiency of the powerhouse turbines. Table 2 lists static heads and turbine efficiencies that were used in the foregone energy generation loss estimates.

Table 2 Powerhouse Static Head and Turbine Efficiencies Used in Foregone Energy Generation Loss Estimates

Powerhouse	Static Head (ft)	Turbine Efficiency
Butt Valley PH	362	80.6%
Caribou #1 PH	1,151	69.1%
Caribou #2 PH	1,150	84.2%
Oak Flat PH	137	80.1%
Belden PH	770	79.6%
Rock Creek PH	535	85.9%
Cresta PH	290	80.1%
Poe PH	488	78.6%
Bucks Creek PH	2,558	78.1%

The Level 3 water temperature reduction alternatives focused on water temperature reduction in July and August and did not extend the increased Canyon Dam release measure to June and September. Since the water temperature reduction measure may need to be operated in June and September of some years, particularly in late June and early September, the foregone energy generation loss was computed for the extended periods of June 15-30 and September 1-15 using the same approach that was used in estimating the foregone energy generation loss for July and August. Table 3 summarizes the estimated foregone energy generation loss, by period and total, for each alternative.

In order to estimate the average annual total energy generation for the UNFFR Project under the baseline condition and to compute the percentage of energy loss for each alternative, an analysis of the available historical monthly discharge data of the powerhouses for the 33 years (1970 – 2002) was conducted. Table 4 summarizes the historical monthly average discharge data and the average annual total energy generation estimate for the UNFFR Project under the baseline condition. Table 5 summarizes the estimated percentage of energy loss for each alternative.

Table 3 Estimated Foregone Energy Generation Loss for the Period of June 16th to September 15th

		Foregone Energy Generation Loss by Period (KWh $\times 10^6$)			Total Annual Energy Loss (KWh $\times 10^6$/year)
Alternative	**Measures**	**Jun 15-30**	**Jul and Aug**	**Sep 1-15**	
Baseline	None				-
"Present Day"	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to Those Given in the Partial Settlement				47.94 [1]
Alternative 3	Install Prattville Intake Thermal Curtain and Remove Submerged Levees				0.00
	Install Caribou Intake Thermal Curtain				0.00
	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 250 cfs	4.58	26.39	6.96	37.93 [2]
					47.94 [1]
	Total				**85.87**
Alternative 3x	Install Prattville Intake Thermal Curtain and Remove Submerged Levees				0.00
	Operate Caribou #1 PH Preferentially	1.18	11.32	2.73	15.23 [3]
	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 600 cfs	17.41	79.17	19.79	116.37 [2]
					47.94 [1]
	Total				**179.54**
Alternative 4a	Install Prattville Intake Thermal Curtain				0.00
	Install Caribou Intake Thermal Curtain				0.00
					47.94 [1]
	Total				**47.94**
Alternative 4b	Install Prattville Intake Thermal Curtain				0.00
	Operate Caribou #1 PH Preferentially	2.86	13.91	4.55	21.32 [3]
					47.94 [1]
	Total				**69.26**
Alternative 4c	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 600 cfs	17.41	79.17	19.79	116.37 [2]
	Operate Caribou #1 PH Preferentially	1.18	11.32	2.73	15.23 [3]
					47.94 [1]
	Total				**179.54**
Alternative 4d	Modify Canyon Dam Low-Level Outlet to Increase Canyon Dam Release to 600 cfs	17.41	79.17	19.79	116.37 [2]
	Install Caribou Intake Thermal Curtain				0.00
					47.94 [1]
	Total				**164.31**

1) Foregone energy generation loss is due to increased Canyon Dam releases to those given in the Partial Settlement and commensurate flow reductions through the Butt Valley, Caribou #1, and Caribou #2 PHs.
2) Additional foregone energy generation loss is due to the increased Canyon Dam release in the summertime under the alternative and commensurate flow reductions through the Butt Valley, Caribou #1, and Caribou #2 PHs.
3) Additional foregone energy generation loss is due to the lower turbine efficiency of Caribou #1 PH relative to Caribou #2 PH (by about 15%).

Table 4 Average Annual Total Energy Generation Estimate for the UNFFR Project under the Baseline Condition

Month	Historical Monthly Average Discharge (cfs)					Energy Generation (Kwh × 10^6)					
	Butt Valley PH	Caribou #1 PH	Caribou #2 PH	Belden PH	Oak Flat PH	Butt Valley PH	Caribou #1 PH	Caribou #2 PH	Belden PH	Oak Flat PH	Total
Jan	690	243	570	847	60	12.67	12.16	34.74	32.67	0.41	92.66
Feb	597	249	506	856	60	9.90	11.26	27.85	29.83	0.37	79.21
Mar	400	218	387	695	60	7.35	10.91	23.58	26.81	0.41	69.07
Apr	454	244	402	640	60	8.07	11.82	23.71	23.89	0.40	67.89
May	420	198	382	544	140	7.71	9.91	23.28	20.99	0.97	62.86
Jun	674	262	543	797	140	11.98	12.69	32.02	29.75	0.94	87.38
Jul	1,073	352	748	1,067	140	19.70	17.62	45.58	41.16	0.97	125.04
Aug	1,290	459	861	1,288	140	23.69	22.98	52.47	49.69	0.97	149.79
Sep	1,241	417	864	1,250	140	22.05	20.20	50.96	46.66	0.94	140.81
Oct	1,096	336	828	1,137	60	20.13	16.82	50.46	43.86	0.41	131.68
Nov	1,082	370	815	1,172	60	19.23	17.92	48.07	43.75	0.40	129.37
Dec	1,033	331	796	1,122	60	18.97	16.57	48.51	43.28	0.41	127.74
Annual	**837**	**306**	**642**	**951**	**93**	**181.45**	**180.86**	**461.23**	**432.34**	**7.61**	**1,263.49**

Table 5 Baseline Average Annual Total Energy Generation and Annual Energy Reduction by Alternative

	Alternative	Energy Reduction (Kwh × 10^6)	Percent in Energy Reduction
Baseline Annual Total Energy Generation		1,263.49	
Energy Reduction by Alternative	Present Day	47.94	3.79%
	Alternative 3	85.87	6.80%
	Alternative 3x	179.54	14.21%
	Alternative 4a	47.94	3.79%
	Alternative 4b	69.26	5.48%
	Alternative 4c	179.54	14.21%
	Alternative 4d	164.31	13.00%

3. Calculate the change in hourly operations for the separate alternatives

The Butt Valley, Caribou #1, and Caribou #2 powerhouses have reported capacities of 2,118 cfs, 1,114 cfs, and 1,464 cfs, respectively. Increasing Canyon Dam releases under Alternatives 3, 3x, 4c, and 4d would require commensurately reducing the volume of discharges at the Butt Valley, Caribou #1, and Caribou #2 powerhouses in order to maintain water levels in Lake Almanor and Butt Valley Reservoir as agreed to in the Partial Settlement. As discussed in Section 1, there will be two general operating options for Alternatives 3, 3x, 4c, and 4d: (i) shorten the duration of peak operations to maintain the baseline hourly discharge rate or power capacity, and (ii) reduce the hourly discharge rate to maintain the duration of the baseline operations, which could result in a reduction in power capacity. Either way, the change in hourly operations can be estimated using a percentage of reduced discharge (due to increased Canyon Dam release under each alternative) relative to the baseline discharge.

Table 6 summarizes the historical monthly discharges and monthly discharge statistics for the Butt Valley, Caribou #1, and Caribou #2 powerhouses during the summertime. Tables 7 to 9 summarize the estimated percentage of reduced powerhouse discharge for each alternative relative to the baseline average monthly discharge for June, July, August, and September for the Butt Valley, Caribou #1, and Caribou #2 powerhouses, respectively. Tables 10 to 12 summarize the estimated percentage of reduced powerhouse discharge for each alternative relative to the powerhouse capacity for the Butt Valley, Caribou #1, and Caribou #2 powerhouses, respectively. Given an increase in the Canyon Dam release for an alternative, the change in the Butt Valley PH discharge would be the commensurate reduction. The total change in the Caribou #1 and Caribou #2 discharges would also be the commensurate reduction. The individual change in the Caribou #1 or Caribou #2 discharge was assumed to be proportionate to their original discharges. For the alternatives that have the measure of preferential use of Caribou #1 over Caribou #2 (i.e., Alternatives 3x, 4b, and 4c), the change in the Caribou #1 discharge could be an increase, but the re-operated discharge at the Caribou #1 PH should not exceed its capacity of 1,114 cfs.

Table 6 Monthly Discharge Statistics of Butt Valley, Caribou #1, and Caribou #2 Powerhouses

Year	Butt Valley PH				Caribou #1 PH				Caribou #2 PH			
	Jun	Jul	Aug	Sep	Jun	Jul	Aug	Sep	Jun	Jul	Aug	Sep
1970 (W)	162	1,101	1,870	1,704	17	181	544	702	204	928	1,395	1,233
1971 (W)	438	1,583	2,035	1,832	89	524	870	638	506	1,050	1,354	1,080
1972 (D)	225	911	1,380	862	27	227	292	243	207	715	1,143	793
1973 (N)	68	803	1,081	867	16	225	388	260	160	546	725	598
1974 (W)	1,761	1,815	1,872	1,376	696	687	766	522	1,197	1,143	1,239	929
1975 (N)	1,314	1,370	1,767	1,093	591	534	703	378	942	866	985	842
1976 (CD)	358	233	264	1,000	94	42	63	270	302	258	255	710
1977 (CD)	200	404	1,135	1,315	47	90	432	369	193	344	809	816
1978 (W)	2	160	1,681	1,430	4	18	576	408	138	194	1,112	1,058
1979 (D)	484	1,256	1,117	712	117	383	293	181	413	864	869	575
1980 (N)	6	845	778	714	0	170	114	102	122	712	669	663
1981 (CD)	1,240	760	840	1,200	242	111	147	238	924	647	701	987
1982 (W)	1,322	1,810	2,110	1,851	359	636	854	609	965	1,191	1,260	1,220
1983 (W)	1,191	1,599	2,140	1,834	440	468	890	1,052	997	1,135	1,256	768
1984 (W)	992	1,102	1,314	1,358	719	428	558	541	1,390	927	890	872
1985 (D)	747	1,474	693	653	85	314	105	13	690	1,210	601	690
1986 (W)	1,637	1,633	1,519	1,831	442	520	431	712	1,229	1,102	1,093	1,394
1987 (CD)	0	80	35	938	81	0	87	137	81	96	87	819
1988 (CD)	5	561	670	1,082	5	66	71	173	161	483	600	892
1989 (N)	788	1,055	1,218	710	54	1	113	123	746	1,077	1,203	607
1990 (CD)	134	670	989	1,109	11	96	167	145	197	579	814	958
1991 (CD)	166	969	977	1,400	2	199	198	489	122	764	794	1,172
1992 (CD)	186	516	1,047	1,262	9	54	226	332	180	537	760	971
1993 (W)	763	1,723	1,678	1,501	240	571	484	418	588	1,145	1,276	1,183
1994 (CD)	182	674	807	1,076	23	3	157	161	181	687	648	945
1995 (W)	2,110	1,690	2,040	1,795	929	576	691	584	1,361	1,114	1,326	1,254
1996 (W)	273	1,017	1,025	1,040	1,100	1,140	1,125	1,136	0	0	0	0
1997 (W)	906	987	1,021	1,196	1,014	1,082	1,109	1,007	0	0	0	0
1998 (W)	1,728	1,534	1,973	1,885	535	518	690	710	1,373	1,132	1,208	1,160
1999 (N)	791	1,451	1,831	793	165	488	574	5	689	1,014	1,132	837
2000 (N)	1,141	1,774	1,643	1,533	272	619	628	483	866	1,200	1,017	1,077
2001 (CD)	768	1,082	1,018	600	194	345	274	130	543	679	695	505
2002 (D)	138	780	990	1,407	21	285	517	497	245	332	484	910
Maximum	2,110	1,815	2,140	1,885	1,100	1,140	1,125	1,136	1,390	1,210	1,395	1,394
10% Exceedence	1,574	1,716	2,022	1,832	715	633	866	711	1,223	1,145	1,273	1,213
25% Exceedence	1,141	1,534	1,767	1,501	440	524	690	584	924	1,102	1,203	1,077
50% Exceedence	484	1,055	1,135	1,200	94	314	432	378	413	764	869	892
75% Exceedence	166	760	989	938	21	96	167	173	180	537	669	710
90% Exceedence	18	427	710	712	6	23	107	125	122	207	300	579
Minimum	0	80	35	600	0	0	63	5	0	0	0	0
Average	**674**	**1,073**	**1,290**	**1,241**	**262**	**352**	**459**	**417**	**543**	**748**	**861**	**864**

Table 7 Change in Discharge of Butt Valley PH Relative to Baseline Condition for Different Alternatives

	Alternative	Change in Discharge (cfs) Jun	Jul	Aug	Sep	Percent Change Jun	Jul	Aug	Sep
Baseline Average Discharge (cfs)		674	1,073	1,290	1,241				
Change in Discharge by Alternative (cfs)	"Present Day"	-90	-55	-45	-25	-13.4%	-5.1%	-3.5%	-2.0%
	Alternative 3	-215	-215	-215	-215	-31.9%	-20.0%	-16.7%	-17.3%
	Alternative 3x	-565	-565	-565	-565	-83.8%	-52.7%	-43.8%	-45.5%
	Alternative 4a	-90	-55	-45	-25	-13.4%	-5.1%	-3.5%	-2.0%
	Alternative 4b	-90	-55	-45	-25	-13.4%	-5.1%	-3.5%	-2.0%
	Alternative 4c	-565	-565	-565	-565	-83.8%	-52.7%	-43.8%	-45.5%
	Alternative 4d	-565	-565	-565	-565	-83.8%	-52.7%	-43.8%	-45.5%

Table 8 Change in Discharge of Caribou #1 PH Relative to Baseline Condition for Different Alternatives

	Alternative	Change in Discharge (cfs) Jun	Jul	Aug	Sep	Percent Change Jun	Jul	Aug	Sep
Baseline Average Discharge (cfs)		262	352	459	417				
Change in Discharge by Alternative (cfs)	"Present Day"	-29	-18	-16	-8	-11.2%	-5.1%	-3.5%	-2.0%
	Alternative 3	-70	-69	-75	-70	-26.7%	-19.6%	-16.3%	-16.8%
	Alternative 3x	-22	+183	+296	+299	-8.4%	+52.0%	+64.5%	+71.7%
	Alternative 4a	-29	-18	-16	-8	-11.2%	-5.1%	-3.5%	-2.0%
	Alternative 4b	+453	+693	+655	+697	+172.9%	+196.9%	+142.7%	+167.1%
	Alternative 4c	-22	+183	+296	+299	-8.4%	+52.0%	+64.5%	+71.7%
	Alternative 4d	-184	-181	-196	-184	-70.2%	-51.4%	-42.7%	-44.1%

Note: The symbol "+" indicates an increase in discharge which results from preferential use of Caribou #1 over Caribou #2. The total discharge of Caribou #1 should not exceed its capacity of 1,114 cfs.

Table 9 Change in Discharge of Caribou #2 PH Relative to Baseline Condition for Different Alternatives

	Alternative	Change in Discharge (cfs) Jun	Jul	Aug	Sep	Percent Change Jun	Jul	Aug	Sep
Baseline Average Discharge (cfs)		543	748	861	864				
Change in Discharge by Alternative (cfs)	"Present Day"	-61	-37	-29	-17	-11.2%	-4.9%	-3.4%	-2.0%
	Alternative 3	-145	-146	-140	-145	-26.7%	-19.5%	-16.3%	-16.8%
	Alternative 3x	-543	-748	-861	-864	-100.0%	-100.0%	-100.0%	-100.0%
	Alternative 4a	-61	-37	-29	-17	-11.2%	-4.9%	-3.4%	-2.0%
	Alternative 4b	-543	-748	-700	-722	-100.0%	-100.0%	-81.3%	-83.6%
	Alternative 4c	-543	-748	-861	-864	-100.0%	-100.0%	-100.0%	-100.0%
	Alternative 4d	-381	-384	-369	-381	-70.2%	-51.3%	-42.9%	-44.1%

Table 10 Change in Discharge of Butt Valley PH Relative to PH Capacity for Different Alternatives

	Alternative	Change in Discharge (cfs) Jun	Jul	Aug	Sep	Percent Change Jun	Jul	Aug	Sep
PH Capacity (cfs)		2,118	2,118	2,118	2,118				
Change in Discharge by Alternative (cfs)	"Present Day"	-90	-55	-45	-25	-4.2%	-2.6%	-2.1%	-1.2%
	Alternative 3	-215	-215	-215	-215	-10.2%	-10.2%	-10.2%	-10.2%
	Alternative 3x	-565	-565	-565	-565	-26.7%	-26.7%	-26.7%	-26.7%
	Alternative 4a	-90	-55	-45	-25	-4.2%	-2.6%	-2.1%	-1.2%
	Alternative 4b	-90	-55	-45	-25	-4.2%	-2.6%	-2.1%	-1.2%
	Alternative 4c	-565	-565	-565	-565	-26.7%	-26.7%	-26.7%	-26.7%
	Alternative 4d	-565	-565	-565	-565	-26.7%	-26.7%	-26.7%	-26.7%

Table 11 Change in Discharge of Caribou #1 PH Relative to PH Capacity for Different Alternatives

	Alternative	Change in Discharge (cfs) Jun	Jul	Aug	Sep	Percent Change Jun	Jul	Aug	Sep
PH Capacity (cfs)		1,114	1,114	1,114	1,114				
Change in Discharge by Alternative (cfs)	"Present Day"	-39	-24	-19	-11	-3.5%	-2.2%	-1.7%	-1.0%
	Alternative 3	-93	-93	-93	-93	-8.3%	-8.3%	-8.3%	-8.3%
	Alternative 3x	0	0	0	0	0.0%	0.0%	0.0%	0.0%
	Alternative 4a	-39	-24	-19	-11	-3.5%	-2.2%	-1.7%	-1.0%
	Alternative 4b	0	0	0	0	0.0%	0.0%	0.0%	0.0%
	Alternative 4c	0	0	0	0	0.0%	0.0%	0.0%	0.0%
	Alternative 4d	-244	-244	-244	-244	-21.9%	-21.9%	-21.9%	-21.9%

Table 12 Change in Discharge of Caribou #2 PH Relative to PH Capacity for Different Alternatives

	Alternative	Change in Discharge (cfs) Jun	Jul	Aug	Sep	Percent Change Jun	Jul	Aug	Sep
PH Capacity (cfs)		1,464	1,464	1,464	1,464				
Change in Discharge by Alternative (cfs)	"Present Day"	-51	-31	-26	-14	-3.5%	-2.1%	-1.8%	-1.0%
	Alternative 3	-122	-122	-122	-122	-8.3%	-8.3%	-8.3%	-8.3%
	Alternative 3x	-565	-565	-565	-565	-38.6%	-38.6%	-38.6%	-38.6%
	Alternative 4a	-51	-31	-26	-14	-3.5%	-2.1%	-1.8%	-1.0%
	Alternative 4b	-90	-55	-45	-25	-6.1%	-3.8%	-3.1%	-1.7%
	Alternative 4c	-565	-565	-565	-565	-38.6%	-38.6%	-38.6%	-38.6%
	Alternative 4d	-321	-321	-321	-321	-21.9%	-21.9%	-21.9%	-21.9%

Figure 1 Stage vs. Discharge Rating Curve of Seneca Reach below Canyon Dam (NF2)

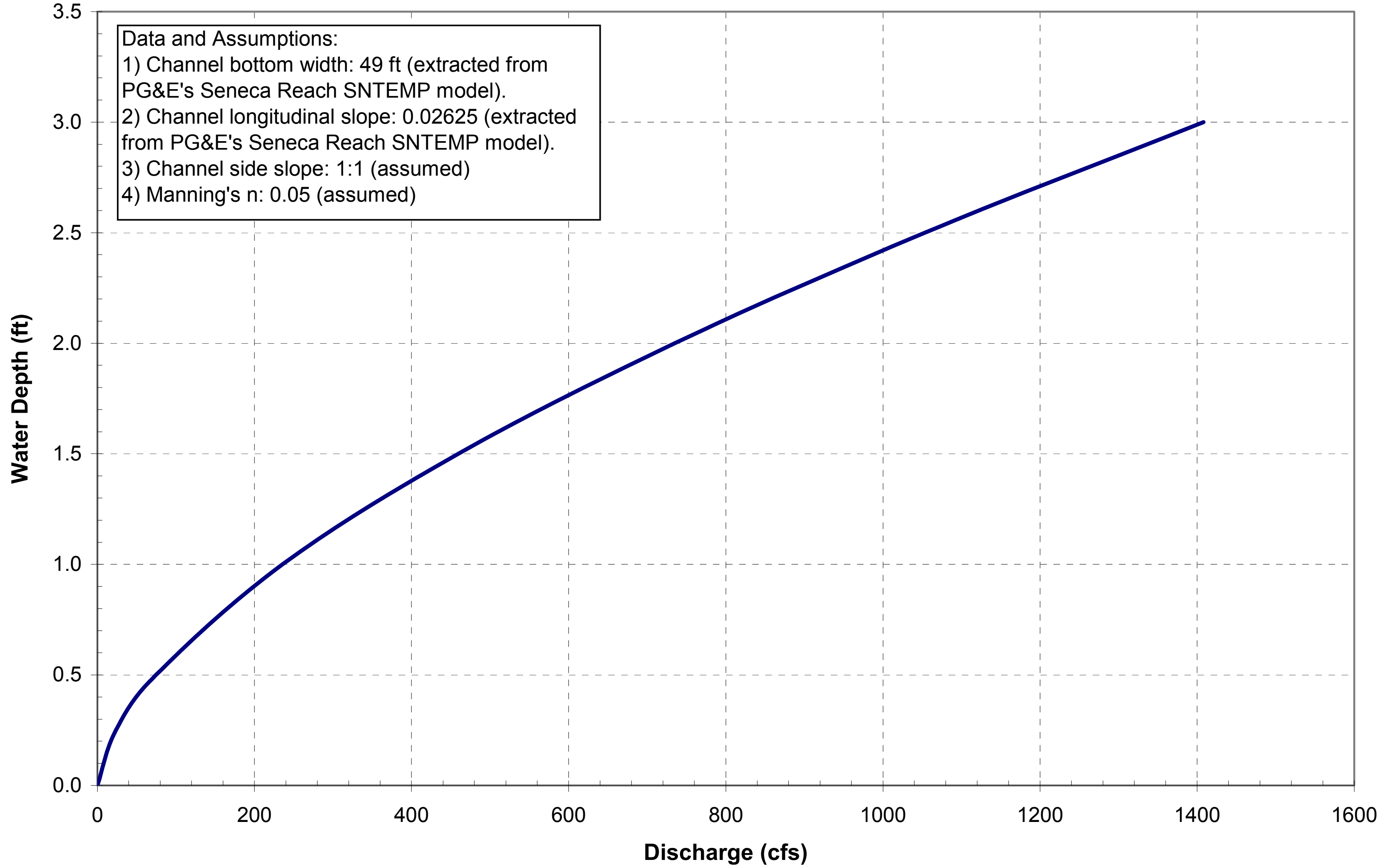


Figure 2 Historical Monthly Discharges of Butt Valley, Caribou #1, and Caribou #2 Powerhouses (1970 - 2002)
(Turbine Capacity: Butt Valley PH = 2,118 cfs, Caribou #1 PH = 1,114 cfs, Caribou #2 PH = 1,464 cfs)

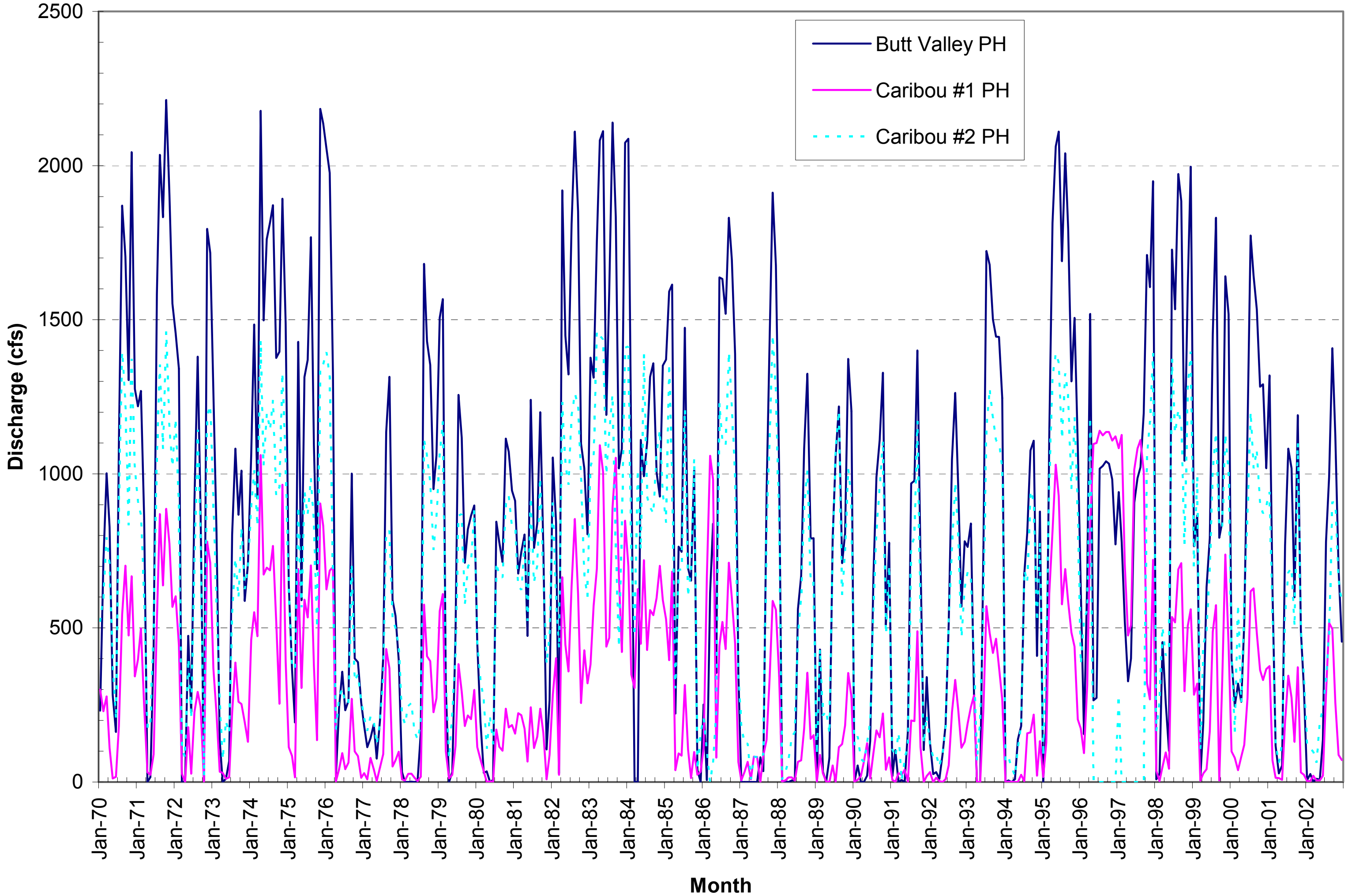


Figure 3 Historical Summertime Monthly Discharge of Butt Valley PH (1970 - 2002)

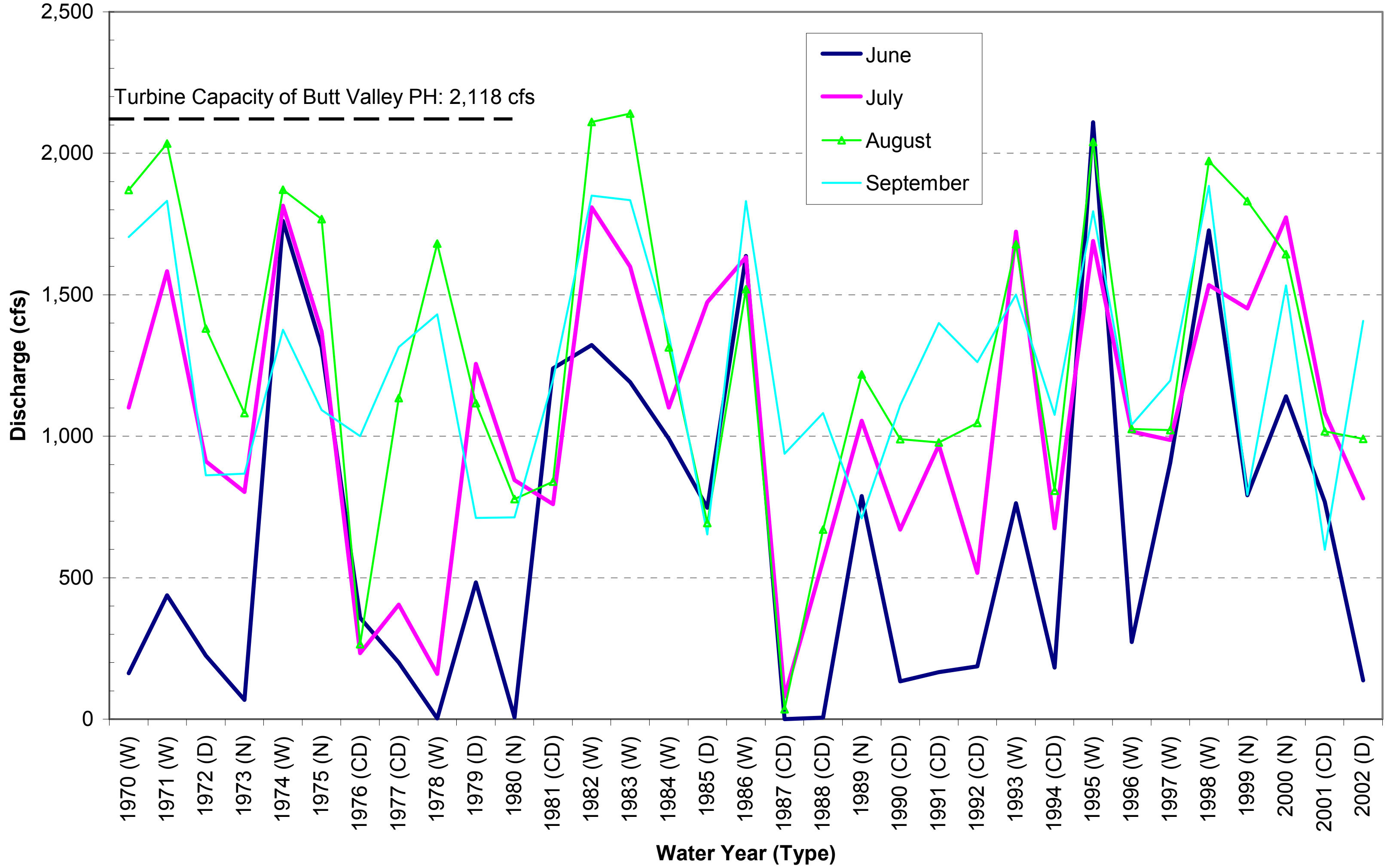


Figure 4 Historical Summertime Monthly Discharge of Caribou #1 PH (1970 - 2002)

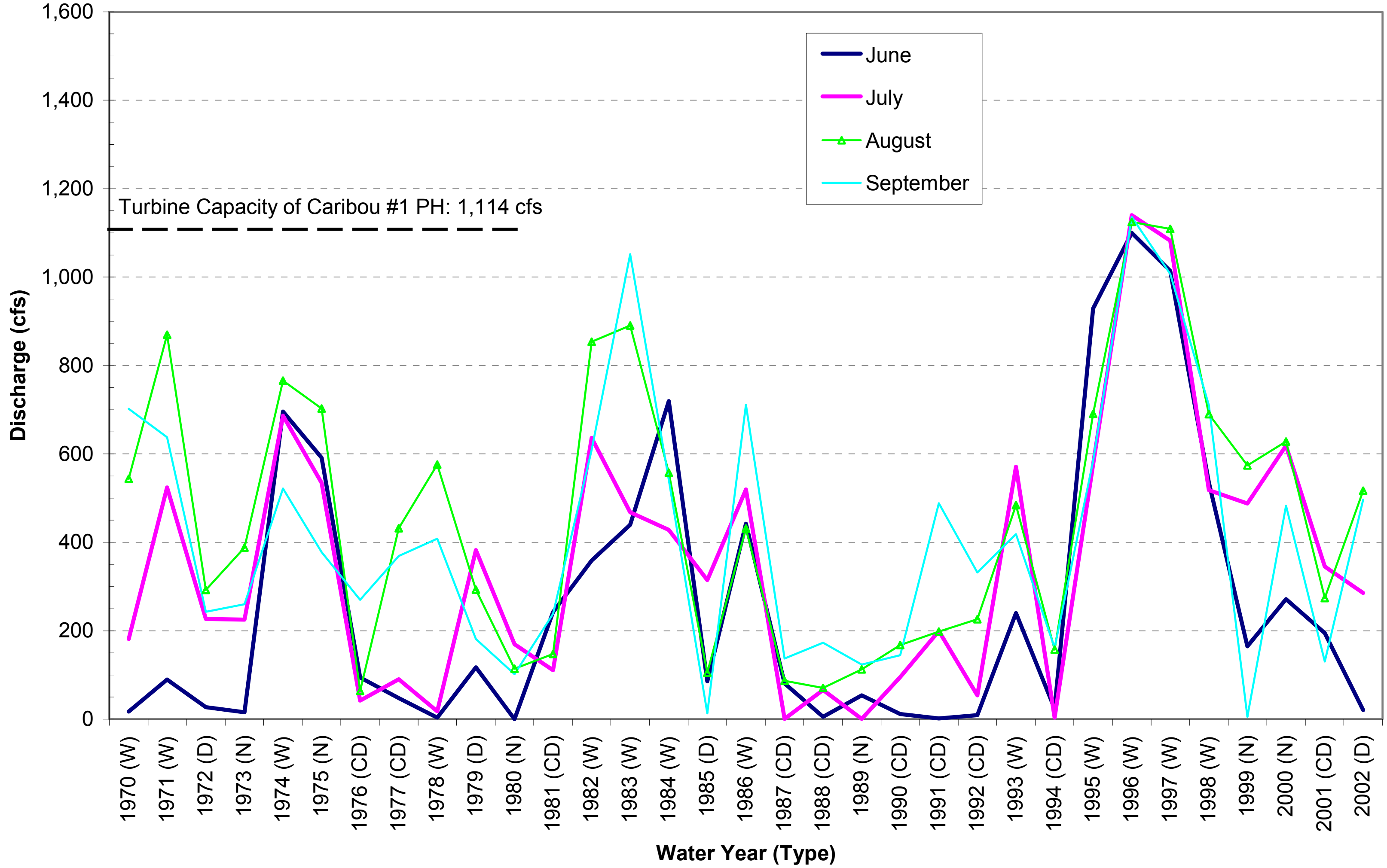


Figure 5 Historical Summertime Monthly Discharge of Caribou #2 PH (1970 - 2002)

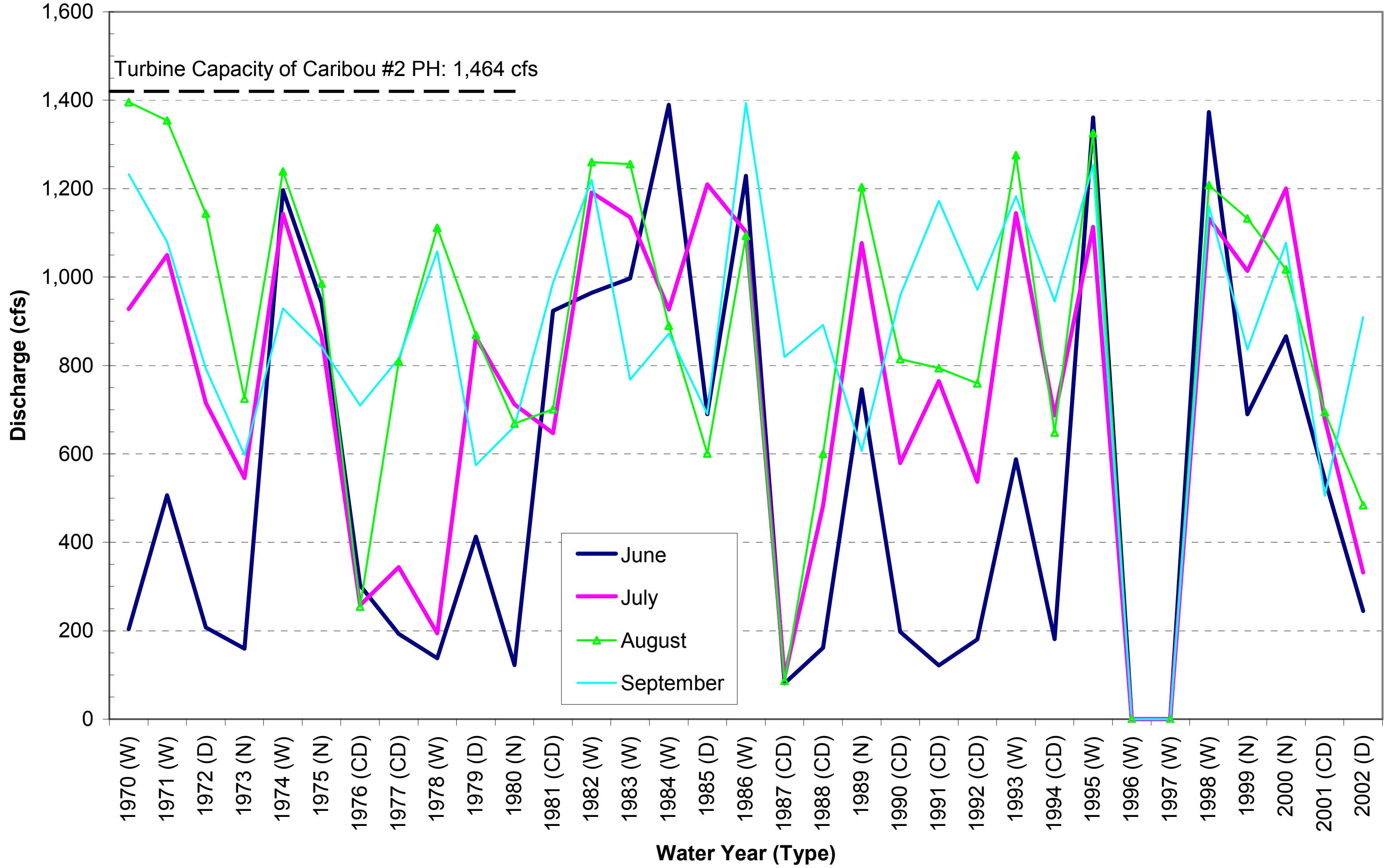


Figure 6a Butt Valley PH Hourly Discharges during the Week of 7/29 - 8/4, 2002 (Dry Year)

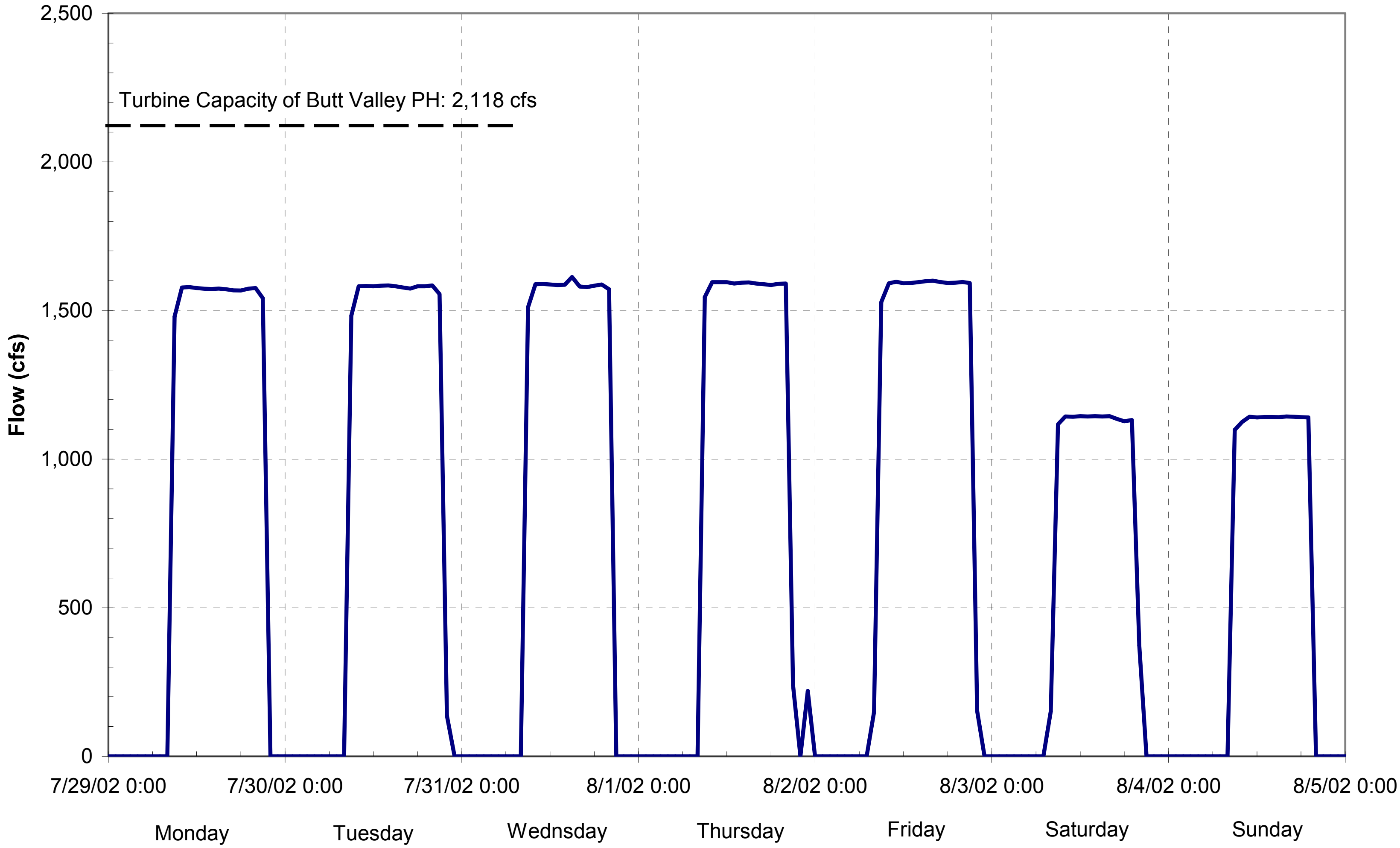


Figure 6b Butt Valley PH Hourly Discharges during the Week of 7/28 - 8/3, 2003 (Normal Year)

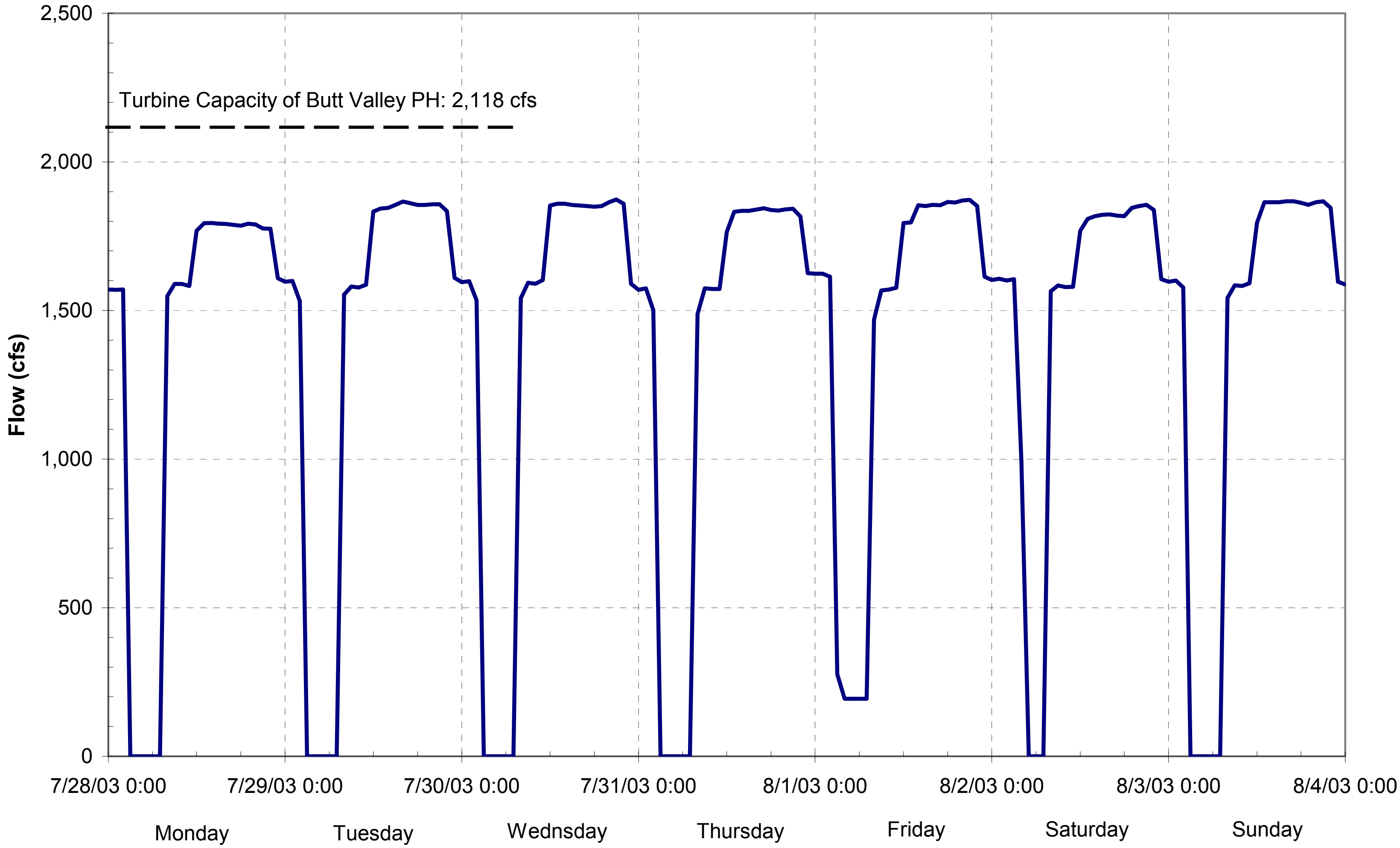


Figure 6c Butt Valley PH Hourly Discharges during the Week of 7/26 - 8/1, 2004 (Normal Year)

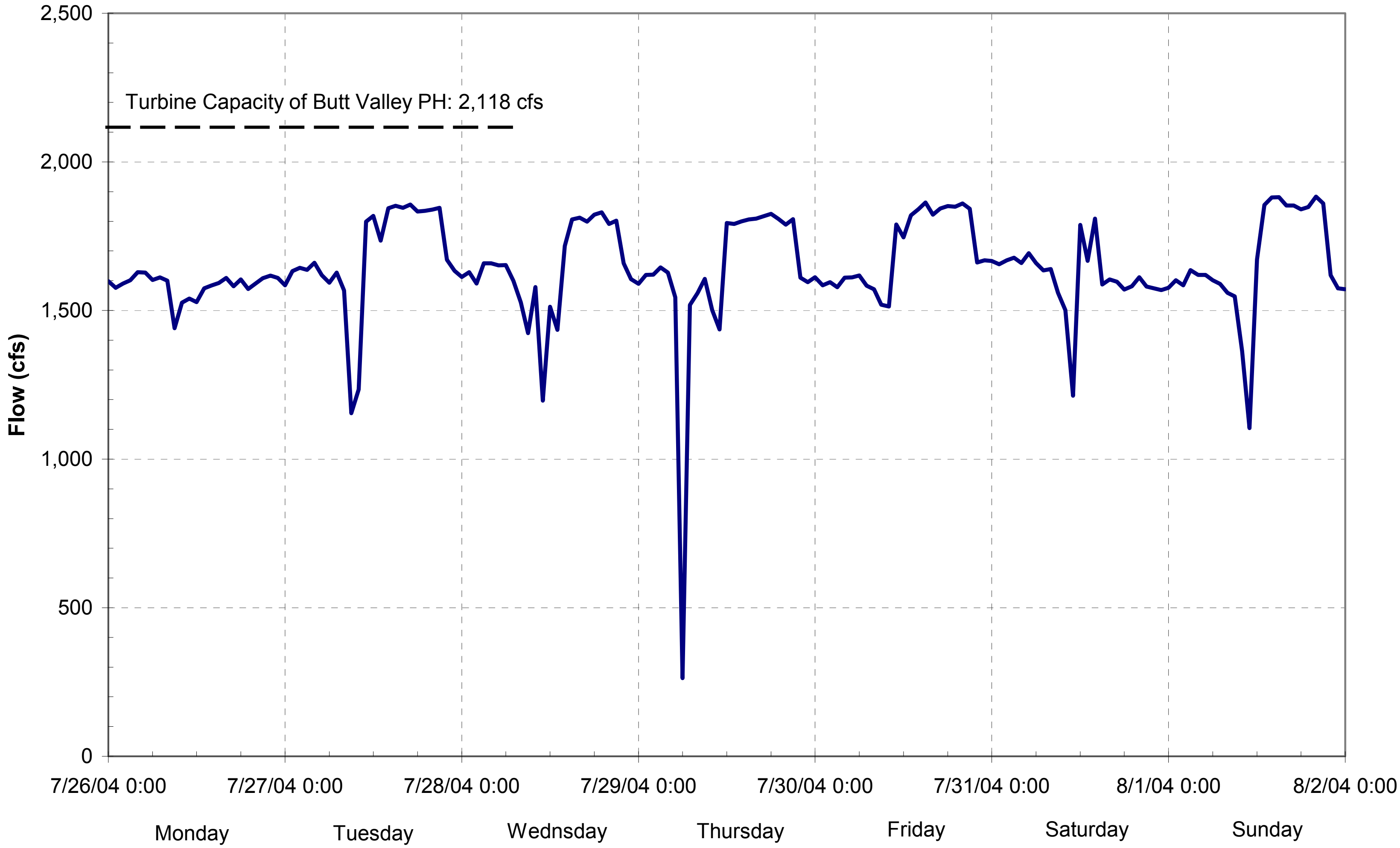


Figure 7a Caribou #1 PH Hourly Discharges during the Week of 7/29 - 8/4, 2002 (Dry Year)

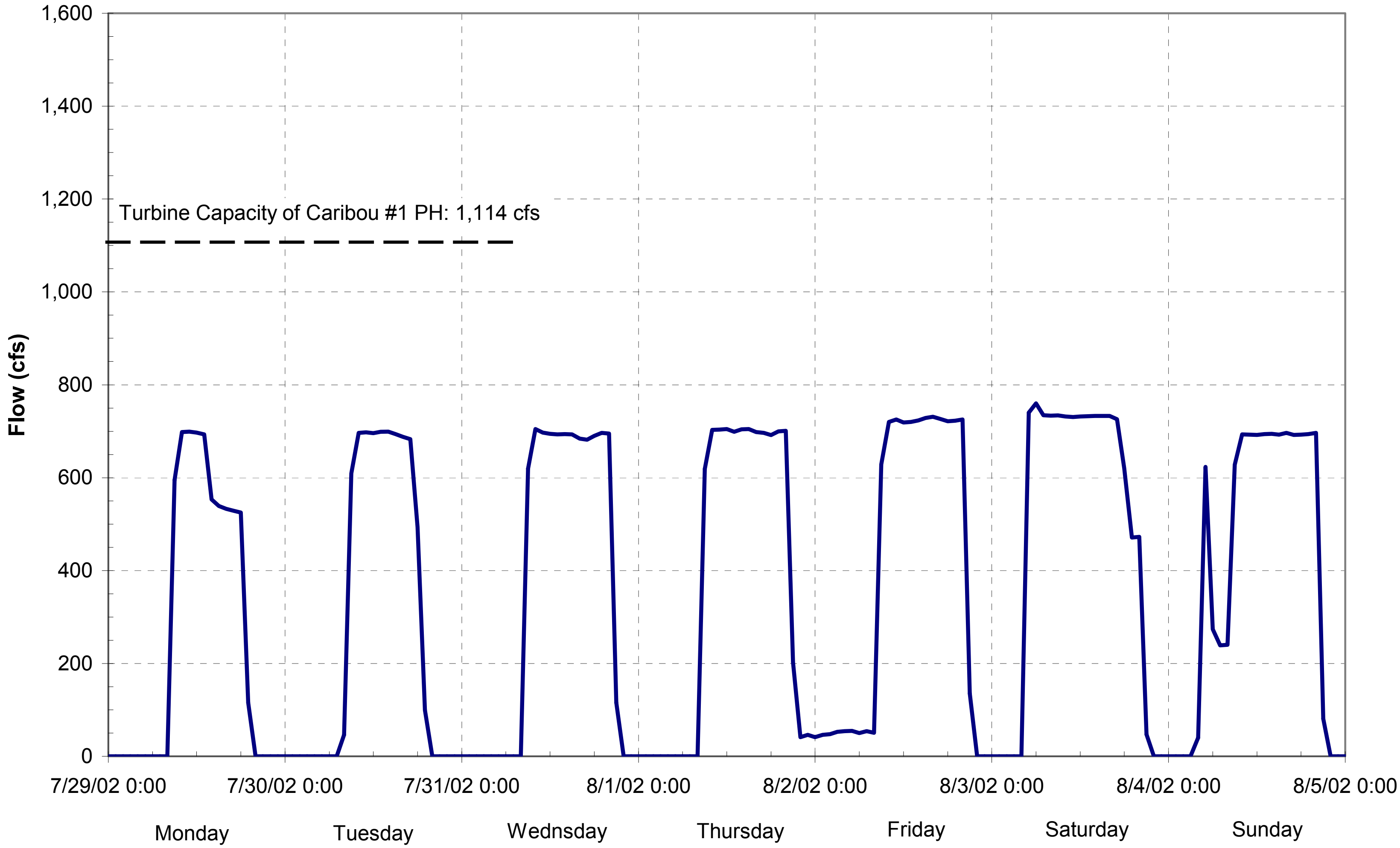


Figure 7b Caribou #1 PH Hourly Discharges during the Week of 7/28 - 8/3, 2003 (Normal Year)

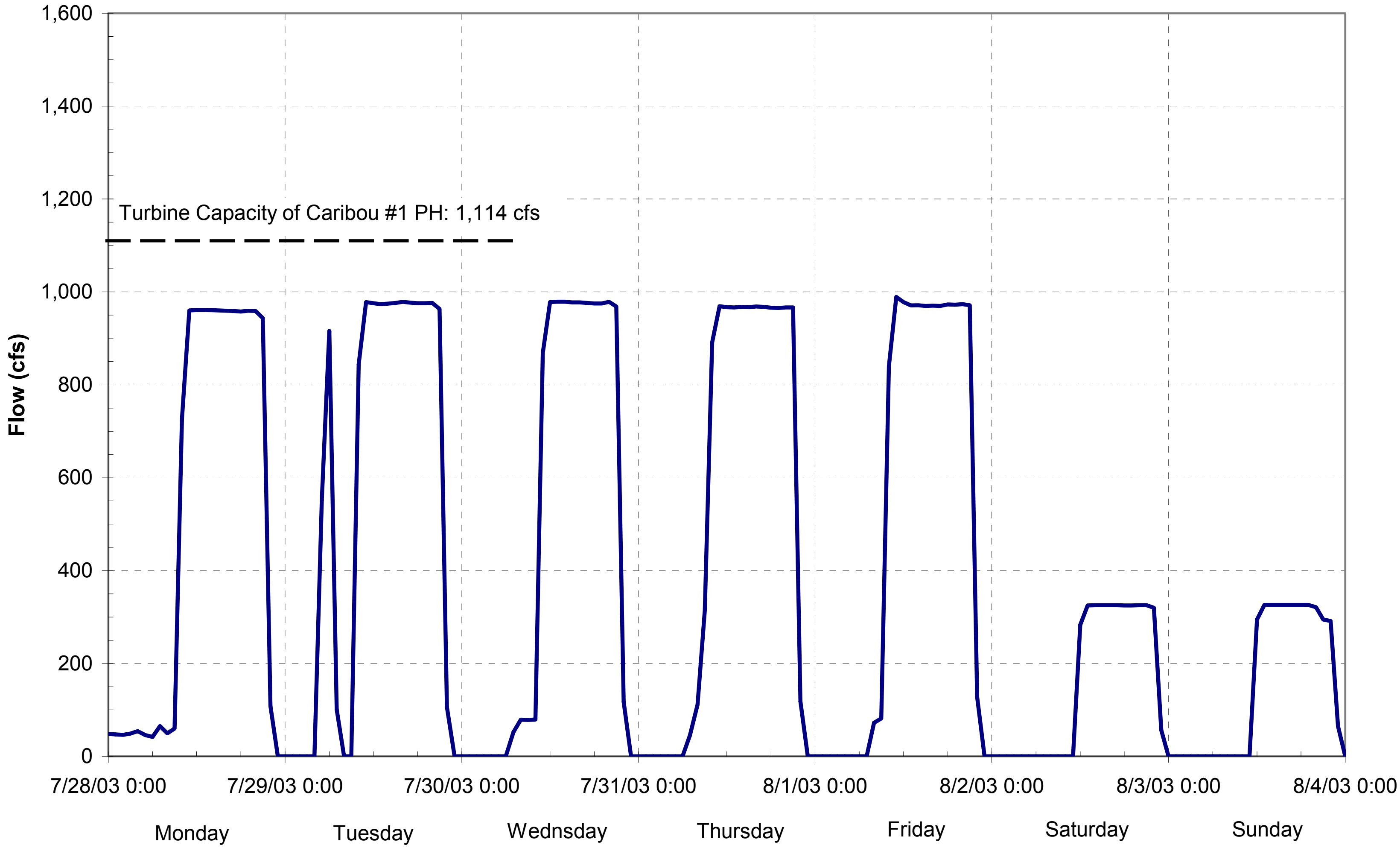


Figure 7c Caribou #1 PH Hourly Discharges During the Week of 7/26 - 8/1, 2004 (Normal Year)

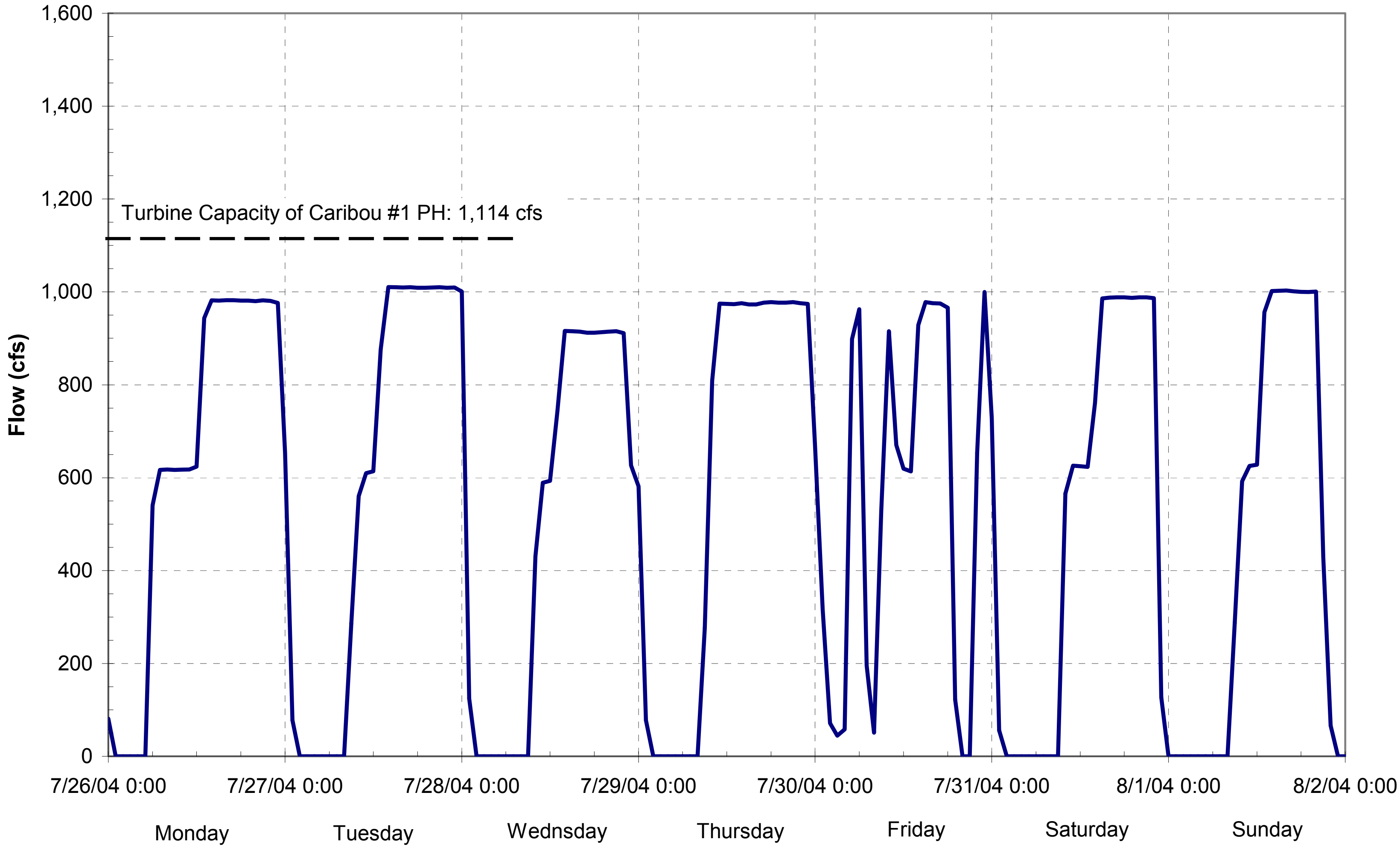


Figure 8a Caribou #2 PH Hourly Discharges during the Week of 7/29 - 8/4, 2002 (Dry Year)

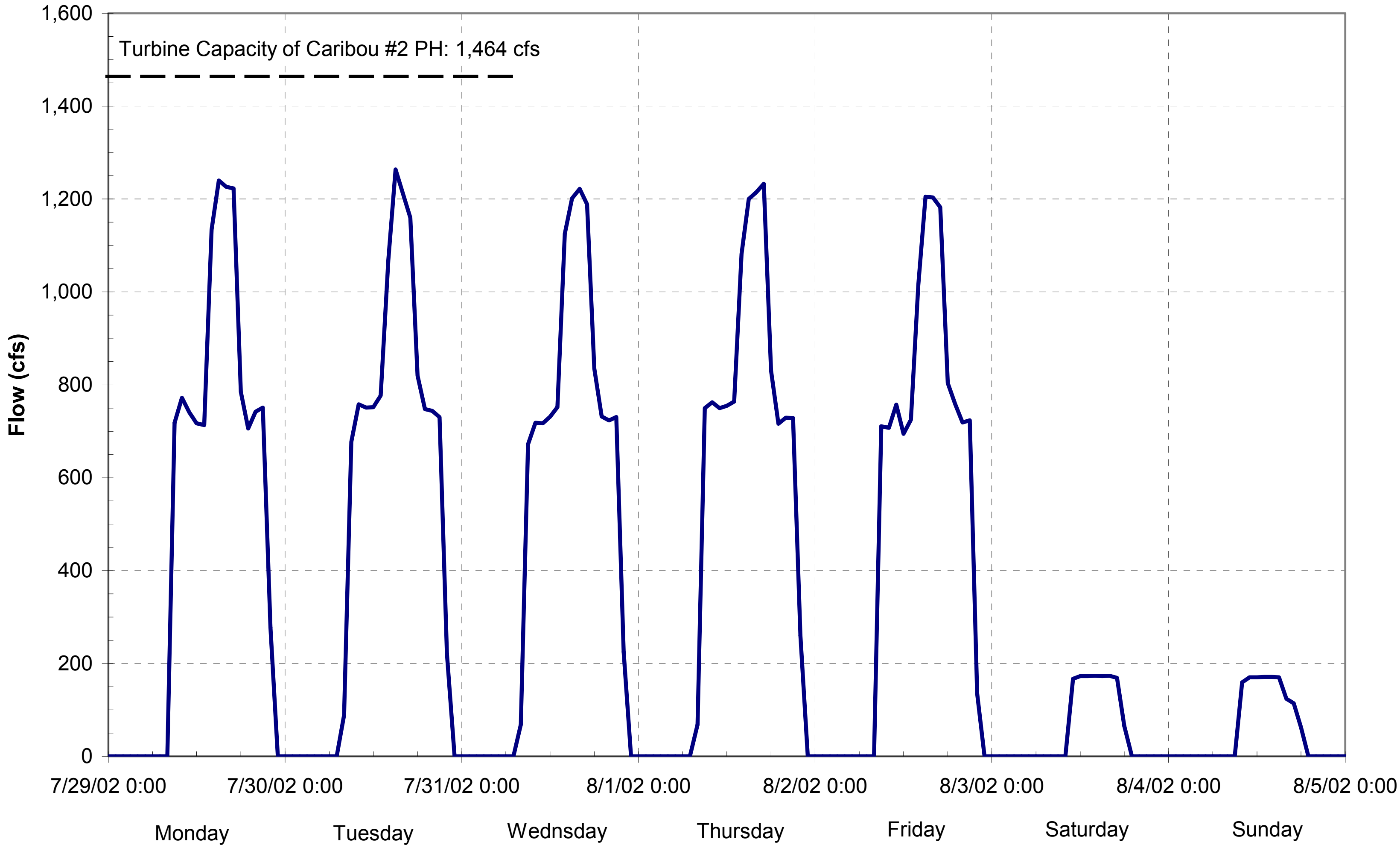


Figure 8b Caribou #2 PH Hourly Discharges during the Week of 7/28 - 8/3, 2003 (Normal Year)

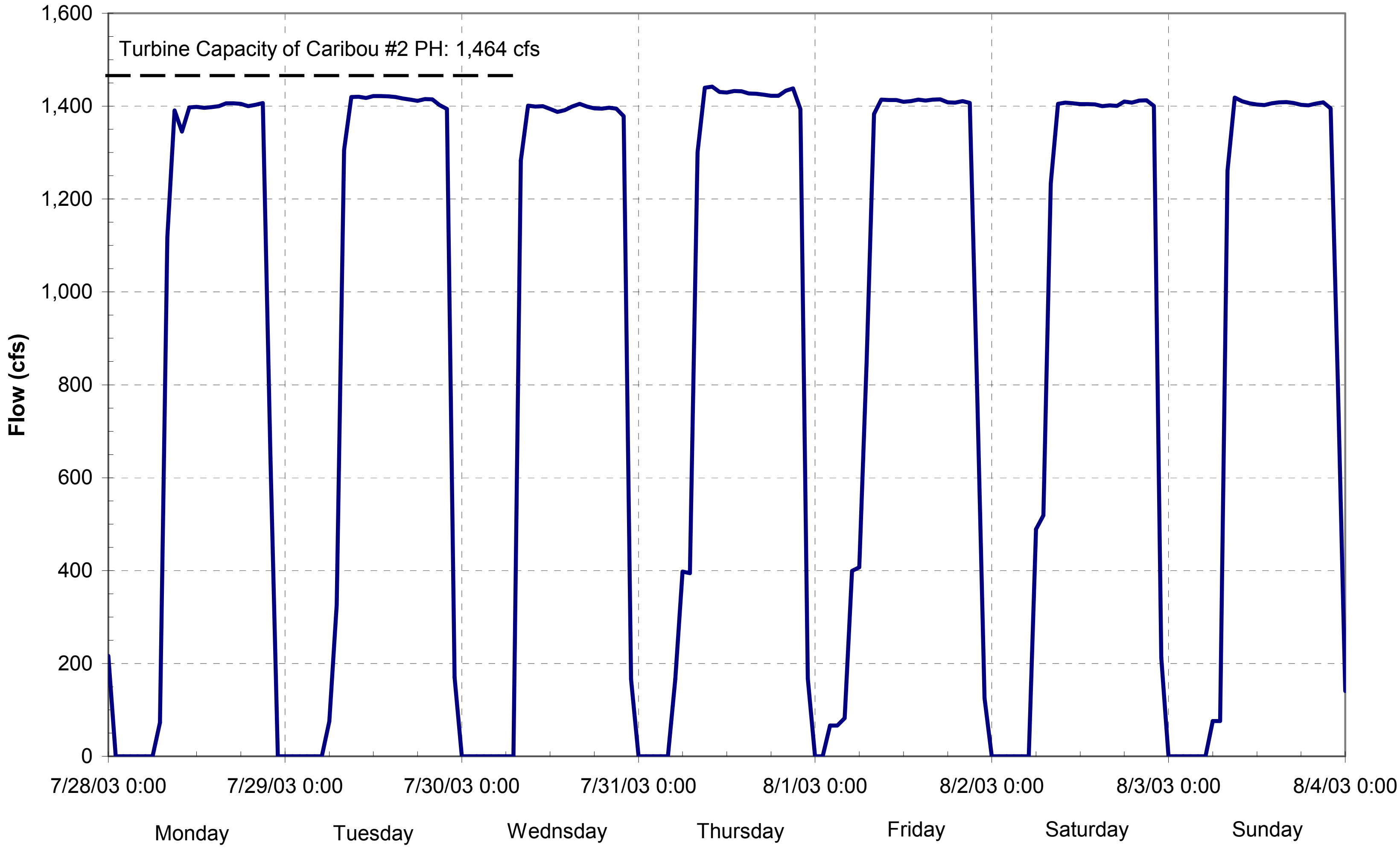
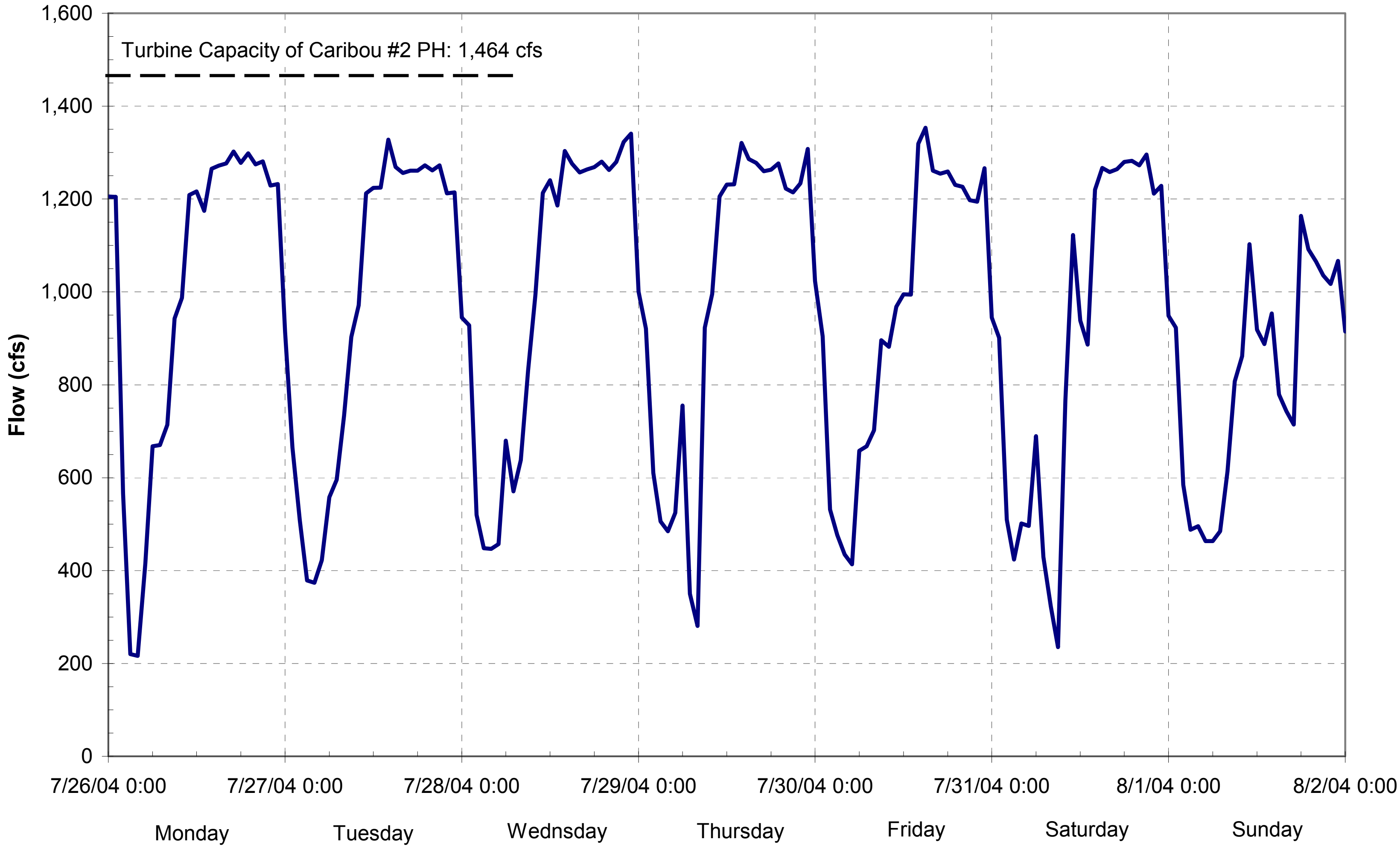
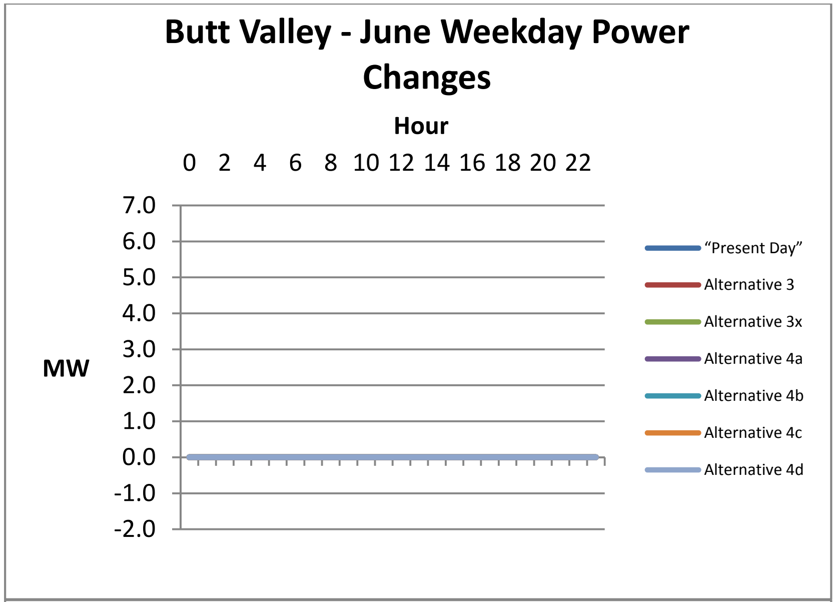


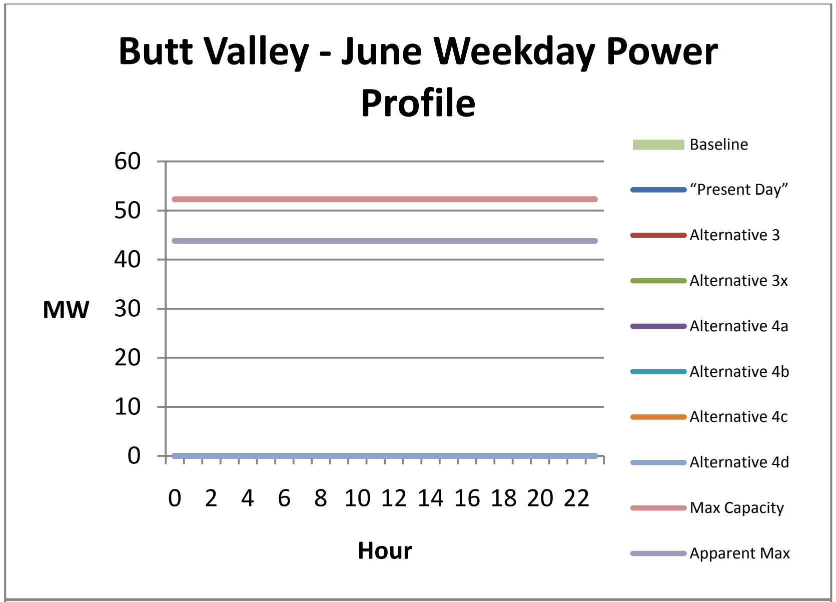
Figure 8c Caribou #2 PH Hourly Discharges during the Week of 7/26 - 8/1, 2004 (Normal Year)

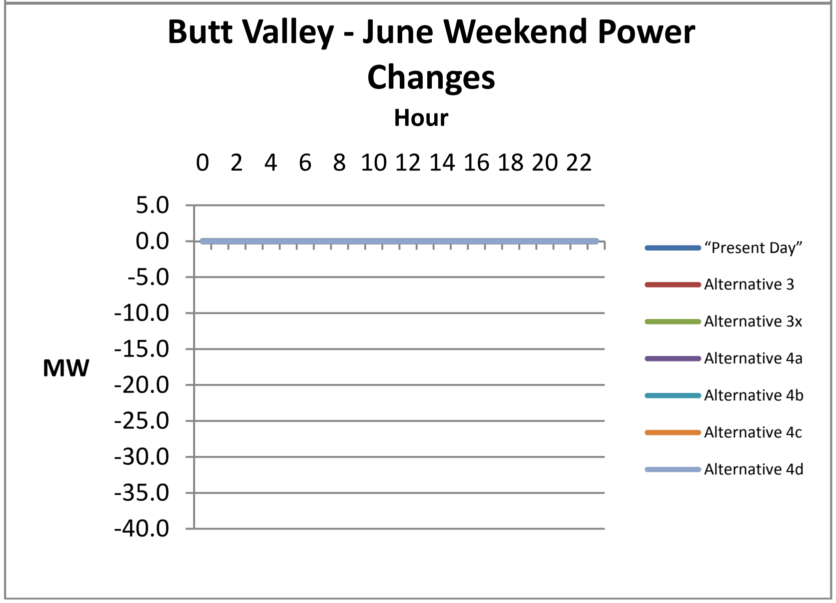


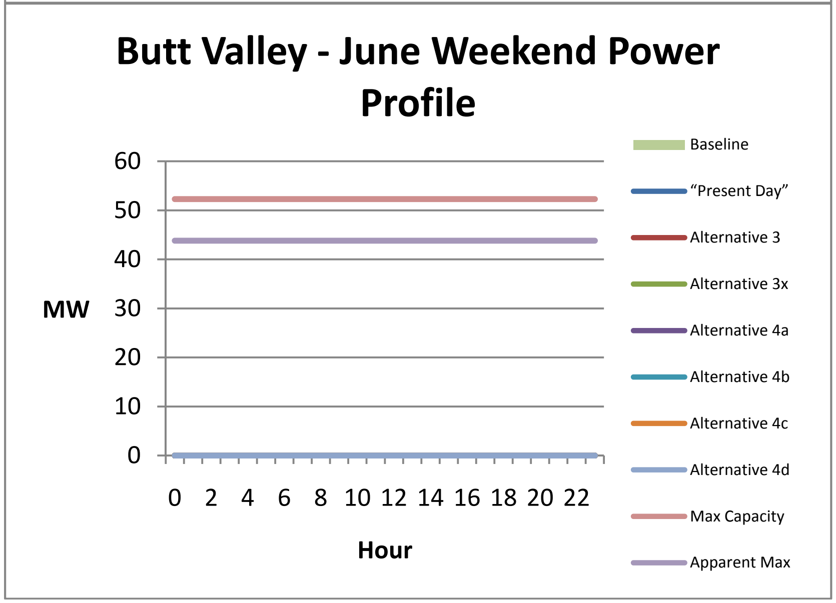
Attachment B

Hourly Operational Changes: 2002 Butt Valley

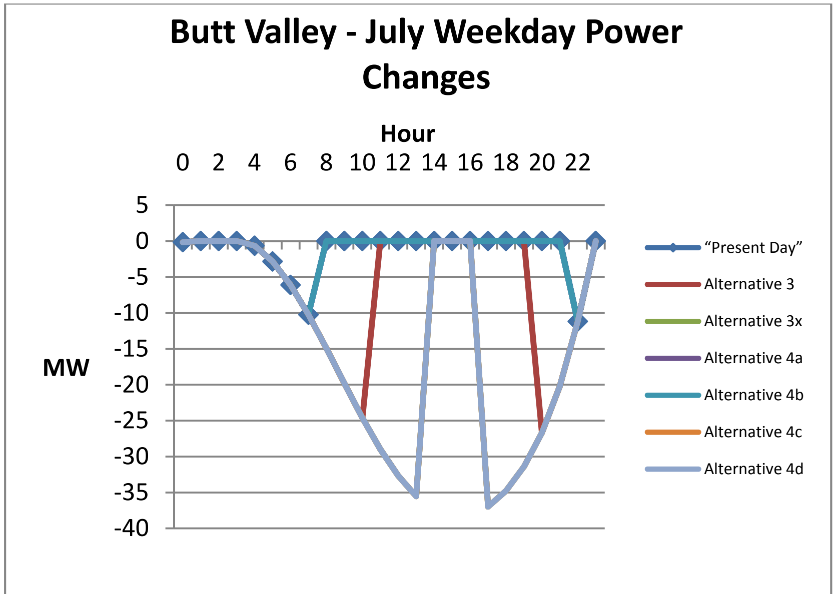


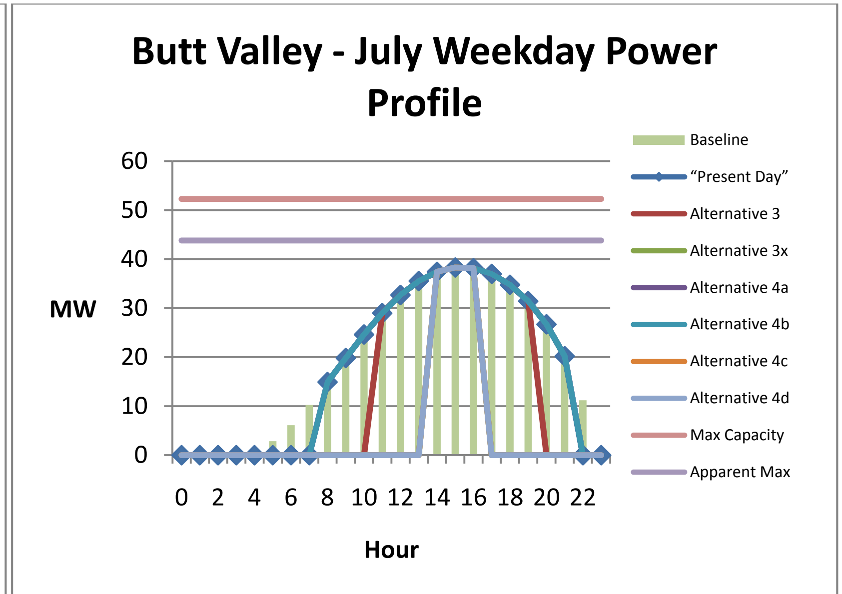


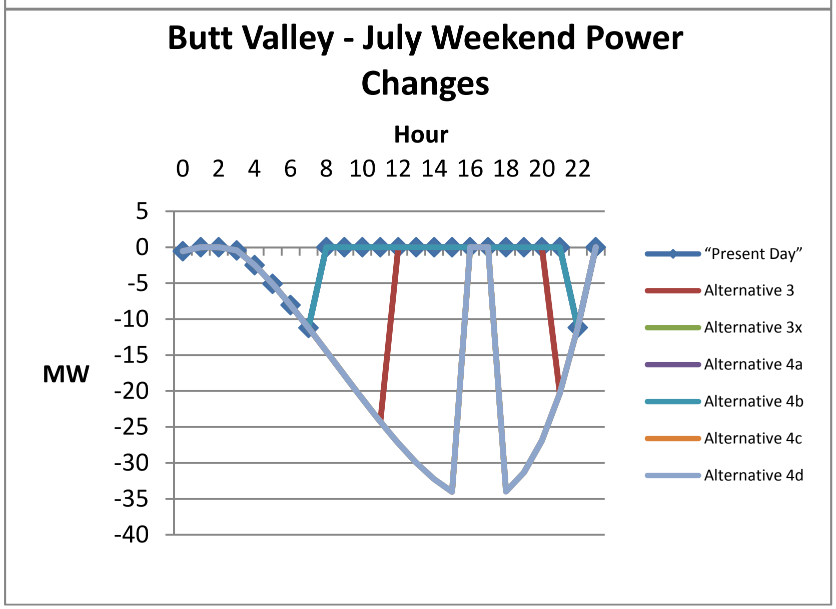


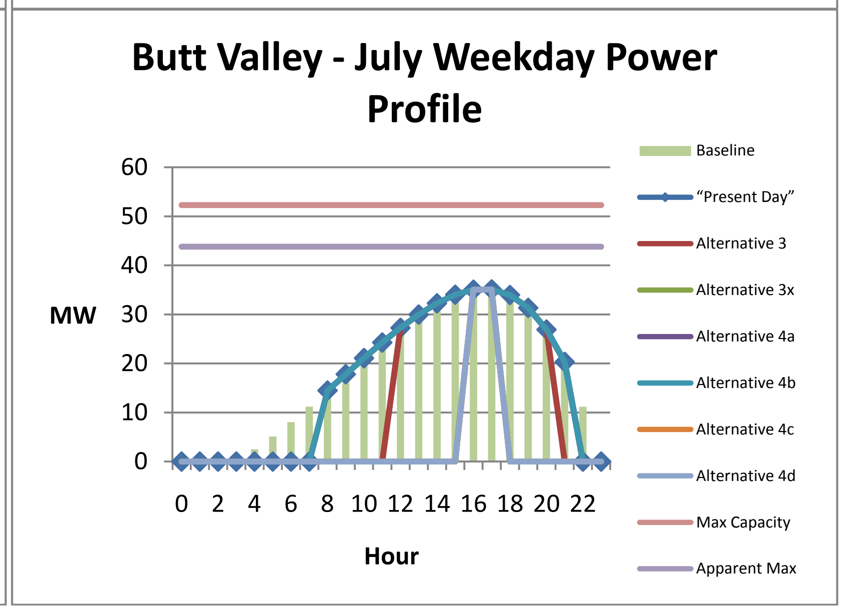


Hourly Operational Changes: 2002 Butt Valley

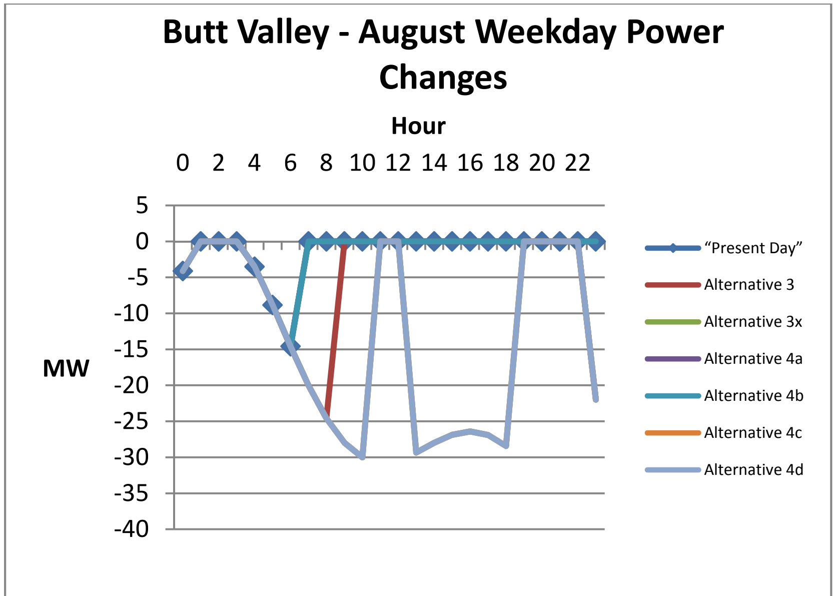


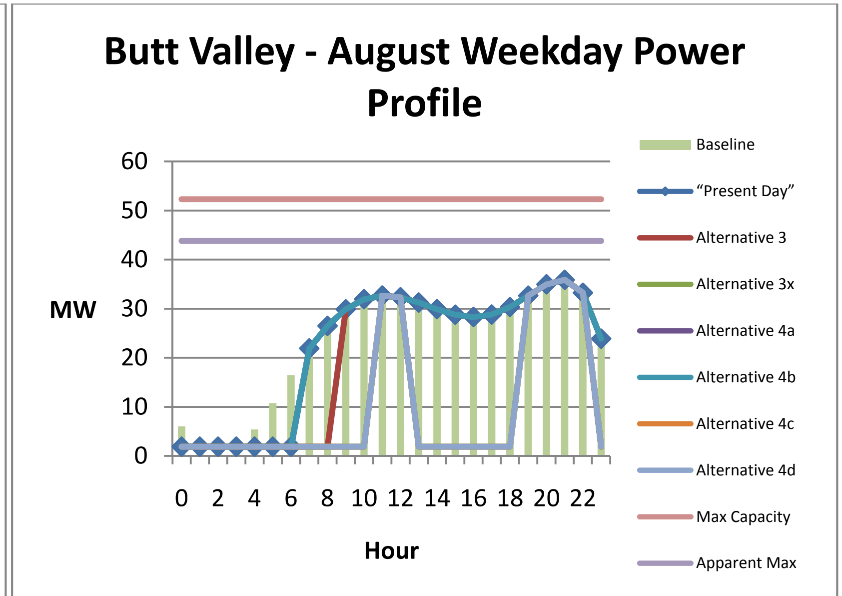


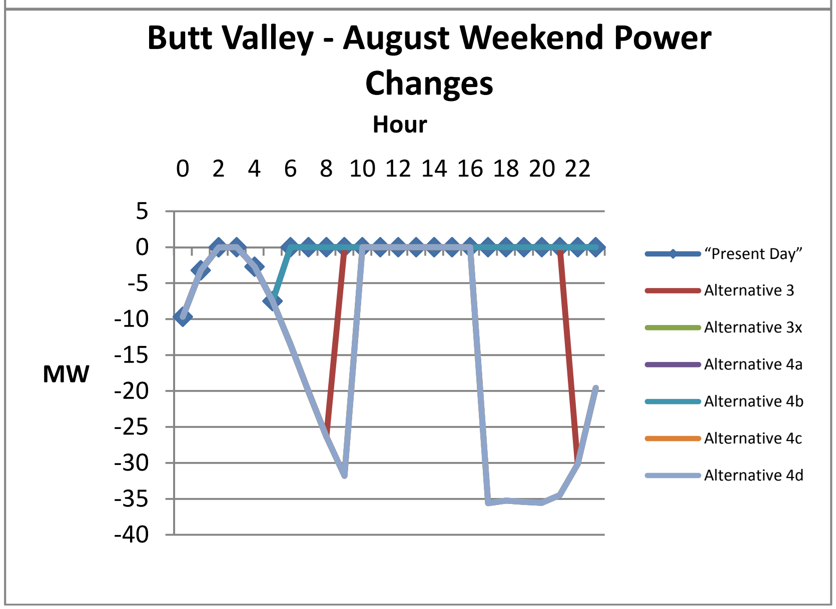


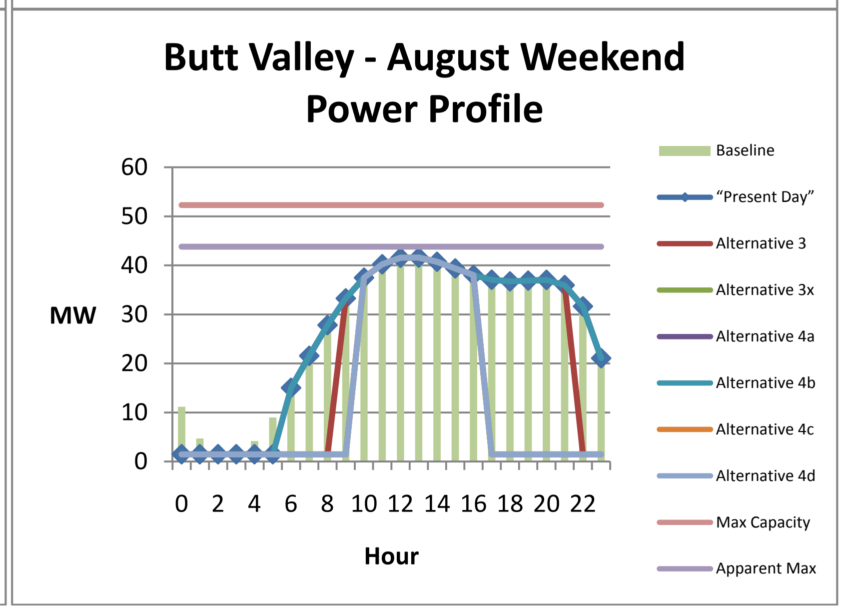


Hourly Operational Changes: 2002 Butt Valley

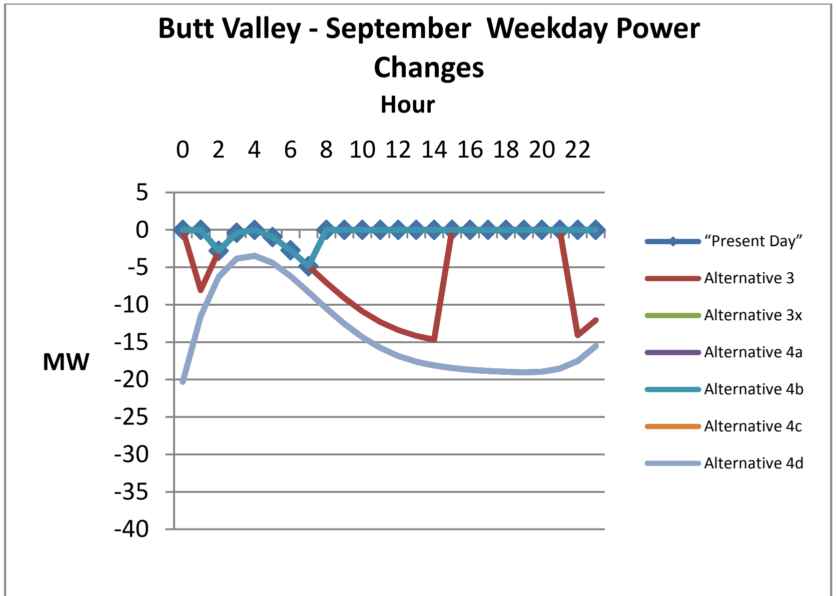


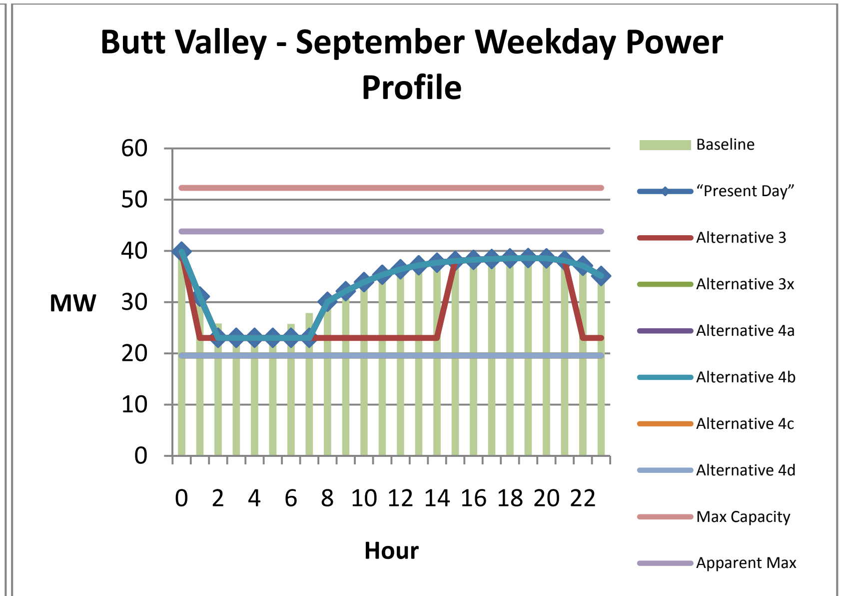


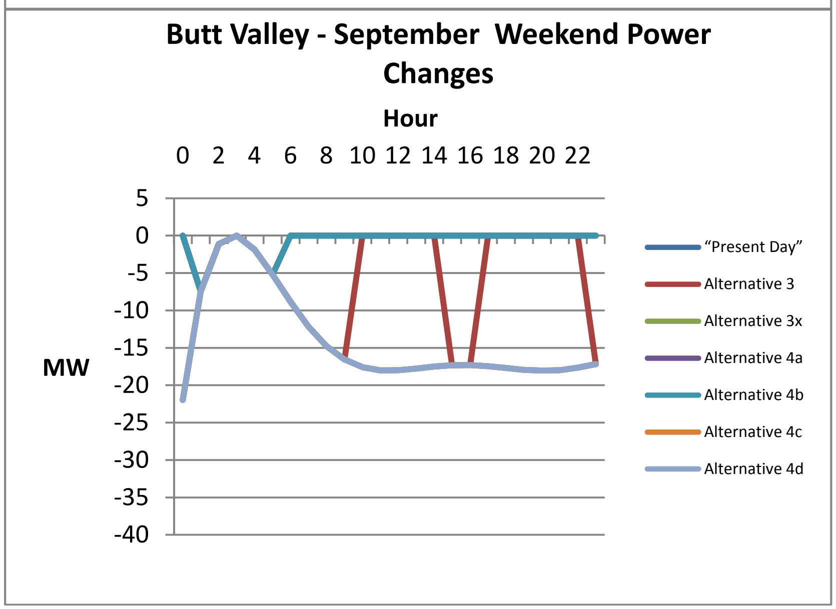


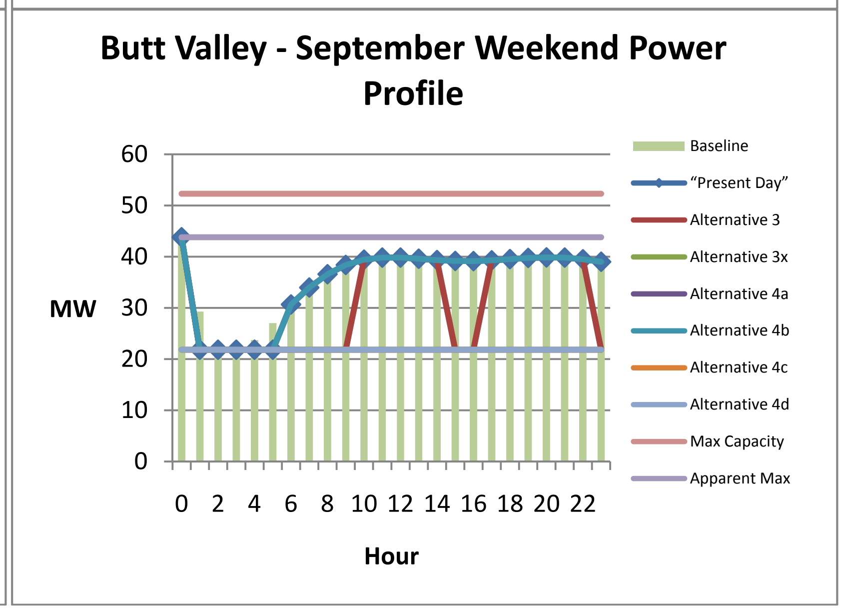


Hourly Operational Changes: 2002 Butt Valley

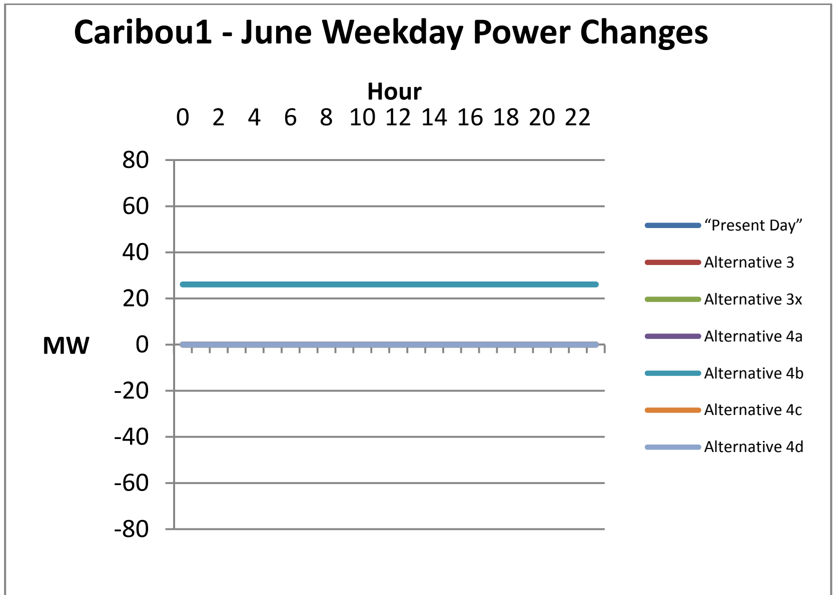


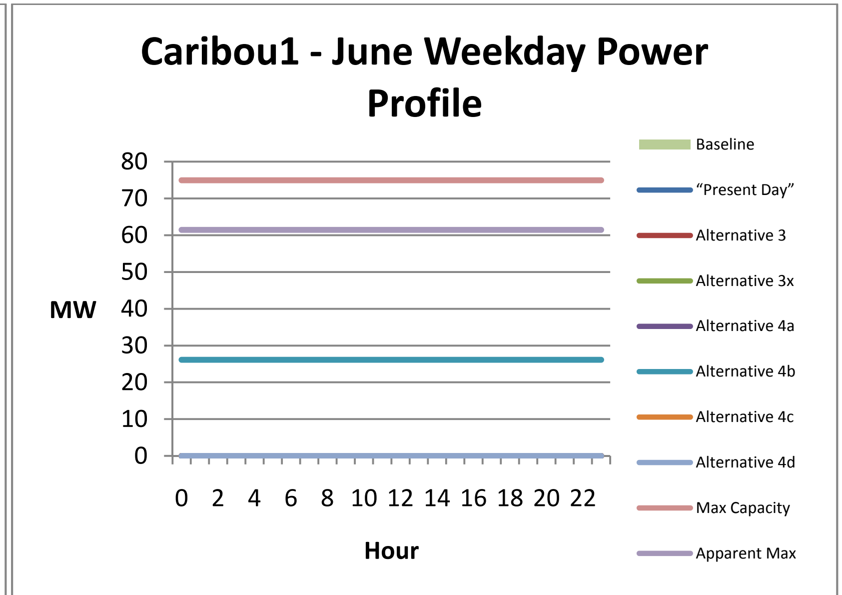


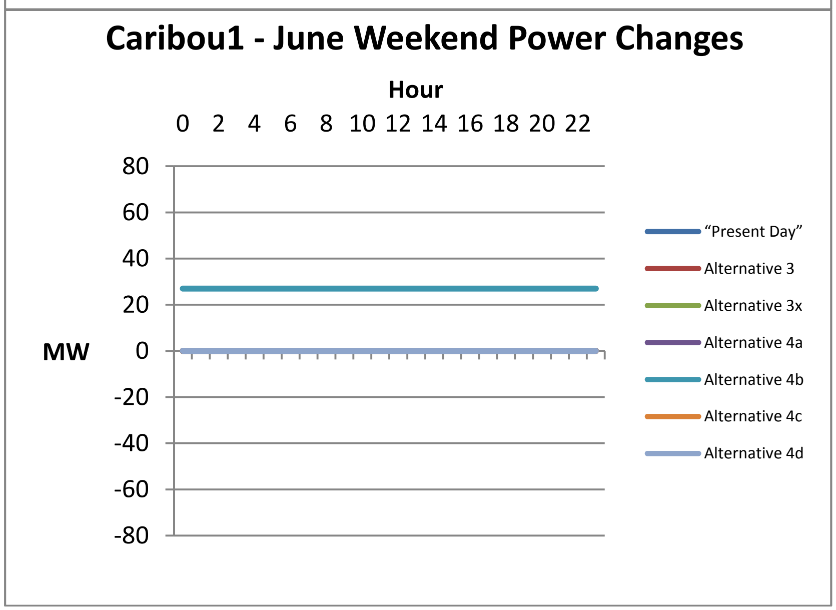


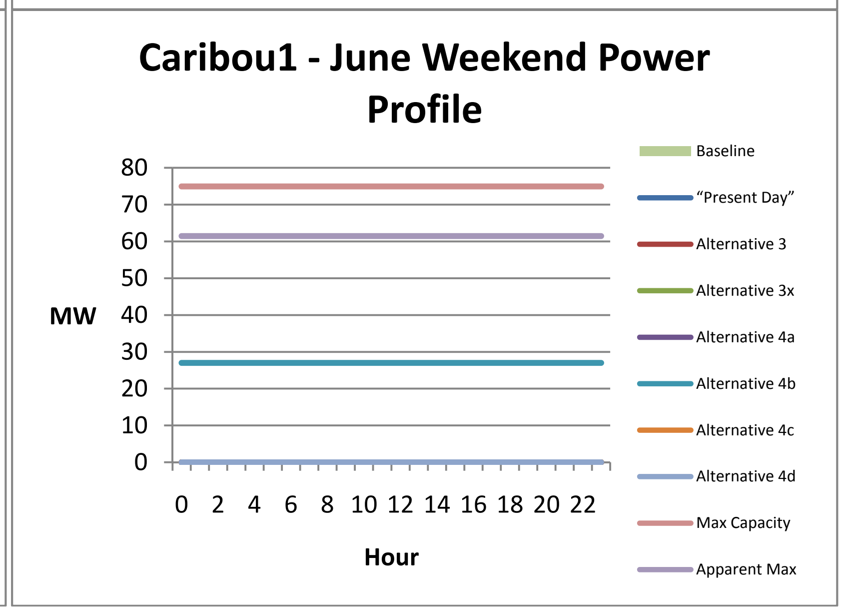


2002 Caribou 1

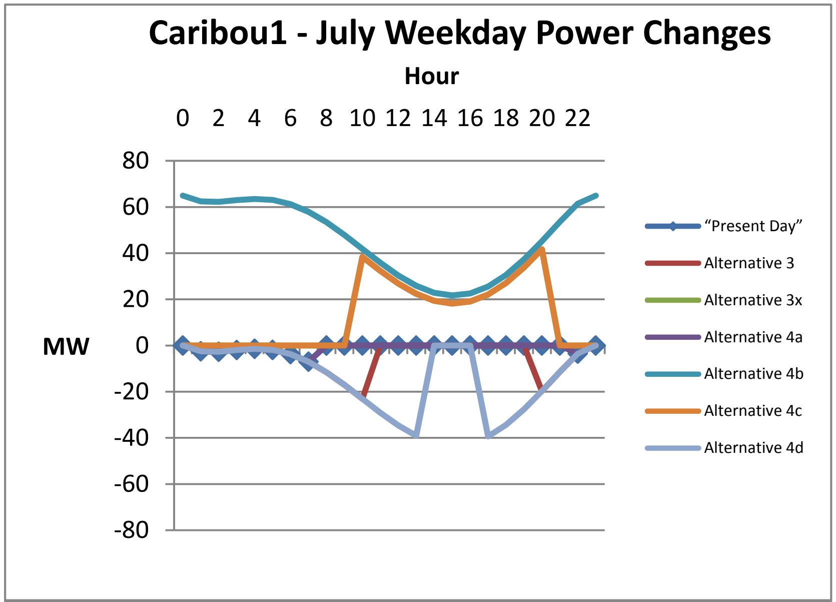


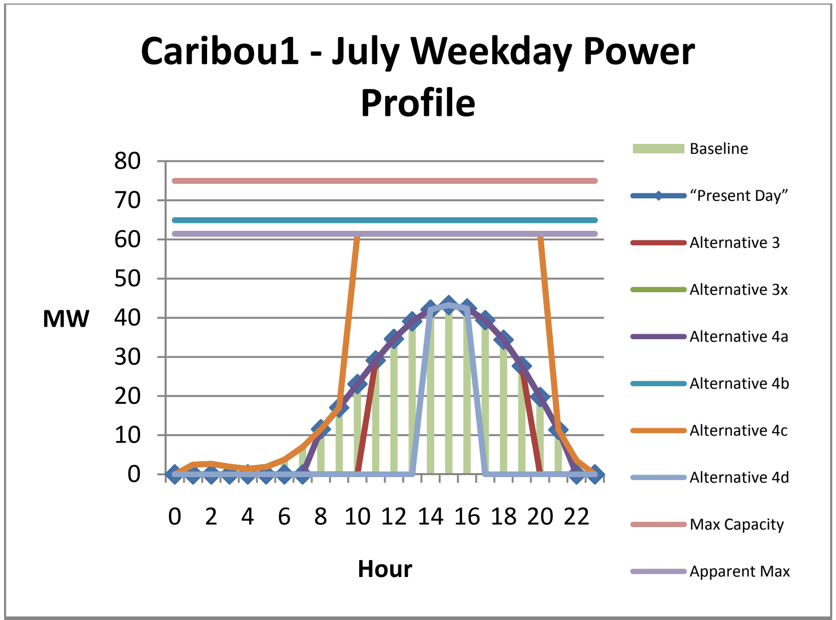


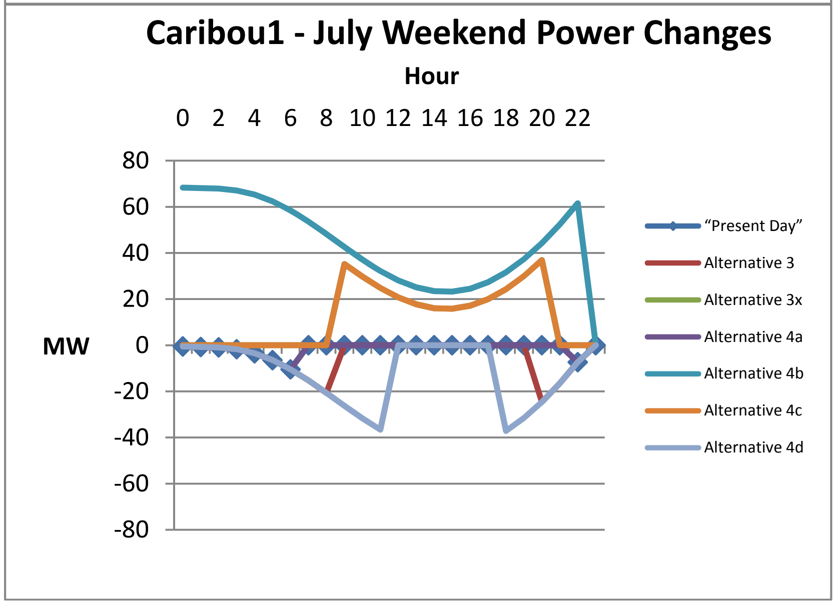


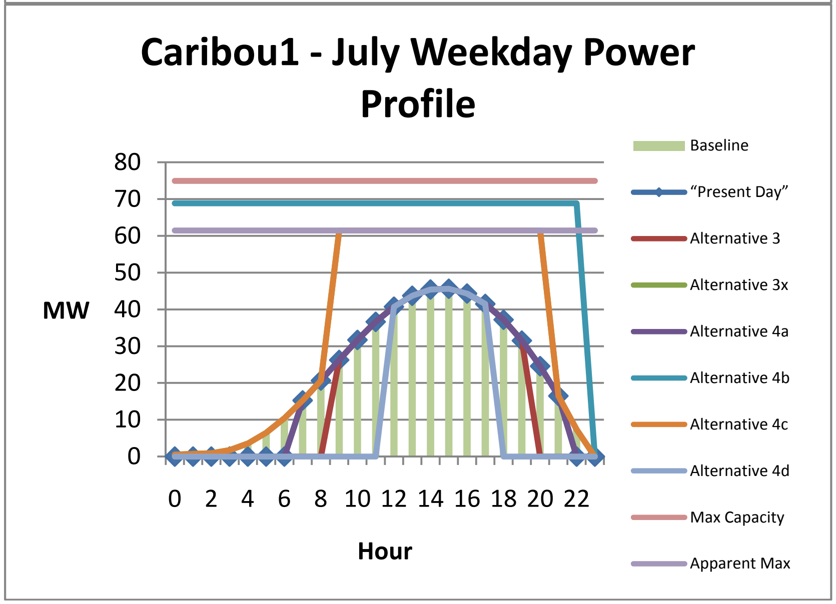


Hourly Operational Changes: 2002 Butt Valley

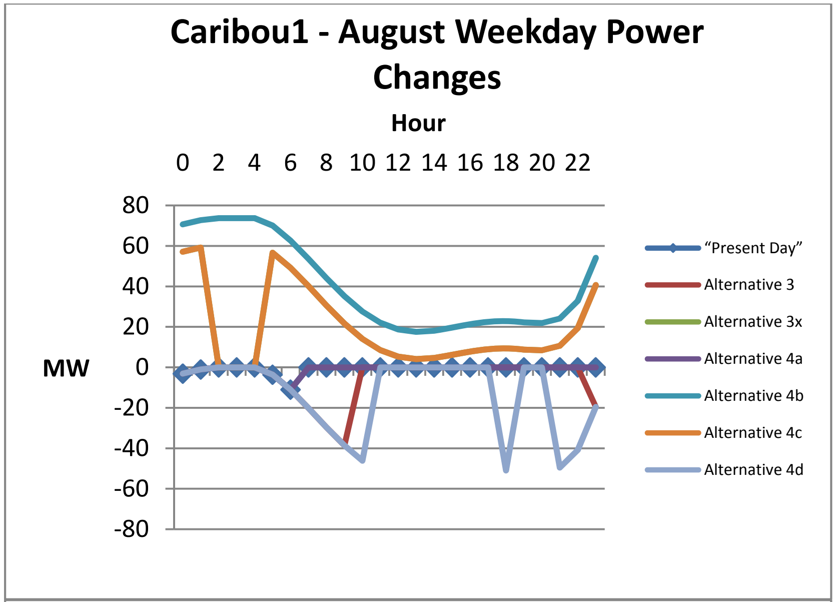


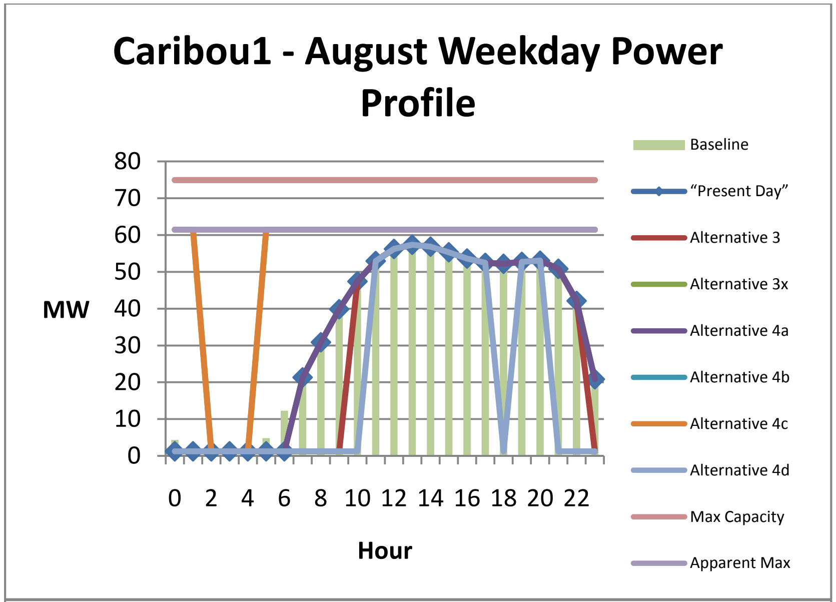


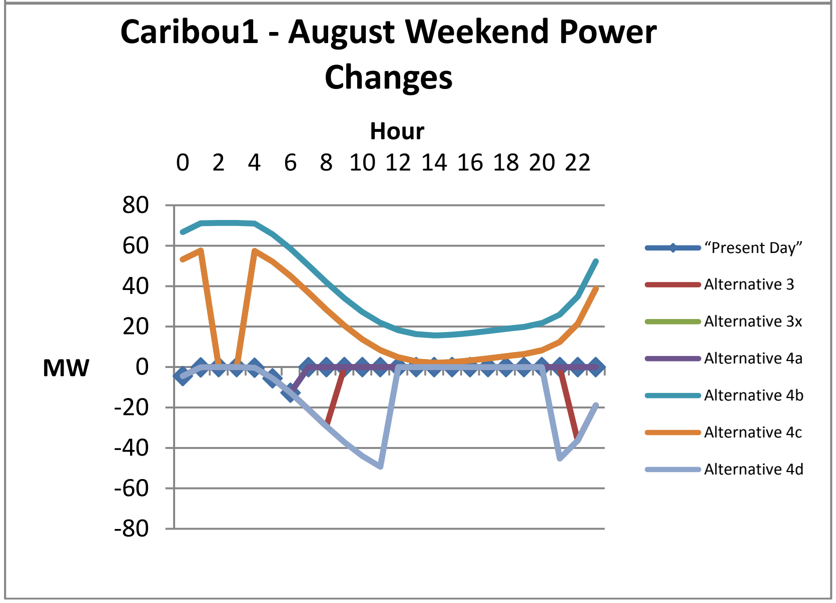


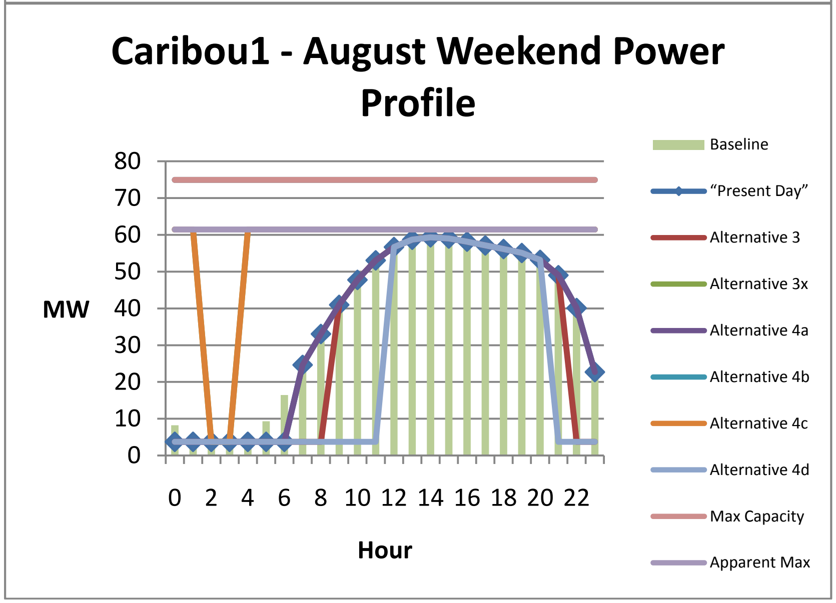


Hourly Operational Changes: 2002 Butt Valley

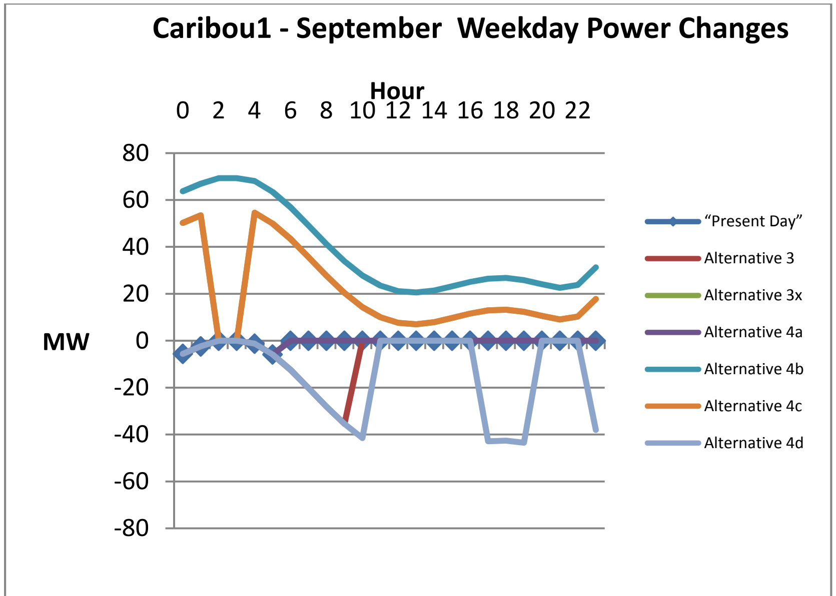


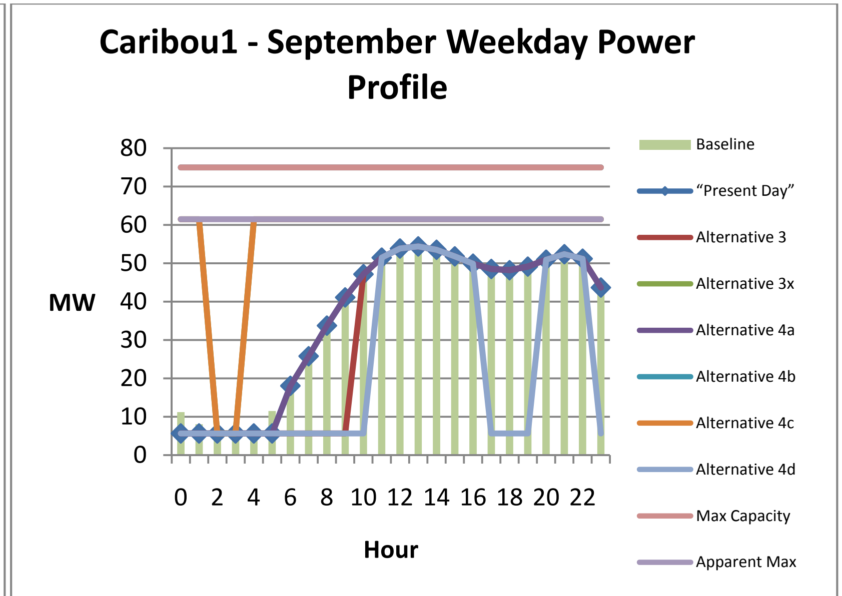


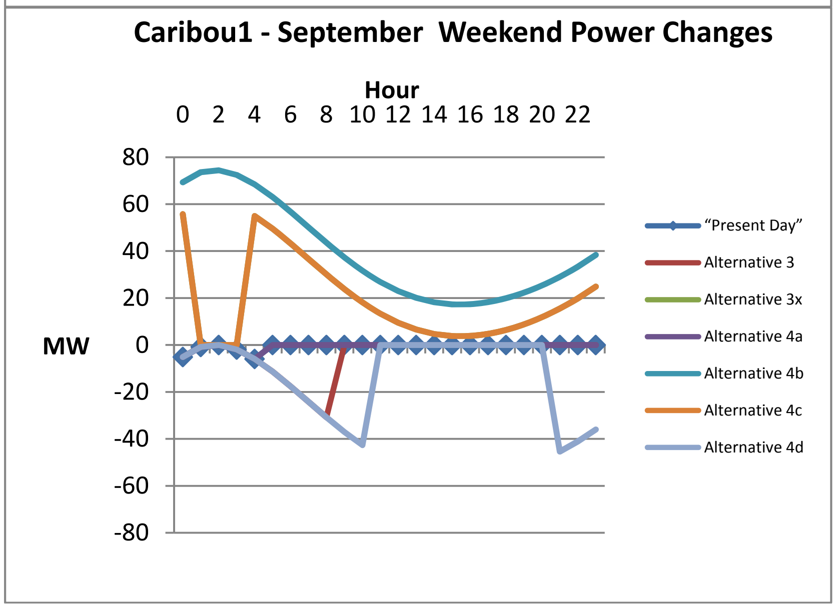


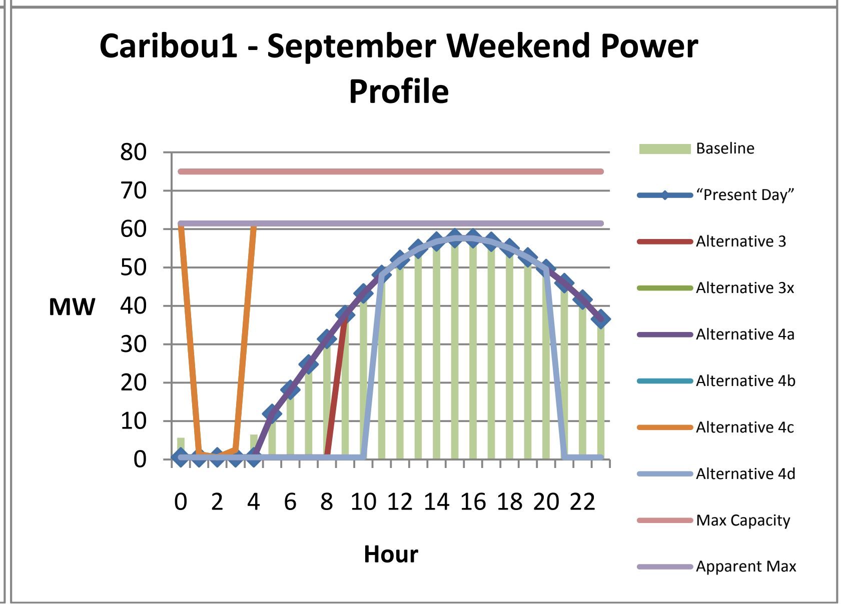


Hourly Operational Changes: 2002 Butt Valley

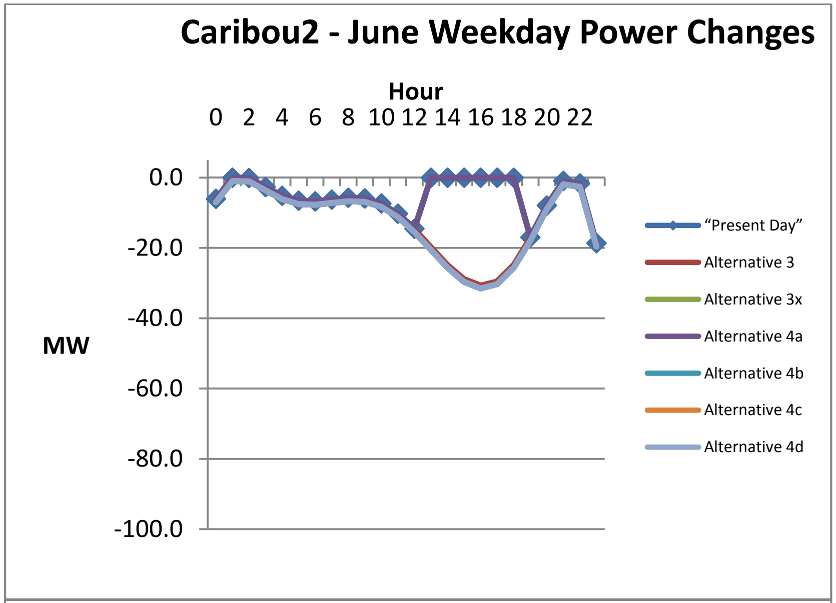


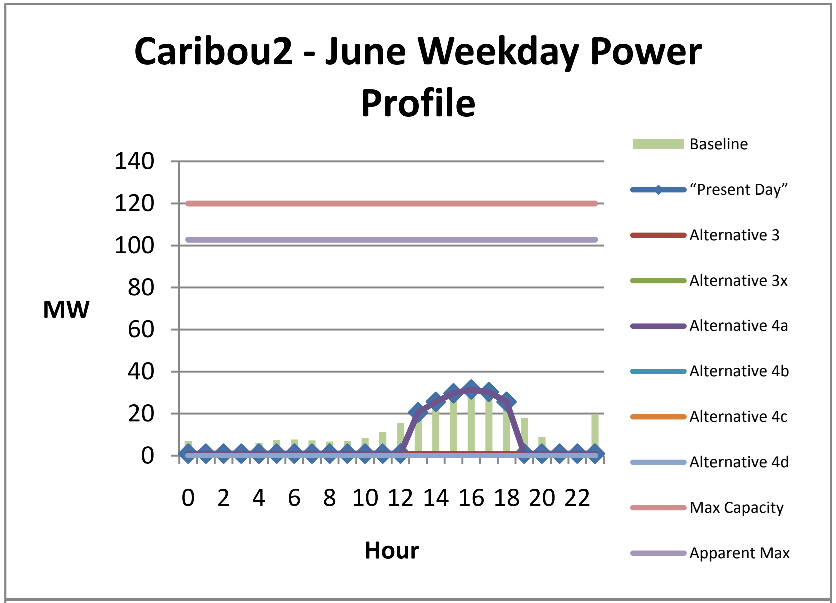


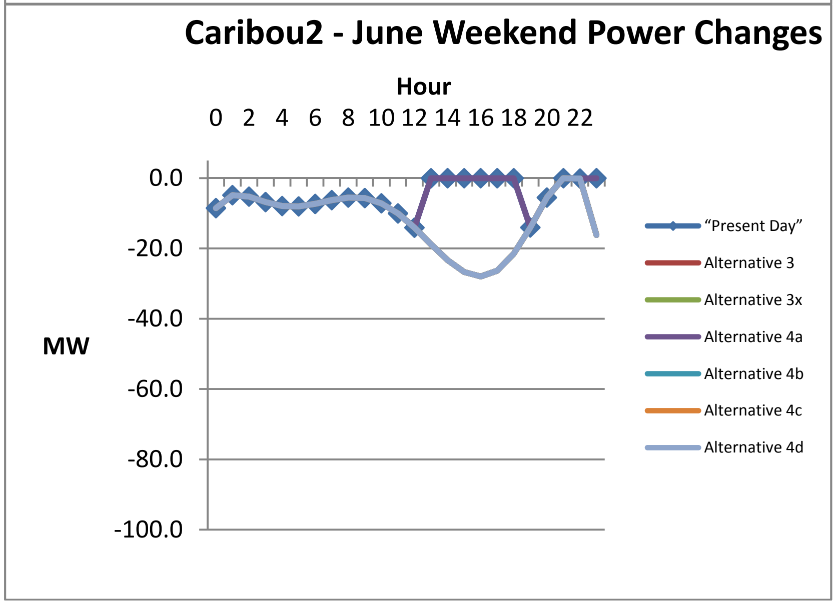


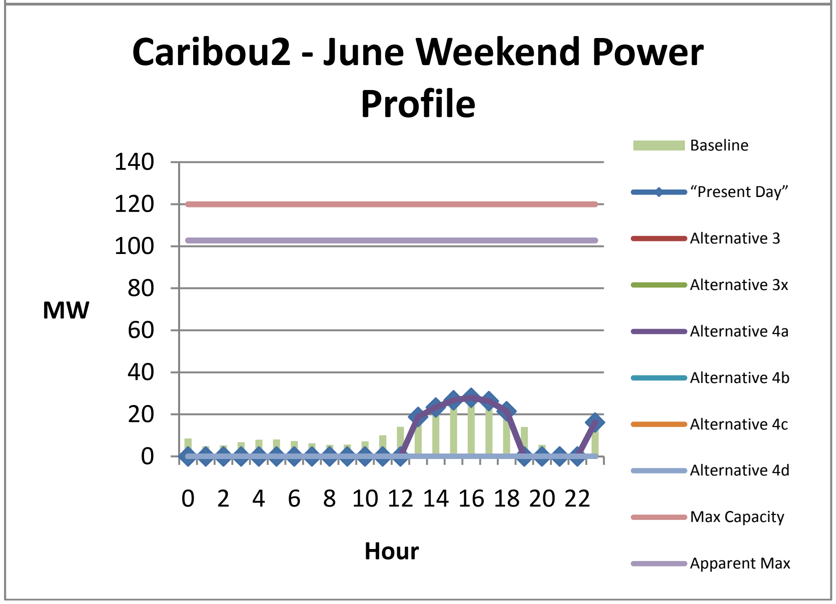


2002 Caribou 2

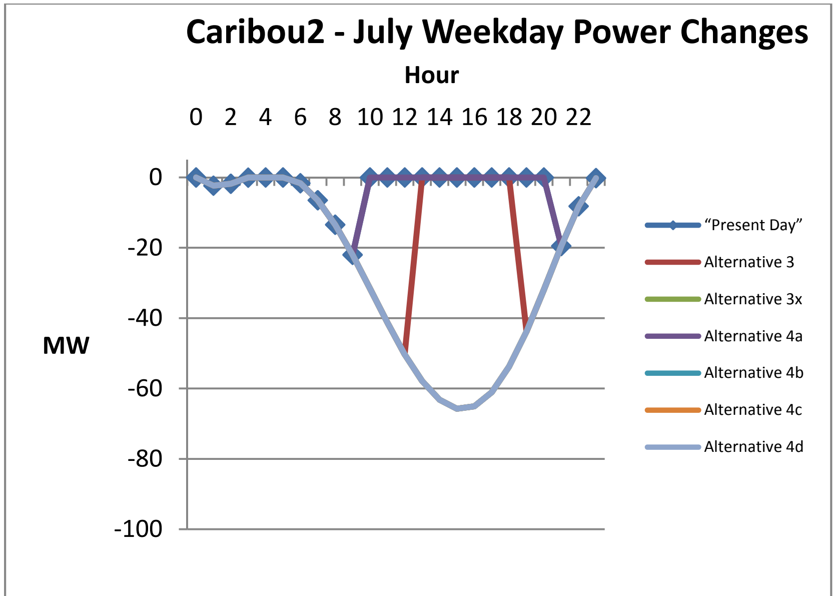


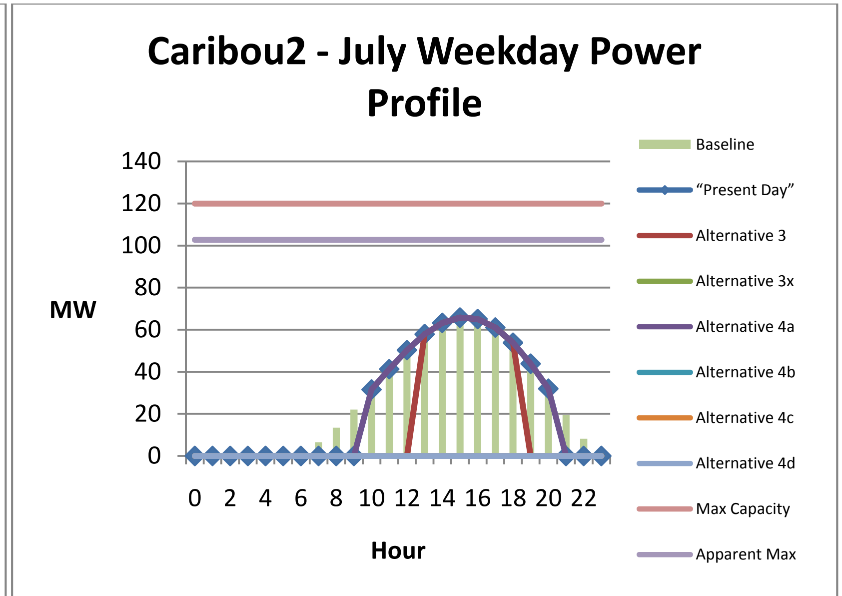


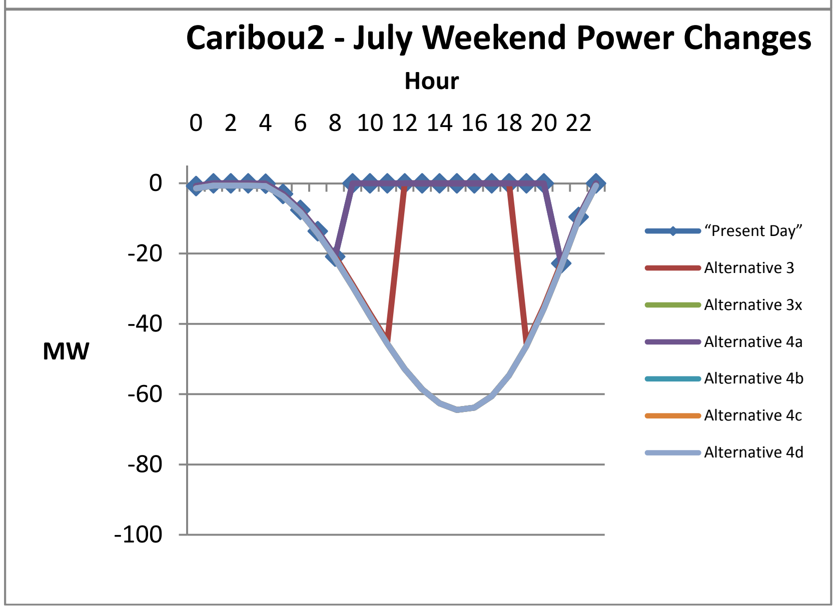


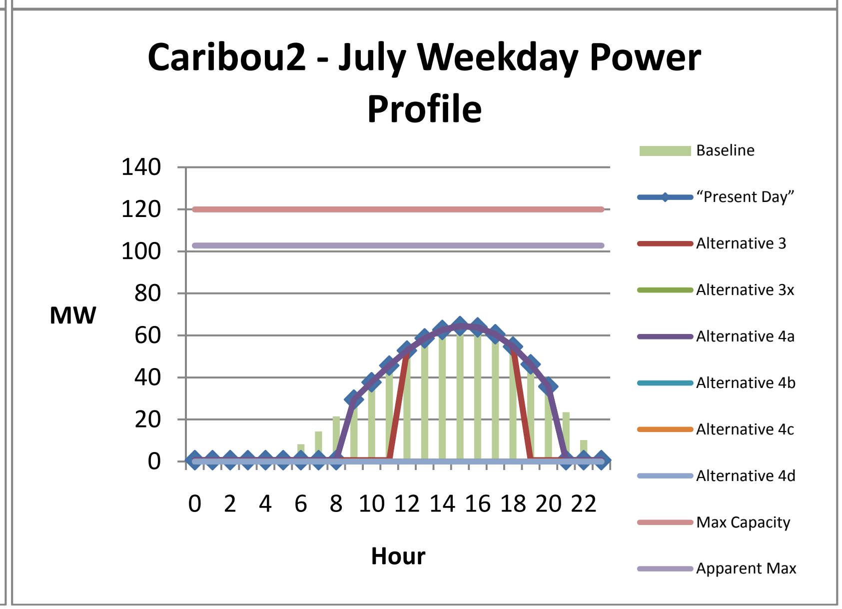


Hourly Operational Changes: 2002 Butt Valley

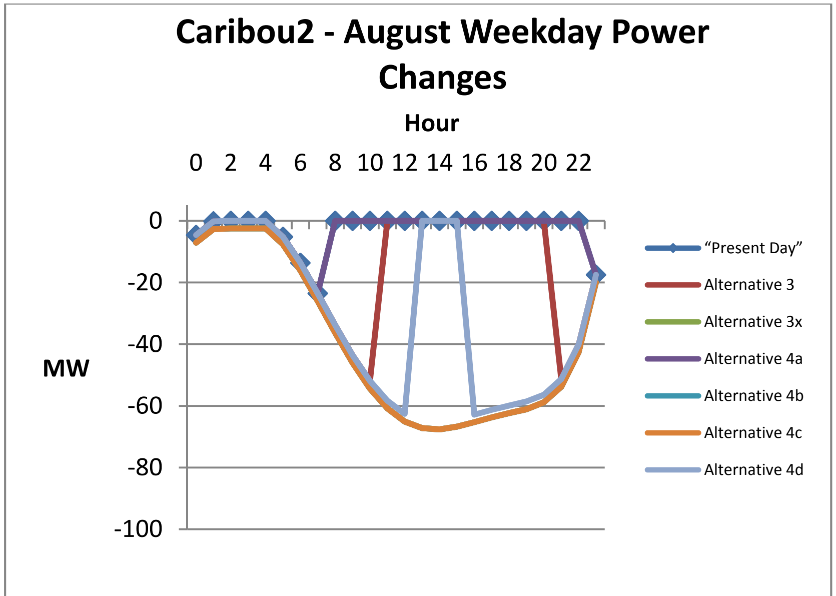


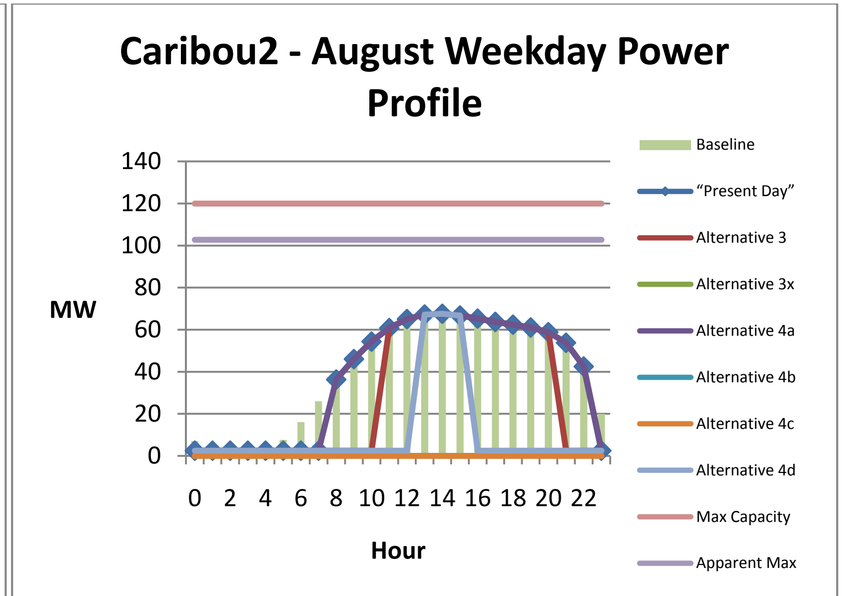


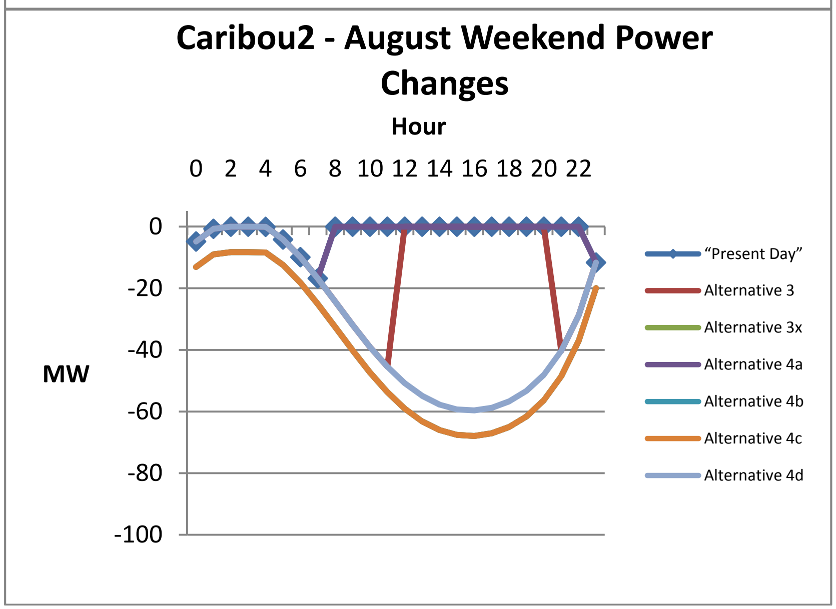


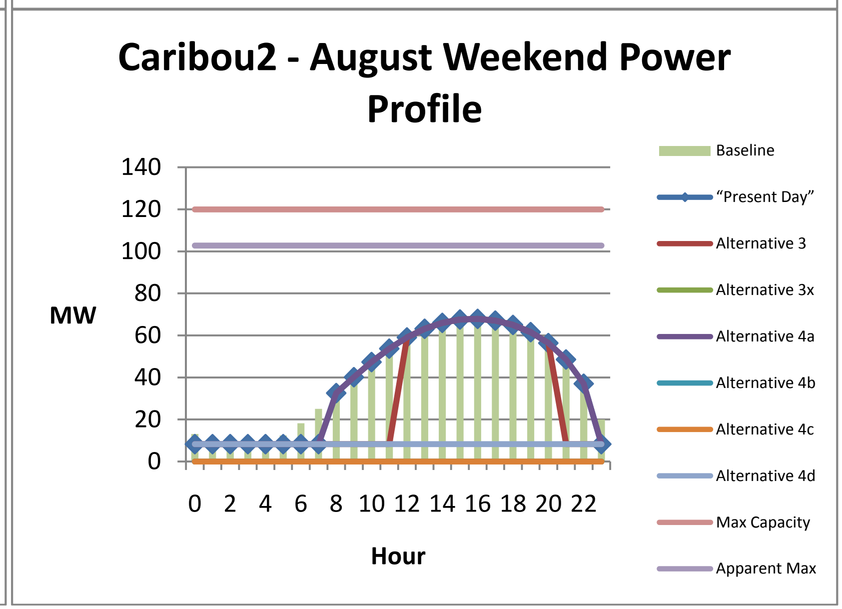


Hourly Operational Changes: 2002 Butt Valley

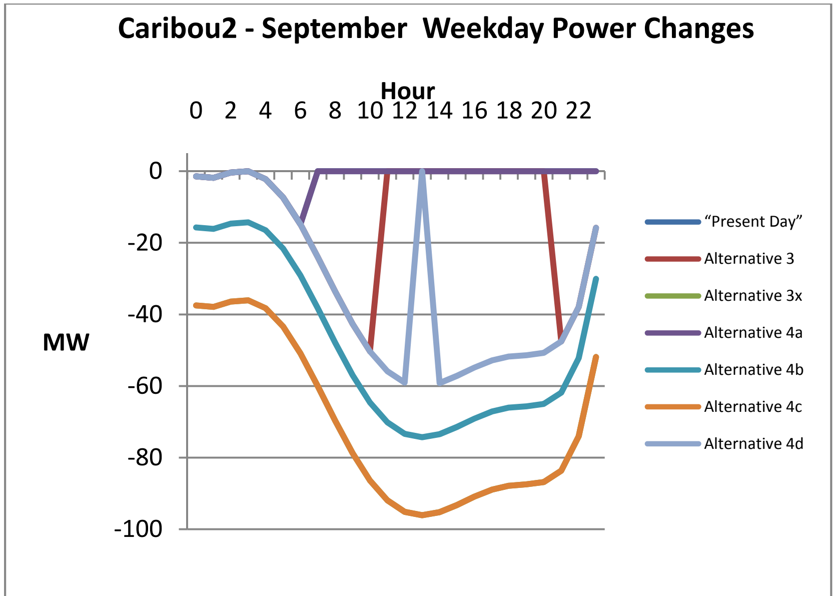


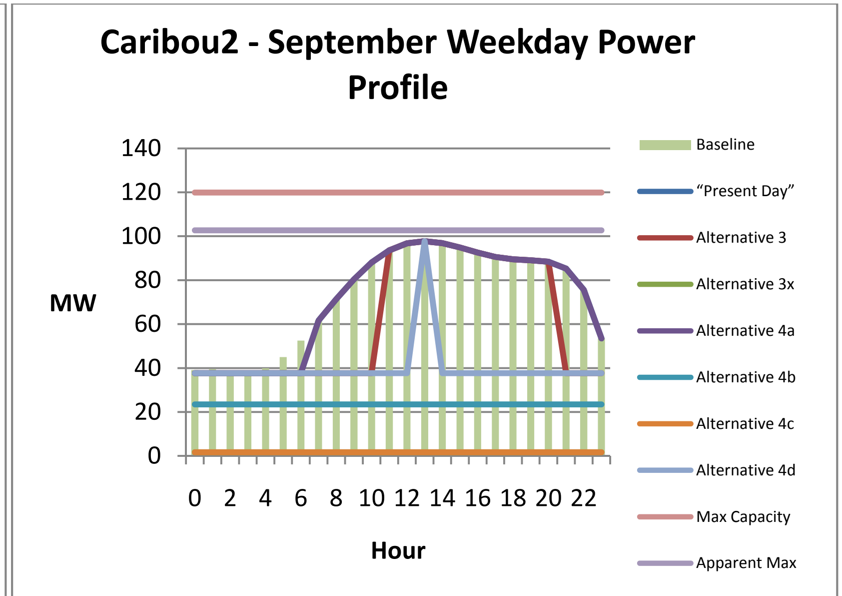


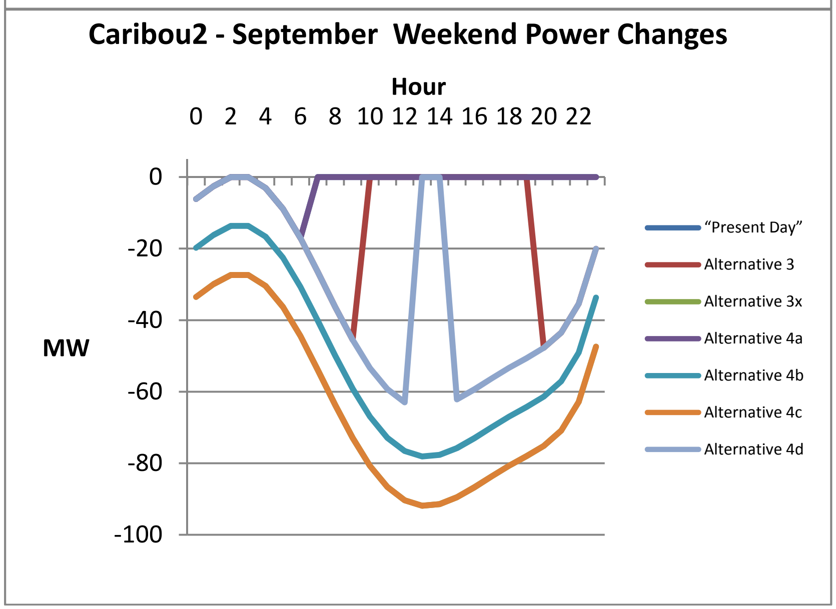


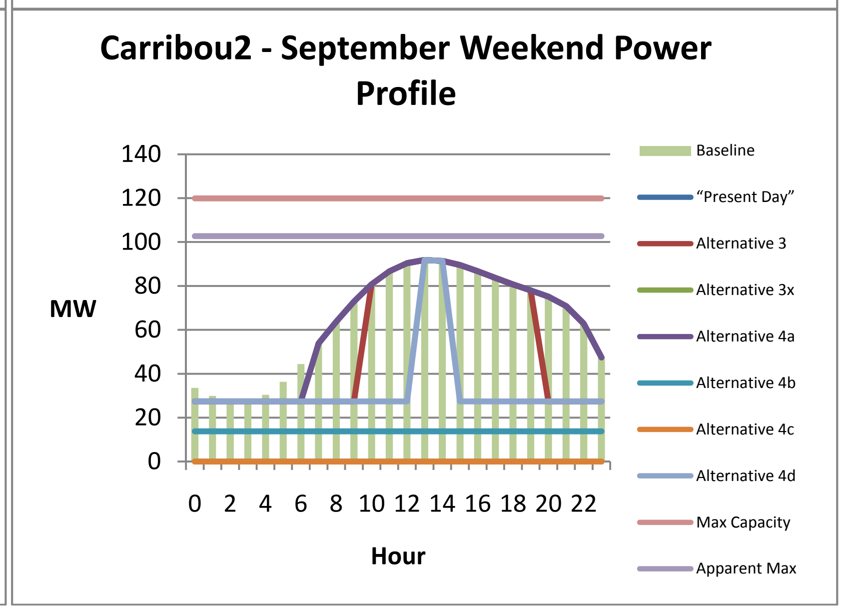


Hourly Operational Changes: 2002 Butt Valley



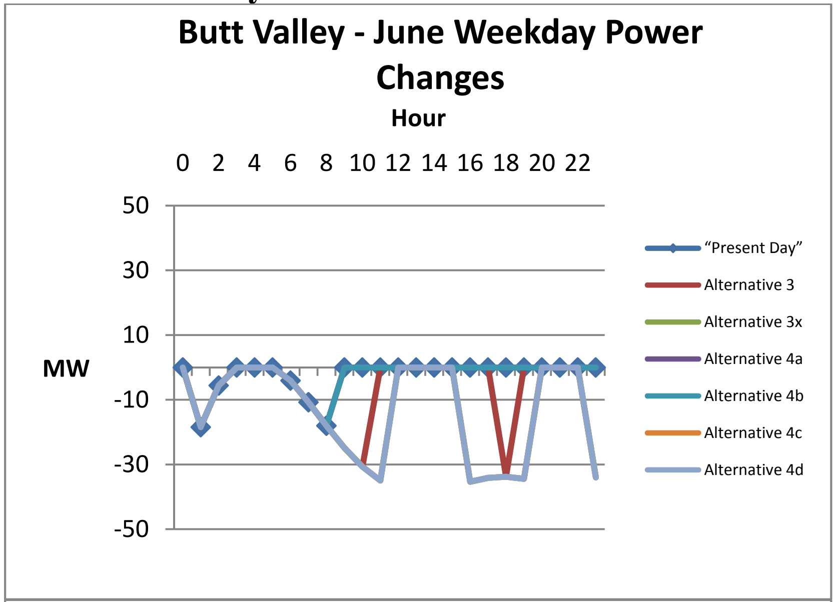


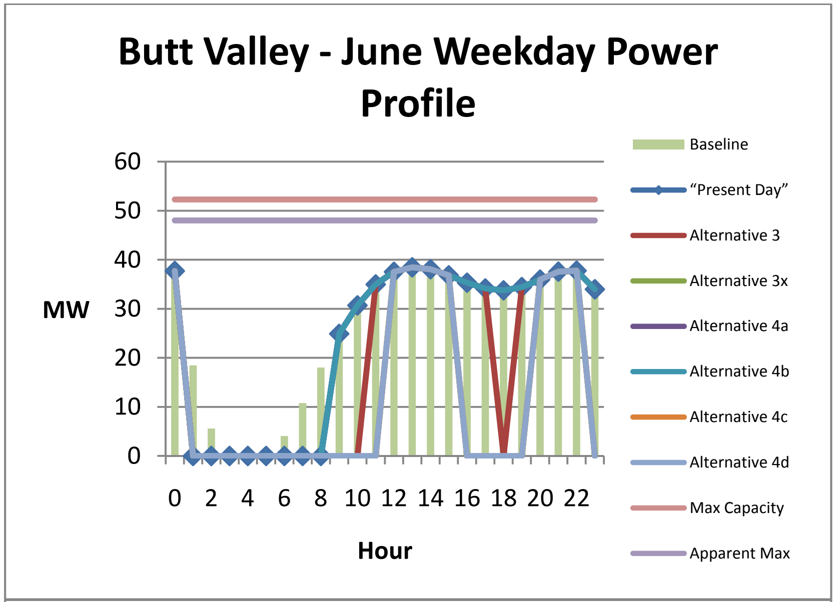


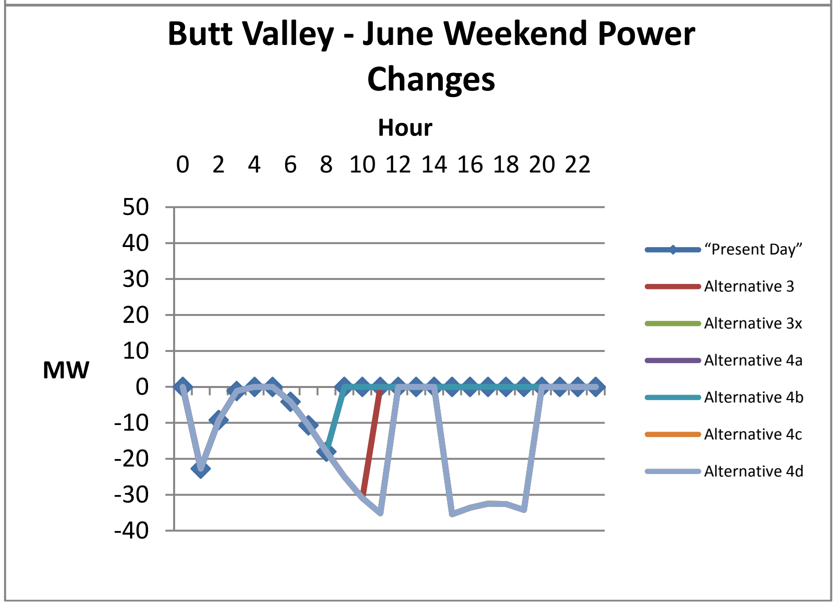


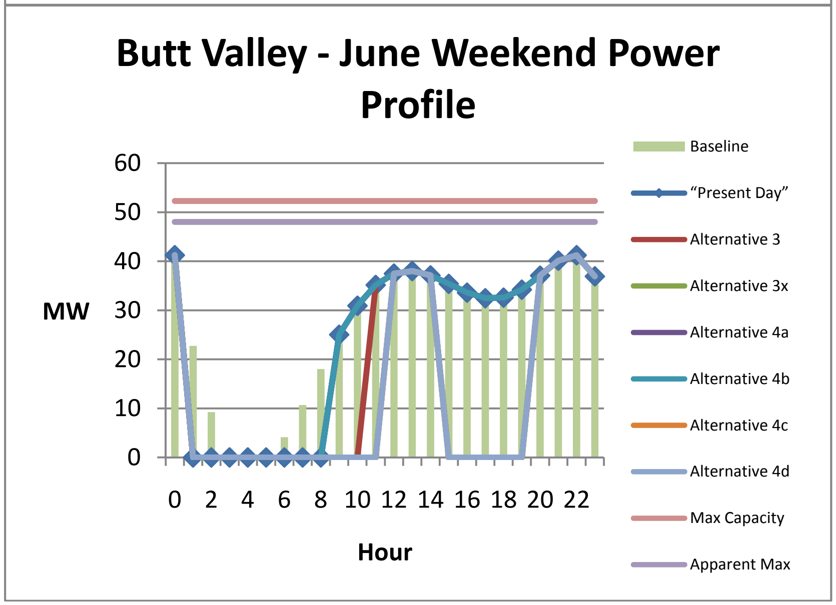
Hourly Operational Changes: 2002 Butt Valley

2003 Butt Valley









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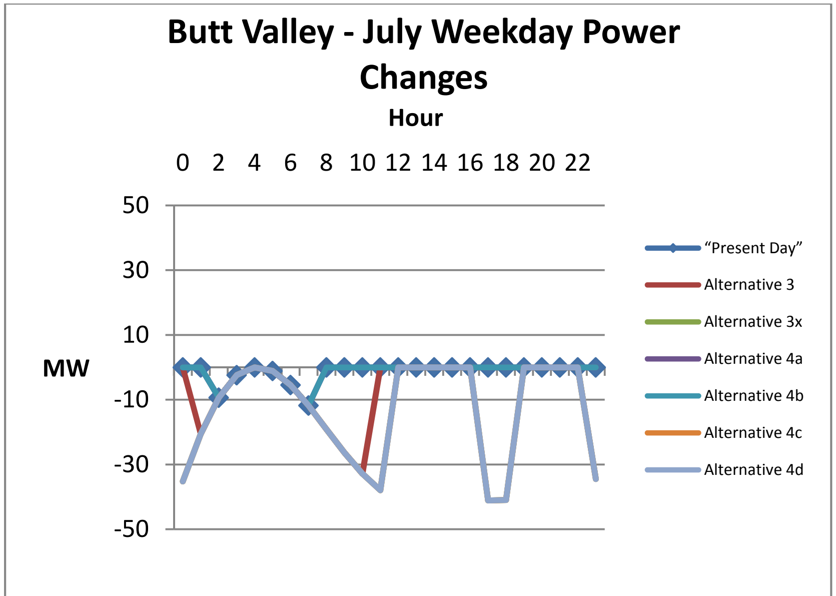

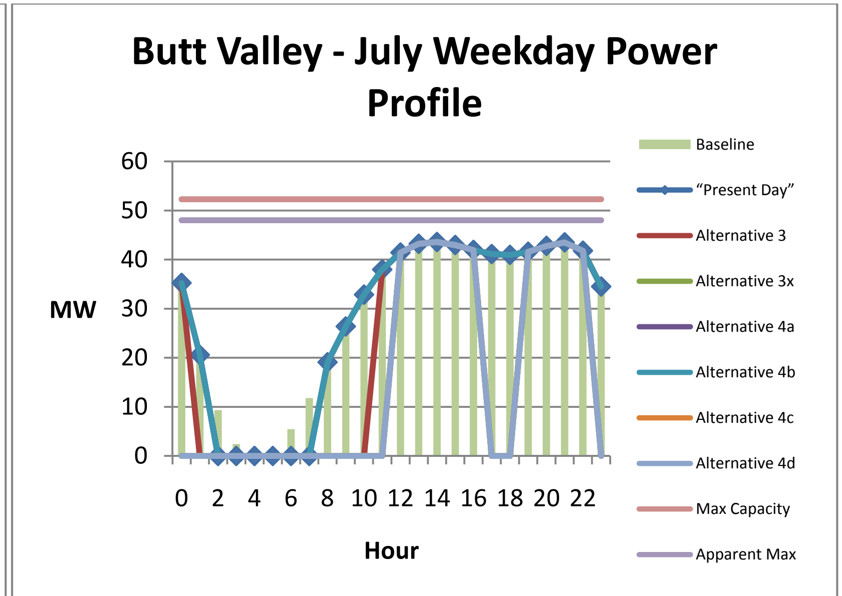

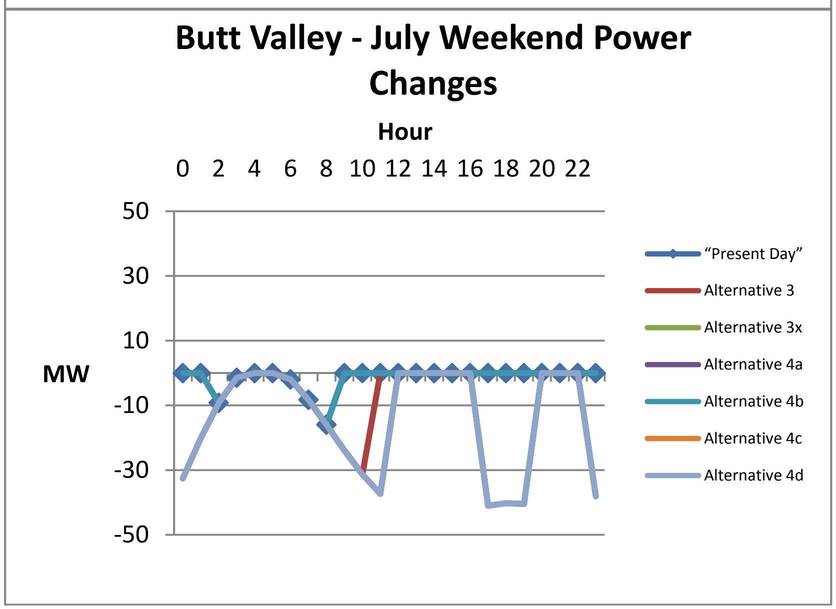

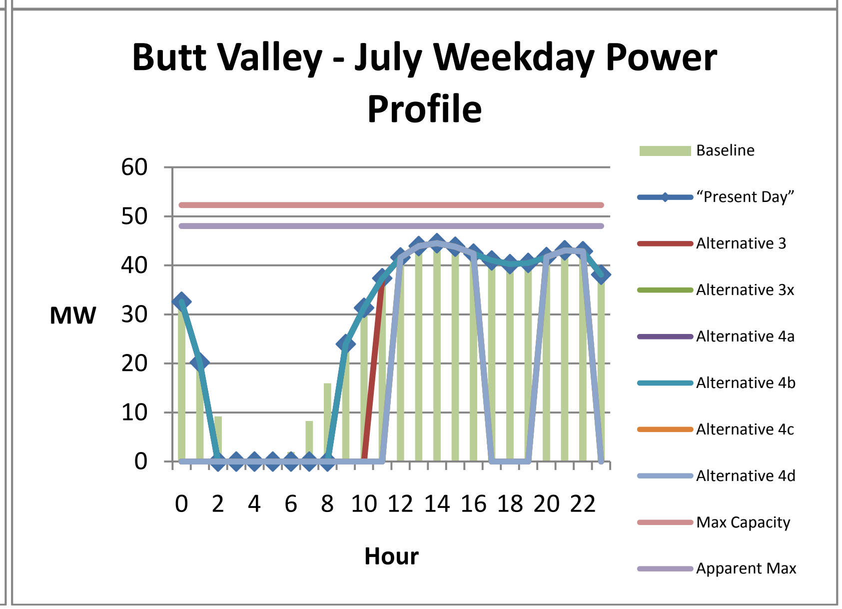

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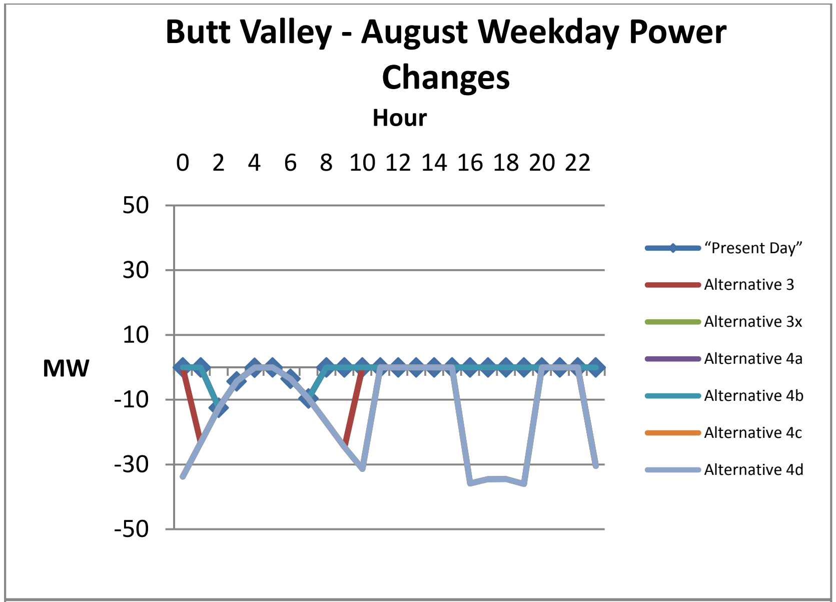

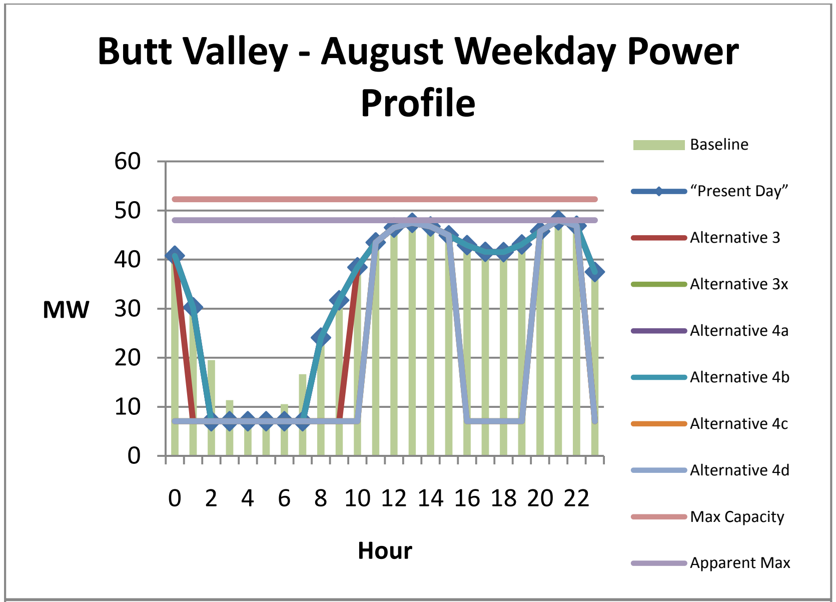

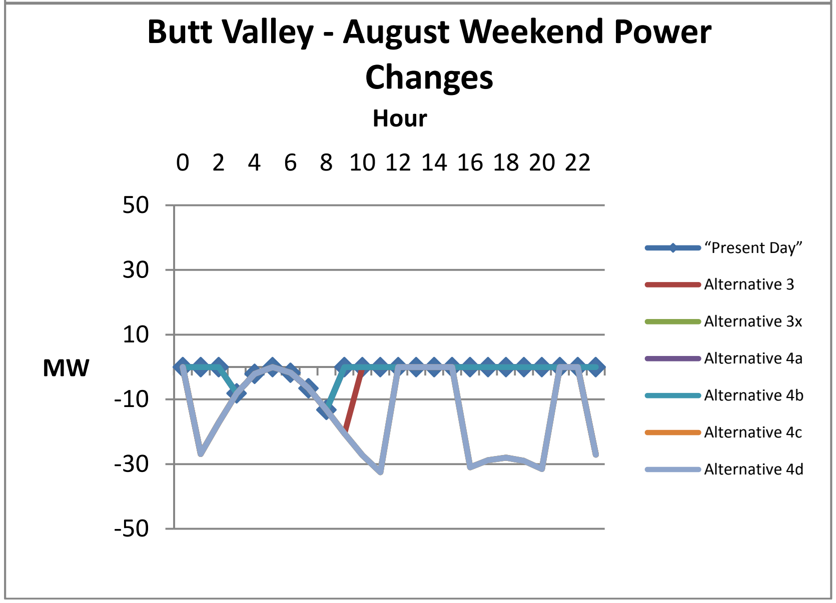

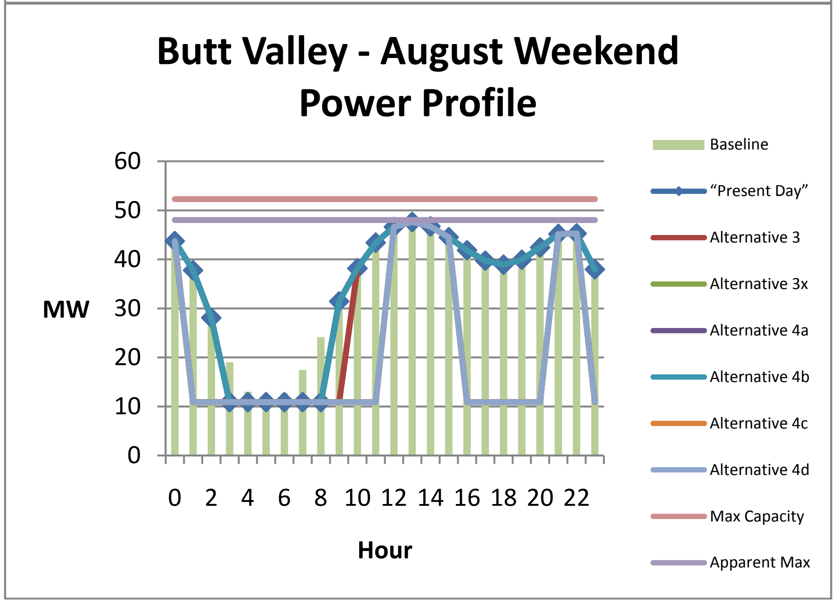

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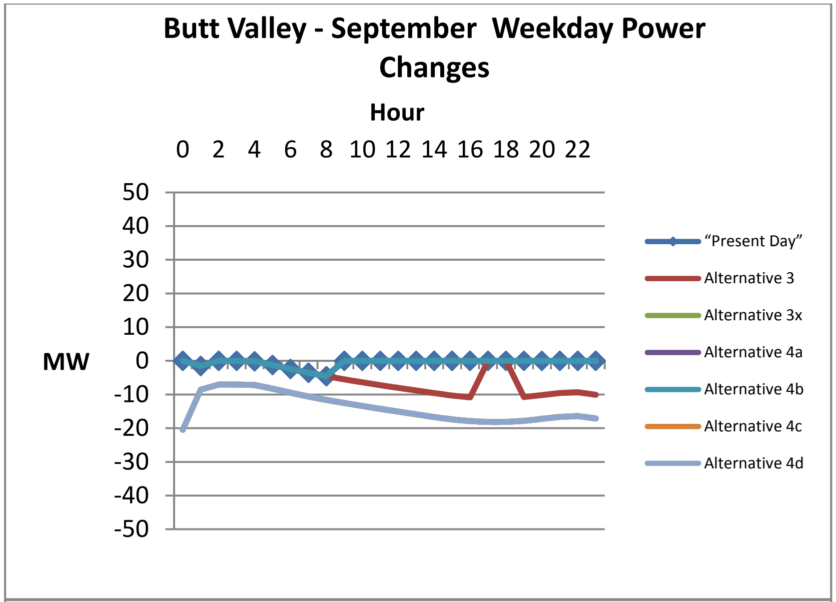
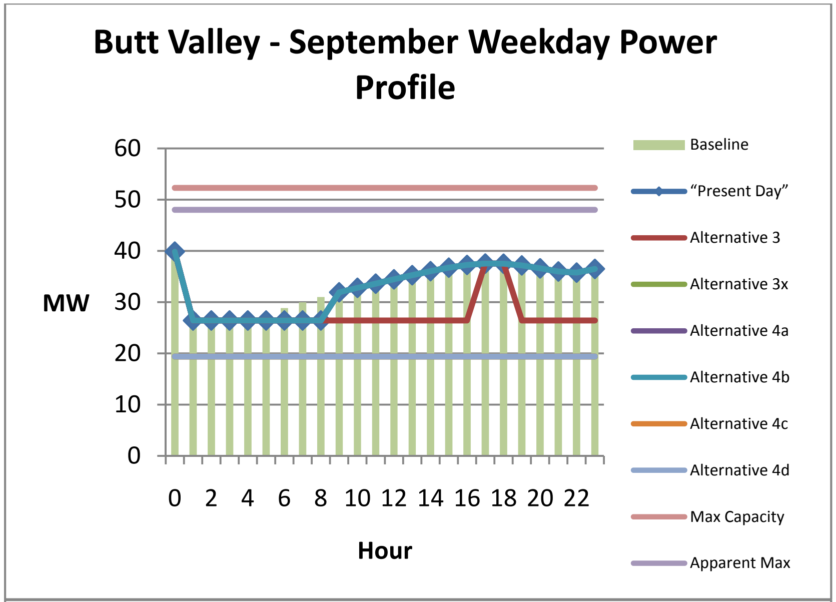
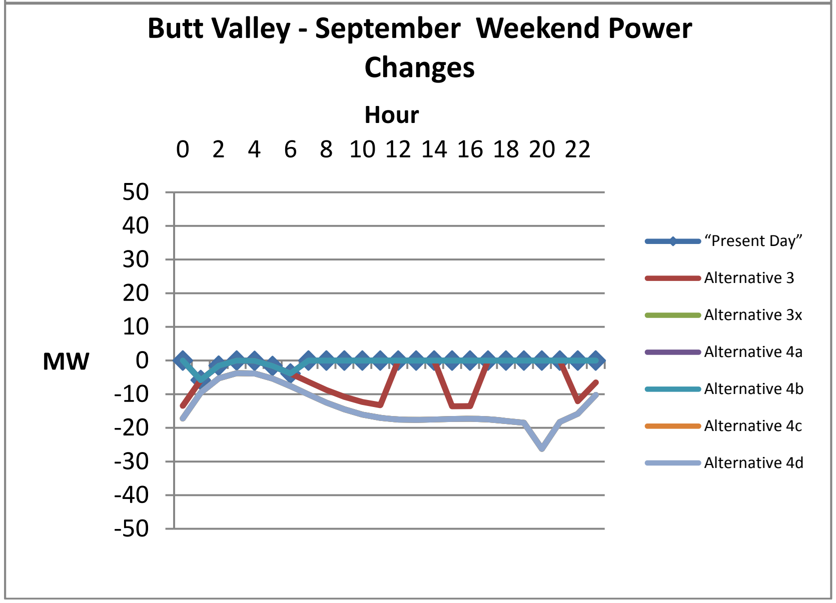
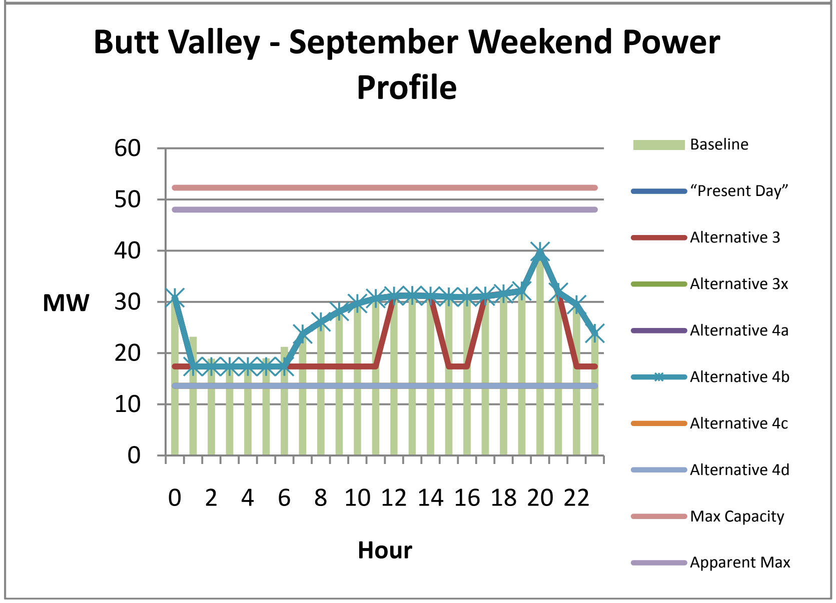
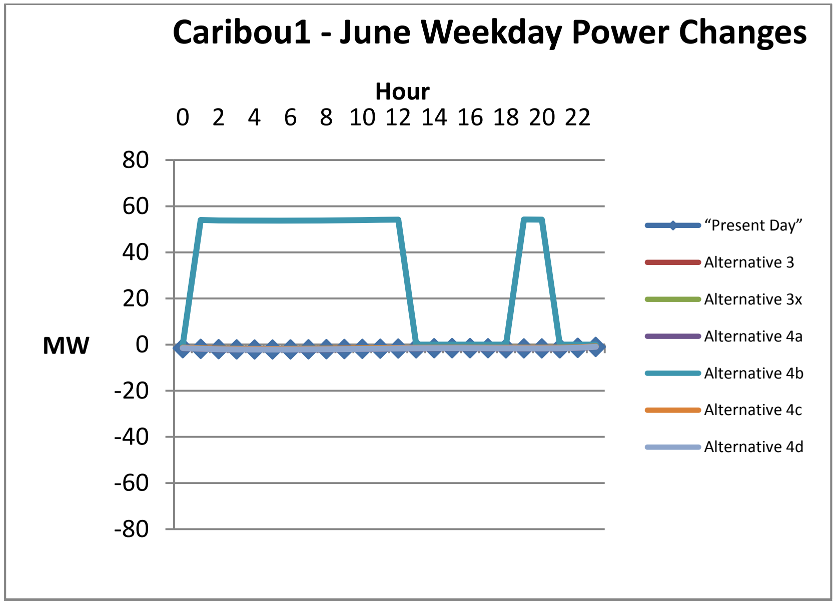


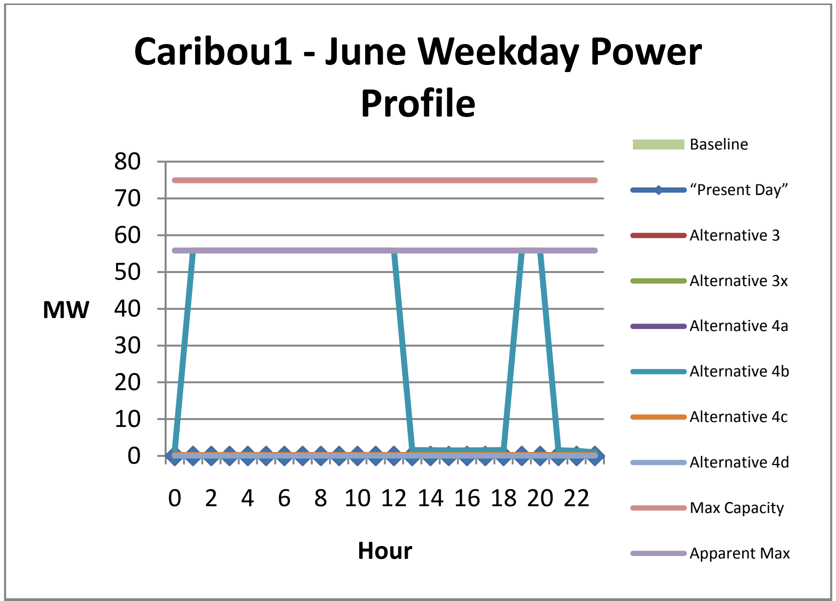


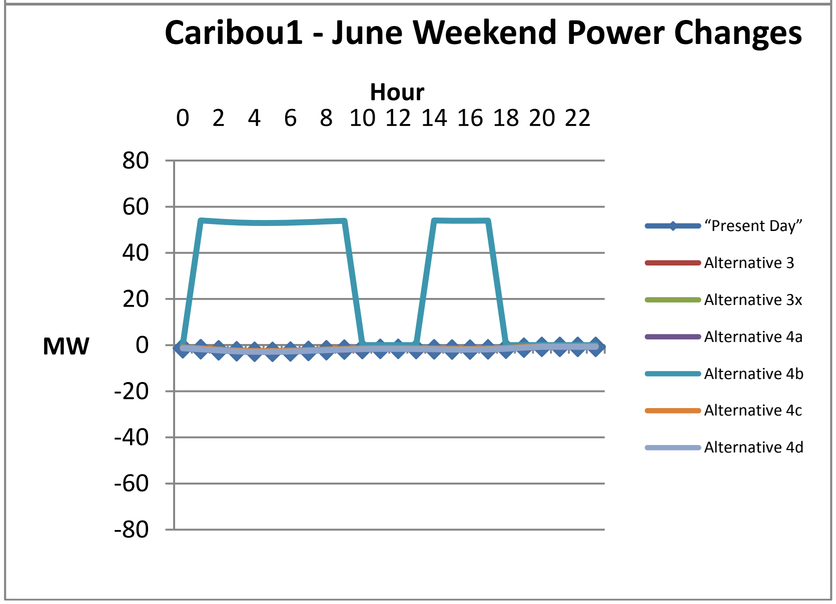


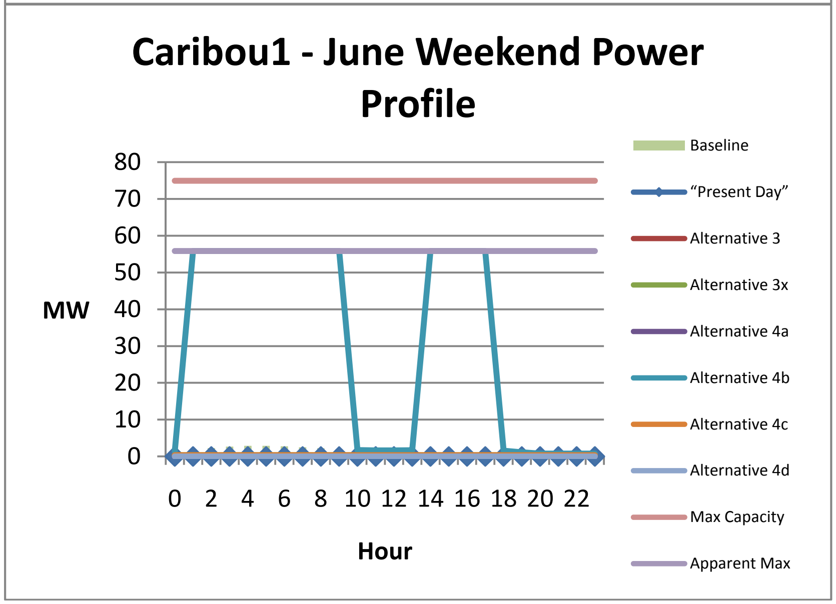


2003 Caribou 1









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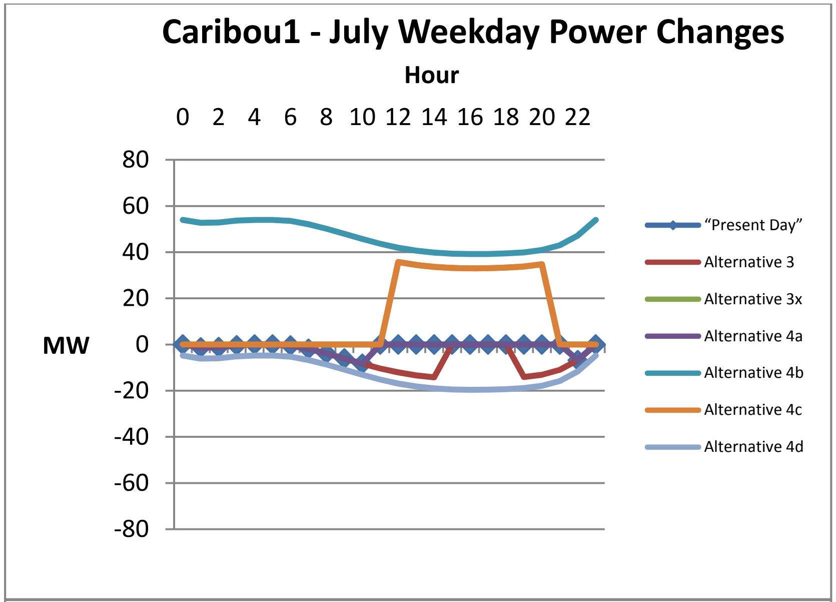

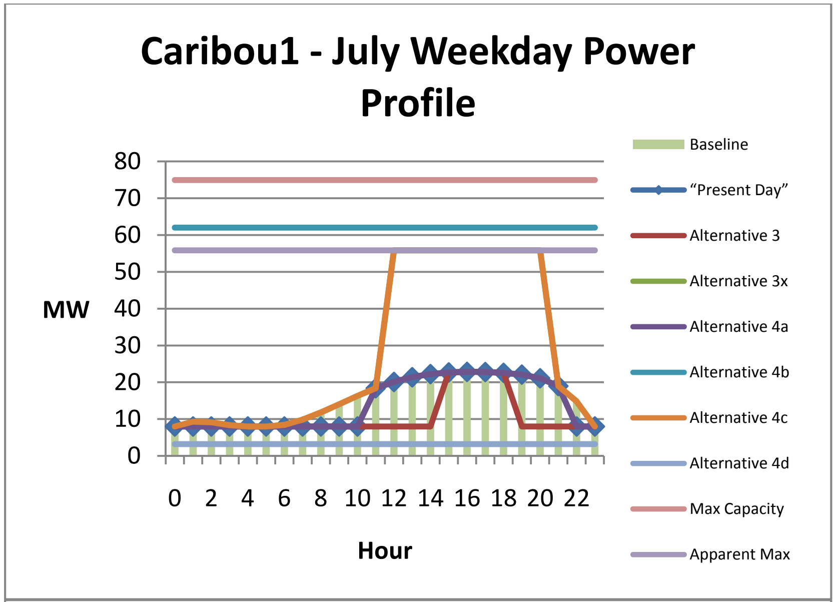

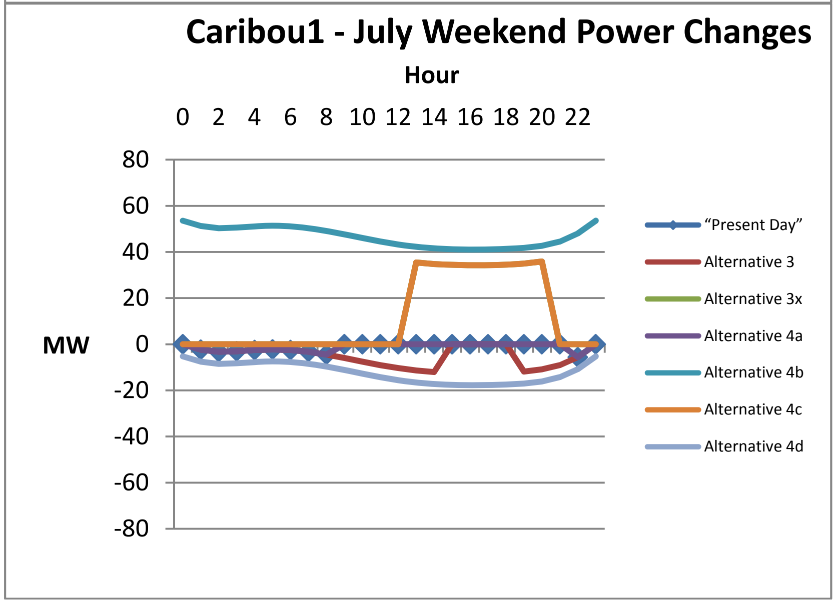

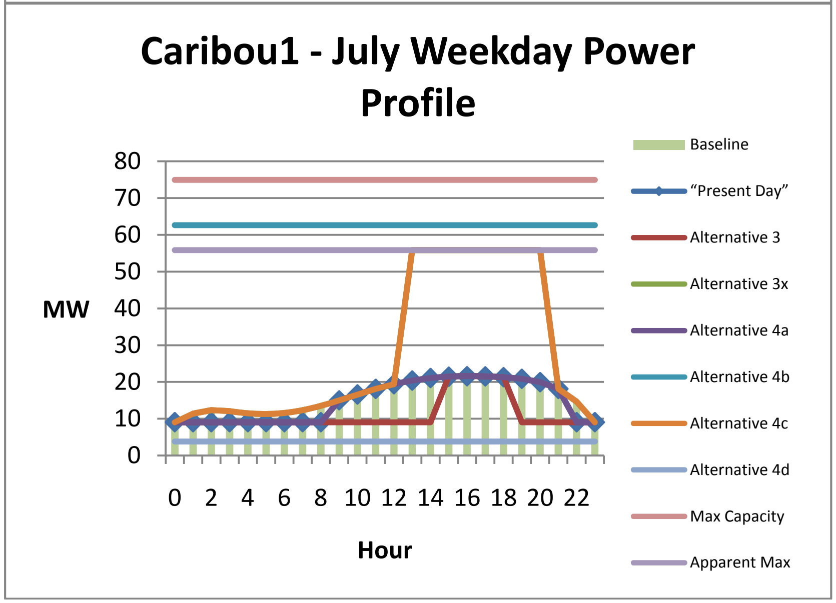

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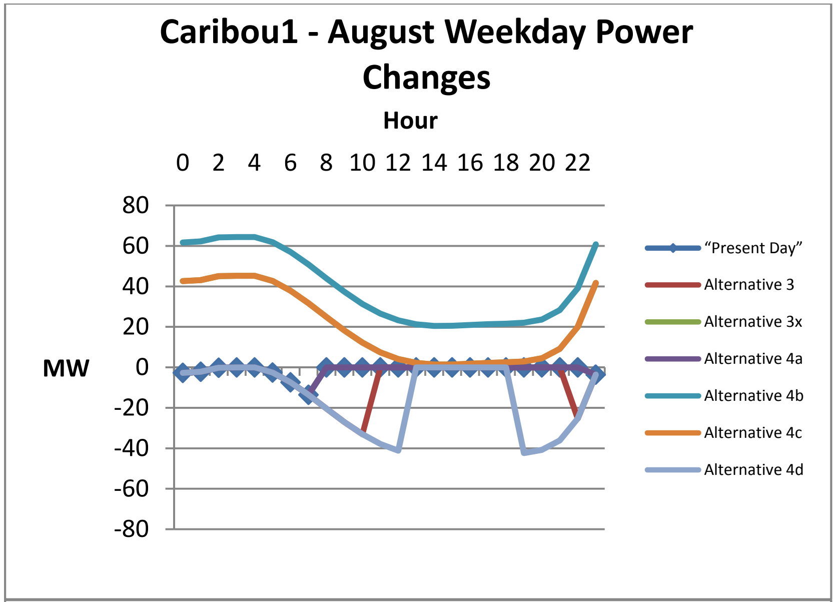

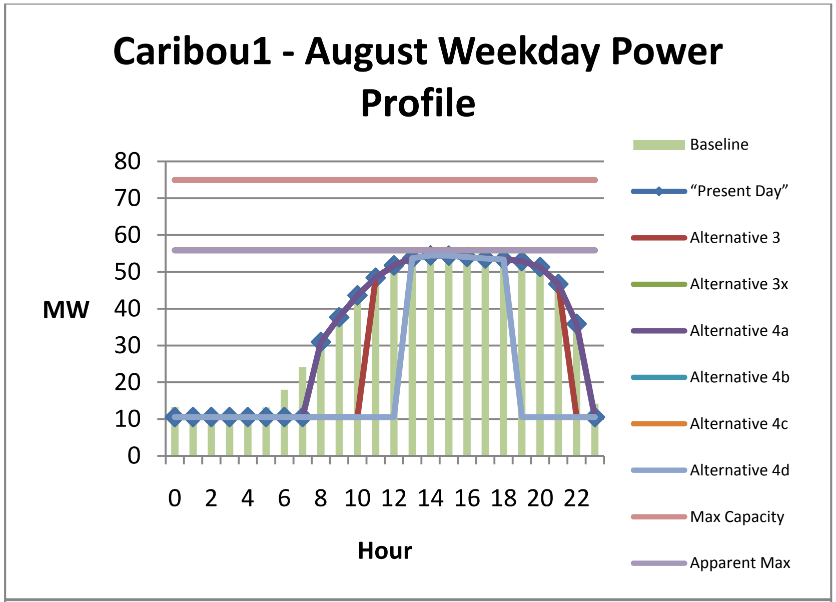

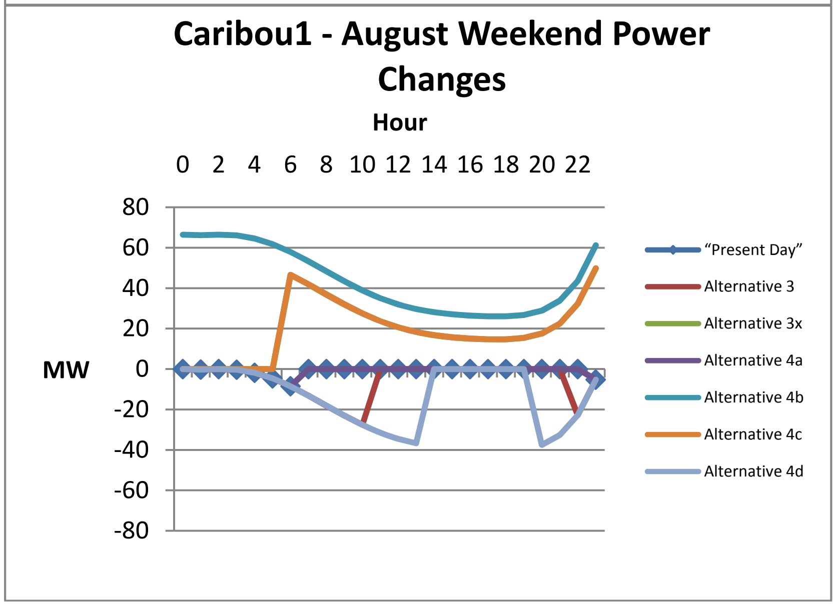

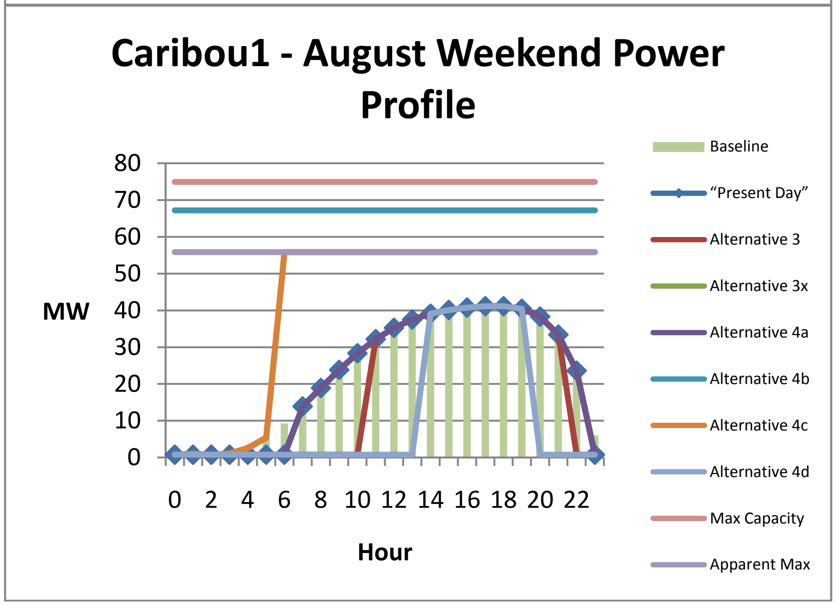

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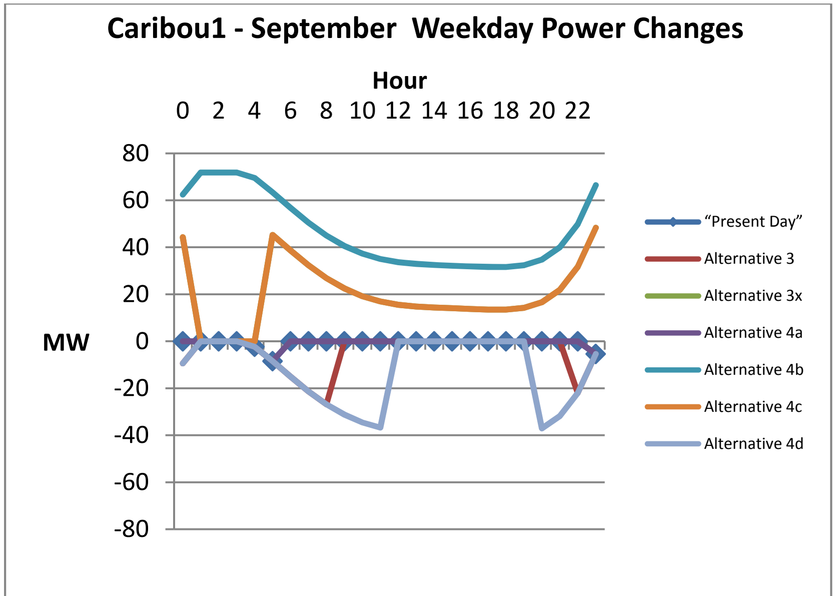
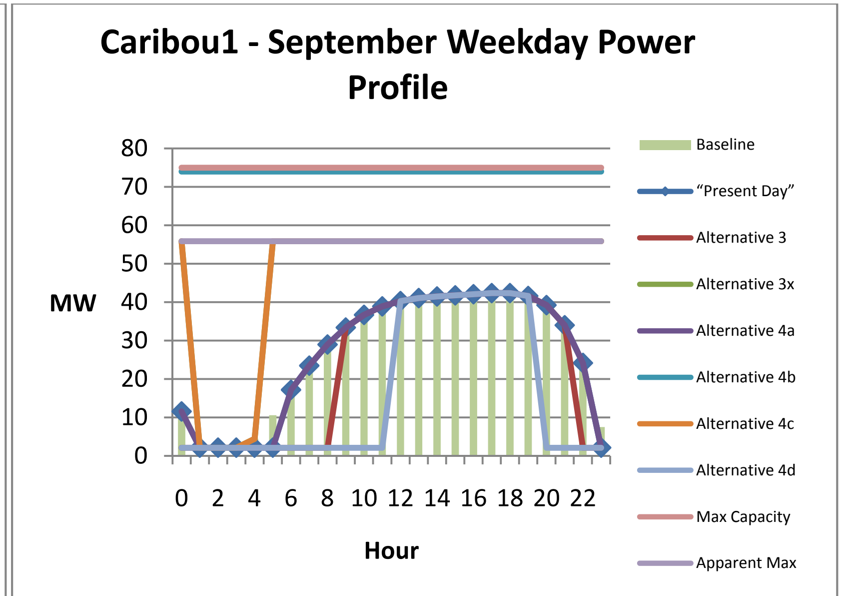
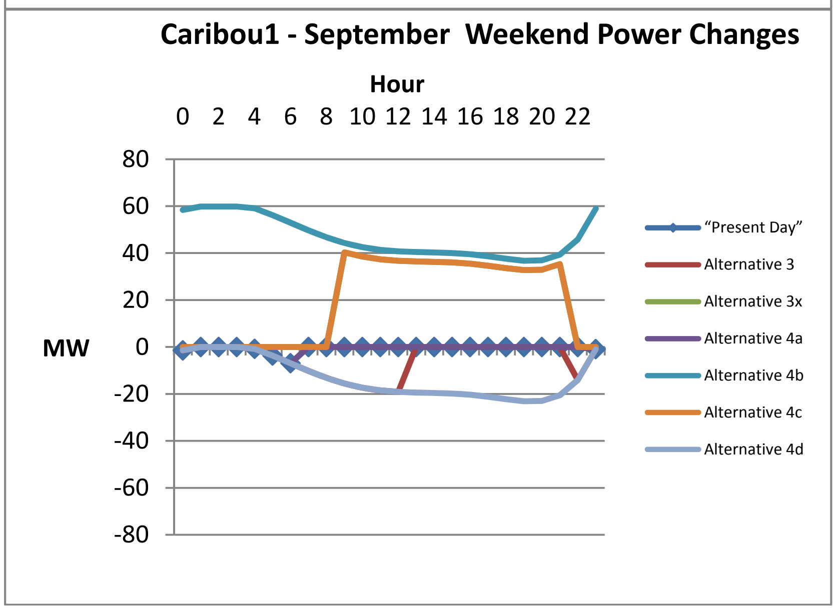
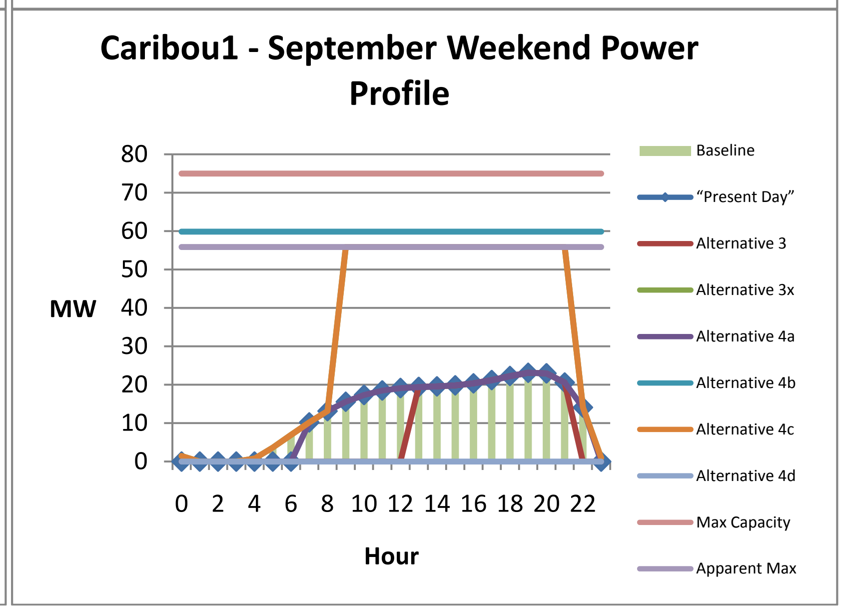
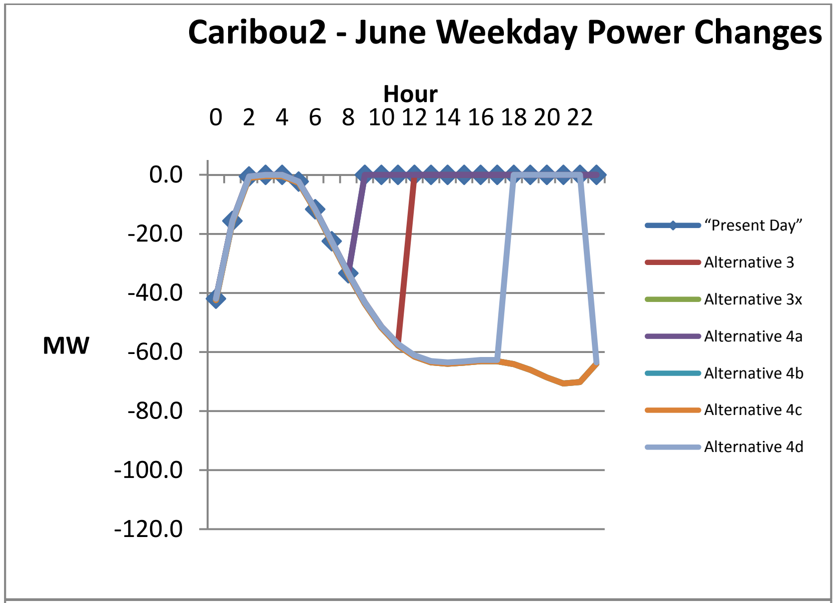


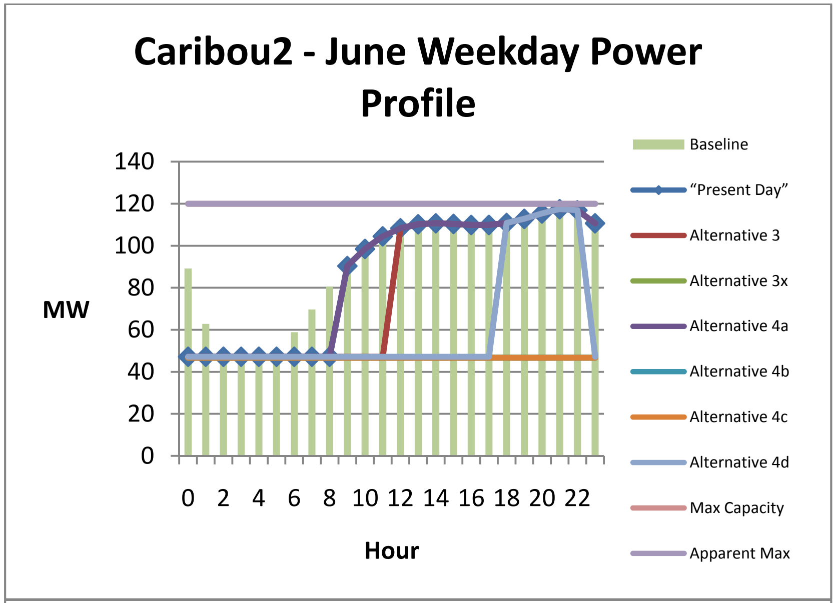


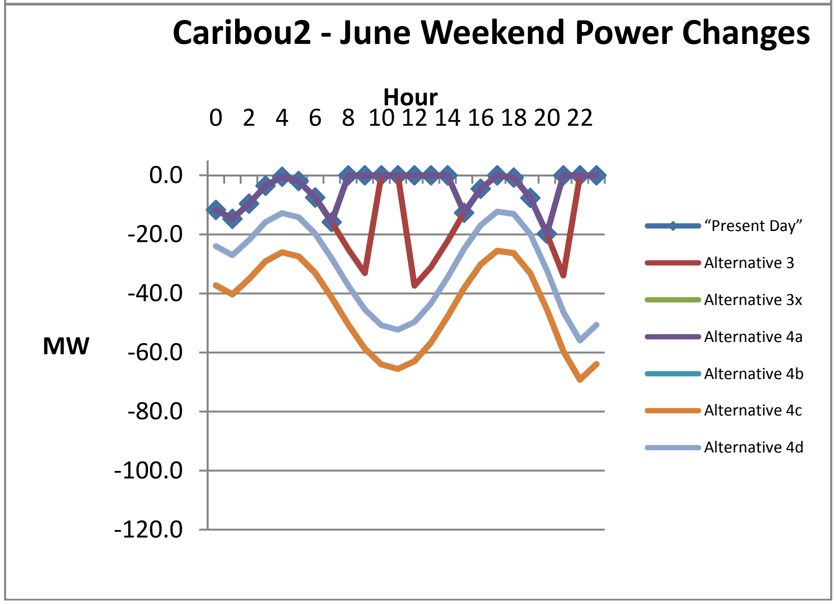


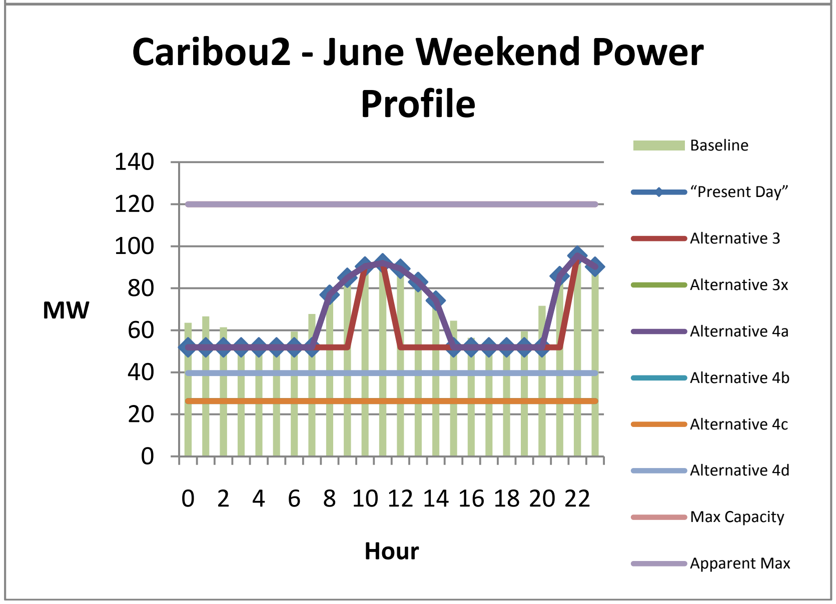


2003 Caribou 2









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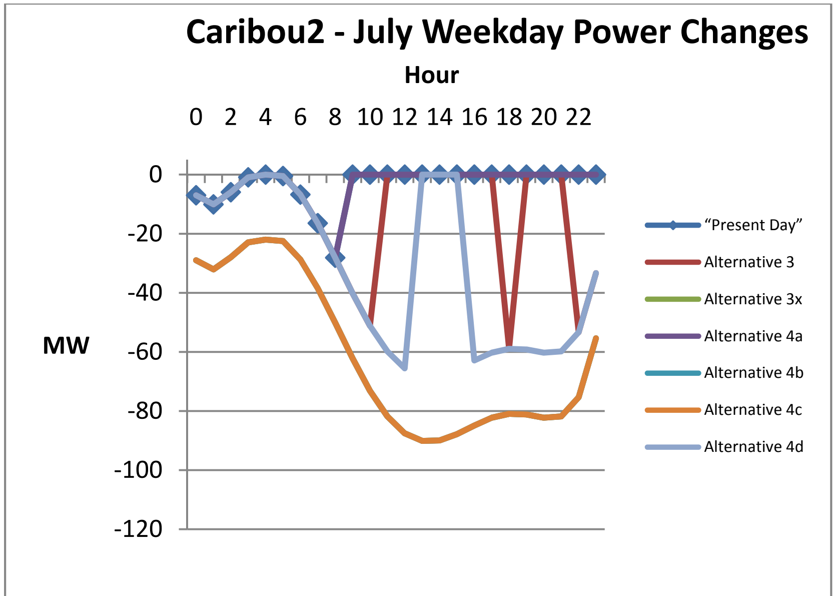

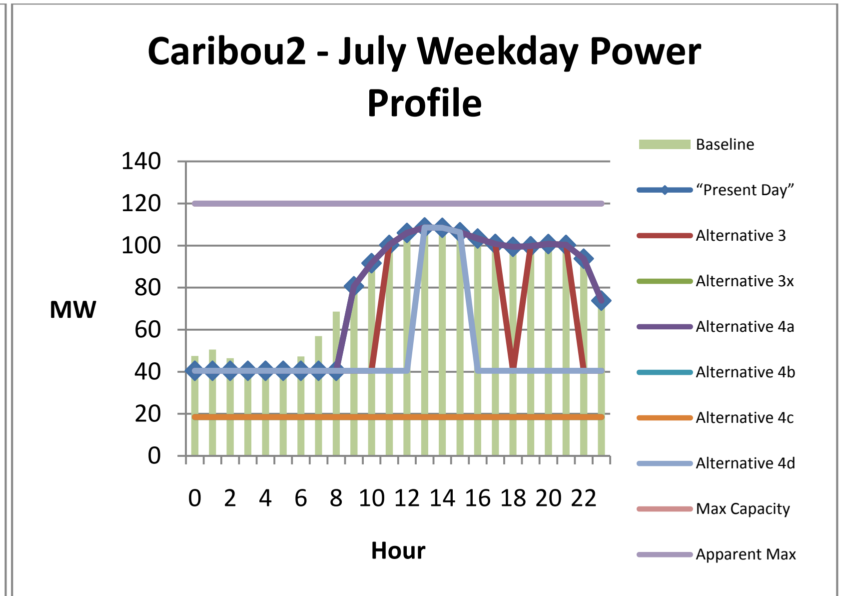

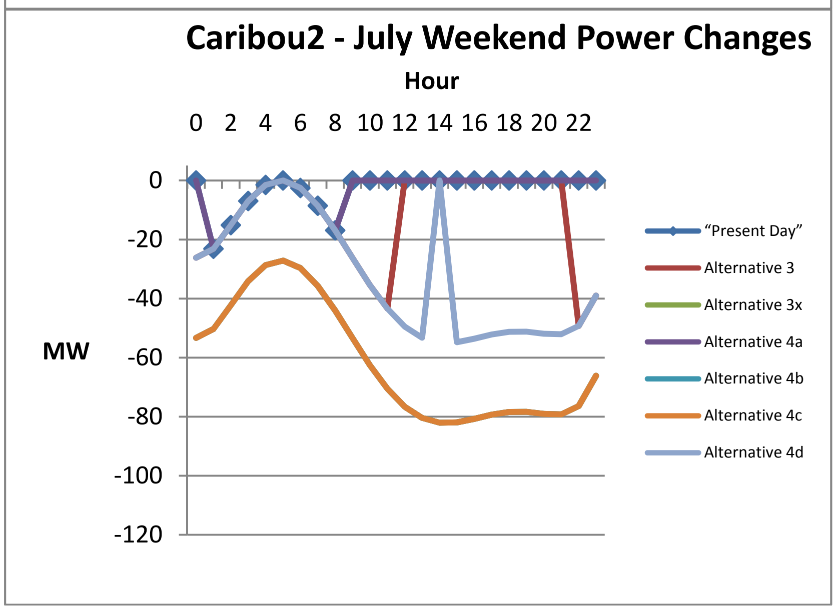

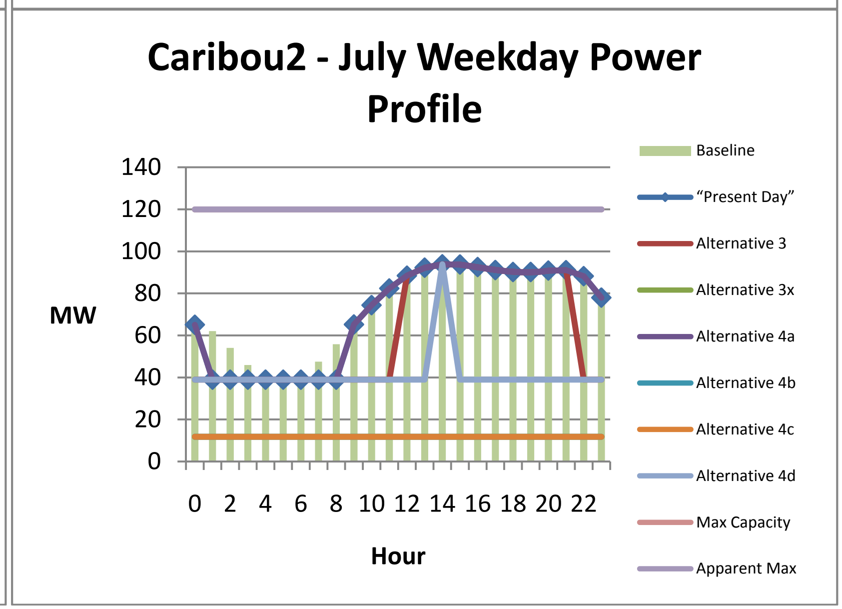

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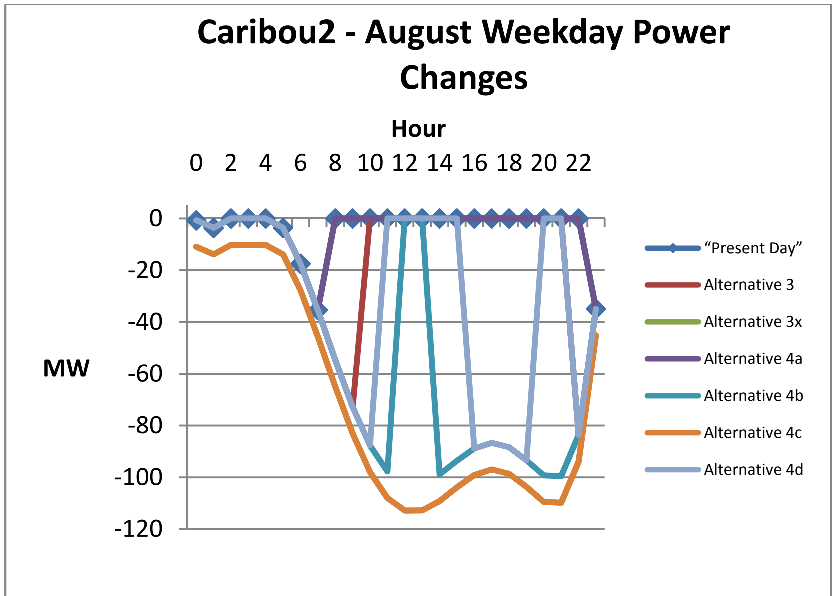

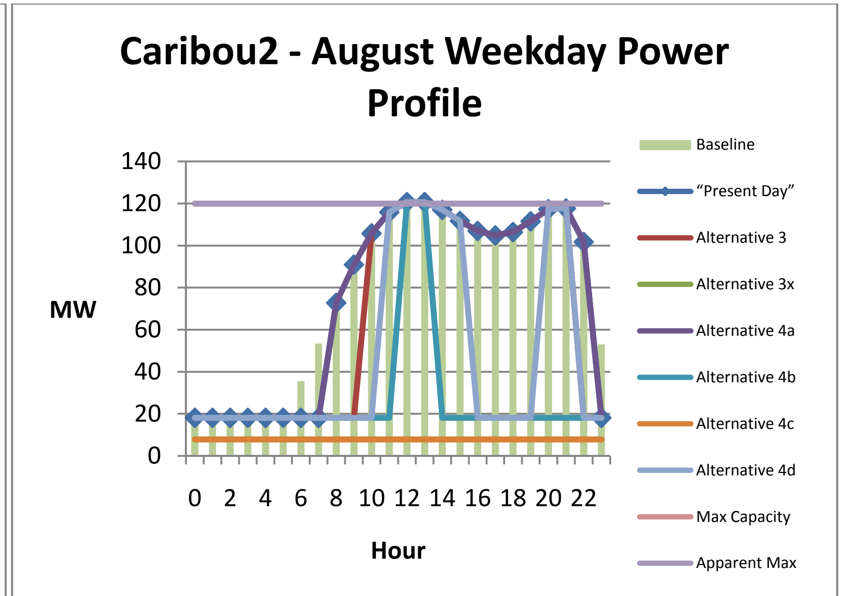

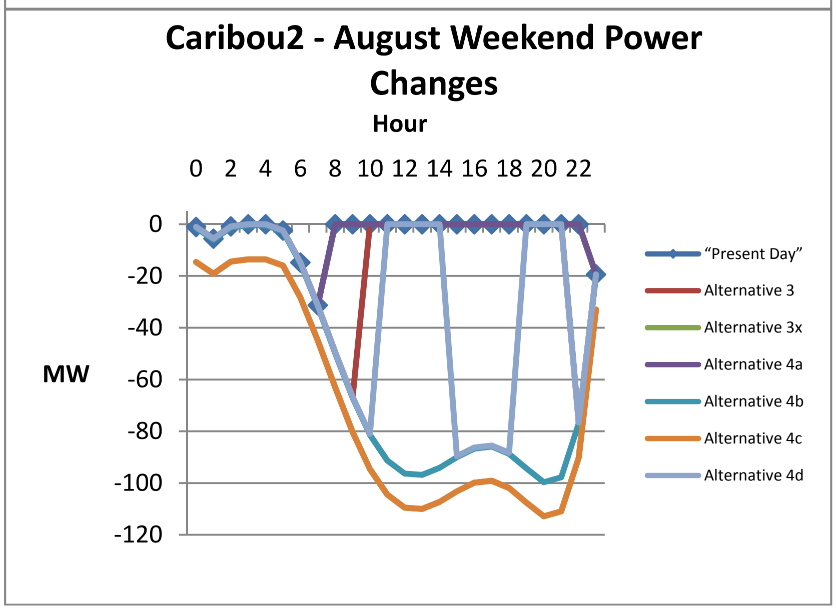

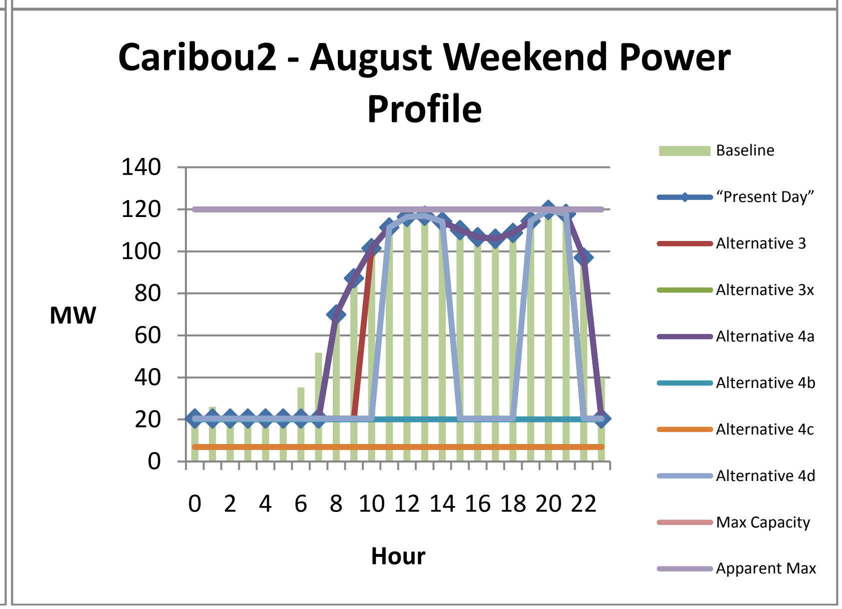

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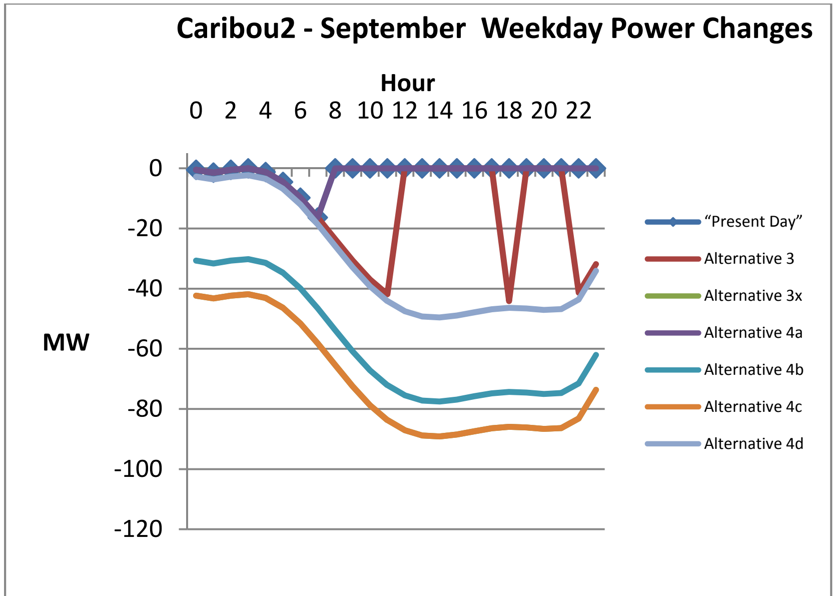

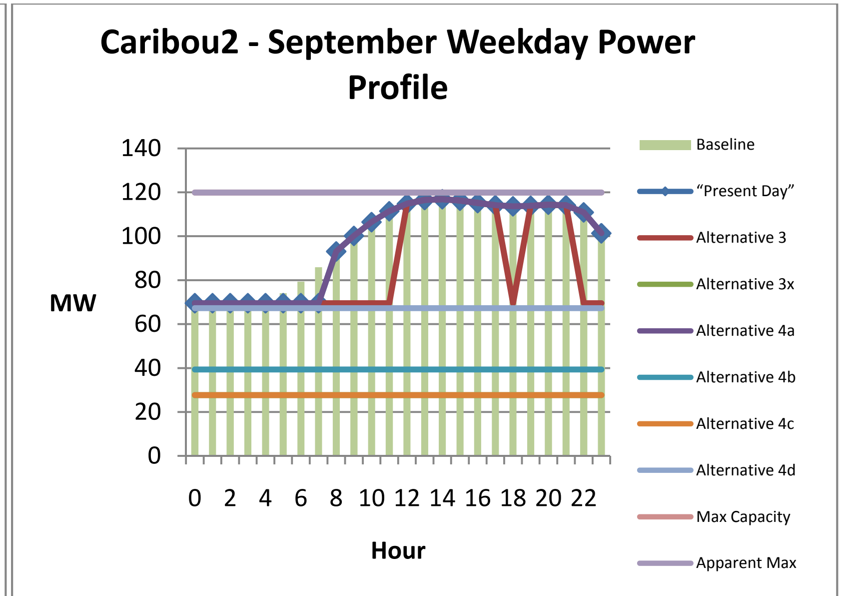

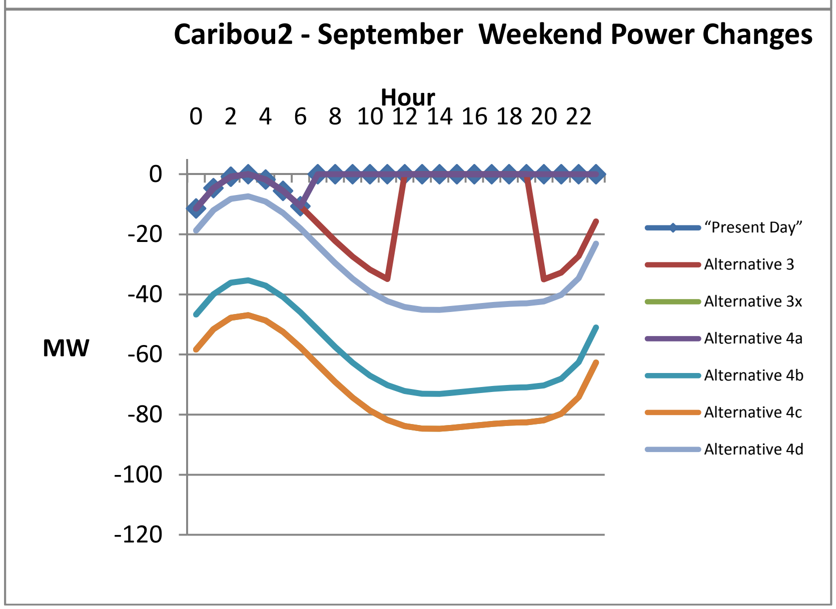

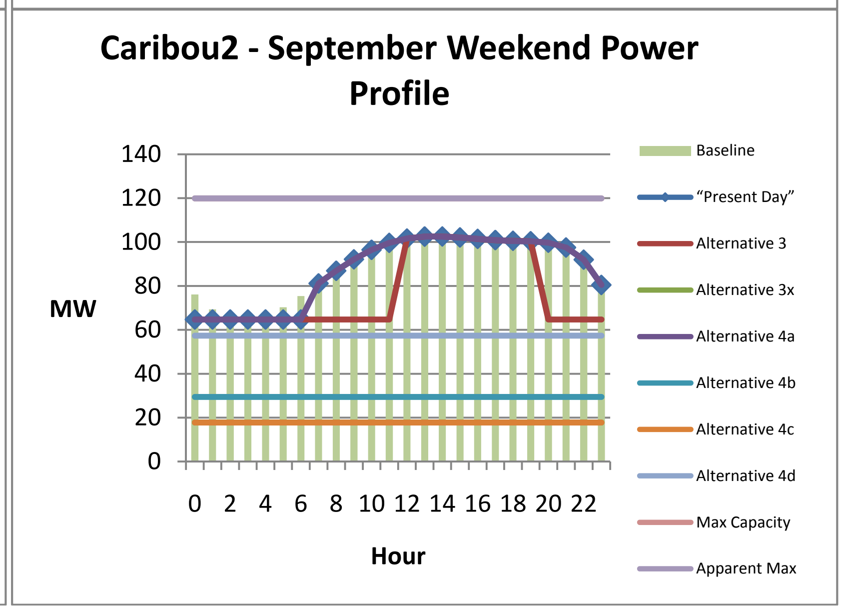

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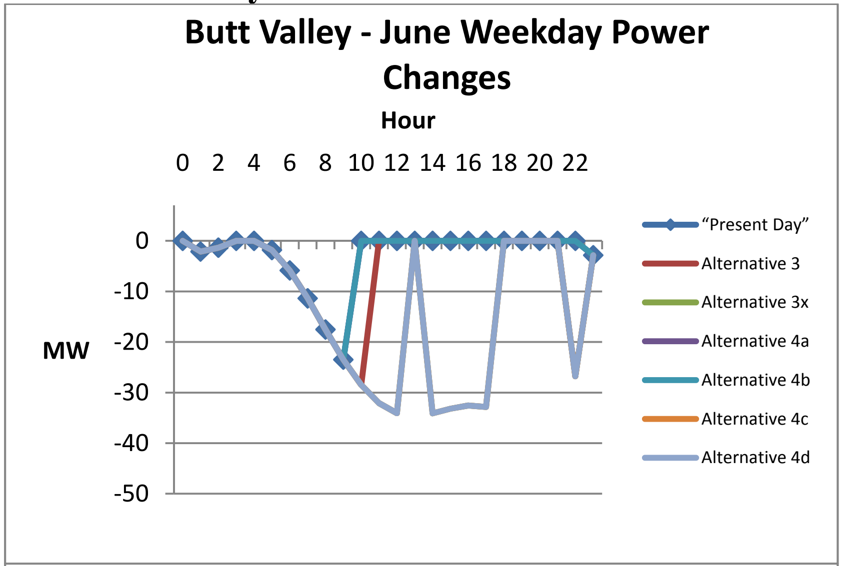

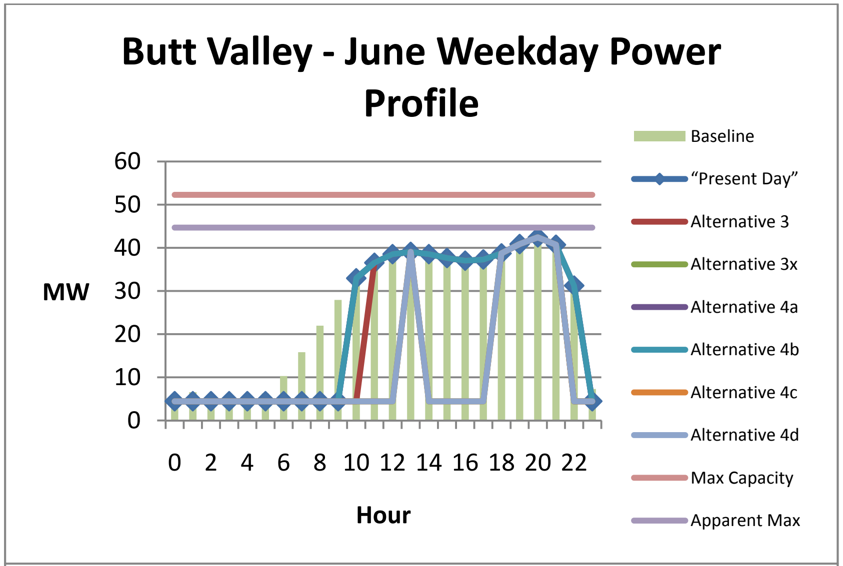

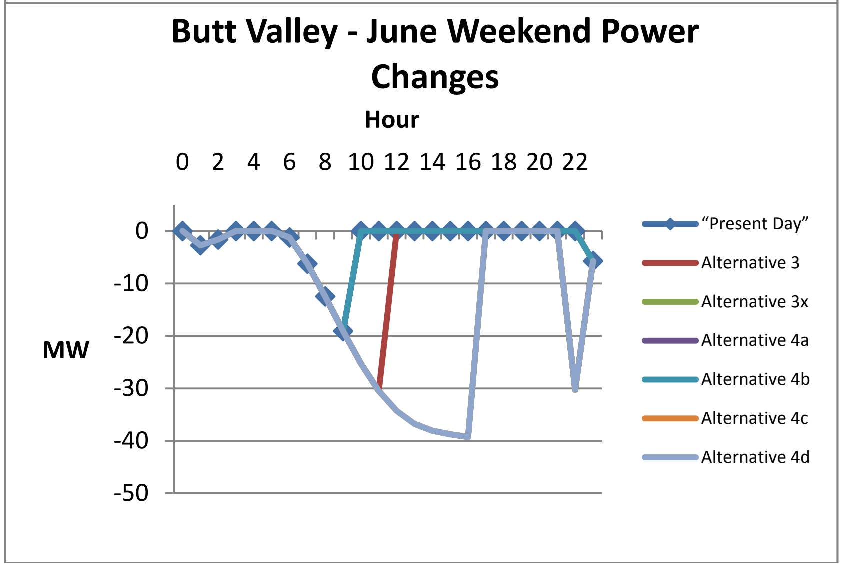

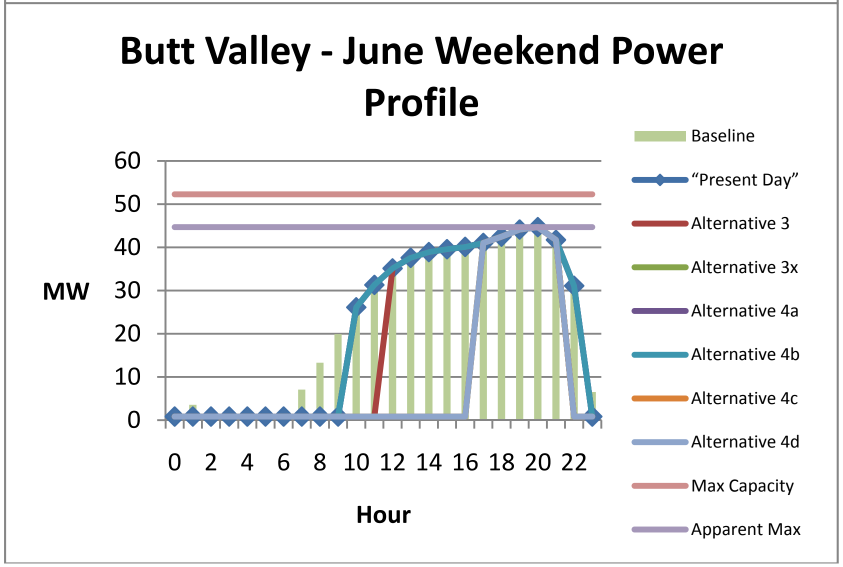

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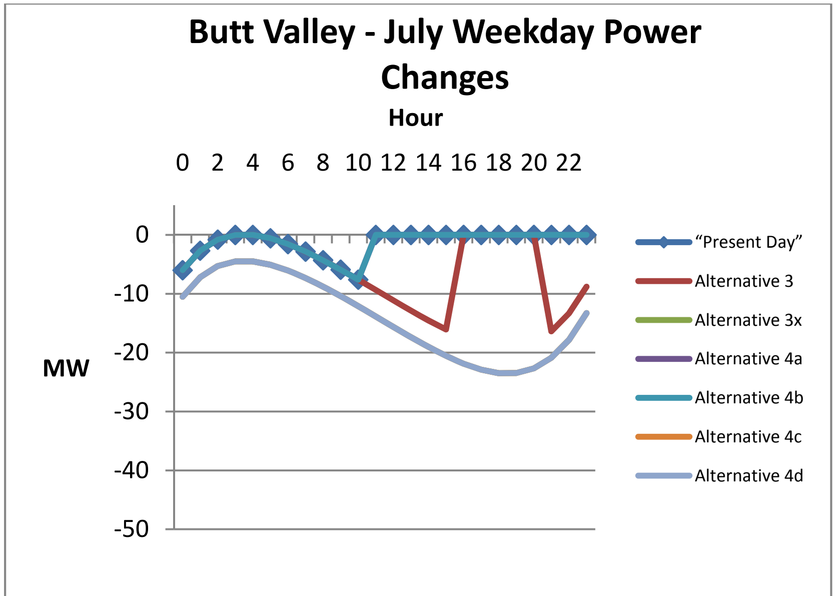

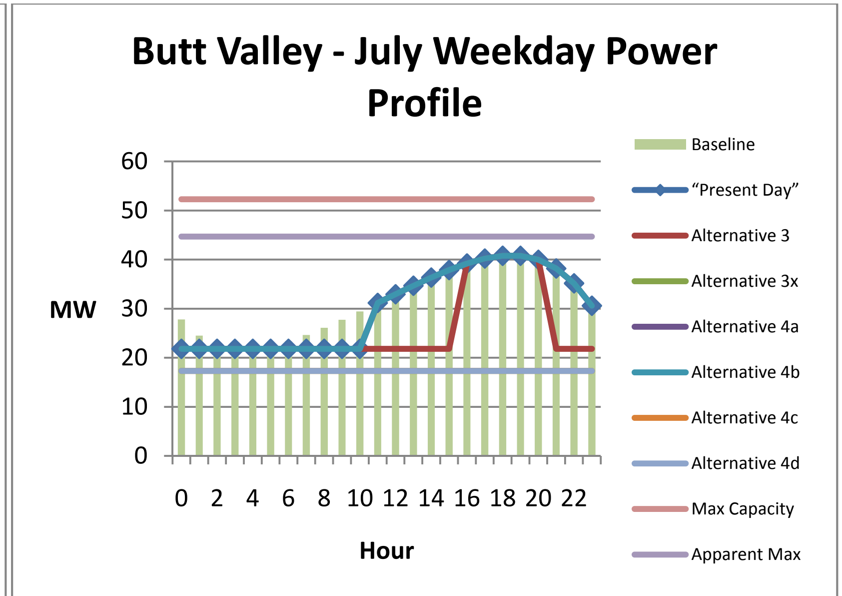

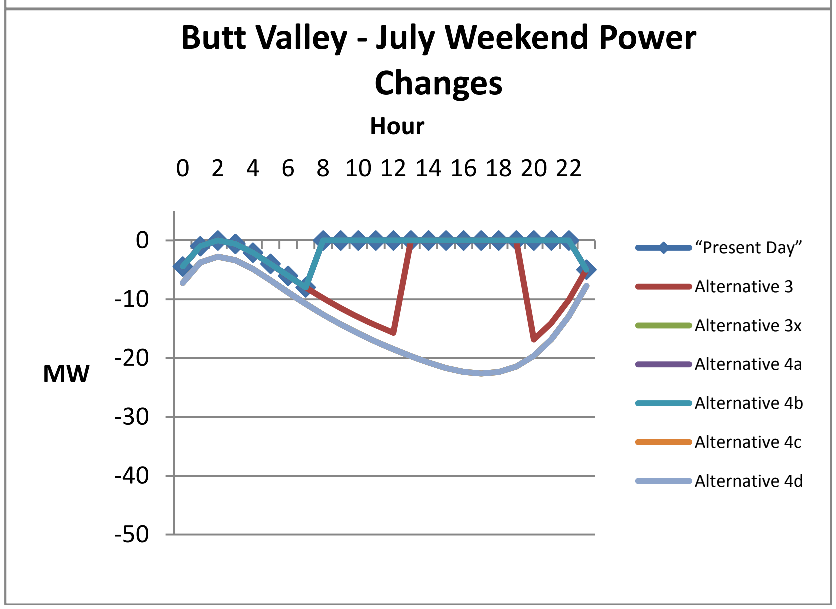

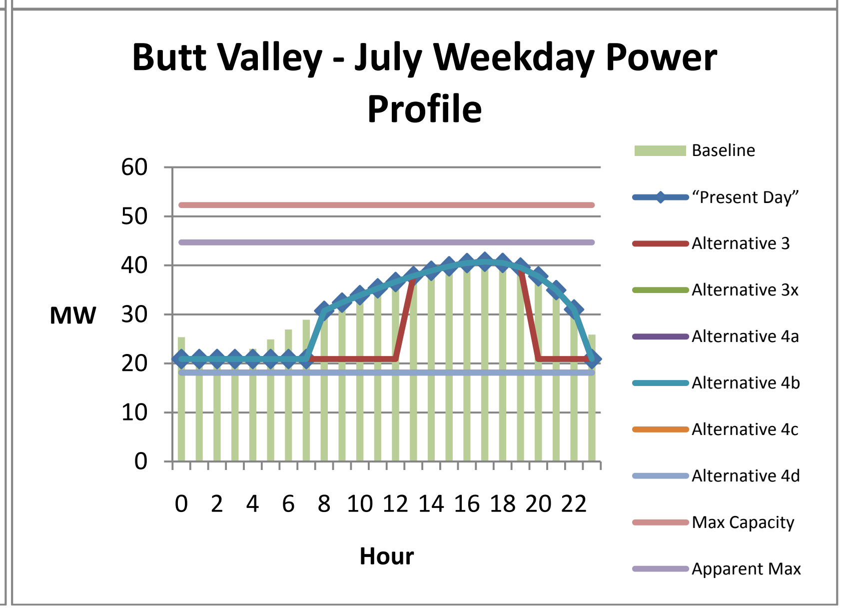

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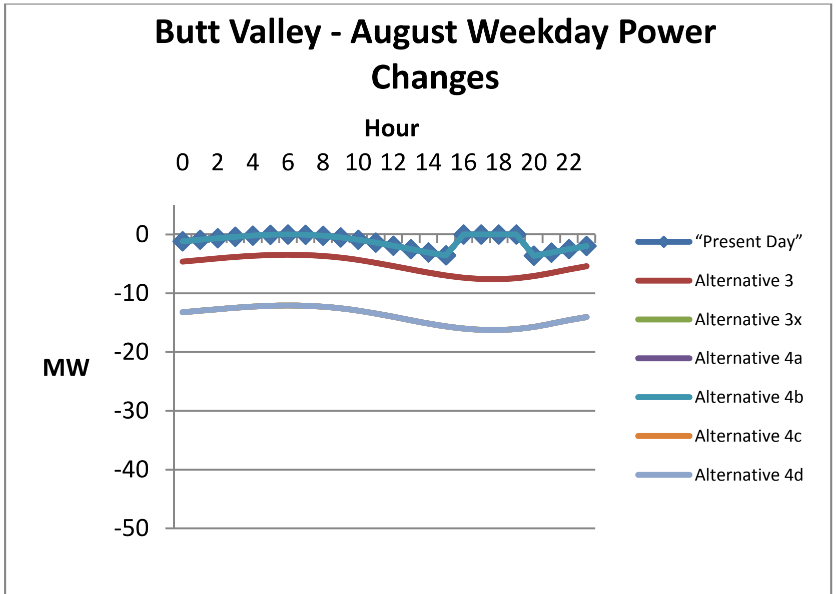

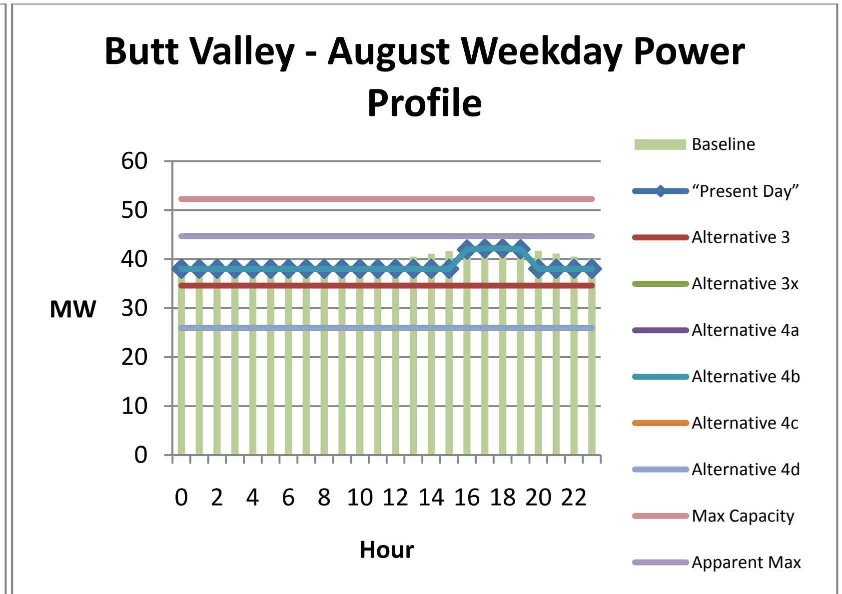

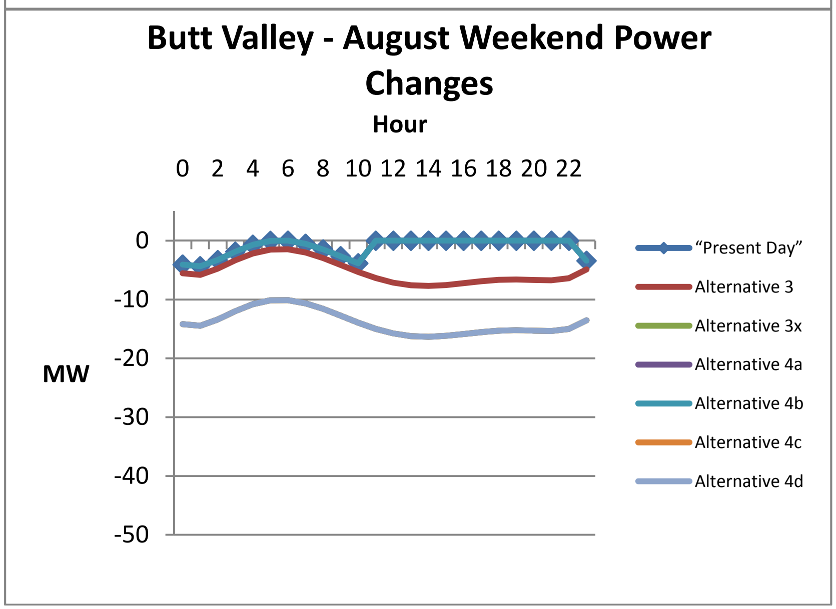

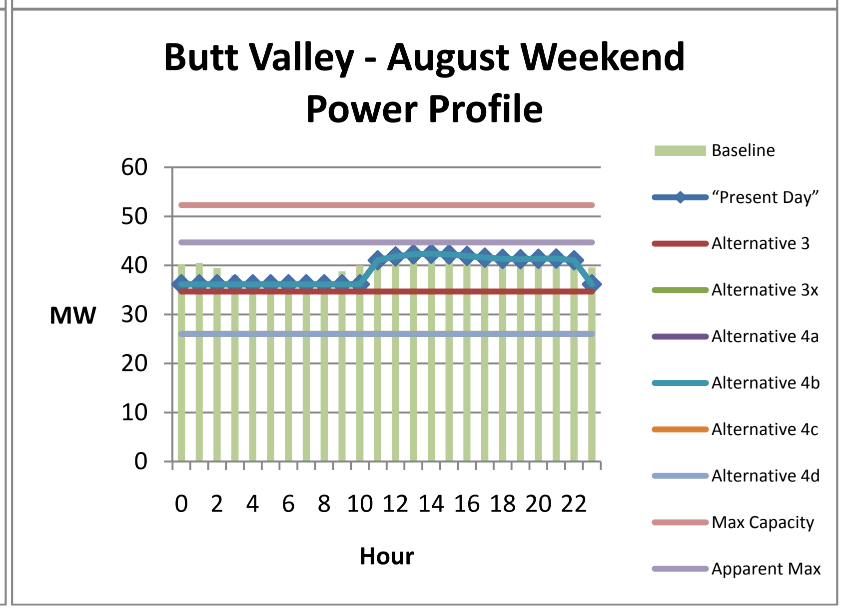

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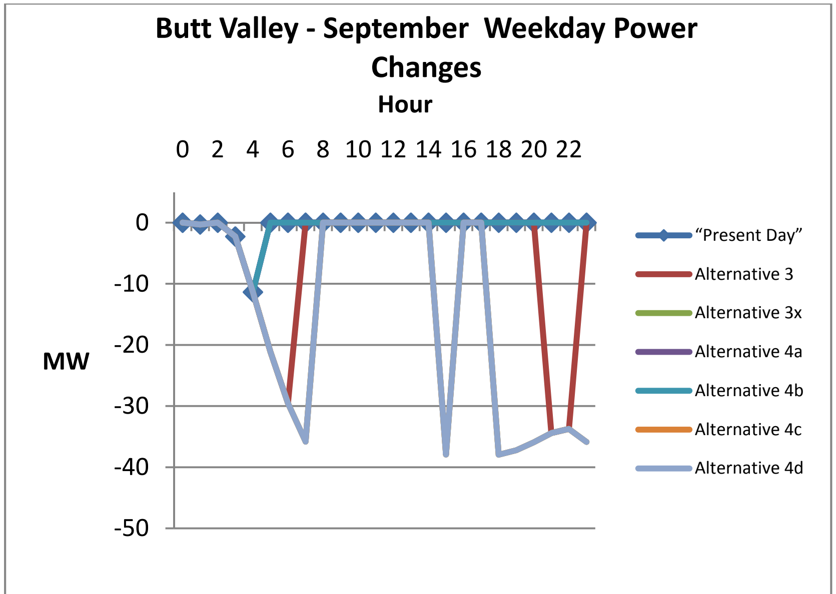

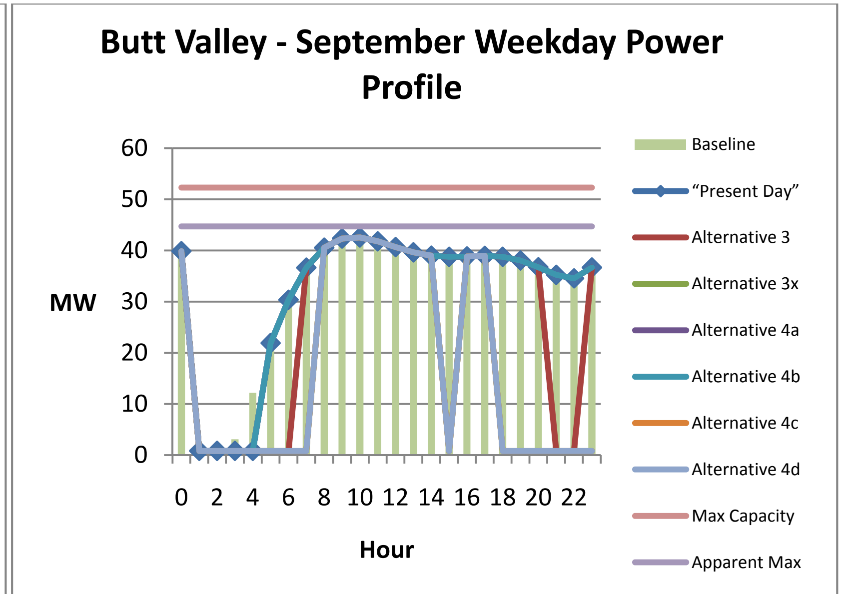

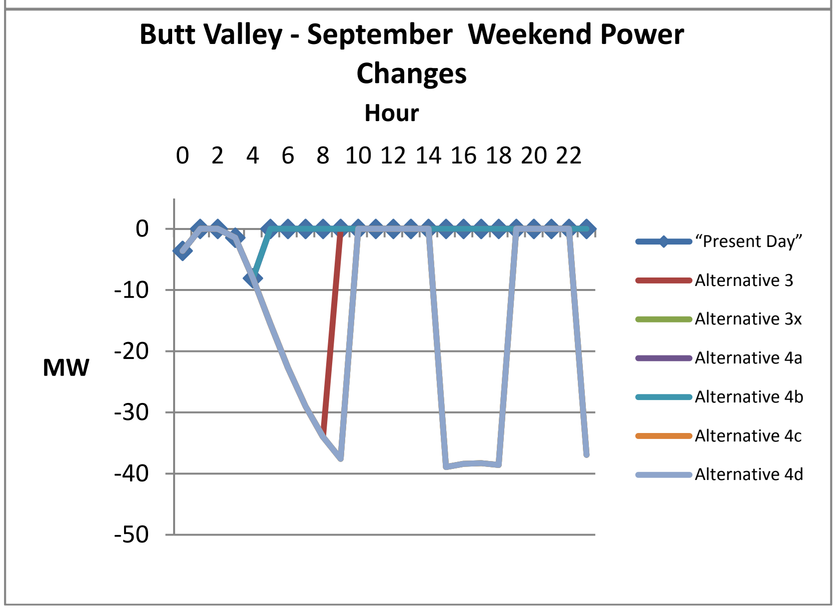

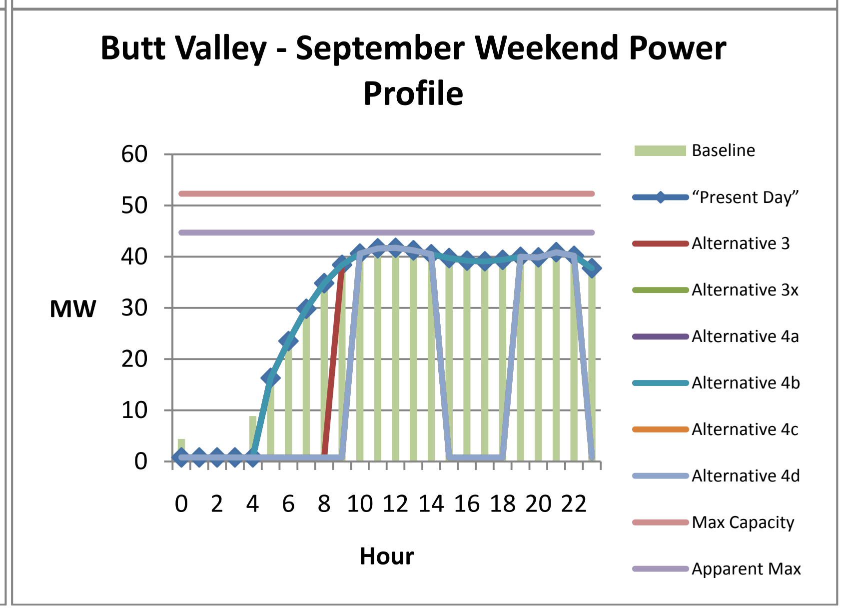

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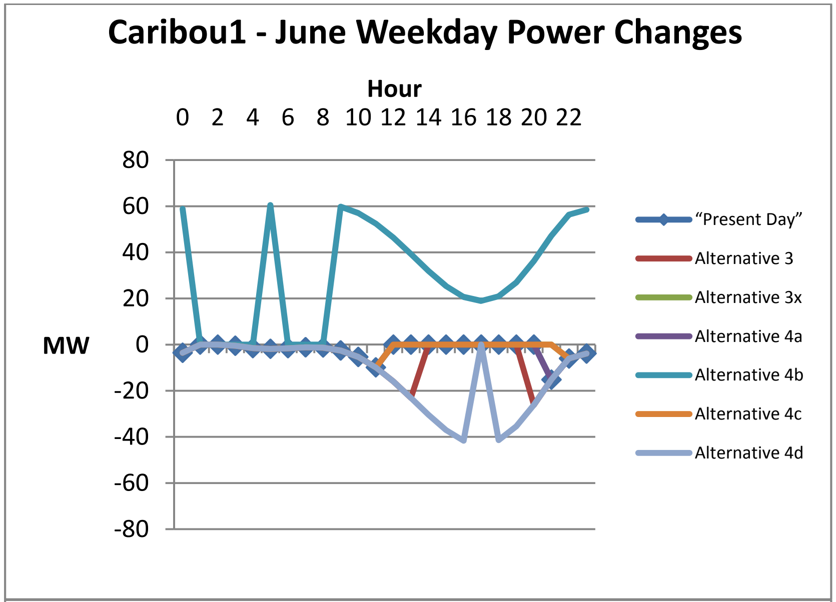

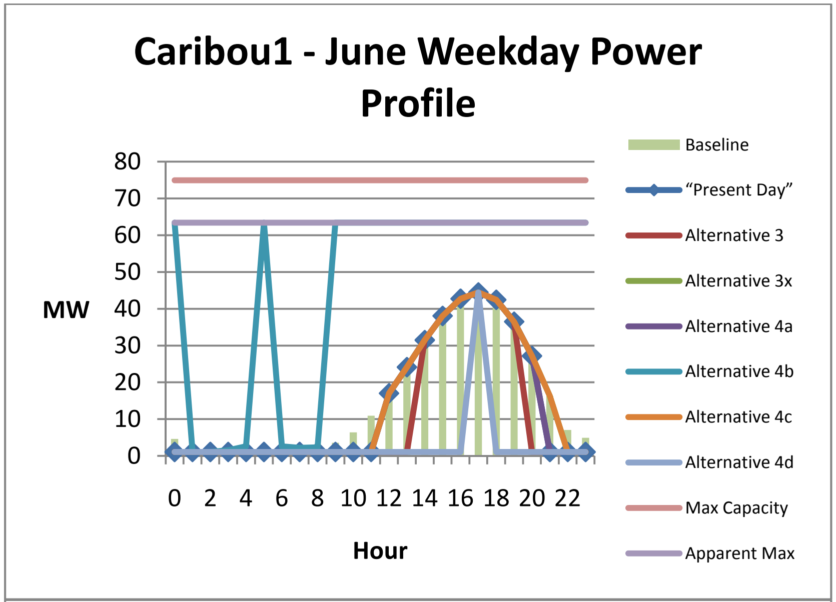

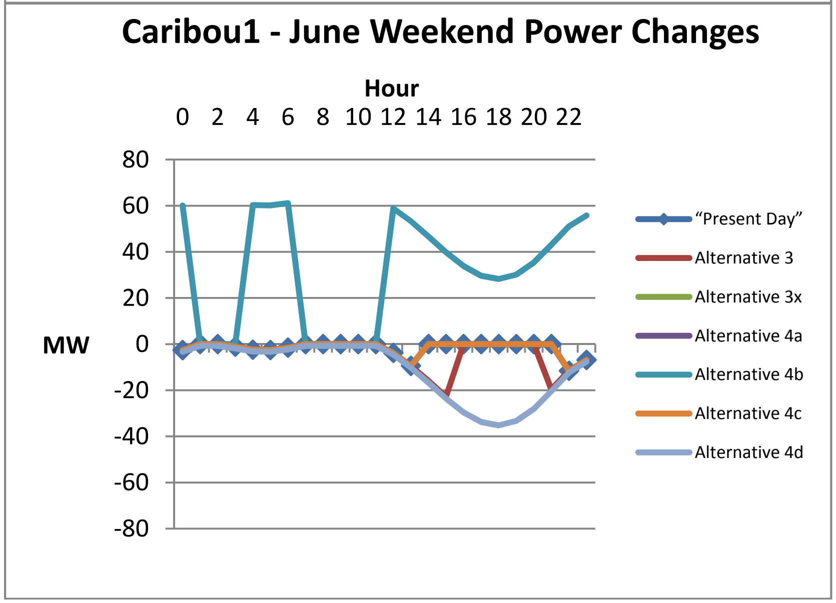

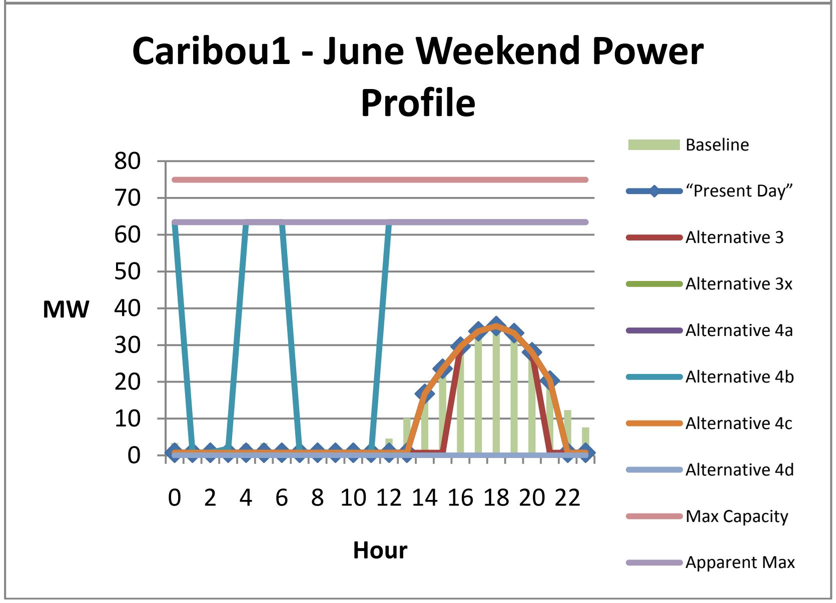

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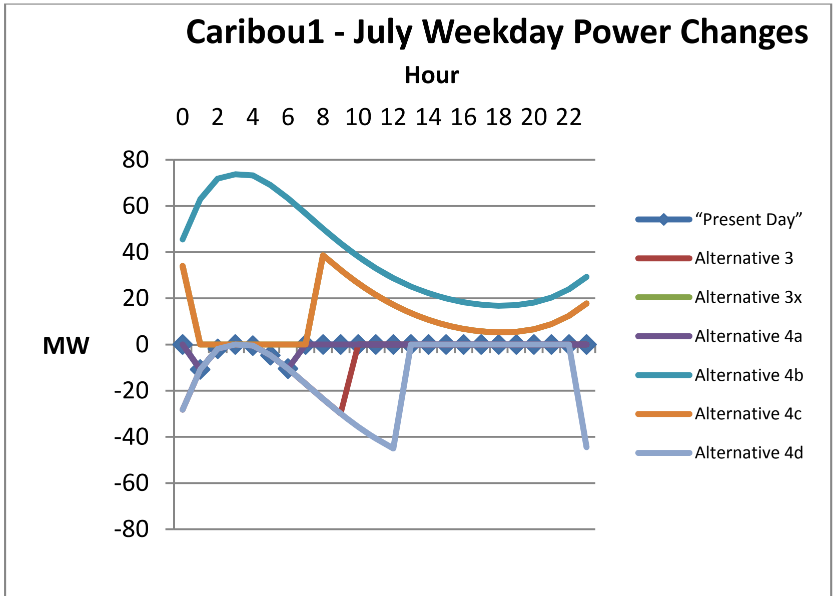
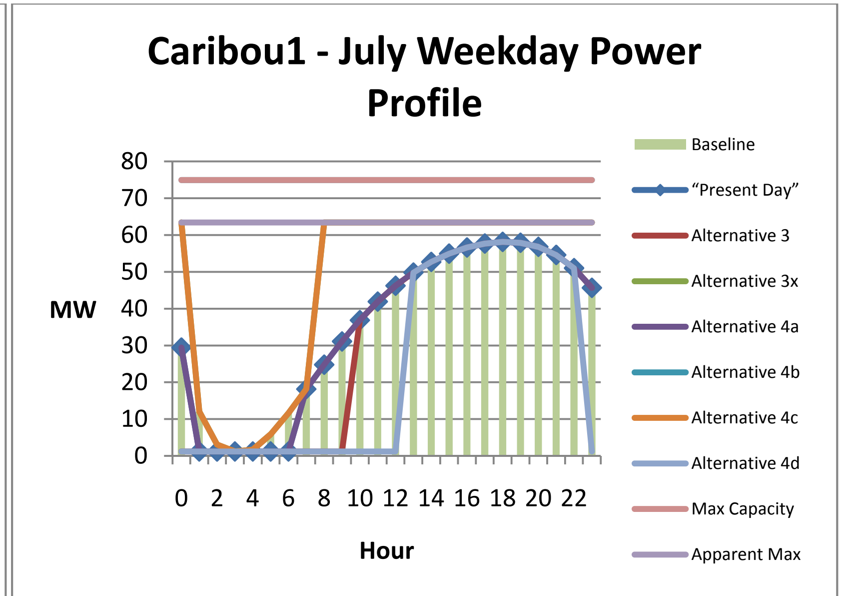
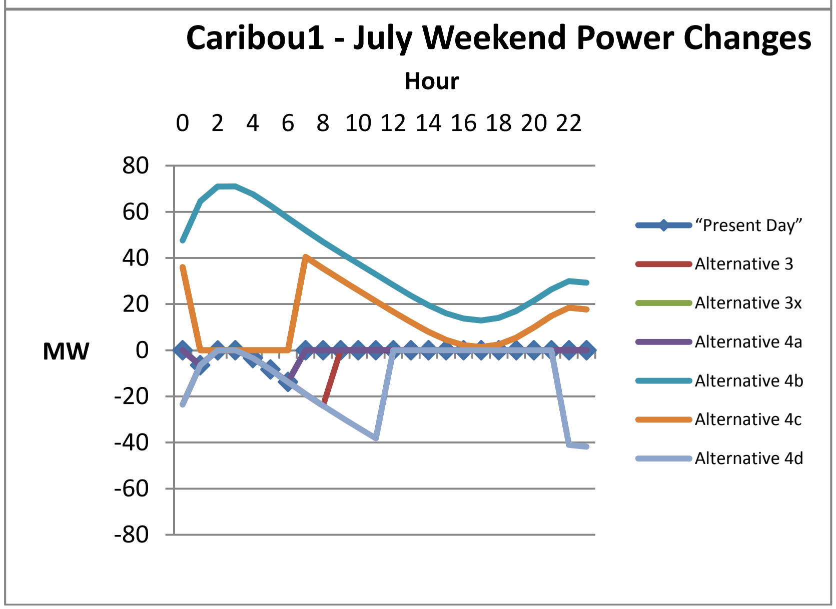
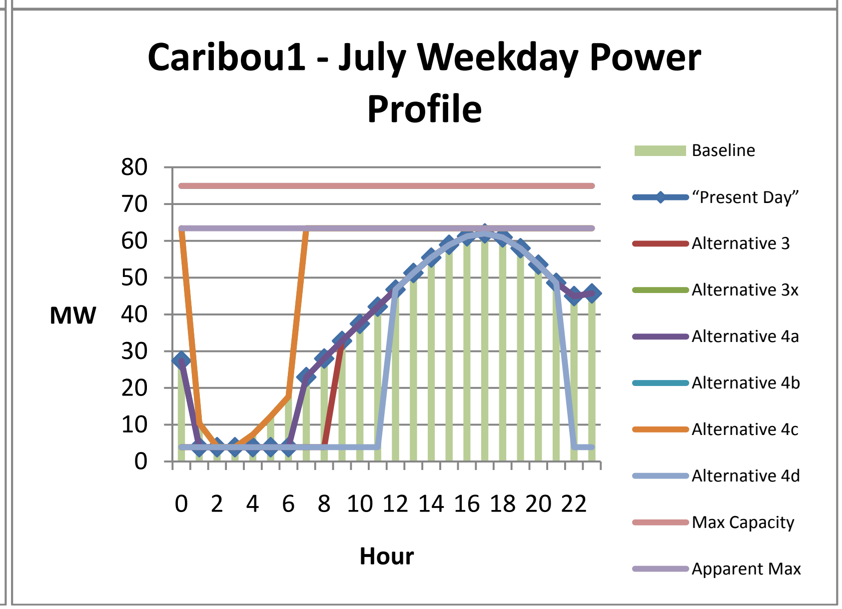
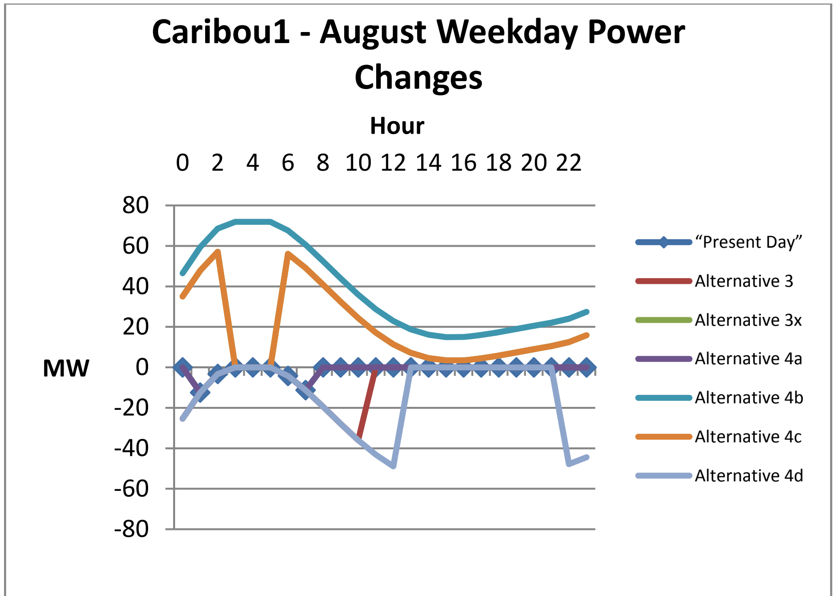


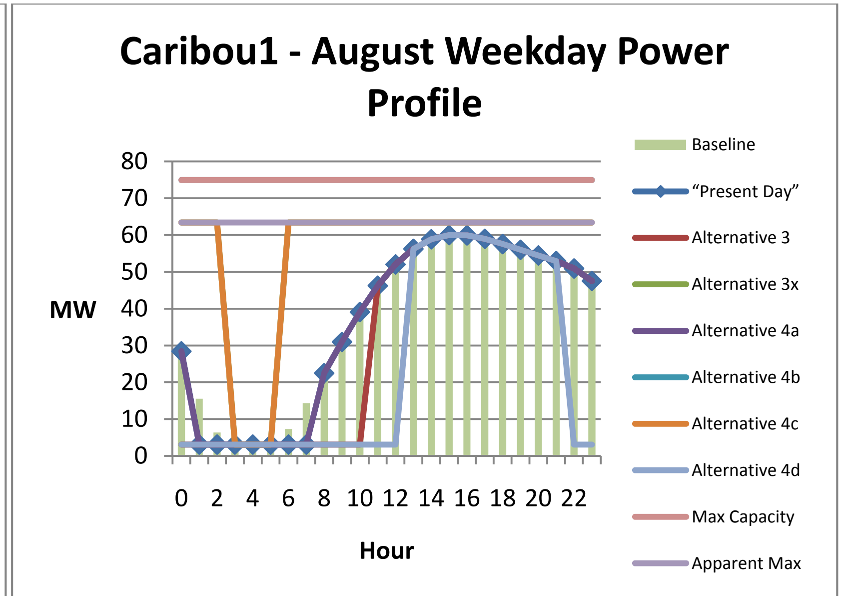


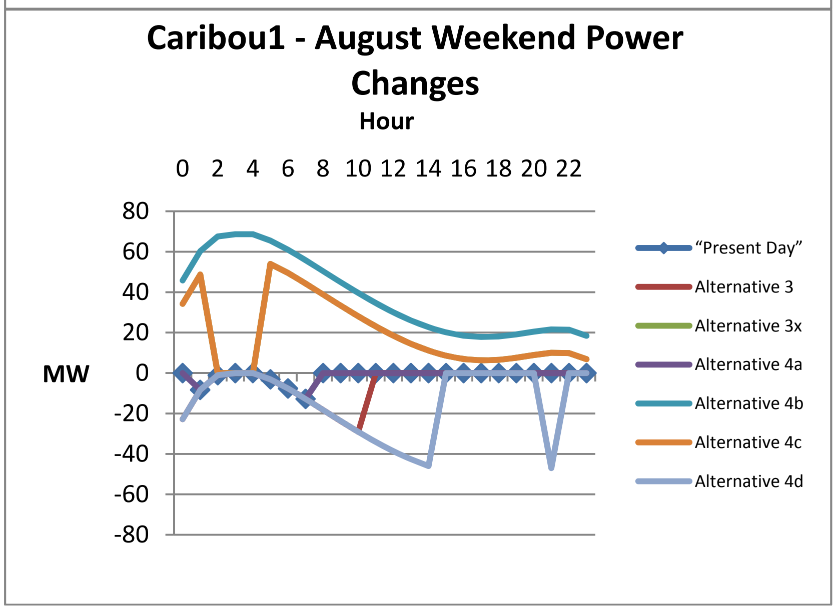


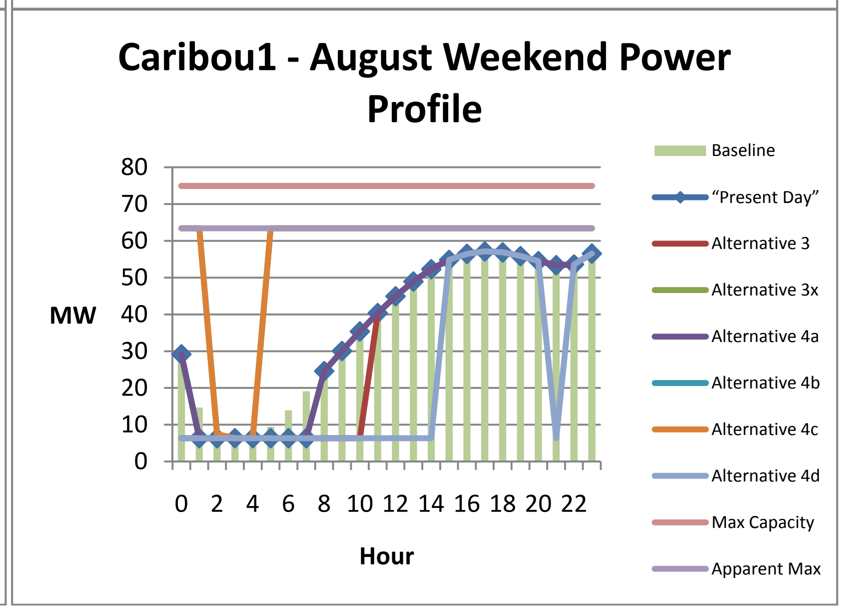


Hourly Operational Changes: 2002 Butt Valley









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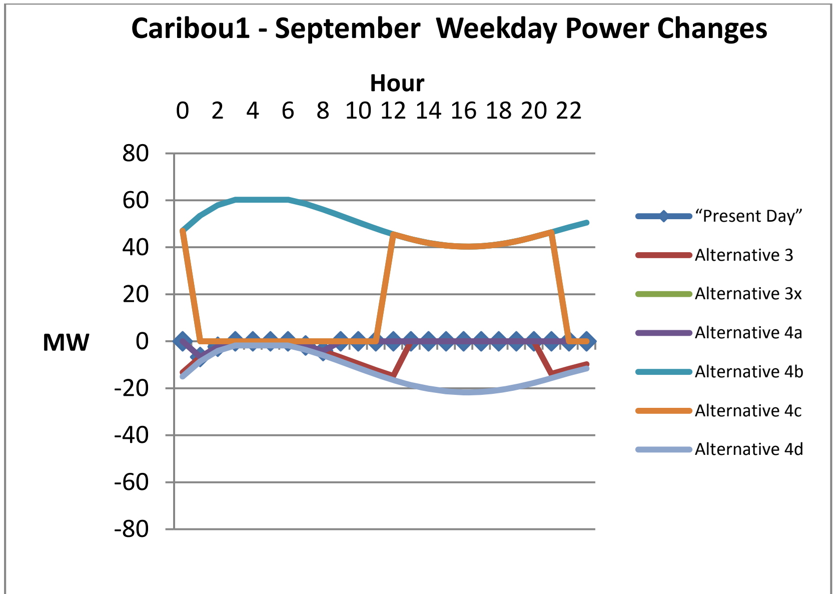

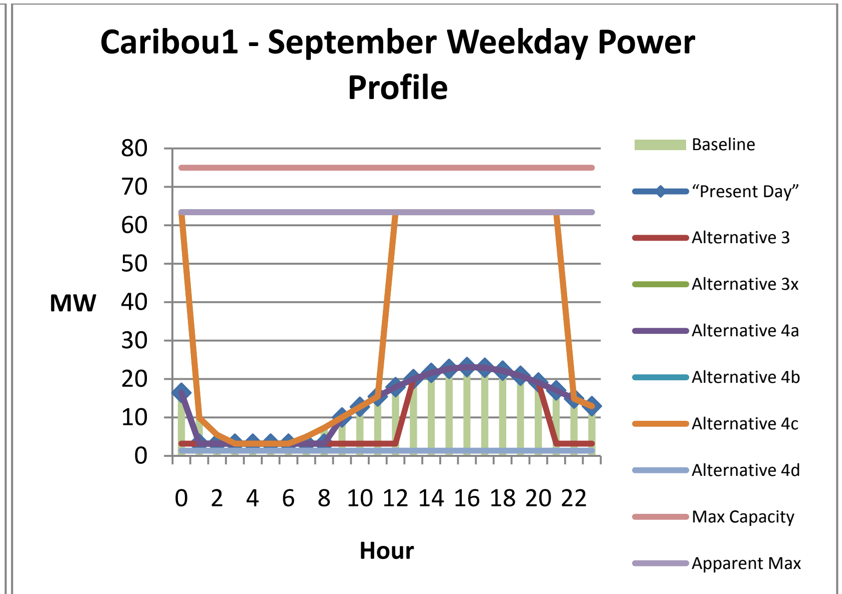

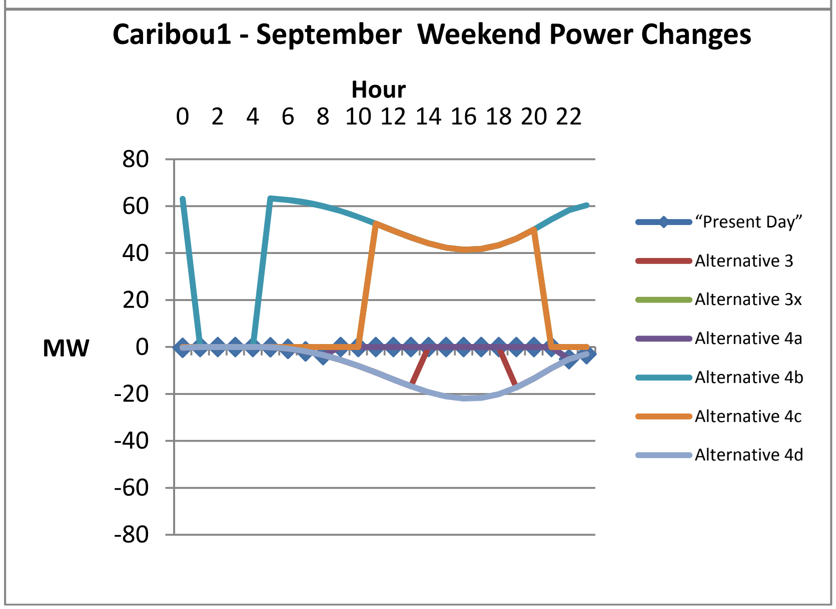

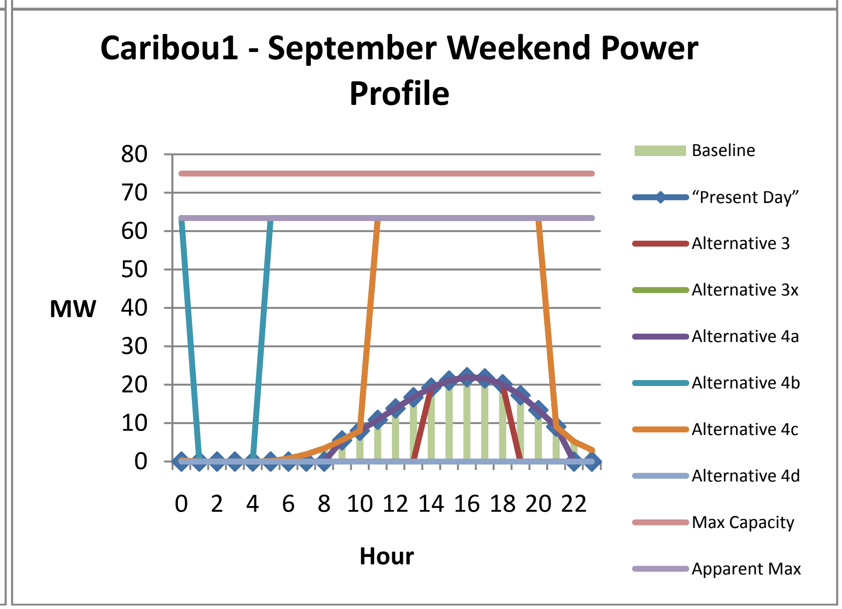

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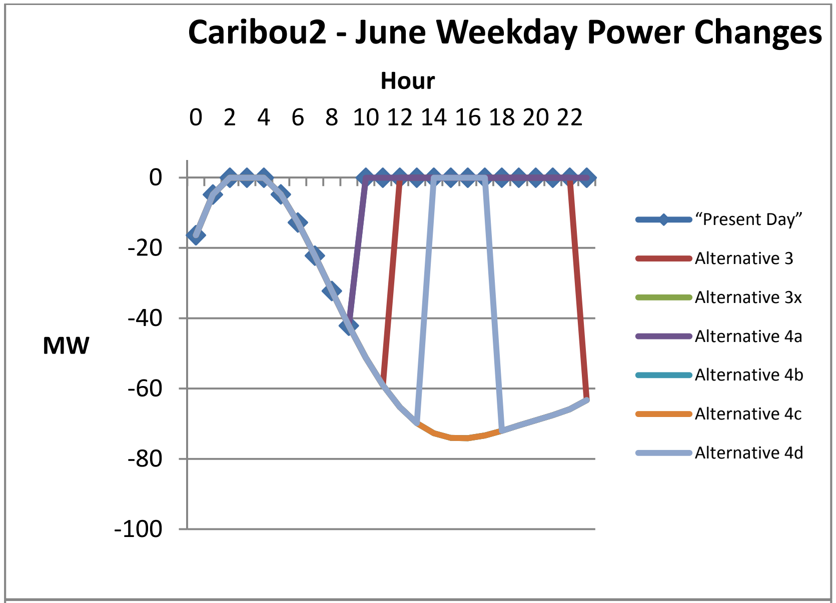

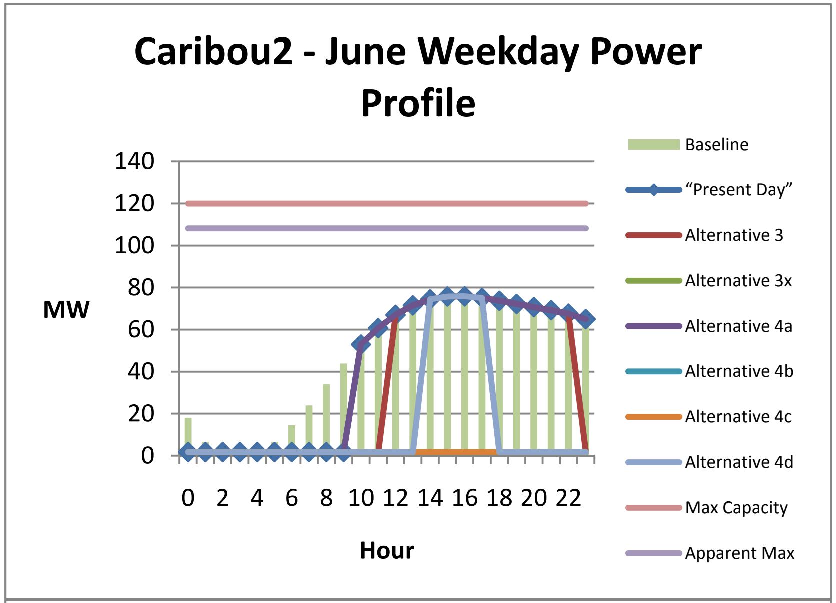

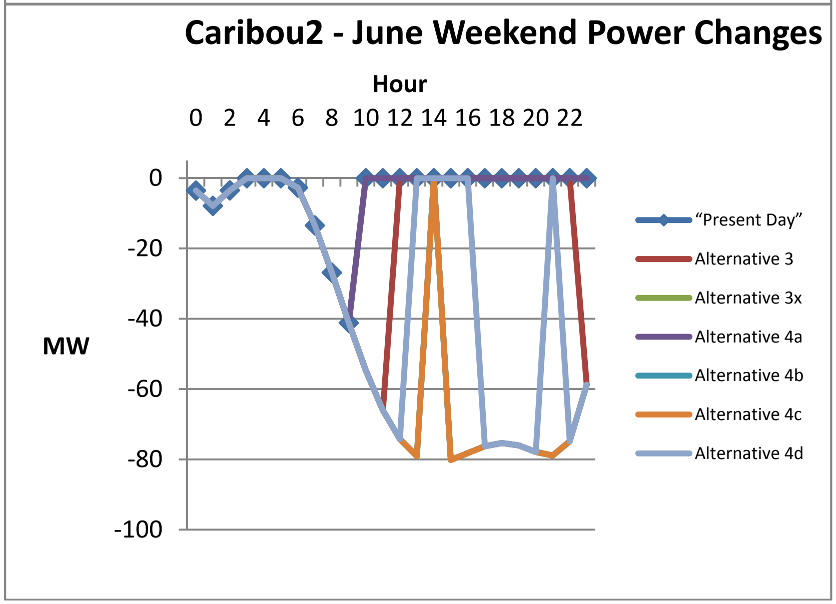

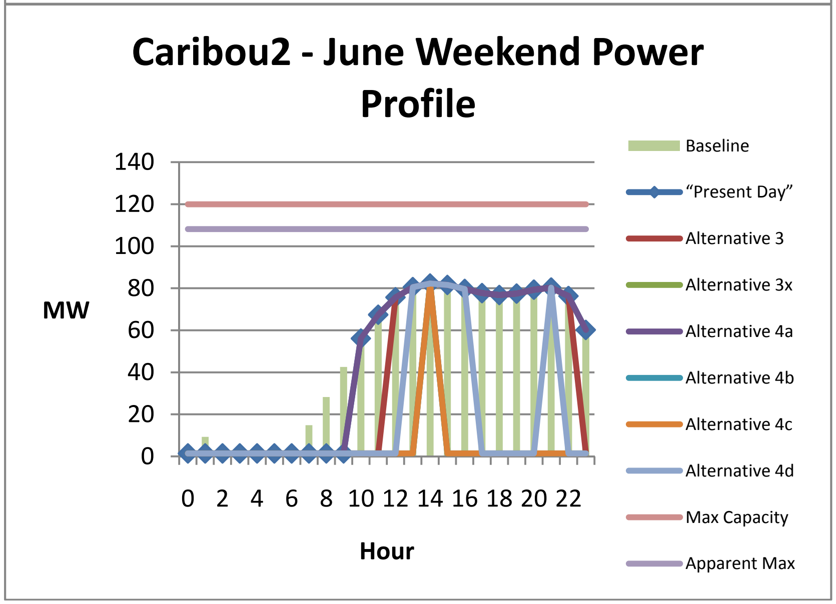

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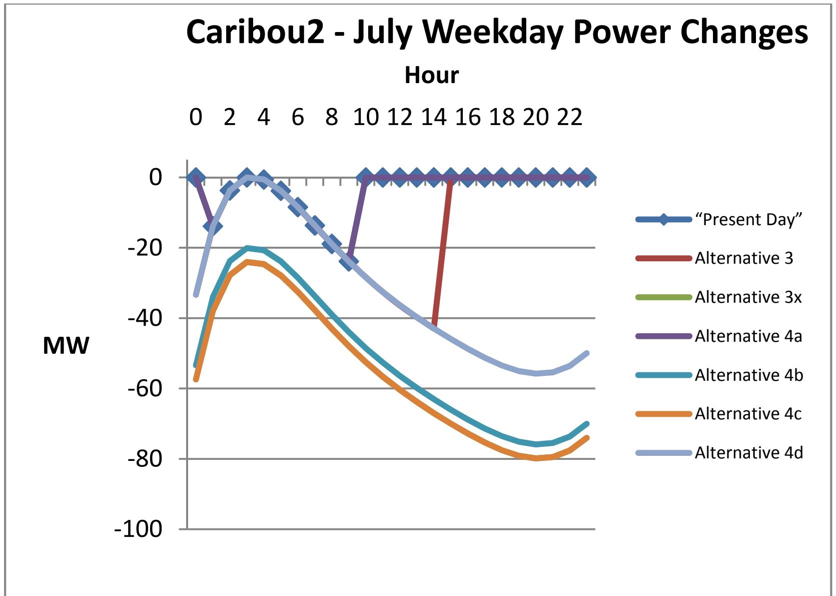

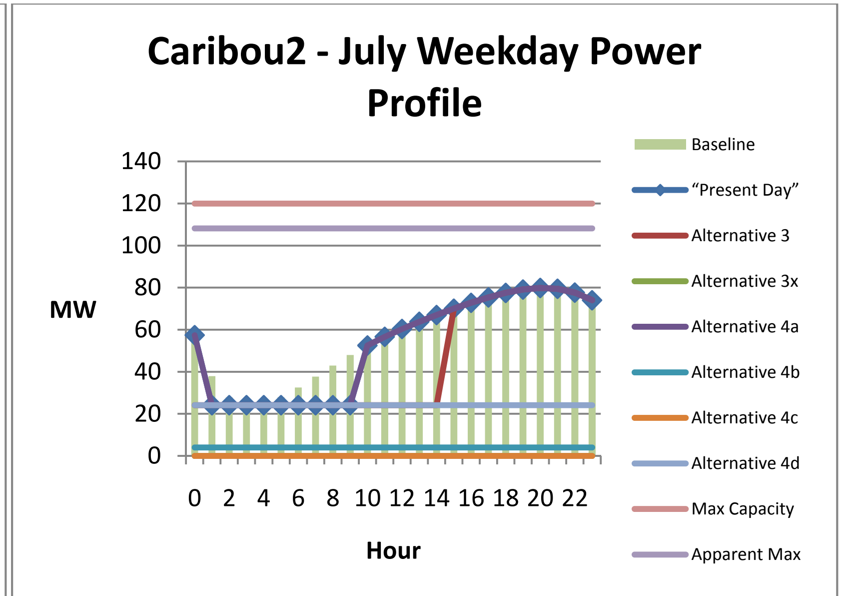

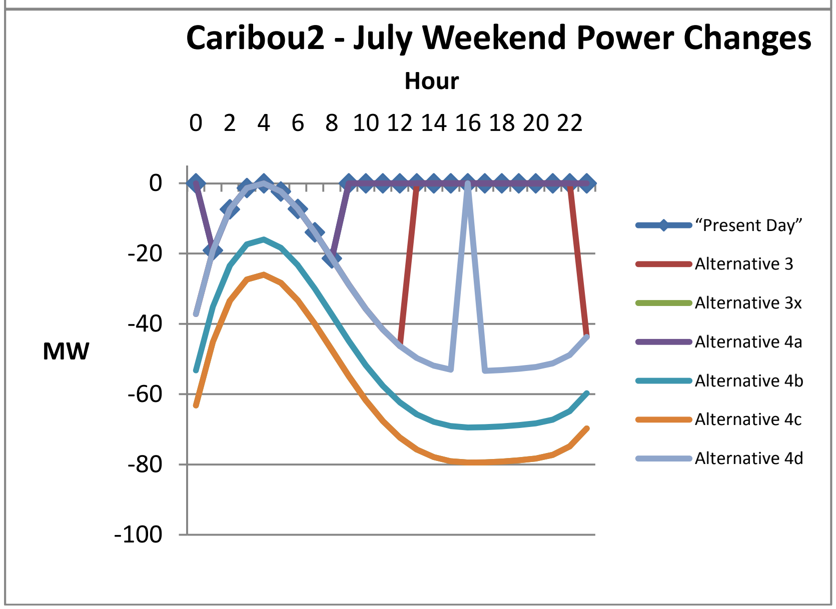

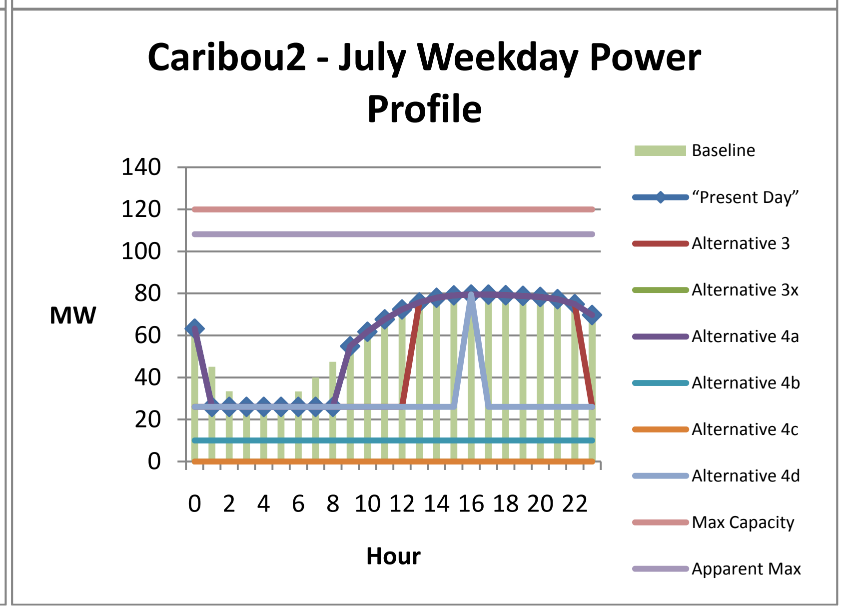

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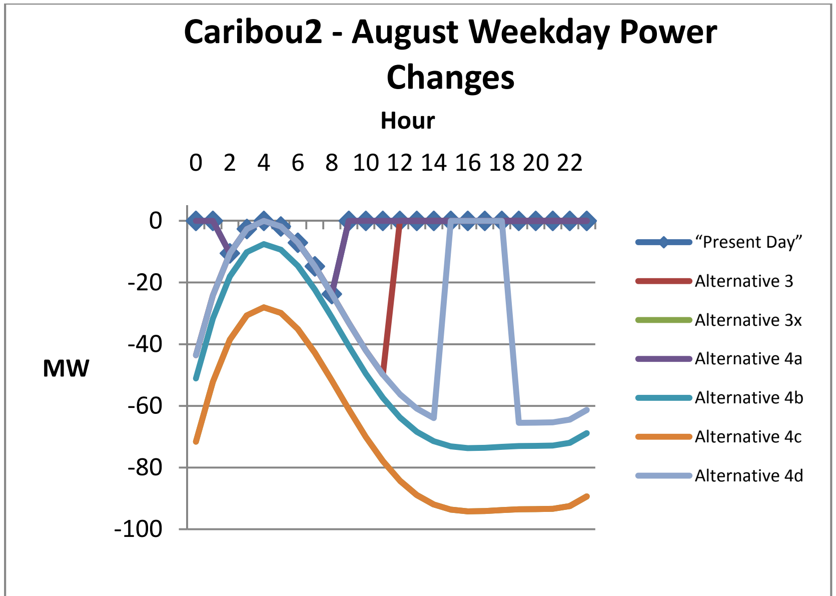

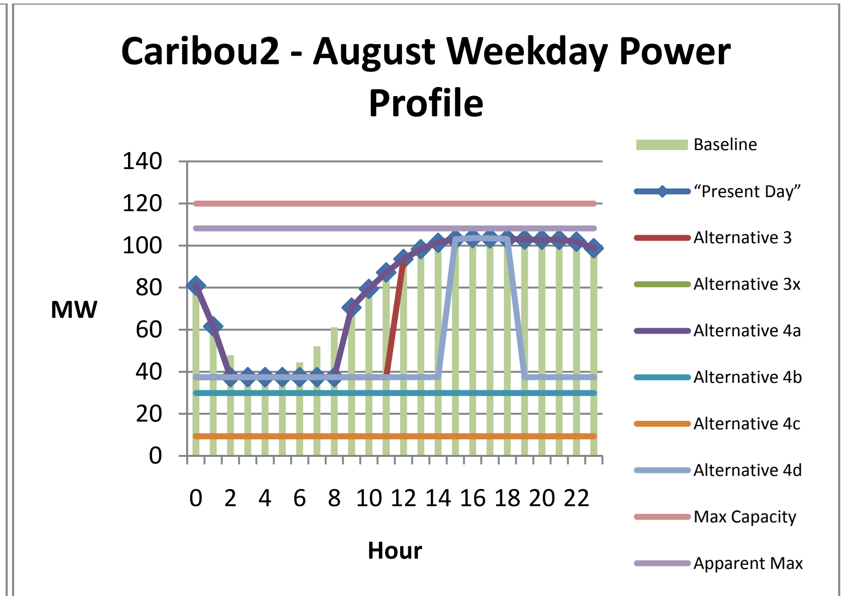

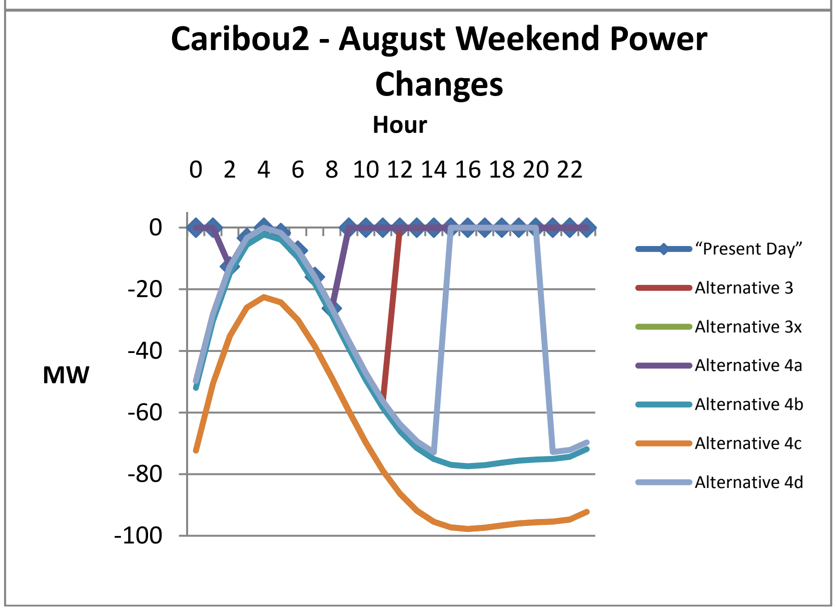

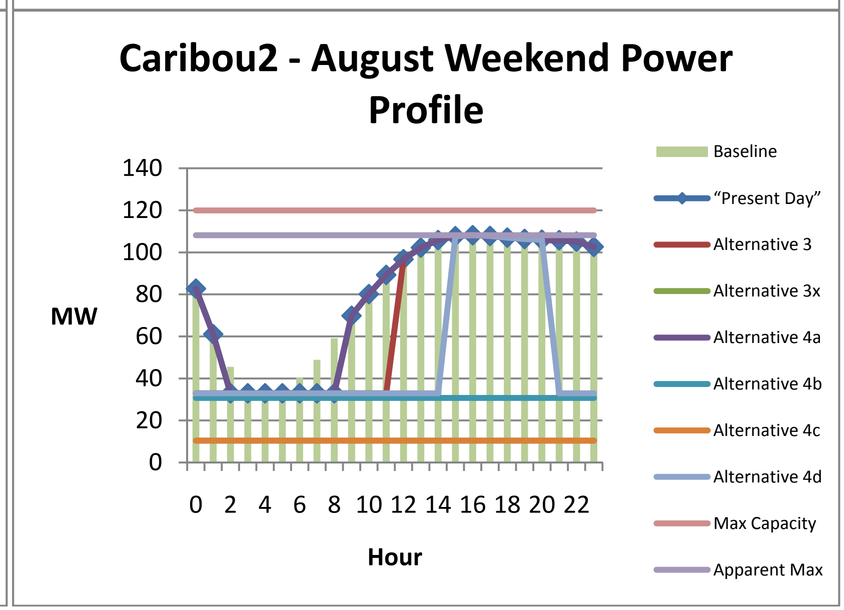

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