GenOn

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April 1, 2011

Mr. Philip Isorena
Chief, NPDES Unit
State Water Resources Control Board
Division of Water Quality, 15th Floor
1001 I Street
Sacramento, CA 95814

Re: Pittsburg Generating Station Implementation Plan for the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy)

Dear Mr. Isorena,

GenOn Delta, LLC (GenOn Delta) owns and operates the Pittsburg Generating Station (PGS), which is subject to the Policy. Attached is GenOn's Implementation Plan for the PGS, submitted pursuant to Section 3(A)(1) of the Policy and the November 30, 2010 letter from the State Water Resources Control Board (State Board) setting forth information requirements related to the Policy's requirement to submit implementation plans.

Please contact me with any questions at (925) 427-3567 or peter.landreth@genon.com.

Sincerely,

Peter Landreth
Director, California Environmental Policy
GenOn Delta, LLC

PITTSBURG GENERATING STATION IMPLEMENTING PLAN FOR THE STATEWIDE WATER QUALITY CONTROL POLICY ON USE OF COASTAL AND ESTUARINE WATERS FOR POWER PLANT COOLING

GenOn Delta, LLP

April 1, 2011

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I. INTRODUCTION

GenOn Delta intends to comply with the State Water Resources Control Board (State Board) "Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling" (Policy) at the Pittsburg Generating Station (PGS) by the prescribed deadline of December 31, 2017, through retrofitting once-through cooled Units 5 & 6 to utilize the existing Unit 7 closed-cycle cooling system, in conjunction with the retirement of Unit 7 itself. GenOn Delta has concluded that this retrofit project would be feasible from a technical, logistical, environmental and permitting perspective. However, the project may be infeasible if GenOn Delta cannot secure sufficient contractual coverage that (1) ensures that the units will remain in service beyond 2017 (the compliance deadline in the Policy), and (2) provides a revenue stream sufficient to fund the costs of the retrofit project. The PGS is contracted through a tolling agreement with PG&E through 2013, with an option to extend through 2015. It is unknown whether PGS will continue to be needed for electrical reliability after that time. If GenOn cannot obtain contractual coverage beyond 2017, or if such a contract would not provide sufficient revenues to fund a retrofit to achieve compliance with the Policy, then GenOn Delta would be forced to retire Units 5 & 6. The market-based constraints that will be relevant to GenOn Delta's Track 1 compliance proposal are discussed in Section III(c).

Section II describes the PGS, and specifically its once-through cooling operations. Section III describes GenOn Delta's Track 1 compliance proposal, including a consideration of reclaimed water and a discussion of market-based constraints as noted above. Finally, Section IV documents GenOn Delta's proposed compliance with the interim requirements set forth in Section 2(c) of the Policy.

II. FACILITY DESCRIPTION

The PGS, owned and operated by GenOn Delta, is located on Suisun Bay in the City of Pittsburg, California. The PGS originally consisted of seven natural gas-fired generating units, which had a design capacity of 2,080 gross megawatts (MWg). The as-built total combined cooling water design flow required to service Units 1-7 was approximately 1,074 MGD. Units 1-4 were once-through cooled units and were retired in 2004 in compliance with USFWS and NFMS requirements to reduce impingement and entrainment of listed species. Units 5 & 6 are the only remaining once-through cooled units and generate a total of 660 MWg of power. Unit 7, a closed-cycle wet cooled unit generates 740 MWg. Together, Units 5-7 can currently generate a total of 1,400 MWg. The current combined maximum cooling water design flow for Units 5-7 is 506 MGD (approximately 231 MGD for each of Units 5 and 6, and approximately 44 MGD for the Unit 7 make up water).

Intake Structures

Cooling water for the PGS is withdrawn from Suisun Bay through two adjacent shoreline intake structures: the Unit 5 & 6 intake structure and the Units 1-4 & 7 intake structure. The bottom of the intake structures are approximately 15 feet below Mean Sea Level. The intake facilities are concrete structures that generally include bar racks, traveling screens, a screenwash system, and circulating water pumps. The Unit 1-4 & 7 intake structure also houses station service water pumps and fire suppression system pumps, including a main fire pump, an auxiliary fire pump and jockey pump.

(1) Units 5 & 6 Intake Structure

Units 5 & 6 are each equipped with two circulating water pumps that supply cooling water to the unit's steam condenser. Units 5 & 6 circulating water pumps have a capacity of 231.1 MGD per unit for a total of 462.2 MGD. The Unit 5 & 6 circulating water pumps were originally single-speed pumps (i.e., pumps were either off or pumping at 100% design flow/speed). In 1987, Variable Speed Drive (VSD) technology was installed, allowing the circulating water pumps to be operated from 50% to 95% of their rated capacity. In early 2004, the VSD controls were replaced with updated Variable Frequency Drive (VFD) technology. When operating in VFD mode, the circulating water pump speed/flow is typically at its minimum level when the unit is at minimum load. The minimum circulating water pump speed/flow is set at 50% of design flow, and may vary due to the temperatures of the intake water or the cleanliness of the condenser tubes (commonly measured as backpressure). In general, the minimum speed/flow will be between 50–60% of design flow at loads less than 65 MWg. As unit load increases, pump speed and flow are increased in accordance with unit conditions. The VFDs are existing mitigation measures required by resource agency permits (as discussed in Section IV(c) of this Plan below). They are not considered in the design intake flow rate.

The Unit 5 & 6 intake structure is equipped with a bar rack system consisting of six bar racks, each approximately 22 feet long and spaced 4.0 inches on center, located about 15 feet in front of the vertical traveling screen system. The bar racks prevent the entry of large objects into the cooling water system. Six vertical traveling screens with a mesh size of 3/8 inch are fixed to each intake structure and retain smaller objects. Each traveling screen is comprised of 30 screened "panels." Each panel is approximately 10 feet wide and 2 feet tall. A high-pressure screenwash spray system removes any debris or fish that have become impinged on the screen face.

(2) Units 1-4 & 7 Intake Structure

The Units 1-4 & 7 cooling water intake structure was used to supply cooling water to the now retired Units 1-4, and currently provides make-up water for closed-cycle cooled Unit 7. Unit 7 make-up water is withdrawn by three 10,100 gpm make-up water pumps. Maximum design flow of the three make-up pumps totals 43.6 MGD. Maximum losses from drift and evaporation have been estimated at about 7,000 gpm (10 MGD). Blowdown flow is discharged through a manifold system, which distributes it into the discharge conduits of Units 5 or 6.

The Unit 1-4 & 7 intake is equipped with eight bar racks, each approximately 26 feet, 10 inches long and spaced 3.75 inches on center are located about 15 feet in front of the vertical traveling screens. The bar racks prevent the entry of large objects into the cooling water system. Seven vertical traveling screens with a mesh size of 3/8 inch retain smaller objects. Each traveling screen is comprised of 30 screened “panels” that are approximately 10 feet 5 inches wide and 2 feet tall. A screenwash system operates for one hour a week to maintain the screens. Station service water, which supplies a water treatment system that produces boiler make-up water for Units 5-7, is also withdrawn from the Units 1-4 & 7 intake.

Discharge

Cooling water withdrawal and discharges are authorized under NPDES Permit No. CA0004880 (San Francisco Regional Water Quality Control Boarcd Order No. R2-2002-0072), which is pending renewal. Cooling water is discharged into Suisun Bay through submerged shoreline discharge tunnels. The discharge tunnels are located approximately 300 yards upstream of the intake. Currently there are two discharge tunnels in use, one for Unit 5 and one for Unit 6.

Operations

PGS was originally a baseload operated facility. However, capacity utilization rates at Units 5-7 have decreased significantly over the last decade and have consistently been in the low single digits for several years. Table II-1 provides the capacity utilization rates for PGS units for the most recent 5-year period (2006–2010). In 2010, annual capacity factors for Unit 5 and Unit 6 were 1.0% and 1.2%, respectively. GenOn Delta anticipates that Units 5-7 will continue to generate at similar low levels in the future.

Table II-1: Annual PGS Capacity Factors 2006–2010

	Annual Capacity Factor (%) Pittsburg Generating Station		
Year	**Unit 5**	**Unit 6**	**Unit 7**
2006	7.7	5.3	1.4
2007	2.7	2.6	0.8
2008	2.3	2.4	0.8
2009	3.8	3.0	0.4
2010	1.0	1.2	0.0
Five Year Average	3.5	2.9	0.7

III. TRACK 1 COMPLIANCE PROPOSAL

a. Technical, Logistical, Environmental and Permitting Feasibility

Track 1 compliance at the PGS would involve retiring Unit 7 and refurbishing the existing Unit 7 mechanical draft closed-cycle cooling towers to be reused for the condenser circulating water system for currently once-through cooled Units 5 & 6.[1] As explained below, this conversion project would be expected to result in a 93.7% reduction in the intake flow rate for each once-through cooled unit, and the through-screen approach velocity for the converted units would be approximately 0.1 feet per second. Accordingly, the conversion project would achieve compliance under Track 1.

The size and design of the existing Unit 7 cooling towers makes them a good fit for retrofitting as proposed because the capacity of Unit 7 is approximately equal to the capacity of Units 5 and 6 together. GenOn Delta does not anticipate that PGS Unit 7 will continue to be needed for electrical reliability in the long term. Additionally, Unit 7 is relatively inefficient and its air pollutant emissions per megawatt are higher than PGS Units 5 & 6. Accordingly, converting Units 5 & 6 to use the Unit 7 cooling towers provides a long-term solution for achieving compliance with the Policy for once-through cooled Units 5 & 6, while retiring an aging and inefficient unit, thereby reducing air pollution.

The principal elements of the Units 5 & 6 conversion project would include refurbishing the existing cooling towers by replacing the existing fill and louvers; installing new pipelines for the cooling flow and hot water return to and from the cooling towers to Units 5 & 6; and installing new condensate coolers at Units 5 & 6, as well as new control systems and valves. The Unit 7 structure itself may or may not be demolished as part of the Units 5 & 6 retrofit project; GenOn Delta would evaluate this option in the process of more detailed design and engineering development. The refurbished cooling towers would be equipped with drift eliminators to minimize and mitigate the effects of cooling tower drift, consistent with Bay Area Air Quality Management District (BAAQMD) requirements.

The converted PGS would continue to withdraw make-up cooling water for the cooling towers through the existing Units 1-4 & 7 cooling water intake structure. The Units 5& 6 intake structure would be retired. As described above in Section II, make-up water for Unit 7 is

[1]GenOn Delta did not assess any other potential Track 1 compliance alternatives, as any alternative to the foregoing conversion project would be environmentally inferior and would offer no advantages from a technical, logistical, permitting, or economical perspective. Note, for example, that the preferred wet cooling retrofit configuration identified by Tetra Tech in its 2008 report for the State Board, entitled "California's Coastal Power Plant: Alternative Cooling System Analysis," would place new cooling towers in the western portion of the existing cooling canal. Tetra Tech Report at p. L-10. Tetra Tech did not take into account the fact that this area is occupied by habitat for the California least tern, a fully protected species under the California Endangered Species Act, effectively precluding any development.

currently provided by three pumps each rated at 10,100 gpm. These pumps would continue to be used, but only one pump would be required for each converted unit, so one 10,100 gpm would provide make-up water for the converted Unit 5, and a second would provide make-up water for the converted Unit 6. Units 5 & 6 currently each have a design intake flow rate of 160,500 gpm. The reduction in the intake flow rate for each unit from 160,500 gpm to 10,100 gpm would be 93.7% per unit, thereby achieving compliance with the standard prescribed in Track 1 of the Policy. The through-screen approach velocity at the cooling water intake structure for the converted units would be consistent with the current rate for Unit 7 make-up water withdrawals, which is estimated at less than 0.1 feet per second at design flows. This rate would be well below the 0.5 feet per second Track 1 standard for impingement mortality reduction in the Policy.

Since the conversion project would utilize existing infrastructure and involve minimal new construction, the environmental impacts of the project would be minimal and associated permitting would be relatively straightforward. GenOn Delta anticipates that permitting would take approximately 6 months, primarily related to various approvals required from the City of Pittsburg and the BAAQMD. GenOn Delta anticipates that the existing PGS NPDES permit, as well as existing permits authorizing the incidental take of listed species under the federal Endangered Species Act and California Endangered Species Act, could be modified or amended to continue to authorize any potential aquatic impacts associated with the operation of the converted Units 5 & 6, which would be significantly less than the potential impacts associated with current once-through cooling operations.

Construction associated with the conversion project would take approximately eleven months, of which two months of outage time would be required for Units 5 & 6 to tie in the new lines. This outage would be coordinated closely with the CAISO to minimize any potential adverse impacts on electrical system reliability. Because the conversion project would utilize existing infrastructure, no transmission upgrades would be required in connection with the project.

GenOn Delta estimates the total time required to design, engineer, permit and construct the conversion project would be approximately two years.

Accordingly, GenOn Delta has concluded that Track 1 compliance is feasible from a technical, logistical, environmental and permitting perspective, but for the reasons discussed below, GenOn Delta cannot commit to actually implementing the conversion at this time based on market-based uncertainties. However, GenOn Delta anticipates that it will have determined whether it is feasible to pursue the conversion project from a market-based perspective sufficiently in advance of the December 31, 2017 compliance deadline to implement the two-year compliance schedule described above. See the implementation timeline in Section III(d) of this Plan.

b. Consideration of Recycled Water

Section 3(A)(2) of the Policy requires that an Implementation Plan proposing closed-cycle wet cooling consider whether tertiary-treated recycled quality would be available for makeup water use. Under California law, only tertiary-treated recycled water may be used in power plant cooling facilities (see 22 C.C.R. Section 60306). As discussed below, the existing and planned amount of tertiary-treated water in the vicinity of the PGS is insufficient to supply the necessary amount of make-up water for Units 5 & 6. The installation of sufficient infrastructure to convey recycled water to the PGS from regional treatment facilities, even if such supplies were available, would generate significant additional environmental impacts associated with the construction, operation and maintenance of supply pipelines and add substantial complexity to the project.

As discussed above, to achieve Track 1 compliance Units 5 & 6 would be converted to reduce cooling water requirements 321,000 gpm to 20,200 gpm (462 MGD to 29 MGD). The Tetra Tech analysis of tertiary-treated water for the PGS identified three potential supply sources within 15 miles of the plant: (1) the Benicia Wastewater Treatment Plant (Benicia WWTP), (2) the Delta Diablo Sanitation District (DDSD); and (3) the Central Contra Costa Sanitation District (CCCSD) water reclamation facility.

The Benicia WWTP is located approximately 13 miles west and across the Carquinez Straight from the PGS. The treatment facility has a maximum discharge capacity of approximately 13 MGD and does not produce any tertiary treated wastewater. As discussed in the Tetra Tech report, PGS use of Benicia WWTP wastewater would require the construction and financing of new tertiary treatment facilities and conveyance pipelines across Suisun Bay or the Carquinez Strait (Tetra Tech, page L-19). Even if all of the Benicia WWTP's capacity could be treated to tertiary levels and conveyed to the PGS, the plant could only supply approximately 40% of the required make-up water. Due to cost, ancillary environmental impacts and regulatory complexity, Benicia is not a feasible source of tertiary recycled water for the PGS.

The DDSD is located approximately 4.5 miles east of the PGS in Antioch, California, and the PGS is within the district's existing service area. On average, DDSD receives approximately 14.2 MGD of wastewater flows and has the design capacity to treat up to 16.5 MGD (Contra Costa Local Agency Formation Commission, Water and Wastewater Municipal Services Review for East Contra Costa County, December 2007, page 8-5)(LAFCO 2007). In 2010, DDSD treated approximately 3,300 MG (9 MGD) of wastewater and recycled approximately 2,200 MG (6 MGD) (DDSD, Strategic Business Plan, September 2010, page 4). The district's recycled water supply is allocated to several users, including the Los Medanos Energy Center and Delta Energy Center for power-generating plant use, irrigation for several parks, the Pittsburg municipal golf course (starting in fiscal year 2009/10), and the Antioch municipal golf course (starting in 2010/11)(DDSD, Strategic Business Plan, September 2010, page 4). According to the DDSD, the district's recycled supplies provide water that is utilized in place of increasingly scarce fresh water supplies (DDSD, Strategic Business Plan, September 2010, page 4). DDSD's recycled water facilities were sized to meet potential peak flow energy generation demands by the Los Medanos Energy Center and Delta Energy Center facilities of up to 12.8 MGD (LAFCO 2007, page 8-13). The Tetra Tech report estimated that DDSD could treat approximately 8 MGD to tertiary standards (Tetra Tech, page L-20), and the Contra Costa Water District Urban Water Management Plan indicates that the district has contracted to deliver approximately 8,680 acre-feet per year (7.8 MGD) of recycled water to the Los Medanos Energy Center, the Delta Energy Center facilities and other users. (Contra Costa Water District, Urban Water Management Plan, 2005, page 19) (2005 UWMP). As of 2005, the Los Medanos Energy Center and Delta Energy Center agreements with DDSD were the largest recycled water projects in California (2005 UMWP, page 19).

As discussed above, virtually all of DDSD's available recycled water has been allocated to existing users. Diverting this supply to the PGS would require the use of freshwater or other supplies that are currently being offset by the use of tertiary-treated water to meet district demand. Based on average wastewater flows of 14.2 MGD, DDSD could potentially generate approximately 1.4 MGD of additional tertiary treated supply above the district's existing potential peak demand levels of 12.8 MGD, or approximately 6 MGD above approximately 8 MGD, the amount that the district has contracted to supply to other users. Generating these additional supplies would require new treatment and conveyance facilities and could provide less than approximately 5% to 20% of the make-up water required for the PGS. The construction of new recycled water treatment facilities, and conveyance pipelines from the DDSD plant to the PGS, would involve significant costs, cause additional environmental impacts and increase the regulatory complexity of the PGS conversion. Consequently, the DDSD is not a feasible source of sufficient tertiary-treated recycled water for the PGS.

The CCCSD is located approximately 9.5 miles southwest of the PGS in Concord, California. The PGS is not located within the district's service area. The district's wastewater treatment plant has an average dry weather flow of from 39.1 to 43 MGD, a peak wet weather flow of approximately 260 MGD and a design capacity of approximately 53.8 MGD (Contra Costa Local Agency Formation Commission, Water and Wastewater Municipal Services Review for Central Contra Costa County, April 2008, page 5-2)(LAFCO 2008). Almost all of the wastewater treated by the CCCSD is discharged into the Suisun Bay. Approximately 1.5 MGD, or less than 4% of the district's average dry weather flow, is diverted to a water reclamation facility and treated to tertiary standards (LAFCO 2008, page 5-1). Approximately 200 million gallons per year (0.54 MGD) of the district's tertiary treated water is supplied to other users for irrigation purposes. CCCSD also utilizes about 400 million gallons per year (1.1 MGD) of recycled water for process and irrigation purposes (CCCSD, Water Recycling Brochure, http://www.centralsan.org/documents/Water_Recycling_Brochure.pdf, downloaded March 29, 2011). The current Contra Costa Water District Urban Water Management Plan indicates that, at build out, CCCSD's recycled water demand will increase to approximately 2.8 MGD (2005

UWMP, page 70). Based on current recycled water demand,[2] CCCSD would not produce enough tertiary treated wastewater to meet more than approximately 5.1% of the PGS make-up water demand. Significantly expanding the district's ability to produce enough recycled water for the PGS would require substantial new treatment plant enhancements and connecting pipelines extending for approximately 10 miles, most of which would be located outside of the district's service area. Upgrading the treatment plants, and extending pipelines in this manner would involve substantial costs, generate potentially significant environmental impacts and jurisdictional disputes, and increase the regulatory risks associated with PGS conversion. Due to these considerations, the CCCSD is not a feasible source of recycled water for the PGS.

As shown in the Tetra Tech report (Tetra Tech, page L-19) no other potential recycled water suppliers are located within a reasonable distance from the PGS. As a result, it is not feasible to meet the make up water and other cooling supply requirements of the PGS with tertiary-treated recycled supplies.

c. Market-Based Constraints

All three units at the PGS are currently contracted through a tolling agreement with PG&E through 2013, and PG&E has an option to extend the agreement through 2015. At this point, it is unknown whether any of the PGS units will continue to be needed for electrical reliability beyond 2015. It would be neither economical nor practical to pursue the Units 5 & 6 conversion project without a contract in place that (1) ensures that the units will remain in service beyond 2017 (the compliance deadline in the Policy) and (2) provides a revenue stream sufficient to fund the costs of the retrofit project. If GenOn cannot obtain contractual coverage beyond 2017, or if such a contract would not provide sufficient revenues to support investment in the conversion project, then GenOn Delta would be forced to retire Units 5 & 6. As discussed below, the principal source of revenue for the PGS is resource adequacy (RA) capacity, which is contracted bilaterally with load-serving entities who must demonstrate that they have contracted for sufficient capacity on a year-ahead and month-ahead basis. GenOn Delta anticipates pursuing contracts for the RA capacity of the PGS units for 2016 and beyond prior to the end of the current tolling agreement. Therefore, by the end of 2015, GenOn Delta expects to have

[2]The Tetra Tech report indicated that CCCSD has the capacity to treat approximately 67% of its wastewater flows, or 30 MGD, to tertiary levels, and that this water is used for "local irrigation projects and other non-potable uses." (Tetra Tech, page L-19). As discussed above, CCCSD, UWMP and LAFCO data indicate that the volume of tertiary treated water that CCCSD can produce, the amount currently used by the district and its customers, and the volume of recycled water the district plans to generate in the future, are substantially lower than the levels suggested in the Tetra Tech report. In a personal communication to GenOn Delta on March 29, 2011, the CCCSD confirmed that current tertiary volume is 1.5 MGD and indicated that the maximum functional capacity of the existing tertiary treatment facilities is approximately 5 MGD. CCCSD would incur substantial capital, operational and maintenance costs associated with maintaining recycled capacity at more than twenty times the district's current demand (1.5 MGD), and more than ten times the district's projected build out demand (2.8 MGD)(2005 UWMP, page 70). As a result, it is likely that significant additional facility construction would be required to increase CCCSD's tertiary-treated water capacity substantially above current levels.

determined whether the PGS will continue be needed beyond 2015, and whether sufficient net revenue certainty will be in place to support the investment in the conversion project.

A fundamental hurdle to any major capital improvement project is the facility's ability to fund the project. In the Supplemental Environmental Document (SED), State Board staff expressly recognized "the complexities of financing" and acknowledged that obtaining financing is a prerequisite to actually constructing improvements.[3] As explained in this subsection, obtaining financing is essentially contingent upon obtaining contractual coverage that provides a reliable revenue stream for the unit. Without this contractual certainty, it would be infeasible to undertake the retrofit project even if it were otherwise feasible from a technical, logistical and environmental perspective. Any compliance plan will require investment – the larger the investment, the greater the required revenue certainty and the longer the time that is likely required to recover the investment. Any form of Track 1 compliance would require significant revenue certainty over many years.

Exhibit A provides an overview of the landscape that must be considered in evaluating such investments. GenOn has limited long-term market opportunities, and as an independent power producer in California, GenOn faces significant market and regulatory risks that create uncertainty regarding revenues and costs. Exhibit A elaborates on the investment criteria that GenOn must consider, and then explains the operating characteristics and capabilities of the PGS, as well as the Mandalay Generating Station and Ormond Beach Generating Station owned and operated by GenOn West, L.P. An introduction is then provided to the market structure in California including how resource adequacy (RA) capacity requirements are developed and how load serving entities contract for RA capacity. The California Independent System Operator (CAISO or California ISO) operates the only transparent competitive markets for energy and ancillary services in California, and a high-level summary of the role and design of those markets is provided. In light of these market and regulatory circumstances, Exhibit A explains the many sources of uncertainty GenOn faces, from the economic outlook to market rules, and summarizes the implications of these uncertainties for investment in the PGS retrofit.

Based on the foregoing market-based constraints, it is impossible for GenOn Delta to state definitively in April 2011 that the conversion will actually be accomplished by the 2017 compliance deadline. GenOn Delta proposes to continue to assess the viability of the conversion project, and to pursue contractual coverage that would enable the PGS to achieve compliance with the Policy and continue operating beyond 2017.

d. Implementation Schedule

In order to implement its Track 1 proposal, and with the contractual setting described above in mind, GenOn Delta anticipates the following implementation schedule:

[3] SED Appendix G at p. G-194.

Table III-1: PGS Track 1 Compliance Implementation Schedule

Implementation Step		Estimated Timeframe
1	Pursue contract providing for implementation of PGS Units 5 & 6 conversion project	2015
2	Design, engineer and permit conversion project; retire Unit 7	2016
3	Construct conversion project	2016-2017
4	Converted Units 5 & 6 online in closed-cycle cooling configuration	No later than December 31, 2017

IV. COMPLIANCE WITH INTERIM REQUIREMENTS

a. Offshore Intake Screening

The PGS does not have an offshore intake, and therefore Section 2(C)(1) of the Policy is inapplicable.

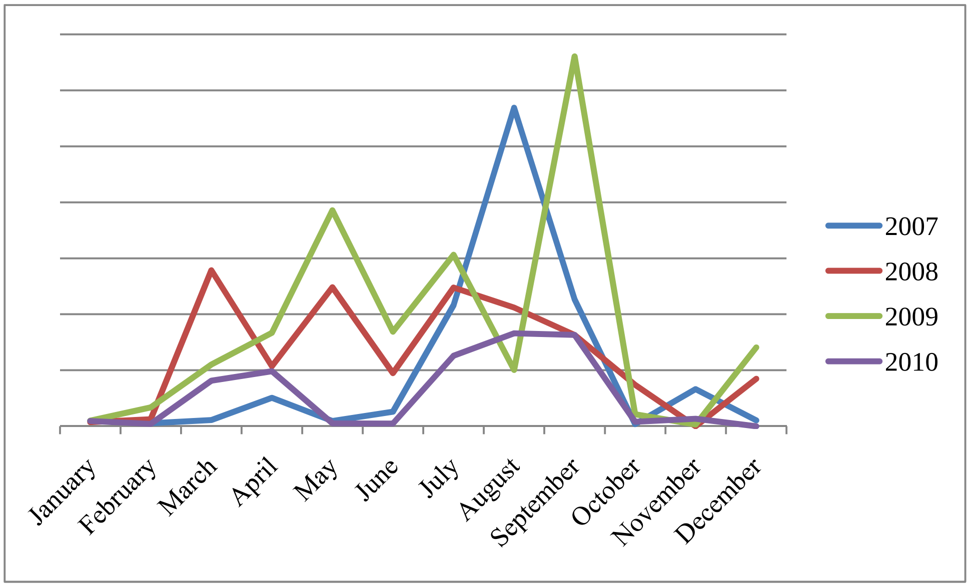
b. Curtailment of Intake Flows

Section 2(C)(2) of the Policy requires an existing power plant unit that is subject to the Policy to cease intake flows when not engaging in power-generating activities or critical system maintenance, unless a reduced minimum flow is necessary for operations. As described in Section II above, GenOn Delta already minimizes power-generation flows by utilizing VFDs, and all other intake flows described in Section II above are either directly related to power generation or critical system maintenance, so no additional flow curtailments are proposed.

The November 30, 2010 Implementation Plan Requirements letter requested "information regarding when it is likely that each unit in your facility may not be generating power, or when you are performing critical system maintenance that would result in the cessation of flows." As illustrated in the graph below, PGS operations are typically concentrated in the hottest summer months, when demand for generation is highest, but generation can and does occur throughout the year. Under the terms of its tolling agreement with PG&E, GenOn Delta has no control over when the units may be dispatched. Accordingly, while a discussion of monthly generation trends can indicate when flows are more or less likely to occur during the year, based on likely electrical demand, they are only illustrative, and GenOn Delta could not guarantee that the annual generation profile in a given year will look exactly the same as another year. Since

GenOn Delta employs VFDs year-round, power-generation flows are minimized whenever generation occurs. Accordingly, GenOn Delta is already in compliance with Section 2(C)(2).

Figure III-1: Actual PGS Monthly Flows 2007-2010



c. Interim Mitigation

Under Section 2(C)(3) of the Policy, GenOn must implement measures to mitigate interim impingement and entrainment impacts resulting from the cooling water intake structures from October 1, 2015 onward, if final compliance with the Policy has not been achieved by that time. GenOn Delta anticipates that PGS Units 5 & 6 will still be operating and that final compliance will not have been achieved by October 2015, so GenOn Delta will be required to meet the requirements of Section 2(C)(3). Section 2(C)(3)(a) of the Policy permits compliance through demonstration to the State Board's satisfaction that the owner or operator is compensating for the interim impingement and entrainment impacts through existing mitigation efforts, including any projects required by state or federal permits as of October 1, 2010. Existing mitigation measures at the PGS fulfill the interim mitigation requirements of Section 2(C)(3).

Under a Memorandum of Understanding (MOU) with the Department of Fish and Game, GenOn Delta must (1) operate VFDs and a traveling fish screen year-round; (2) rotate and clean intake screen assemblies in operation at a frequency of not less than once every four hours; and (3) pay a mitigation fee annually in order to minimize and fully mitigate entrainment and impingement of aquatic species. These measures are also required by GenOn Delta's federal Endangered Species Act authorizations issued by the U.S. Fish and Wildlife Service ("USFWS") and the National Marine Fisheries Service ("NMFS").

1. *Existing Entrainment and Impingement Data*

Attached as Exhibit B is a summary of historic entrainment and impingement studies conducted at the PGS. Since GenOn Delta is proposing to comply with the Policy under Track 1, Section 4 of the Policy is inapplicable, and the data is not relevant to achieving compliance. However, these studies provide useful context for a discussion of the PGS and may inform the Policy's interim mitigation requirements discussed below.

2. *Existing Mitigation Measures*

GenOn's existing mitigation measures consist of both technological measures as well as mitigation fee measures, as discussed below.

i. Technological Measures

It is important to highlight existing impact reduction measures in place at the PGS that significantly reduce entrainment and impingement mortality from baseline levels. These existing measures must also be credited against the interim mitigation requirements of the Policy.

As discussed above in Section II, when the PGS does operate, the primary minimization measure implemented to reduce PGS cooling water system effects is the year-round use of VFDs, which enable the circulating water pumps to operate at variable speed, rather than being either on (100% speed) or off as in conventional once-through cooling systems. As determined by the Department of Fish and Game, the requirement to utilize VFDs significantly reduces once-through cooling flows. When operating in VFD mode, the circulating water pump speed /flow is between 50-95% of design flow at loads less that 65 gross megawatts. By operating the circulating water pumps in VFD mode, over a 7-day running average, circulating water flows will be reduced to 80% of design capacity (20% below design flow) on a year-round basis. In general, VFD controls reduce approach velocities in front of the bar racks from the design approach velocity of approximately 0.6 fps to as low as 0.16 fps with only one of the two units operating at 50% of design flow.

The VFD control procedure is written as follows:

> There are two modes of VFD operation depending on the time of year. Generally, from May 1 to July 15, a feed forward curve controls the circulating water pump speed at 50% speed until 172 MWg is achieved. The speed then gradually ramps to 95% speed at 322 MWg. The speed is maintained at 95% through a full load of 345 MWg. A discharge temperature setpoint of 85ºF also cascades into the control logic to increase or decrease the pump speed as needed. The pump speed is always maintained for minimum flow and optimum temperature (<86ºF) in the range of 50 to 95% except in the rare occurrence when a condenser

backpressure greater than 2.0 inches Hg is impacting the reliability of the unit. Except during conditions of electrical grid system reliability as dictated by the Independent System Operator (ISO), the unit load is reduced to prevent pump speed from exceeding 95% due to either exceeding a backpressure of 2.0 inches Hg or exceeding discharge temperature of 86ºF.

During the remainder of the year, a feed forward curve maintains 50% of speed until 65 MWg when the speed is gradually ramped to 100% at 115 MWg. The 100% speed curve is maintained through full load at 345 MWg. Turbine backpressure is cascaded into the control logic to allow a maximum backpressure of between 0.8 and 1.8 inches Hg between 50 and 345 MWg. Exceeding the turbine backpressure curve will allow the pump speed to exceed the feed forward curve.

The requirement to rotate and clean the intake screen assemblies at least once every four hours during operations is also in place for the purpose of maintaining intake water velocities as close as practicable to design levels, thereby minimizing impingement and entrainment.

ii. Mitigation Restoration Payments

In addition to technological impact reduction measures, GenOn Delta provides substantial restoration payments to the Department of Fish and Game to mitigate the aquatic impacts of once-through cooling at the PGS. The annual fee is calculated by taking the sum of the acre-feet of water diverted, a Delta Smelt Fall Midwater Trawl Index factor, and the Water Diversion Factor, as follows:

(Acre-feet of water diverted) * (Water Diversion Factor) * (Delta Smelt Fall Midwater Trawl Index Factor) = (Annual Interim Mitigation Compensation).

Under the MOU, the Department of Fish and Game increased the fee in 2007 such that the current “Water Diversion Factor” is $2 per acre-foot of water ($6.14 per million gallons) diverted from February 1 - July 31, and $1 per acre-foot of water ($3.07 per million gallons) diverted from August 1 - January 31. Most recently, GenOn Delta submitted a fee on February 1, 2011, covering PGS flows for the year 2010, in the amount of $33,936. These fees contribute to funding Department of Fish and Game programs within the Sacramento-San Joaquin Delta that benefit Delta aquatic species.[4]

[4]Note that the provisions of Section 2(C) expressing a preference for funding mitigation projects overseen by the California Coastal Conservancy in consultation with the California Ocean Protection Council should not apply to the PGS, which is not located in coastal waters, is not within the jurisdiction of the Ocean Protection Council, and is outside the areas where the California Coastal Conservancy is active. GenOn Delta believes that funding Department of Fish and Game programs that will specifically benefit Delta species is appropriate.

For reference, GenOn Delta notes that on December 14, 2010, the State Board proposed amendments to its Policy that included additional language to Section 3(A)(1)(c) of the Policy. That additional language would have clarified compliance with Section 2(C)(3)(a)-(c) and (e) by establishing a $3 per million gallons fee payable annually for the purposes of meeting the mitigation requirements set forth in those subsections. While these amendments were not adopted, GenOn believes the $3/million gallons mitigation approach provides a reasonable and practicable method for meet the Policy's requirements. It is worth noting that the fees GenOn Delta already pays under the MOU are greater than the proposed $3 per million gallons rate, as explained above.

iii. Interim Mitigation Conclusion

In sum, GenOn will meet and exceed the requirements of Section 2(C)(3) of the Policy by complying with the mitigation requirements of the Department of Fish and Game MOU (and USFWS and NMFS authorizations) at PGS by operating the VFDs year round, rotating and cleaning the intake screens, and paying fees annually to the Department of Fish and Game based on the amount of once through cooling water drawn through the units (at an amount that exceeds the $3 million per million gallons considered in the proposed Policy amendment). These measures are anticipated to continue through final compliance.[5]

[5]On March 1, 2011, GenOn submitted an application for a California Endangered Species Act 2081 permit to the Department of Fish and Game pursuant to the MOU (consultation with the USFWS and NMFS under the federal Endangered Species Act has also been reinitiated). Mitigation requirements for impingement and entrainment impacts resulting from the final 2081 permit and/or federal authorizations may revise and supersede the existing requirements and will be incorporated into this Implementing Plan at that time to satisfy Section 2.C.3 of the Policy.

Exhibit A

DISCUSSION OF MARKET AND CONTRACTING FACTORS RELATED TO INVESTMENT IN COMPLIANCE MEASURES FOR THE ONCE-THROUGH COOLING POLICY

AT

GENON'S MANDALAY, ORMOND BEACH & PITTSBURG GENERATING STATIONS

ORGANIZATION

DISCUSSION OF MARKET AND CONTRACTING FACTORS RELATED TO INVESTMENT IN COMPLIANCE MEASURES

GenOn West, L.P. has prepared Implementation Plans for the Mandalay Generating Station (MGS) and the Ormond Beach Generating Station (OBGS), and GenOn Delta, LLC has prepared an Implementation Plan for the Pittsburg Generating Station (PGS) to comply with the State Water Resources Control Board's (State Board) "Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling" (Policy).[1] GenOn has a viable Track 1 compliance plan for the PGS, and viable Track 2 compliance plans for the MGS and OBGS. Even though GenOn has viable compliance plans for each station, GenOn is unable at this time to make an unqualified commitment to the significant investment necessary to comply with Track 1 of the Policy at PGS, nor is GenOn necessarily able to commit to the investment required for compliance under Track 2 at the MGS and OBGS in light of significant market-based uncertainties facing independent power producers in California.[2] The purpose of this exhibit is to provide background and explain the market-based constraints that prevent GenOn from making an unqualified commitment to the significant capital investment required to undertake compliance with the Policy. If GenOn cannot secure the funding necessary to make the investment necessary to implement the identified Track 1 and Track 2 compliance measures, then GenOn would likely be forced to retire or repower its effected units.

This Exhibit first provides an overview of the criteria by which GenOn must evaluate incremental investment decisions, and then describes the reliability services that GenOn's once through cooled generating units are capable of providing. An overview of the contracting and market opportunities through which GenOn is compensated for providing reliability services is then presented, followed by a discussion of the external factors that contribute to the uncertainty GenOn faces in forecasting the future net revenues from the sale of these reliability services. This exhibit concludes with a summary of why, as of April 1, 2011, these uncertainties prevent GenOn from making an unqualified commitment to the investment required for the compliance measures described in the Implementation Plans for the PGS, MGS and OBGS.

[1] Hereafter, GenOnWest, L.P. and GenOnDelta, LLC, either individually or collectively, are referred to as "GenOn." This Exhibit is common to the each of the Implementation Plans submitted by GenOn for the PGS, MGS and OBGS,

[2] For the PGS, Track 1 compliance would involve retirement of PGS Unit 7 and conversion of that unit's cooling towers for use by PGS Units 5 and 6. Track 1 compliance at the MGS and OBGS would require investment in new cooling towers, if feasible, while Track 2 would require the implementation of one or more technological measures to reduce impingement mortality and entrainment and may involve operating restrictions that could have a significant impact on revenues.

1. Investment Criteria

GenOn is a competitive energy company that produces and sells electricity in the United States. GenOn is focused on the operational performance of our generating facilities, and prudent growth of our business. GenOn makes major investments in environmental controls, and also employs a targeted maintenance program to ensure long-term availability of our generating stations. GenOn must factor in appropriate return for shareholders when deciding which investments to make, and must also comply with all covenants and restrictions associated with any project financing used to fund major capital projects.

GenOn sells capacity, energy and ancillary services on a short-term basis or through power sales agreements. GenOn is not guaranteed recovery of our costs or any return on our capital investments through regulated rates. Whether an appropriate return can be earned for investors depends on the sufficiency and the certainty of net revenues after meeting all operation and maintenance expenses, ordinary capital expenditures and payment obligations on any project financing. Operating revenue depends on market and competitive forces that are beyond GenOn's control.

Retrofit to closed-cycle cooling to comply with Track 1, or implementation of a combination of measures to meet Track 2 would require a significant investment as explained in each Implementation Plan. Given the uncertainty regarding the fixed and annual costs of compliance with the Policy, as well as significant uncertainty regarding revenues, GenOn cannot reasonably assure that it will recover the investment required for cooling towers, or any other combination of technologies and operating restrictions that might allow the generating units to comply with the Policy, and is therefore unable at this time to commit without qualification to those investments. These factors are discussed in more detail below.

2. Operating Characteristics and Available Services

The following describes the existing operating characteristics and capabilities of the MGS, OBGS and PGS. When matched with the contracting and market opportunities discussed later, these capabilities define the potential revenues that must support any capital investment at those plants.

A. Operating Characteristics

The operating characteristics of the PGS, MGS and OBGS allow these plants to play a key role in supporting reliable operation of the electric grid.

An important characteristic of each station is its location. The California Independent System Operator (CAISO) relies on the PGS, MGS and OBGS units to support local and system reliability during maintenance of the high voltage grid. Both the MGS and OBGS are in the Big Creek Ventura Area, and are used by the CAISO to assure that load in Ventura and Santa Barbara Counties can be served when the transmission lines providing imports to the local area are threatened, particularly by fires or other natural disasters.

The MGS and OBGS turbines also provide rotating mass that contributes inertia required to support imports into Southern California.

The PGS is located in the Pittsburg sub-area of the Greater Bay Area. The PGS supports grid operations in the Greater Bay Area and provides support for the transmission system in the North Bay Area as well. This support not only protects the local grid but enables imports into the load centers located in the Bay Area from the bulk transmission system connecting the Bay Area with northern California and the Northwest.

The MGS units have relatively quick start-up times, particularly when the units are hot and start times are less than two hours. This allows the CAISO to cycle these units daily. The minimum load of each unit is 20 MW, which is less than 10% of the peak capability. The OBGS and PGS units have wide operating ranges and fast ramp rates which are important characteristics for reliability purposes.[3] While the OBGS ramp rates are already high (e.g. up to 12 MW/Min), there is on-going analysis to increase OBGS ramp rates to even higher levels in response to forecasted flexibility needs. Both OBGS units have also been tested to operate at reduced minimum loads.

While there are some key differences among the PGS, MGS and OBGS stations, each station plays an important role in supporting electric system reliability and integrating intermittent renewable resources. The services available from these facilities are described in more detail below.

B. Available Services

The CAISO presently relies on several services provided by the PGS, MGS and OBGS. Some of these services are defined as market products that are procured in advance of the operating day, and for which there is some degree of fungibility so that the products can be competitively procured and priced. The services available from each unit represent the potential sources of revenue. Contracting and market mechanisms to compensate suppliers for providing these services are discussed later.

1. Resource Adequacy (RA) Capacity

The CAISO performs technical studies to establish minimum capacity requirements for each of several "local reliability areas" to assure that load in those areas can be reliably served. All load-serving entities (LSEs) are then required to demonstrate that they have procured sufficient "net qualifying capacity" to serve their peak load, plus a planning reserve margin of 15% to 17%. The net qualifying capacity of each resource is determined by the CAISO based on testing, verification, applicable performance criteria and deliverability for the purpose of meeting peak demands, based on rules for determining the qualifying capacity of each resource type as established by the California Public Utilities Commission (CPUC). According to this process, the MGS, PGS and OBGS have net qualifying capacity equal to the maximum output of each unit, as shown below:

[3] An operating range is the difference between a unit's Net Qualifying Capacity and its Pmin. In the case of OBGS Unit 2, the operating range is 725 MW (NQC of 775 MW minus Pmin of 50 MW).

Unit	Net Qualifying Capacity (MW)
PGS 5	312
PGS 6	317
PGS 7	682
MGS 1	215
MGS 2	215
OBGS 1	741
OBGS 2	775

As explained in more detail below, the CAISO performs technical studies to establish minimum capacity requirements for each identified local reliability area to assure that load in those areas can be served without violating transmission constraints. Some portion of the total capacity required to serve load in each of these local reliability areas is then required to be located within the local reliability area (i.e., that portion of the capacity requirement cannot be provided by resources external to the local reliability area).

RA capacity is obligated to be available and capable of being committed and dispatched. Since the CAISO could call on these units at any time, the PGS, MGS and OBGS units support reliability of the grid even when the units are off-line and not producing energy. The RA capacity value of these units helps assure the long term reliability of the grid, and that value is independent of how much energy they actually produce.

2. *Local Emergency Capacity*

During certain conditions that have occurred recently, the CAISO has relied upon the MGS and OBGS to assure reliable electric service to the local reliability area. For example, due to wildfires in September 2009 that were threatening the transmission lines across which energy is imported to Santa Barbara and Ventura Counties, the CAISO relied upon the MGS and OBGS units to assure that load in these two counties could be served without interruption.

3. *Energy*

When committed and dispatched to minimum load or greater, the PGS, MGS and OBGS units provide energy that helps the CAISO perform its obligation to continuously balance loads and resources within the CAISO Balancing Authority Area, while respecting all transmission limits. Energy bids are submitted to the CAISO for use in the day-ahead and real-time markets, and the CAISO commits and dispatches resources to economically serve load and relieve any transmission congestion that might arise.

4. *Regulation*

Regulation is generally regarded as the highest value Ancillary Service that the CAISO procures to assure the reliable operation of the grid. Regulation requires a unit to change output in response to signals provided by the CAISO's energy management system every four seconds through automatic generation control. Each of the MGS and OBGS units, and PGS Unit 5, are certified to provide regulation. The CAISO competitively procures Regulation through its markets.

5. Spinning Reserve

The CAISO is required to maintain sufficient spinning reserve, which is synchronized and available to immediately respond when dispatched. This capacity service is required so that the CAISO is able to respond when a contingency occurs, such as the loss of a major transmission line or generating unit, assuring that applicable reliability criteria are met. The CAISO competitively procures Spinning Reserve through its markets.

6. Frequency Response

Conventional generating units are synchronous machines that are electrically coupled to the grid. All of the PGS, MGS and OBGS units meet applicable WECC criteria for frequency response, and when operating and synchronized these units respond immediately and automatically in proportion to frequency deviations through the action of a governor set according to the minimum governor performance standards defined by the CAISO (i.e., 5 percent droop and +/- 0.036 Hz deadband). There is currently no CAISO market for frequency response.

7. Voltage Support

The PGS, MGS and OBGS units are operated to follow voltage schedules established by the CAISO by producing or consuming "Mvars" which is a measure of reactive power. Reactive power is necessary to maintain system voltage in an alternating current system. Synchronous generators such as the PGS, MGS and OBGS units represent one of the most flexible and effective sources of reactive power available to the grid, and play a key role in assuring the voltage stability of the grid. There is currently no CAISO market for voltage support.

8. Inertia

The MGS and OBGS play a key role in supporting energy imports to Southern California. The stability of the grid depends on assuring a balance between imports across these paths, and the amount of inertia, or rotating mass available in southern California. The PGS provides the same function for Northern California and specifically the Greater Bay Area load center, which depends on significant imported energy over several paths. There is currently no CAISO market for inertia.

3. California Electric Market Structure Overview

The purpose of this section is to explain the existing wholesale electric market design in California. This understanding is essential background to an assessment of the financial feasibility of the capital investments required to comply with the Policy.

There are two principal categories of customers – the LSEs who must purchase RA capacity (e.g. PG&E, SCE, SDG&E, energy service providers (ESPs) and local publicly-owned utilities) and the CAISO, which acts as an intermediary between suppliers and loads by operating day ahead and real time markets for energy and ancillary services. GenOn sells RA capacity from the MGS and OBGS and bids those units into the CAISO markets. For the PGS, GenOn has entered a "tolling" agreement under which PG&E has acquired the rights to all the RA capacity, energy and Ancillary Services through 2013, with an option to extend this agreement through 2015. PG&E has the right to all the PGS RA capacity, and is responsible for bidding and scheduling those units in the CAISO markets.

A. RA Program

The RA program is an existing bilateral framework administered by the CPUC, the California Energy Commission (CEC) and the CAISO. The CPUC establishes resource adequacy requirements for all LSEs in its jurisdiction, which include the three major investor-owned utilities (IOUs) serving bundled customers, and the energy service providers (ESPs) who serve load under California's rules for retail competition. Each LSE is required to maintain physical generating capacity that is both adequate to meet its load requirements (including peak demand and planning and operating reserves) and deliverable to load. The capacity procured must be sufficient to meet the planning reserve and reliability criteria established by the Western Electricity Coordinating Council.[4]

The local publicly-owned utilities in California are not under the jurisdiction of the CPUC, but are required to prudently plan for and procure resources that are adequate to meet peak demand and provide the reserves necessary to provide reliable electric service to its customers. The CEC has authority to oversee the resource adequacy programs of the local publicly-owned utilities.[5]

1. Demand Forecasts

An initial step in the annual RA process is the preparation of demand forecasts for the coming year. Each May of the year preceding the RA compliance year, LSEs regulated by the CPUC submit demand forecasts for the RA compliance year to the CEC. CEC staff review the forecasts and make adjustments as needed so that the sum of the adjusted forecasts is within one percent of the adopted CEC forecast for each distribution service area. The CEC then transmits the demand forecasts to the CPUC, which in turn transmits them to LSE's, usually in the July prior to the RA compliance year.

2. Local Capacity Technical Studies

Each year the CAISO conducts a Local Capacity Area Technical Study (referred to as the Local Capacity Requirements or LCR Study) to identify the minimum capacity required in each local capacity area defined by the CAISO. In October 2010, the CAISO began the process to define local capacity requirements for 2012 by publishing a draft manual on the criteria, method and assumptions to be used in the LCR Study. The CAISO adopted a final manual in December 2010, presented draft results in March 2011, and will publish its final LCR report for 2012 by the end of April. The CPUC will then review the conclusions of the CAISO LCR Study in its annual resource adequacy proceeding. The CPUC adopts local capacity requirements by the end of June so that LSEs are able to procure local RA capacity for the following year in accordance with the requirements adopted by the CPUC.

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[4] Section 380 of the California Public Utilities Code.
[5] Section 9620 of the California Public Utilities Code.

The CAISO Tariff provides that in conducting the LCR Study, the CAISO will identify and resolve contingencies based on performance levels specified in North American Electric Reliability Corporation (NERC) Reliability Standards, as supplemented by CAISO reliability criteria. While the studies are carefully performed to meet the NERC standards, they are also designed to maximize the import capability in each local area and minimize the local generation required to meet reliability requirements. The CAISO identifies the most stringent contingencies based on NERC criteria, and then loads the limiting element to 100% of its applicable rating for constraints that result from equipment loading limits, while targeting the minimum allowable voltage and/or reactive margin after the most restrictive contingencies are taken.[6]

The LCR Study defines the portion of the total capacity required to serve load in each of these local reliability areas that is required to be located within the local reliability area (i.e., that portion of the capacity requirement cannot be provided by resources external to the local reliability area). The results of the LCR Study may show a surplus in a local area, but that does not necessarily mean that generation equal to that surplus can be retired. The CAISO acknowledges that not all capacity in a local area is equally effective in solving local constraints.[7] The PGS, MGS and OBGS all have high effectiveness factors. The CAISO may also require generation in local areas for other purposes that are not considered in the LCR Study. For example, additional generation in a local area may be required to allow maintenance to the high voltage transmission grid, or to provide inertia to support transmission limits and the stability of the grid.

3. Local and System Resource Adequacy Obligations

Based on the minimum local requirements identified in the CAISO's annual LCR Study, the CPUC adopts local capacity requirements, which are assigned to LSEs based on what share of load they serve in that local area. Each July the CPUC staff provides each LSE with load forecasts and local obligations. Each September, LSEs must demonstrate they have procured 100% of their share of the local capacity requirement for the coming year. The difference between an LSE's share of the capacity requirement for the local capacity area, and the total capacity required to serve that LSE customers in the local area, can be procured from the net qualifying capacity of any local or system resource. As explained above, the PGS is in the Greater Bay Area, and the MGS and OBGS are in the Big Creek / Ventura Area, meaning that each station is eligible to meet the local capacity obligations of LSEs under the RA program.

Each October, LSEs must demonstrate procurement of 90% of system obligations, with demonstration of remaining system obligations due on a month-ahead basis during the compliance year. The timing of these obligations defines the opportunities for marketing RA capacity from the MGS and OBGS currently, and for the PGS after the tolling agreement with PG&E expires.

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[6] California ISO, *Final Manual - 2012 Local Capacity Area Technical Study*, December 2010, page 7. (available at: http://www.caiso.com/2867/286794795d0b0.pdf)
[7] Id.

4. *Standard Capacity Product*

Operators of units with RA commitments are subject to must-offer obligations in the CAISO markets, and also are subject to availability charges and bonuses based on the extent of unplanned outages that render the resource adequacy resource unavailable for commitment and dispatch by the CAISO. The risk of non-availability charges and possible opportunity to earn availability bonuses must be taken into account during operations, and in planning outages to maintain and replace equipment.

B. Energy and Ancillary Services Markets

The CAISO provides open and non-discriminatory access to the high voltage transmission network under its operational control, operates Day Ahead markets for energy and ancillary services, and establishes schedules for energy and load that are consistent with applicable constraints on transmission facilities and other elements of the grid. In operating the day ahead market, the CAISO first assesses market power, determines what bids need to be mitigated, and then determines what reliability must-run units must be committed to meet reliability requirements. It then operates an integrated forward market to schedule resources and set prices.

The integrated forward market uses a security constrained unit commitment optimization to determine the commitment and dispatch of resources to jointly minimize the cost of required locational energy, and all ancillary services forecast to be required to meet reliability criteria each hour of the next operating day, while respecting all applicable transmission constraints. Hourly locational prices are set for energy and ancillary services. The ancillary services procured include regulation up, regulation down, spinning reserve and non-spinning reserve. To the extent that the demand scheduled in the integrated forward market falls short of the CAISO forecast, then a residual unit commitment market is run to commit additional capacity to meet the difference in forecast and scheduled demand.

A real-time unit commitment tool is used in both the hour ahead scheduling process and the real time markets to adjust energy schedules and to procure any additional ancillary services required due to changed conditions. The real-time unit commitment process is run every 15 minutes, and the CAISO dispatches energy based on bid prices to set locational marginal prices every 5 minutes to balance the system, with regulation used to provide moment to moment balancing and maintain system frequency.

C. Exceptional Dispatch

If the CAISO market models fail to reflect all applicable constraints, or do not specify all the products that the CAISO requires to reliably operate the system, then the CAISO may rely on an out-of market process referred to as “exceptional dispatch” to commit and dispatch resources based on their locational and operating characteristics. Units that are exceptionally dispatched are compensated based on mitigated bids if the exceptional dispatch is needed to relieve a non-competitive transmission constraint.

D. Reliability Must Run

The CAISO has the authority to procure uneconomic capacity that it determines to be essential to local reliability through a cost-of-service mechanism provided by reliability must-run (RMR) contracts. The CAISO makes the determination of whether a generator is required for reliability based on the LCR Study, or other technical analysis that the CAISO conducts. The RMR contract gives the CAISO the right to call on energy, or to require the supplier to provide ancillary services. When designated for RMR, a generating unit that might otherwise retire is obligated to provide the CAISO with proposed rates for reliability must-run services, which are then filed with the Federal Energy Regulatory Commission (FERC).

The RMR contract is a year-to year contracting mechanism that requires the generator to develop comprehensive cost exhibits supporting its proposed rates. Under the CAISO tariff, the RMR contract is designed for addressing local reliability, black start services, voltage support and non-competitive constraints, and does not allow the CAISO to procure or dispatch such capacity for broader system reliability purposes that might be fulfilled by other generating units.

E. Capacity Procurement Mechanism

The CAISO tariff allows the CAISO to procure capacity from resources without a resource adequacy contract under the CAISO's "interim capacity procurement mechanism" which expired March 31, 2011. The CAISO has proposed a permanent backstop capacity procurement mechanism (CPM) that would compensate resources based on their "going forward" costs. The new CPM became effective April 1, 2011.

Features of the CAISO's permanent CPM mechanism include expanded authority to designate resources without RA contracts for a CPM contract. This authority includes designations for units at risk of retirement that the CAISO determines are needed for reliability. Parties protested the CAISO's proposal at FERC, seeking changes in the purpose, pricing, term and amount of capacity that the CAISO is authorized to procure under CPM. In a March 17, 2011 decision adopting most of the CAISO's proposed design details, FERC concluded that the CAISO's proposal to pay going forward costs "may create the potential for distorted pricing signals and deny resources a reasonable opportunity to recover fixed costs," and directed FERC staff to schedule a technical conference to explore CPM pricing.[8] The ability to recover fixed costs is an essential prerequisite for GenOn to fund Track 1 or Track 2 measures required to comply with the Policy.

F. Renewable Integration and New Products

The CAISO forecasts substantial reductions in revenues to the existing thermal fleet as renewable resource penetration increases, and energy generated by thermal resources is displaced by renewable energy. Specifically, the CAISO recently concluded that:

[8] Federal Energy Regulatory Commission, Order on Tariff Revisions, Docket No. ER11-2256-000 Order 134 FERC ¶ 61,211, paragraph 57.

> "The combination of increased production of wind and solar energy will lead to displacement of energy from thermal (gas-fired) generation in both the daily off-peak and on-peak hours. Due to this displacement and to simultaneous reduction in market clearing prices, there may be significant reductions in energy market revenues to thermal generation across the operating day in all seasons."[9]

The revenue impact of this displacement of energy by renewable resources will depend on many factors as discussed herein, but certainly inhibits investments such as those required to comply with the Policy.

While energy revenues to thermal power plants are projected to decrease, the CAISO will have significantly greater need for many of the services these resources provide. In operating a power system, it is vital that sufficient generation resources are available to allow hourly and real-time deviations between forecasted load and supply to be balanced by the grid operator. These deviations can take place in the upward or downward direction and have historically have been caused by changes in load. With increasing reliance on intermittent renewable resources, which are characterized by deviations in output that can be large and difficult to predict, the root cause of the CAISO's need for resources to balance the system is evolving.

Intermittent renewable resources contribute significant variability in hour-to-hour and intra-hour output, as well as significant uncertainty in forecasting that output, and generally do not contribute the same benefits of frequency response and inertia that are essential to assuring the security of the grid. As more renewable resources are added, the CAISO's need for additional regulation, ramping, reserves and on-line capacity is likely to materially increase.

For these reasons, it is critical that the CAISO has enough dispatchable resources and other reliability services under its control. The CAISO is performing extensive analysis of the impact of California's renewable portfolio standard (RPS) on reliable operation of the CAISO balancing area, and has concluded that substantially more ancillary service capacity will be required to integrate renewable resources.[10] At a recent symposium, the CAISO's CEO spoke about the operational challenges in integrating renewables, and estimated that procurement of some ancillary service products will need to double or triple.[11]

To assure that the CAISO is procuring the required capability from the existing fleet of generators, the CAISO has developed a flexible ramping constraint which is incorporated into the market optimization software. By using this constraint, the CAISO can impose a minimum ramping capability across a specified period of time, which may result in

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[9] Integration of Renewable Resources - Operational Requirements and Generation Fleet Capability at 20% RPS, CAISO (Aug. 31, 2010), p. v. This report is available at the following link: http://www.caiso.com/2804/2804d036401f0.pdf.
[10] Id.
[11] Yakout Mansour, *ISO Symposium Keynote Speech*, October 19, 2010, available at: http://www.caiso.com/2836/2836f22a24980.pdf

changes in the commitment and dispatch of resources if this constraint is binding. The use of such a constraint is not fully transparent and does not properly value the capacity services that are thereby made available to the CAISO. Recognizing that new products may be required, the CAISO is initiating a process in April 2012 to examine its requirements and to consider defining new ancillary service products to facilitate the integration of intermittent renewable resources.

G. Other Western Markets

NERC is the national entity responsible for developing reliability standards, which are the planning and operating rules that assure that each operating entity supports system reliability. The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating reliability of the bulk electric system in the western interconnection, which includes 14 western states, two Canadian provinces, and part of Mexico. The CAISO is obligated to comply with the planning and operating standards administered by WECC and NERC, and to procure the required ancillary services to assure the reliable operation of the CAISO's balancing area.

The CAISO is the only centrally administered day-ahead and real-time market in the western states. WECC members are considering the establishment of an imbalance energy market as part of the "efficient dispatch toolkit." Such a mechanism has the potential to increase liquidity, transparency and reliability of the western interconnection.

H. Procurement Background

1. CPUC Long Term Procurement Planning (LTPP) Process

The LTPP Rulemaking provides a biennial review of the IOUs' procurement process, established pursuant to AB57. The IOUs submit LTPPs that serve as the basis for utility procurement and comprehensively integrate Commission decisions from all procurement related proceedings. By approving ten-year procurement plans in advance, the CPUC provides up-front standards for procurement which eliminates the need for after-the-fact reasonableness review by the CPUC of the specific resource procurement decisions each IOU pursues in implementing the approved procurement plan.

Independent power producers engage in the LTPP process to better understand the energy and capacity needs of the IOUs. As stated in a recent assigned commissioner ruling issued in the CPUC's current LTPP process:

> "Track I will identify California Public Utilities Commission (CPUC)-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of IOU procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through- cooling (OTC)."[12]

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[12] Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, R.10-05-006, Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling (December 3, 2010), Attachment 2 (Standardized Planning Assumptions (Part 2 –

As an independent power producer in California with both existing assets and a new project in development,[13] GenOn participates in each LTPP process to understand how all of our current assets and future developments may play a role in meeting the aforementioned Track I needs.

2. Utility and ESP Procurement Practices

Traditionally, California's IOUs have procured capacity, energy, and ancillary products from existing assets through short-term (up to five years out) Request-For-Offer (RFO) processes. GenOn, and its predecessor companies, have always participated in these processes and it is the primary means for securing contracts for capacity, energy, and ancillary products. California's IOUs have historically purchased bundled capacity and energy products from new facilities through long-term (generally 10 years) RFO's designed specifically for new facilities. Existing assets are not eligible to participate in these "new-build" RFOs.

California's Energy Service Providers (ESPs) have a much shorter term business model and they tend to just purchase capacity and energy products a year in advance. Most of this contracting takes place bi-laterally.

The net result of the IOU and ESP purchasing practices is that there is little financial certainty beyond 2-3 years in terms of contracted revenues. Accordingly, it becomes very difficult to forecast revenues beyond this window. In addition, while market participants such as GenOn have access to forward supply and demand forecasts from various California agencies, there is very little information provided in terms of what specific generating assets will be needed in the future. Independent power producers like GenOn face substantial uncertainty in interpreting available data, forecasting future demand for services from each plant, and estimating future revenues from the sale of such services. This uncertain environment and short horizon for procurement by our customers may lead to suboptimal decisions for the broader market as capital intensive businesses such as power plant development and operation have longer term planning horizons for capital expenditures.

3. Once-Through Cooling Capacity Replacement

As stated in the "State Water Resources Control Board Resolution No. 2010-0020":

> The State Water Board staff formed an Interagency Working Group (IAWG) that met regularly to develop realistic implementation plans and schedules for this Policy that will ensure that the beneficial uses of the State's coastal and estuarine waters are protected while also ensuring that the electrical power needs essential for the welfare of the citizens of the State are met. The IAWG included representatives from the California Air Resources Board, the California Coastal

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Renewables) for System Resource Plans), p. 6. A copy of Attachment 2 is available at the following link: http://docs.cpuc.ca.gov/efile/RULC/127544.pdf.

[13] The Marsh Landing Generating Station, owned by GenOn Marsh Landing, LLC, an affiliate of GenOn Delta, LLC and Genon West, L.P., is currently under construction.

Commission, the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), the California State Lands Commission, the California Independent System Operator (CAISO), and the State Water Board.

The compliance dates for the Policy were developed in consideration of a report produced by the energy agencies, titled "Implementation of OTC Mitigation Through Energy Infrastructure Planning and Procurement Changes."[14] The key milestones in planning for the PGS, MGS and OBGS compliance dates are set forth below:

Infrastructure Replacement Milestone	**Description**	**PGS Date**	**MGS OBGS Date**
CAISO Enhanced LCR Study	CAISO completes an enhanced Local Capacity Requirement (LCR) study identifying the impacts of specific OTC retirements or transmission developments on the local area's LCR projections 10 years out.	Q4 2009	Q4 2010
Infrastructure Replacement Plan	The CAISO, CEC, and the CPUC complete Infrastructure Replacement Plan identify the complete set of infrastructure needed to make OTC plants/units redundant for grid reliability. It would advise the SWRCB about the reliability designations of specific power plants.[15]	Q1 2010	Q2 2011
CAISO Annual Transmission Plan	Transmission solutions (upgrade and/or new addition) that would make specified OTC system redundant would be analyzed in the California ISO Annual Transmission Plan. The California ISO will consider SWRCB directives and schedules limiting or canceling water permits required to operate OTC plants/units in the 2011 and subsequent annual Transmission Planning Process (TPP). The California ISO will conduct analysis as part of its TPP reflecting projected OTC plant/unit retirements as a result of SWRCB directives and schedules, which shall be incorporated in to the California ISO's annual Transmission Plan that serves as the basis for further transmission upgrades or additions.	2011	2012
LTPP Approval	CPUC modifies LTPP proceeding and procurement processes to require the IOUs to assess replacement infrastructure needs, conduct targeted RFOs to acquire replacement or repowered generation capacity, and order the IOUs to procure new (or repowered) fossil generation for system reliability.	2011	2013
Generation Project Approval	Once authorized to procure by a CPUC LTPP decision, it takes 18 months for the IOUs to issue an RFO for generation (new or repowered), sign contracts and submit applications to the CPUC for approval. Approval by the CPUC takes 9 months.	2013	2015
CPUC Transmission Permitting	Proposed transmission facilities to meet needs identified in the California ISO Annual Transmission Plan to replace OTC plants/units would be brought to the CPUC for approval.	2015	2016

[14] California Energy Commission, California Public Utilities Commission, California Independent System Operator, *Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement*, Appendix B, July 2009, available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF

[15] No "Infrastructure Replacement Plan" that identifies the complete set of infrastructure needed to make OTC plants/units redundant for grid reliability has been published on the CEC, CPUC or CAISO web sites as of March 31, 2011.

Infrastructure Replacement Milestone	Description	PGS Date	MGS OBGS Date
Unspecified Replacement Infrastructure Operational	These compliance dates may change subject to the California ISO-Energy Commission-CPUC Infrastructure Replacement Plan produced in Q1 2010 and updated periodically. All dates assume a generation solution that requires an Energy Commission permit. If a permit has been acquired prior to CPUC contract approval, then an earlier on line date is possible. If transmission solutions are selected, then longer time lines would be expected.	2017	2020

The energy agencies worked diligently to develop the schedule outlined above, and it is instructive to consider the performance to that schedule over the 18 months since it was published. In developing the Policy, the State Board recognized that the compliance dates in this Policy may need to be revised based on the reliability needs of the electric system as determined by the energy agencies included in the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS). Among the responsibilities of the SACCWIS is the review of generator implementation plans to consider whether or not local and system reliability has been considered.

One task planned by the energy agencies in the above schedule to support planning for the potential retirements that may arise due to the Policy is the development of "infrastructure replacement plans" in the first quarter of 2010 and 2011 that would identify the "complete set" of infrastructure needed to make OTC plants/units "redundant for grid reliability." Although the CAISO and other agencies have performed substantial analysis and planning for OTC retirements and the impacts of building out renewable resources to serve 20% to 33% of energy serving load in California, no infrastructure replacement plans have been developed, demonstrating the significant complexity of planning for the implementation of the Policy.

4. Sources of Uncertainty

The purpose of this section is to further describe several of the important uncertainties regarding costs and revenues that GenOn faces, and to then explain how these uncertainties leave GenOn with insufficient confidence in the adequacy of net revenues to recover the cost of the substantial investment required to comply with the Policy given the current market and contracting structures, thereby preventing an unqualified commitment to such investment at this time.

A. Economic Outlook

A major source of uncertainty facing any company evaluating the merits of a major investment to comply with a regulatory policy is the economic outlook in California. The recent recession has depressed the demand for electricity. A CEC report issued in March 2011 shows reductions in forecasted peak demand for 2011 and 2012 ranging from 2.9% to 4.7% below what had previously been forecasted in 2009 for the same period.[16] In

[16] See Miguel Garcia-Cerrutti, Tom Gorin. Chris Kavalec. Lynn Marshall. Committee Final Report: Revised Short-Term (2011-2012) Peak Demand Forecast. California Energy Commission, Electricity

other words, in a relatively short period of time, demand forecasts show significant fluctuation due to the recession. As these reductions in the demand forecasts suggest, the overall demand for electricity is less than what is was before the recession. Given the reduced demand for electricity and uncertain economic outlook, there is significant uncertainty about the volume or price of energy sales from GenOn's generating stations.

B. Environmental Mitigation Costs

Among the requirements of the Policy is the development of interim mitigation measures that must be in place by October 1, 2015. The mitigation plan may include existing mitigation efforts, or a California Coastal Conservancy project funded by GenOn, and will be overseen by a panel of experts. There is substantial uncertainty regarding the cost of this program.

As explained in the OBGS and MGS Implementation Plans, GenOn will also examine operating restrictions as a potential flow-based compliance measure to reduce impingement and entrainment. Such measures could limit the availability of these stations to provide energy and related services, potentially reducing revenues to a degree that compliance with the Policy, if dependent on such operating restrictions, is uneconomic.

C. Ongoing Capital Expenditures

GenOn employs a condition-based maintenance program to ensure that we meet reliability standards for each of our units. A condition-based maintenance program is a program in which ongoing capital expenditures are valued by the economic return of restoring equipment life and/or improving functionality. This is largely dependent on the remaining economic life of the plant over which the investment is recouped.

Availability standards are typically discussed in terms of a target for NERC Generating Availability Data System (GADS) Equivalent Forced Outage Rate for Demand ($EFOR_d$), but other factors such as contractual availability rebates and CAISO Standard Capacity Product charges also play a key role in the development of GenOn's operations and maintenance program. GenOn sets an aggressive $EFOR_d$ target for our California assets, but that target is set based on GenOn's expectation that net revenues from operations will support the capital investment required to maintain this level of reliable performance. Both the amount of capital expenditures and the adequacy of net revenues to support such investment are uncertain.

D. Renewable Integration

There is significant uncertainty regarding the extent of renewable development, the amount by which energy revenues to thermal resources are reduced, the future requirements for operating flexibility from renewable resources, and the market revenues from existing or new ancillary services procured to support renewable integration.

Supply Analysis Division. CEC-200-2011-002-CTF. This report is available at the following link: http://www.energy.ca.gov/2011publications/CEC-200-2011-002/CEC-200-2011-002-CTF.PDF .

One key challenge in forecasting the role GenOn's units would play in renewable integration is estimating the pace of renewable development and the operating characteristics of renewable projects. It is not clear as to which types of renewable projects will get fully developed, permitted and eventually built. Policy makers, regulators, and market participants are all grappling with various RPS build-out scenarios as the mix of renewable technologies (e.g. wind vs. solar), location and dispatchability can have vastly different implications in terms of reserve capacity and ancillary services required for integration.

There is also significant uncertainty about how the intermittency of renewable resources will be addressed. If the CAISO relies on operating constraints such as the flexible ramping constraint discussed above, rather than competitively procured and priced market products, then revenues to suppliers like GenOn will be negatively affected, increasing uncertainty and reducing net revenues.

E. RA Rules

As currently constructed, the RA rules only require a year-ahead demonstration by an LSE that it has procured sufficient capacity to serve its needs. As a result, existing generation only has access to relatively short term capacity contracts. This short timeframe of current year-ahead process does not support investment in new generating capacity, which also means there is little to no supply flexibility. For the magnitude of the investment likely required to comply with the Policy, it may not be possible to structure a capacity offer that is both competitively structured, and of sufficient value (based on MW, price and duration) to compensate investors or support debt financing.

The current bilateral contracting framework does not recognize the full value of capacity, does not provide transparent prices, significantly increases transaction costs, and fails to provide an integrated, durable backstop procurement mechanism. Efforts to improve the forward capacity contracting process through the creation of a centralized capacity market have not yet succeeded.[17] The uncertainty surrounding the creation of a centralized capacity market adds to the difficulty of knowing whether market revenues will be sufficient to support the investment necessary to comply with the Policy. Finally, possible changes to the planning reserve margin and related RA reliability metrics further complicate any projection of what revenues might be available to recover the investment required to comply with the Policy.

F. CAISO Market Rules

Evolving CAISO market rules create additional uncertainty. For example, in April 2011, FERC staff is expected to conduct a technical conference to explore what changes in

[17] "Valuing capacity products in the state is still far from market basis. But the only way to reflect a market value of a product is to have a market and the stakeholders are split on whether to have one. In the meantime, our only available approach is the regulated, largely cost based approach. Believe me, we don't dislike it any less than the generator community does and we see no way around creating a capacity products market for this purpose and equally important opening a wider door for demand response. We will have to reopen the debate again, hopefully this time in a conclusive consensus when guided by the recent findings." See Yakout Mansour's keynote address from the 2010 Stakeholder Symposium at http://www.caiso.com/2836/2836f22a24980.pdf .

pricing are necessary to assure that the CPM, described above in Section 3(E), is just and reasonable, and allows generators an opportunity to recover fixed costs.

Another important initiative discussed above is the CAISO's consideration of new products required to integrate renewable resources. It is unclear whether the CAISO will ultimately decide to establish new products, or simply use tools such as the flexible ramping constraint to obtain the services required. The outcome could have significant implications for revenues available to capacity resources. These uncertainties make it difficult to project future net revenues to support additional investment.

G. Infrastructure Requirements

There are substantial uncertainties about the nature, cost and timing of the transmission system improvements required to support integration of renewable resources, uncertainty about the availability of emission reduction credits necessary to build new thermal generation or repower existing project, and uncertainty about which OTC generators will be required beyond their compliance deadlines to provide inertia and other ancillary services in support of reliable system operation.

H. Demand Side Management and Energy Efficiency

Demand-side management and energy efficiency play a key role today in California's energy markets and will be important resources that California will depend upon to meet AB 32's greenhouse gas reduction objectives.

According to the 2010 CPUC LTPP Load and Resource Tables, demand-side management will account for approximately 9% of the peak demand starting in 2013 for the period through 2020.[18] From the same tables, incremental uncommitted energy efficiency will grow from 1.5% of the peak demand in 2013 to 10% in 2020. These are impressive forecasts, but some of this technology and many of the new programs are untested, making it difficult to forecast their impact, and some of these forecasts have been challenged by consumer advocates.[19]

GenOn believes that there is significant uncertainty regarding the actual results of these programs, and whether or not more conservative estimates of their impacts will be adopted. Such a step may be prudent until there is a proven track record with regard to specific technologies, program participation, and reliability of estimated savings. The growth of these demand-side resources and intermittent renewable resources creates a market in 2020 where approximately 30% of the capacity is coming from non-

[18] Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, R.10-05-006, Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling (December 3, 2010), Attachment 1 (Standardized Planning Assumptions (Part 1) for System Resources). A copy of Attachment 1 is available at the following link: http://docs.cpuc.ca.gov/efile/RULC/127543.pdf.

[19] "TURN takes the position that the settlement agreement business case overstates the likely benefits of a Peak-Time Rebate (PTR) program, and the assumptions underlying the analysis of PTR should be adjusted to reflect lower expected benefits." Source: DECISION APPROVING SETTLEMENT ON SOUTHERN CALIFORNIA EDISON COMPANY ADVANCED METERING INFRASTRUCTURE DEPLOYMENT - Decision 08-09-039 September 18, 2008

conventional resources (e.g. renewables, demand response, energy efficiency and combined heat and power). Accordingly, reserve margins may be over-estimated, leading to the erroneous conclusion that some existing generating units are no longer needed. This uncertainty inhibits investment in existing thermal resources that may prove to be needed beyond their currently assumed retirement dates.

I. Technological Innovations

California is aggressively pursuing modernization of its electric grid into a smart grid. The "smart grid" encompasses several technological enhancements, from the tools and data available to system operators to monitor every important element of the transmission network with perfect synchronization, to the use of smart meters to control appliances and give customers more information that will help them lower their electric bills by reducing or shifting electric consumption. A smart grid will also take advantage of distributed generation resources, which lower transmission losses and the need for new transmission lines, and energy storage resources, which adapt energy production to energy consumption.

Like demand-side management and efficiency programs, these innovations also hold a lot of promise and in some cases can be considered to be transformative. As such, they will require an unprecedented level of coordination and communication between all market participants and policy makers. The cost and scale of these technologies create uncertainty regarding the extent to which they will be adopted, and how that adoption will affect market opportunities for existing resources relying on conventional technology. This uncertainty can inhibit investment necessary to comply with the Policy.

J. Regulatory Policy

General regulatory uncertainty further clouds the availability of future revenues for gas-fired generation, adding to the difficulty of preparing a compliance plan for the Policy. A description of some of the areas of regulatory policy impacting the operation of the plants follows.

1. Climate Change Policy and Implementation

While the California Air Resources Board (ARB) has indicated it will implement a cap-and-trade program for greenhouse gas (GHG) emissions effective as of January 1, 2012, ARB has yet to adopt final details related to how that cap-and-trade program will actually work. What is known is that GenOn will have to purchase credits to cover its GHG emissions. ARB has specified a floor price for those credits at $10 per ton but has not established a hard cap on the cost of those credits. At this point, GenOn cannot predict the cost to procure the requisite GHG credits to cover its operations or whether the application of a carbon fee will allow its plant to remain competitive. A recent court ruling found deficiencies in the ARB's environmental review, adding additional uncertainty to the timing and cost of a final policy.

2. Technology Set-Aside Policy

California's demand for technology set-asides in the context of serving the electrical grid adds to regulatory uncertainty and whether there will be sufficient revenues to cover significant infrastructure investment. Current law requires IOUs to meet a 20% renewable portfolio standard by 2010.[20] In 2008, Governor Schwarzenegger adopted an Executive Order establishing a 33% renewable electricity standard.[21] Legislation has been passed by the California Legislature to place into statute the 33% requirement established by executive order.[22] As noted earlier, the displacement of thermal energy from conventional power plants will cause significant reductions in revenues to those resources – the same resources that provide the ramping and reserves necessary to reliably integrate intermittent renewable resources. The prospect of lower revenues reduces the ability of independent power producers to commit to incremental investments.

Pursuant to a directive issued by AB 2514,[23] the CPUC recently initiated a rulemaking to examine the role that storage will play, and one possible result could be the creation of a storage portfolio standard. All such technology set-asides increase uncertainty about the availability of future revenues that are necessary to finance the investment to comply with the Policy.

5. Availability of Funding for Compliance Measures

As explained in the Implementation Plans for the PGS, MGS and OBGS, GenOn has completed significant engineering and environmental work to evaluate compliance alternatives and develop reasonable programs for additional studies necessary to define final compliance plans. GenOn has identified preliminary Track 2 compliance plans at the MGS and OBGS and a viable Track 1 plan for the PGS, but GenOn cannot determine whether any of the compliance plans is financially feasible as of April 1, 2011. GenOn will seek to reduce the multiple sources of uncertainty that prevent a reasonable forecast of compliance costs, future revenues, and the sufficiency and certainty of net revenues to support funding the final plans over the next several years.

GenOn first must be able to reasonably estimate the final cost of the compliance plans, including any negative impact on revenues resulting from operating restrictions necessary for the MGS and OBGS to meet the Track 2 requirements for reduced impingement and entrainment. When costs and any operating restrictions are reasonably defined, GenOn can evaluate the amount, duration and certainty of available revenues from RA contracts, tolling contracts or other contracting or market mechanisms. Only then can a reasonable assessment of the sufficiency of net revenues, including expected value, term and security of net revenues be assessed against the capital requirements of each compliance plan.

In each Implementation Plan, GenOn has proposed a schedule for conducting additional studies and other work necessary to finalize the compliance alternative for each unit in time to allow a decision on whether to pursue the compliance investments for each facility sufficiently in advance of the prescribed compliance deadlines in the Policy (December 31, 2017 for the PGS, and December 31, 2020 for the MGS and OBGS).

[20] SB 1078 (Stats. 2002, Ch. 516).
[21] Executive Order S-14-08 (Nov. 17, 2008).
[22] S.B. No. 2 (1st Extraordinary Session), sponsored by Senators Simitian, Kehoe and Steinberg.
[23] Stats. 2010, Ch. 469.

GenOn will also endeavor to secure the multi-year forward commitments to buy capacity, energy and and/or ancillary services from each unit that will be necessary to commit to investing in compliance with the policy. GenOn will seek such commitments with sufficient lead time to allow engineering and construction to be completed so that the units at each station can be taken out of service at a time and on a schedule acceptable to the CAISO, and compliance measures are fully implemented and operational as of the compliance deadlines specified in the Policy.

However, as explained above, there are many sources of uncertainty beyond GenOn's control that may make it impossible for GenOn to commit to funding compliance investments in time to meet the Policy's deadlines. If GenOn ultimately determines that investment in compliance measures is uneconomic for any unit, GenOn will work with the CAISO and the SACCWIS to consider extending the compliance deadline, or pursue other options for the assets which may include repowering or retirement.

Exhibit B

ENTRAINMENT AND IMPINGEMENT STUDIES

Several entrainment and impingement studies have been conducted at the Pittsburg Generating Station (PGS). The 1978–1979 316(b) entrainment and impingement studies are summarized in Section B.1 and the 1986–1992 Striped Bass Density Monitoring Program is summarized in Section B.2. The 2007–2009 and the 2010–2011 entrainment and impingement monitoring programs are summarized in Sections B.3 and B.4, respectively.

B.1 1978–1979 Cooling Water Intake Structures 316(b) Demonstration

In response to the requirements of Section 316(b) of the Clean Water Act, PG&E, PGS's former owner, conducted an intensive study in 1978–1979[1] of the entrainment and impingement of fishes and invertebrates resulting from the operation of the PGS cooling water system. Although the conclusion of these studies was that no alternative intake technologies or changes to the operations of PGS were required to reduce impacts to entrained or impinged fish species, the Regional Water Quality Control Board (Water Board) required that PG&E install and operate pumps equipped with variable speed drives (VSDs) during the time that young striped bass are susceptible to entrainment at PGS (generally May–mid–July).

B.1.1 Entrainment

The objective of the PG&E entrainment abundance and survival studies at PGS was to estimate the number and taxa of organisms exposed to the Generating Station's cooling water system, and to determine if organisms survived contact with the Generating Station's cooling water system. The entrainment abundance and survival studies focused on the early life stages of fishes (ichthyoplankton) and selected macroinvertebrates (the opossum shrimp *Neomysis mercedis* and the Oriental shrimp *Palaemon macrodactylus*). The species composition, length (for ichthyoplankton), and the seasonal and diel patterns of entrainment were also determined.

The numbers of ichthyoplankton and macroinvertebrates entrained were estimated by sampling a portion of the cooling water flow for a period of 24 hours once or twice a week for 16 months (March 1978 through July 1979), and then multiplying the densities of ichthyoplankton and macroinvertebrates observed by the volumes of cooling water withdrawn by the Generating Station. Entrainment sampling was conducted from the PGS Unit 6 gate well, which is located in between the condenser outlet and the shoreline discharge. Studies comparing the densities of organisms collected from the discharge gate wells of Units 1-4 and Unit 5 supported the

[1] Pacific Gas and Electric Company. 1981. PG&E Pittsburg Power Plant Cooling Water Intake Structures 316 (b) Demonstration. Prepared by Ecological Analysts, Inc. PG&E. San Francisco, California.

hypothesis that the densities of organisms collected from the Unit 6 gate well were representative of densities at the other units.

B.1.1.1 Results

An estimated 2.0 million fish eggs were entrained during the first 12 months of the study (March 1978–March 1979) (Table B-1). Striped bass *Morone saxatilis* eggs comprised 55% of the total number of fish eggs entrained. Osmeridae (smelts), northern anchovy *Engraulis mordax*, and Cyprinidae (minnows) eggs were also entrained. Fish eggs were entrained from February to July, with greatest densities (up to $0.11/m^3$) in April 1978.[2] The eggs found during the April time period were mainly striped bass eggs, and were thought to have been associated with the effects of high outflow conditions in spring 1978.

An estimated 468 million larval and juvenile fishes were entrained under actual flow conditions at PGS from March 1978–March 1979 (Table B-1). Fish larvae and juveniles were entrained during the winter, spring, and summer, with greatest densities were in May 1978 (up to $5.1/m^3$).[3] The following eight taxa made up approximately 86% of the fishes entrained: striped bass, smelts, prickly sculpin *Cottus asper*, Pacific herring *Clupea harengus pallasii,* yellowfin goby *Acanthogobius flavimanus*, gobies Gobiidae, northern anchovy, and threadfin shad *Dorosoma petenense*.

Striped bass was the most abundantly entrained fish; an estimated 283 million were entrained during the first 12 months of the study (Table B-1), and an estimated 35 million were entrained during the April through July 1979 time period.[4] Smelts were the second most abundantly entrained larval and juvenile fish taxa. Approximately 50 million smelts were estimated to have been entrained from March 1978–March 1979. Larval smelts could not be distinguished from each other at the time the study was conducted; the smelt family includes both longfin smelt *Spirinchus thaleichthys* and delta smelt *Hypomesus transpacificus*. Prickly sculpin was the third most common entrained larval and juvenile fish. There were approximately 30 million estimated to have been entrained during the first 12 months of the study.

Fishes having potential economic value, but entrained in low numbers included Chinook salmon *Oncorhynchus tshawytscha* and American shad *Alosa sapidssima*. During the first 12 months of the study, the collection of two fall-run Chinook salmon resulted in entrainment estimates of 17,000, and the collection of 21 American shad resulted in entrainment estimates of 170,000.

The major invertebrate taxa entrained from March 1978-March 1979 were the opossum shrimp, the amphipod *Corophium stimpsoni,* the oriental shrimp, and the pebble crab *Rhithropanopeus*

[2] Ibid.
[3] Ibid.
[4] Ibid.

harrisii. *Neomysis mercedis* was the most abundant macroinvertebrate entrained. An estimated 9.3 billion were entrained during the first 12 months of the survey (March 1978–March 1979) (Table B-1). An estimated 860 million *Corophium stimpsoni* were entrained during the first 12 months of the survey (March 1978–March 1979).

Table B-1. Estimated[a] numbers (millions) of selected ichthyoplankton and macroinvertebrates entrained at the PGS under actual pump operation from March 1978-March 1979.

Taxon		Units 1-4		Units 5&6		Unit 7		Units 1-7	
Common Name	**Scientific Name**	**Number Entrained**	**Standard Error**	**Number Entrained**	**Standard Error**	**Number Entrained**	**Standard Error**	**Total Number Entrained**	**Percentage Composition**
Fish Larvae and Juveniles									
Striped bass	*Morone saxatilis*	177.6	21.66	96.70	13.22	9.01	1.27	283.29	60.5
Smelts[b, c]	Osmeridae	26.75	—	22.42	—	1.14	—	50.29	10.7
Prickly sculpin[d]	*Cottus asper*	15.21	—	13.23	—	1.17	—	29.61	6.3
Pacific herring	*Clupea harengus pallasii*	10.34	3.71	11.24	4.18	0.54	0.21	22.12	4.7
Yellowfin goby	*Acanthogobius flavimanus*	3.55	0.35	2.30	0.23	0.21	0.02	6.07	1.3
Northern anchovy	*Engraulis mordax*	2.74	0.95	2.22	0.77	0.11	0.04	5.08	1.1
Unidentified gobies	Gobiidae	2.37	0.58	1.60	0.39	0.11	0.02	4.07	0.9
Threadfin shad	*Dorosoma petenense*	0.35	0.08	0.30	0.07	0.03	0.01	0.67	0.2
Other fishes		39.88	—	25.22	—	1.91	—	67.02	14.3
Total		278.79		175.23		14.23		468.22	
Fish Eggs									
Striped bass	*Morone saxatilis*	0.46	0.17	0.57	0.25	0.05	0.02	1.08	54.8
Smelts	Osmeridae	0.32	0.28	0.27	0.23	0.01	0.01	0.60	30.5
Northern anchovy	*Engraulis mordax*	0.07	0.03	0.05	0.02	*	*	0.12	6.1
Minnows	Cyprinidae	0.02	0.01	0.01	0.01	*	*	0.03	1.5
Unidentified	Osteichthyes	0.07	0.03	0.07	0.04	*	*	0.14	7.1
Total		0.94		0.97		0.06		1.97	
Macroinvertebrates									
Opossum shrimp	*Neomysis mercedis*	4,926.0	265.8	4,134.2	252.5	254.6	14.0	9,314.8	
Amphipod[e]	Gammaridae	467.0	143.5	374.0	122.9	19.4	5.4	860.4	
Amphipod	*Corophium stimpsoni*	425.9	140.2	342.7	121.2	17.6	5.3	786.2	
Oriental shrimp	*Palaemon macrodactylus*	363.2	46.5	282.8	45.6	17.0	1.8	663.0	
Pebble crab	*Rhithropanopeus harrisii*	242.3	55.1	217.2	55.8	11.2	2.8	470.7	
Total		6,424.4		5,350.9		319.8		12,095.1	

(a) Computed using Equations 3-5 and 3-6 from PG&E 1981.

Source: PG&E 1981

(b) Smelts include delta smelt, longfin smelt, and Osmeridae.

(c) The category "smelts" is comprised of both delta smelt and longfin smelt. During the time the entrainment studies were conducted, taxonomic keys had not yet be developed so that larval smelt could be distinguished from each other. The delta smelt listed on this table are likely post larval specimens

(d) All *Cottus* spp. were determined to be *C. asper* after the database was established.

(e) Gammaridae includes all amphipods (see Appendix E of PG&E 1981b).

Note: * indicates less than 10,000 individuals; (—) indicates that combined standard errors were not calculated.

B.1.2 Impingement

Two complementary studies were conducted at PGS by PG&E to provide a quantitative assessment of the numbers of fishes and macroinvertebrates impinged and lost to the local population due to the operation of the PGS cooling water system.[5] The first study, impingement abundance, was designed to determine the species composition, lengths and weights, and sex ratio and maturity of the impinged organisms. Also of interest were diel and seasonal patterns of impingement, the probability of impingement at the bar racks, and the relationship between PGS operations and impingement. The second study, impingement survival, was designed to provide species specific data that would allow for computation of proportional impingement survival rates.

The objectives of the impingement abundance study were to:

- Determine the species composition of the organisms impinged,
- Determine the lengths and weights of impinged organisms,
- Determine the sex and gonadal maturity of selected organisms,
- Determine diel and seasonal patterns of impingement,
- Examine the relationship between PGS operation parameters and impingement rates, and
- Assess the occurrence of impingement on the bar racks.

Impinged fishes and macroinvertebrates, and debris were washed off the vertical traveling screens and into screenwash sluiceways where the material ultimately was collected in sampling baskets at the lower end of the sluiceway. Samples were collected during one 24-hour period once per week.

B.1.2.1 Results

Impingement estimates of the most commonly impinged fishes and macroinvertebrates for the period March 1978–March 1979 and May 1979–November 1979 based on actual pump operation are provided in Tables B-2 and B-3, respectively. Annual fish impingement estimates based on actual pump operation for the March 1978–March1979 period at Units 1-4 were approximately 161,000 and 220,000 for Units 5&6 (Table B-2). For the period May–November 1979 estimates of fish impingement based on actual pump operation for Units 1-4 were 46,000 and for Units 5&6 were 17,700 (Table B-3).

[5] Ibid.

Six species accounted for approximately 93% of the fishes collected during March 1978–March 1979 (both intakes combined). These species were striped bass, threadfin shad, longfin smelt, yellowfin goby, starry flounder *Platichthys stellatus,* and splittail *Pogonichthys macrolepidotus.* The same six species accounted for approximately 89% of the fishes collected from May–November 1979 study (both intakes combined) (Table B-3).

Estimated annual impingement of macroinvertebrates was 1.4 million for Units 1-4 and 1.7 million for Units 5&6 during the March 1978–March 1979 study (Table B-2). Estimates for the May–November 1979 study were 1.2 million for Units 1-4 and 1.0 million for Units 5&6 (Table B-3). The most frequently impinged macroinvertebrates during both the March 1978–March 1979 and the May–November 1980 study were the bay shrimp *Crangon franciscorum,* Oriental shrimp *Palaemon macrodactylus,* and the pebble crab *Rhithropanopeus harrisii* (Tables B-2 and B-3).

Table B-2. Estimated numbers and weights of selected fishes and macroinvertebrates impinged at PGS Units 1-4 and Units 5&6 under actual pump operation: March 1978–March 1979.

Taxon		**Units 1-4**			**Units 5&6**			**Total**			
Common Name	Scientific Name	Number	Standard Error	Weight (kg)	Number Entrained	Standard Error	Weight (kg)	Number	Percent	Weight (kg)	Percent
Fishes											
Striped bass	*Morone saxatilis*	48,057	9,687	334.6	63,242	17,047	403.7	111,299	29.2	738.3	33.7
Threadfin shad	*Dorosoma petenense*	42,400	9,200	242.8	46,465	11,124	249.4	88,865	23.3	492.2	22.5
Longfin smelt	*Spirinchus thaleichthys*	32,740	5,280	104.2	71,805	23,258	232.4	104,545	27.4	336.6	15.4
Yellowfin goby	*Acanthogobius flavimanus*	13,911	907	118.9	17,608	1,660	136.0	31,519	8.3	254.9	11.6
Starry flounder	*Platichthys stellatus*	5,684	1,032	14.1	6,172	907	7.7	11,856	3.1	21.8	1.0
Sacramento splittail	*Pogonichthys macrolepidotus*	5,573	2,330	42.3	1,025	155	15.9	6,598	1.7	58.2	2.7
Other fishes		12,786	1,238	163.8	14,407	3,547	125.3	27,193	7.1	289.1	13.2
Total fishes		161,151	18,663	1,020.7	220,364	53,558	1,170.4	381,515		2,191.1	
Macroinvertebrates											
Oriental shrimp	*Palaemon macrodactylus*	996,331	41,753	7,33.7	1,138,868	102,086	850.0	2,135,199	69.1	1,583.7	61.5
Bay shrimp	*Crangon franciscorum*	371,880	72,578	410.9	430,407	78,348	468.6	802,287	26.0	879.5	34.1
Pebble crab	*Rhithropanopeus harrisii*	49,211	6,162	44.0	76,872	31,398	69.4	126,083	4.1	113.4	4.4
Jellyfish	Cnidaria	18,189	4,500		7614	2,000		25,803	1.0		
Other macroinvertebrates		503	142	0.2	32	18	*	535	*	0.2	*
Total Macroinvertebrates		1,436,115	89,775	1,188.8	1,653,793	134,918	1,388.0	3,089,908		2,576.8	

Note: There may be slight discrepancies in percentages that are due to rounding.

Source: PG&E 1981

Table B-3. Estimated numbers and weights of selected fishes and macroinvertebrates impinged at PGS Units 1-4 and Units 5&6 under actual pump operation: May–November 1979.

Taxon		**Units 1-4**			**Units 5&6**			**Total**			
Common Name	Scientific Name	Number	Standard Error	Weight (kg)	Number Entrained	Standard Error	Weight (kg)	Number	Percent	Weight (kg)	Percent
Fishes											
Striped bass	*Morone saxatilis*	16,823	3,346	326.4	5,687	221	112.0	22,510	35.2	438.4	49.5
Starry flounder	*Platichthys stellatus*	5,514	870	7.4	4,098	418	6.4	9,612	15.0	13.8	1.5
Yellowfin goby	*Acanthogobius flavimanus*	3,807	636	32.1	3,417	407	34.1	7,224	11.3	66.2	7.5
Longfin smelt	*Spirinchus thaleichthys*	5,232	1,503	29.4	1,913	347	8.1	7,145	11.2	37.5	4.2
Threadfin shad	*Dorosoma petenense*	5,954	630	34.3	241	156	1.3	6,195	9.7	35.6	4.0
Sacramento splittail	*Pogonichthys macrolepidotus*	3,835	777	98.5	458	63	29.6	4,293	6.7	128.1	14.5
Other fish		5,160	709	118.9	1,887	128	48.2	7,074	11.1	167.1	18.9
Total fishes		46,325	4,281	646.9	17,701	842	239.7	64,026		886.6	
Macroinvertebrates											
Bay shrimp	*Crangon franciscorum*	642,950	154,221	612.3	420,343	75,224	367.7	1,063,293	46.9	980.0	51.8
Oriental shrimp	*Palaemon macrodactylus*	492,603	37,685	399.6	506,217	33,525	369.1	998,802	44.0	768.7	40.7
Pebble crab	*Rhithropanopeus harrisii*	111,360	10,567	78.0	95,578	4,740	64.3	206,938	9.1	142.3	7.5
Total Macroinvertebrates		1,246,913	156,692	1,089.3	1,022,138	90,770	801.1	2,269,051		1,890.4	

Note: There may be slight discrepancies in percentages that are due to rounding.

Source: PG&E 1981

B.2 1986–1992 Striped Bass Density Monitoring Program

The Striped Bass Density Monitoring Program (SBDMP) was developed to determine the presence and abundance of striped bass at both PGS and the nearby Contra Costa Generating Station (CCGS). The 316(b) studies and the SBDMP were conducted to comply with National Pollutant Discharge Elimination System (NPDES) permit provisions issued by the Water Board and were conducted cooperatively with California Department of Fish and Game (CDFG), U.S. Fish and Wildlife Service (FWS), and National Marine Fisheries Service (NMFS). As part of the program to reduce striped bass entrainment losses, the SBDMP was conducted at PGS from 1986–1992; an impingement component of the SBDMP was added in 1987–1990 to estimate the numbers of impinged striped bass. Each year, entrainment monitoring commenced May 1 and typically continued to mid-July and from 1987–1990 impingement monitoring commenced in August and ended in February. Annual reports[6] containing information specific to striped bass were submitted to the Water Board. Information on the collection of other fish species was recorded but not provided in annual reports since the SBDMP was specifically designed to provide information on the abundance and distribution of striped bass. However, PG&E, who had the data sheets from the SBDMP, summarized data regarding the collection of listed or species of special concern (delta smelt, longfin smelt, green sturgeon, Chinook salmon, and steelhead). Results of these analyses were subsequently reported by GenOn in its draft Multispecies Conservation Plan.[7]

The SBDMP was designed to provide information on the relative abundance and temporal distribution of larval and juvenile striped bass susceptible to entrainment at the PGS between May 1 and July 15, or the date that CDFG predicted that the 38-mm striped bass index was to be set, whichever was earlier. This program consisted of two related monitoring programs: a Threshold Monitoring Program and an Entrainment Abundance Monitoring Program. The monitoring programs are described in NPDES Permit from the Water Board and the Agreement Between the Pacific Gas and Electric Company and the California Department of Fish and Game for the Monitoring and Mitigation of Striped Bass in the Sacramento-San Joaquin Estuary. The monitoring was conducted annually unless waived by mutual consent of PG&E/GenOn and CDFG. Specific details of the sampling program are discussed below.

Samples of entrained organisms were collected by filtering water pumped from either Units 1-4, Unit 5, or Unit 6 discharge gate wells with a 4-in. diameter recessed-impeller pump and 4-in. PVC sampling pipes.

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[6] Pacific Gas and Electric Company. Best Technology Available Technical Reports for the Contra Costa and Pittsburg Power Plants. Submitted to the San Francisco and Central Valley Regional Water Quality Control Boards. Annual Reports from 1986–1992.

[7] Mirant Delta, LLC. 2001. Draft-Revision 6 Multispecies Conservation Plan. Pittsburg and Contra Costa Power Plants. January 30, 2001.

Each entrainment sample was sorted using an illuminated magnifier to remove fish larvae and eggs. Striped bass eggs and larvae were identified, counted, and the total lengths of larvae were measured to the nearest millimeter. All other fishes were identified to species when possible. Following identification and measurement, fish eggs and larvae were placed in labeled vials and archived. Archived samples were generally discarded after one year, with CDFG consultation and approval.

Concentrations of striped bass were calculated from the entrainment samples; no data analysis was conducted for other species as part of the SBDMP. The striped bass concentrations were used to estimate entrainment based on actual cooling flows during the time monitoring was conducted.

B.2.1 Impingement Investigations from 1987 through 1990

Impingement monitoring was conducted at cooling water intakes for both PGS and CCGS from 1987–1990. In general, the impingement sampling was done once a month from August–February. Unlike entrainment monitoring where a relatively small volume of cooling water is sampled, 100 percent of the actual PGS flow was "filtered" by the traveling screens during impingement sampling.

Annual reports[8] containing information specific to striped bass impingement were submitted to the Water Board. Information on the impingement of other fish species was recorded but not provided in annual reports since the SBDMP was specific to striped bass. However, PG&E, who had the data sheets from the SBDMP, summarized data regarding the collection of listed or species of special concern (delta smelt, longfin smelt, green sturgeon, Chinook salmon, and steelhead). Results of these analyses were subsequently reported by GenOn in its draft Multispecies Conservation Plan.[9]

B.3 GenOn Delta Entrainment and Impingement Monitoring Plan–Amendment 1

The FWS and NMFS initially issued Biological Opinions in 2002 authorizing incidental take of listed species, including the delta smelt and listed salmonids, pursuant to Section 7 of the Endangered Species Act (ESA). In 2004, in light of the fact that one of the mitigation measures, the experimental Aquatic Filter Barrier (AFB) was determined to be unsuccessful at another location, GenOn Delta proposed alternative conservation measures in a 2004 Biological

[8] Pacific Gas and Electric Company. Best Technology Available Technical Reports for the Contra Costa and Pittsburg Power Plants. Submitted to the San Francisco and Central Valley Regional Water Quality Control Boards. Annual Reports from 1987–1990.

[9] Mirant Delta, LLC. 2001. Draft-Revision 6 Multispecies Conservation Plan. Pittsburg and Contra Costa Power Plants. January 30, 2001.

Assessment. In response, FWS reinitiated consultation with the Corps of Engineers (COE). FWS completed this reinitiation process in September 2004 with a letter that set forth alternative mitigation measures in lieu of the previously proposed AFB, including expanded delta smelt entrainment monitoring. In May 2005, GenOn Delta submitted an Entrainment Monitoring Plan intended to fulfill the expanded monitoring requirement.

In response to GenOn Delta's July 2005 Entrainment Monitoring Plan, FWS requested that GenOn Delta work with the Interagency Ecological Program (IEP) for the San Francisco Bay/Sacramento-San Joaquin Estuary, and specifically its Pelagic Organism Decline (POD) Work Team, led by CDFG, to review the May 2005 Entrainment Monitoring Plan and to address POD concerns.

As discussed below, through discussions with the IEP, the Entrainment Monitoring Plan evolved into the GenOn Delta Entrainment and Impingement Monitoring Plan for IEP (GenOn Delta Monitoring Plan), and it was approved by the IEP, as amended by Amendment 1 in October 2007. Monitoring began in November 2007. The FWS and NMFS reinitiated consultation again in 2006/2007, and in letters dated October 30, 2007, the agencies affirmed that monitoring pursuant to the GenOn Delta Monitoring Plan should proceed.

In order to better characterize the source water population and inform the ongoing reconsultation regarding the Contra Costa and Pittsburg Generating Stations' aquatic impacts, it was determined that GenOn Delta's monitoring should look at both entrainment and impingement and such sampling should be conducted concurrently with the existing IEP and CDFG monitoring programs, regardless of whether the Generating Stations' circulating water pumps were operating to generate electricity. The IEP/CDFG monitoring programs are listed below:

- 20-mm Delta Smelt Survey,
- Spring Kodiak Trawl Survey,
- Summer Townet Survey, and
- Fall Midwater Trawl Survey.

GenOn Delta completed the two-year monitoring program. In June 2009, GenOn Delta submitted the first annual report, *Entrainment and Impingement Monitoring Plan for IEP Annual Report, November 2007–October 2008, Contra Costa and Pittsburg Power Plants*, to CDFG, FWS, NMFS, and the COE. In March 2010 GenOn Delta submitted the second annual report, *Entrainment and Impingement Monitoring Plan for IEP Annual Report, November 2008–October 2009, Contra Costa and Pittsburg Power Plants*. On December 30, 2009, IEP provided written documentation that GenOn Delta had fulfilled its monitoring obligations under Amendment 1 of the GenOn Delta Monitoring Plan.

B.3.1 2007–2009 Amendment 1 Impingement Monitoring

Impingement surveys began at the PGS Units 5&6 cooling water intake structure in November 2007. This section provides the data collected from two years of monitoring (November 9, 2007, the study's inception, through October 14, 2009). As required by the GenOn Delta Monitoring Plan and Amendment 1, GenOn Delta impingement surveys were scheduled to occur during times when IEP was conducting the Fall Midwater Trawl Survey, Spring Kodiak Trawl Survey, and Summer Townet Survey at stations near the Generating Station. Site-specific information was collected on the composition, abundance, length, and weight of all fishes, caridean shrimps, and decapod crabs that were collected during the two-year study.

Impingement surveys were conducted at the PGS Units 5&6 intake structure from November 2007 through October 2009. Twenty-nine impingement surveys were conducted at PGS during this two-year time period (Table B-4). Impingement surveys were conducted once per month when IEP was conducting the Fall Midwater Trawl and the Spring Kodiak Trawl surveys. Impingement sampling increased to every other week coinciding with IEP's Summer Townet Survey schedule. If possible, impingement sampling was scheduled to occur on the same day and tidal stage that IEP sampled in the vicinity of PGS, but if schedules could not be coordinated, sampling generally occurred within 24 hours during the same tidal stage as the IEP surveys.

In order to collect impingement samples, circulating water pumps must be operated. If a unit was generating electricity, both of its circulating water pumps were operated in normal mode (Variable Frequency Drive [VFD] operation) during impingement sampling. If units were not generating electricity, GenOn Delta was required by IEP to operate the pumps at full flow. To minimize water intake, GenOn Delta generally scheduled its routine VFD pump maintenance testing and/or water quality monitoring to coincide with impingement sampling.

Table B-4. Date of Amendment 1 impingement monitoring surveys conducted at the Pittsburg Generating Station from November 2007–October 2009.

Pittsburg Generating Station
11/09/07
12/11/07
01/10/08
02/08/08
03/13/08
04/10/08
05/08/08
06/05/08
06/19/08
07/02/08
07/16/08
08/01/08
08/15/08
09/11/08
10/10/08
No survey*
12/04/08
01/15/09
02/13/09
03/19/09
04/16/09
05/12/09
06/12/09
06/26/09
07/09/09
7/23/09
08/05/09
08/19/09
09/15/09
10/15/09
Total Number of Surveys = 29

*PGS Units 5&6 intake was shut down for maintenance overhaul.

Methods

Before each impingement sampling effort, the circulating water pumps were operated and all of the intake screens were rotated and rinsed for a period of one hour. The sluiceways and collection baskets were cleaned before the start of each sampling effort. The collection basket(s) were installed and during the majority of surveys the intake screens remained stationary for a period of 3.5 hours.[10] After the 3.5-hour period ended, the traveling screens were rotated and rinsed for 30 minutes, which resulted in a total survey period of four hours. Impinged material was rinsed from the screens into the sluiceways, where it flowed by gravity into the collection baskets. The collection baskets were constructed of mesh smaller than the 3/8-inch mesh of the intake screens.

All impinged material was removed from the collection baskets and sluiceways at the end of the 4-hour survey. All impinged material was sorted by hand for fishes, caridean shrimps, and decapod crabs. The presence of other organisms, such as jellyfish and crayfish, was recorded on the data sheet. All fishes, shrimps, and crabs collected at the end of each 4-hour survey were identified and counted. Any damaged organisms were identified to the lowest taxonomic level possible and counted, but their lengths and weights were not recorded. If field personnel were unable to identify an organism, it was preserved in a 10% formaldehyde solution and brought into Tenera’s laboratory for identification. All moribund longfin smelt and delta smelt identifications were verified by Dr. Johnson Wang, National Environmental Services. Live longfin smelt and delta smelt were released after specimens were measured and weighed. The qualitative body condition of individual fishes, shrimps, and crabs was determined and recorded, using codes for decomposition and damage. The amount, weight, and type of debris (e.g., *Egeria densa*, filamentous algae) and any unusual operating conditions in the screen wash system was noted by writing specific comments in the “Notes” section of the data sheet.

Impinged fishes, shrimps, and crabs that were not damaged were measured to the nearest mm and weighed to the nearest 0.1g. The wet body weight of individual organisms was determined after shaking loose water from the body. All undamaged fishes were measured and weighed. The fork length (FL) was measured for fishes with forked tails while total length (TL) was measured for fishes without forked tails.

Field observations (weather and wind) and water quality parameters such as dissolved oxygen (D.O.), water temperature, and salinity were recorded during each impingement survey. The water quality parameters were measured using a calibrated YSI Model 85 water quality instrument. Weather parameters were measured using a Speedtech SM-28 Skymaster Wind

[10] During times of extremely heavy algal loading, it was necessary to rotate and rinse the traveling screens and collect the impinged material throughout the 4-hour survey period.

Meter. The operating status of the circulating water pumps and the number of screens rotated and rinsed during impingement collections were also recorded on the data sheets.

A QA/QC program was implemented for the field sampling component of impingement monitoring. Routine QA checks were done on a quarterly basis by senior staff to ensure that the field sampling and sample handling was properly conducted. Field data were recorded on data sheets formatted for entry into a computer database for analysis and archiving. Printed spreadsheets were checked for accuracy against original field data sheets.

Data presented in this section are from the 29 PGS impingement surveys from November 9, 2007 through October 15, 2009. The PGS Units 5&6 intake screens filtered a total of 7,852,190 m^3 of water during the 29 impingement surveys (Table B-5). A total of 1,087 gallons of impinged material (mainly filamentous algae and plants such as *Egeria densa*) weighing 1,895 kg (4,173 lb) was collected during the two year study (Table B-5) and all was sorted for fishes, shrimps, and crabs.

A total of 22 fish species was identified from all 29 PGS surveys combined. The 22 fish species included 220 individuals. Table B-6 provides information regarding the collection of fishes and selected macroinvertebrates during the two-year impingement monitoring study.

Table B-5. Survey date, duration of survey, volume of water sampled, and volume and weight of impinged material collected during Amendment 1 monitoring at the Pittsburg Generating Station Units 5&6 intake from November 9, 2007 through October 15, 2009.

Survey Number	Survey Date	Duration of Survey (hr:min)	Volume of Water Sampled (m^3)	Volume of Debris Collected (gallons)	Weight of Debris Collected kg (lb)
1	11/09/07	4:00	145,798	11	2 (4.0)
2	12/11/07	4:07	279,588	9	13 (29)
3	01/10/08	4:00	142,823	1	1 (2)
4	02/08/08	4:00	291,596	7	8 (18)
5	03/13/08	4:12	306,176	5	12 (26)
6	04/10/08	4:15	309,821	10	14 (31)
7	05/08/08	4:11	304,961	7	14 (31)
8	06/05/08	4:18	313,466	12	25 (55)
9	06/19/08	4:16	307,367	35	35 (77)
10	07/02/08	5:03	290,401	143	143 (315)
11	07/16/08	4:00	285,621	230	230 (506)
12	08/01/08	4:00	291,596	72	202 (444)
13	08/15/08	4:03	295,241	106	286 (629)
14	09/11/08	4:00	257,692	61	135 (297)
15	10/10/08	4:00	291,596	8	10 (22)
	No survey*				
16	12/04/08	4:00	291,445	5	5 (11)
17	01/15/09	4:00	145,723	2	2 (4)
18	02/13/09	4:00	145,723	<1	<1 (<2)
19	03/19/09	4:00	291,445	1	2 (4)
20	04/16/09	4:00	291,445	2	4 (9)
21	05/12/09	4:00	291,445	1	1 (2)
22	6/12/09	4:00	291,445	5	5 (11)
23	06/26/09	4:00	291,445	30	52 (115)
24	07/09/09	4:00	269,114	13	23 (51)
25	07/23/09	4:00	255,866	18	29 (64)
26	08/05/09	4:02	294,095	85	130 (287)
27	08/19/09	4:00	291,445	160	415 (915)
28	09/15/09	4:04	296,366	35	72 (159)
29	10/15/09	4:00	291,445	13	24 (53)
	Total	**118:31**	**7,852,190**	**1,087**	**1,895 (4,173)**

*No survey was conducted in November 2008 due to maintenance work at the Units 5&6 intake structure.

Table B-6. Information regarding the fishes and selected invertebrates collected during Pittsburg Generating Station Units 5&6 Amendment 1 impingement surveys from November 2007–October 2009.

Taxon	Common Name	Total Number Collected	Percent Composition
Tridentiger bifasciatus	Shimofuri goby	46	20.9%
Morone saxatilis	Striped bass	41	18.6%
Dorosoma petenense	Threadfin shad	21	9.5%
Gasterosteus aculeatus	Threespine stickleback	18	8.2%
Cottus asper	Prickly sculpin	15	6.8%
Hysterocarpus traski	Tule perch	13	5.9%
Micropterus salmoides	Largemouth bass	11	5.0%
Clupea pallasii	Pacific herring	9	4.1%
Pomoxis nigromaculatus	Black crappie	7	3.2%
Lepomis macrochirus	Bluegill	7	3.2%
Acanthogobius flavimanus	Yellowfin goby	7	3.2%
Tridentiger trigonocephalus	Chameleon goby	6	2.7%
Hypomesus transpacificus	Delta smelt	3	1.4%
Pomoxis annularis	White crappie	3	1.4%
Spirinchus thaleichthys	Longfin smelt	2	0.9%
Engraulis mordax	Northern anchovy	2	0.9%
Leptocottus armatus	Pacific staghorn sculpin	2	0.9%
Lepomis microlophus	Redear sunfish	2	0.9%
Platichthys stellatus	Starry flounder	2	0.9%
Alosa sapidissima	American shad	1	0.5%
Lepidogobius lepidus	Bay goby	1	0.5%
Lampetra spp.	Lampreys	1	0.5%
	Total Fishes	**220**	
Exopalaemon modestus	Siberian prawn	619	44.2%
Palaemonidae	Unid damaged Palaemonidae shrimps[1]	586	41.9%
Palaemon macrodactylus	Oriental shrimp	142	10.2%
Crangon franciscorum	Franciscan bay shrimp	30	2.1%
Rhithropanopeus harrisii	Harris' mud crab	22	1.6%
	Total Invertebrates	**1,399**	

B.3.2 2008–2009 Amendment 1 Entrainment Study

Entrainment sampling using a 1,600-micron mesh net began at the PGS Units 5&6 intake structure in March 2008. This section provides the data collected from two years of monitoring (March 7, 2008 through July 8, 2008 and from January 7, 2009 through July 1, 2009). Beginning in 2009, entrainment sampling was also conducted from January–March using a 505-micron mesh net. As required by the GenOn Delta Monitoring Plan, GenOn Delta entrainment surveys were scheduled to occur during times when IEP was conducting the Smelt Larval Survey (2009 only) and the 20-mm Survey (2008 and 2009) at stations near the PGS irrespective of whether or not the units were generating. Two types of nets targeting the collection of larval and juvenile fishes were used to collect entrainment samples. A 1,600-micron mesh net was used to collect fishes in 2008, while both the 1,600-micron mesh net and the 505-micron mesh net were used to collect fishes in 2009.[11] A total of 55 entrainment samples was collected with the 1,600-micron mesh net and 15 were collected with the 505-micron mesh net during the Amendment 1 entrainment study (Table B-7).

Methods

Sampling was conducted directly in front (offshore) of the intake structure PGS (Figure B-1). A deck was constructed above the PGS Units 5&6 intake structures to provide a platform for entrainment sampling. A sampling apparatus containing a moveable boom system was built. The sampling boom is on a track approximately 25 m long that spans the entire length of the Unit 5&6 intake structure. The boom system was designed so various-sized collection nets could be attached and the nets could be raised and lowered to filter water at different depths. In 2008, field technicians manually pushed the boom along the track from one end to the other until the apparatus was motorized in 2009. When the end of track was reached the net was manually turned and the boom apparatus was pushed back to the other end of the track (referred to as a "pass"). This process was repeated until the desired number of passes was achieved.

[11] Per the GenOn Monitoring Plan, commencement of the 505-micron sampling is coordinated with IEP's Smelt Larval Survey (SLS). IEP did not conduct the SLS in 2008; therefore, GenOn did not conduct entrainment sampling with the 505-micron mesh net. IEP conducted the SLS in 2009 and GenOn coordinated its 505-micron mesh net entrainment sampling with the SLS sampling. While the 505-micron mesh net is more consisted used for larval fish sampling, not all facilities report the numbers of larvae collected; for example, the State Water Project and the Central Valley Project sample with 505-micron mesh nets, but simply report the catch of longfin and delta smelts as "present" or "absent."

Table B-7. A summary of information regarding Amendment 1 entrainment sampling with the 1,600-micron and 505-micron mesh nets at the Pittsburg Generating Station from March 7, 2008 through July 8, 2008 and January 7, 2009 through July 1, 2009.

Pittsburg Generating Station				
Date Collected	505 micron mesh net		1,600 micron mesh net	
	Total Number of Samples Collected	Total Volume of Water Filtered (m^3)	Total Number of Samples Collected	Total Volume of Water Filtered (m^3)
03/07/08	0	–	1*	193.9
03/18/08	0	–	3	565.3
04/02/08	0	–	3	581.7
04/15/08	0	–	3	581.7
04/30/08	0	–	3	581.7
05/15/08	0	–	3	581.7
05/28/08	0	–	3	581.7
06/10/08	0	–	3	581.7
06/24/08	0	–	3	581.7
07/08/08	0	–	3	581.7
01/07/09	3	115.2	0	–
01/22/09	3	120.9	0	–
02/03/09	3	133.2	0	–
02/18/09	3	134.6	0	–
03/03/09	3	135.8	0	–
03/13/09	0	–	3	551.06
03/24/09	0	–	3	580.02
04/07/09	0	–	3	578.92
04/21/09	0	–	3	570.3
05/5/09	0	–	3	565.31
05/19/09	0	–	3	562.7
06/03/09	0	–	3	581.54
06/15/09	0	–	3	478.71
07/01/09	0	–	3	450.01
Total	**15**	**639.7**	**55**	**10,331.4**

1. Only one sample was collected due to problems with the sampling boom.

The 1,600-micron mesh net was 10 feet long, 42 inches (approximately 1 m) in diameter, and had a codend constructed of 505-micron mesh. Three samples were collected during each survey. A total of 10 passes (~250 m total distance covered) was conducted for each sample. For the first six passes the net was near the surface of the water at a depth of about 0.5 m below the surface, and it was lowered for the last four passes to a depth of about 2 m below the surface.

The target water volume to be filtered by the nets was 200 m^3 per sample. The volume of water sampled was calculated by multiplying the distance the net was pushed along the track by the area of the mouth of the net. Upon completion of the passes, the net was retrieved from the water and all of the collected material was rinsed from the outside of the nets into the codend. The contents of each sample were placed in a labeled jar immediately after collection, and were preserved in a 10% formalin solution. Location, date, and time were recorded for each sample. The information was logged onto a sequentially numbered data sheet that was used by the data management system to track the sample through laboratory processing, data analysis, and reporting.

The 505-micron mesh net was 5 feet long, approximately 20 inches (0.5 m) in diameter, and had a codend constructed of 505-micron mesh. The area of the mouth of the net was approximately 2.2 ft^2 (0.2 m^2) and the target water volume to be filtered by the nets was 45 m^3 per sample. Three samples were collected during each survey. A total of 10 passes (~250 m total distance covered) was conducted for each sample. For the first six passes the net was near the surface of the water at a depth of about 0.5 m below the surface, and it was lowered for the last four passes to a depth of about 2 m below the surface.

Field observations (weather and wind) and water quality parameters such as dissolved oxygen (D.O.), water temperature, and salinity were recorded during each entrainment survey. Water quality parameters were measured using a YSI Model 30 water quality meter. Weather parameters were measured using a Speedtech SM-28 Skymaster Wind Meter. The operating status of the circulating water pumps was also recorded on the data sheets.

A QA/QC program was implemented for the field sampling component of the entrainment monitoring program. Routine QA checks were done on a quarterly basis by senior staff to ensure that the field sampling and sample handling was properly conducted. Field data were recorded on data sheets formatted for entry into a computer database for analysis and archiving. Printed spreadsheets were checked for accuracy against original field data sheets.

Figure B-1. Location of the Pittsburg Generating Station Units 5&6 entrainment sampling station.

Laboratory processing of entrainment samples consisted of removing, identifying, and enumerating all fishes from the samples collected by the 1,600-micron and 505-micron mesh nets. Sorting accuracy was verified and maintained by Tenera Environmental's quality control (QC) program. All listed species were identified by Dr. Johnson Wang, National Environmental Services. Fishes were identified to the lowest taxonomic level possible and total length was measured. All laboratory data were entered into a computer database that was verified for accuracy against the original data sheets.

B.3.2.1 2008–2009—1600-micron mesh net collections

Data presented in this section are from the 55 PGS entrainment samples collected with the 1,600-micron mesh net during the two-year entrainment study. A total of 10,331 m^3 of water was filtered by the 1,600-micron mesh net during the two-year study (Table B-7). A total of 14 fish species/taxon was identified from all 55 PGS samples combined. The 14 fish species included 608 individuals (Table B-8).

Table B-8. Information regarding the fishes collected during Pittsburg Generating Station Units 5&6 Amendment 1 entrainment surveys using the 1,600-micron mesh net from March 7, 2008–July 8, 2008 and from March 1, 2009–July 1, 2009.

Taxon	Common Name	Total Number Collected	Percent Composition of Total Number Collected
Clupea pallasii	Pacific herring	513	84.4%
Morone saxatilis	Striped bass	24	3.9%
Cottus asper	Prickly sculpin	19	3.1%
Hypomesus transpacificus	Delta smelt	16	2.6%
Tridentiger spp.	*Tridentiger* spp gobies	15	2.5%
Gasterosteus aculeatus	Threespine stickleback	7	1.2%
Spirinchus thaleichthys	Longfin smelt	4	0.7%
Engraulis mordax	Northern anchovy	2	0.3%
Leptocottus armatus	Pacific staghorn sculpin	2	0.3%
Pogonichthys macrolepidotus	Sacramento splittail	2	0.3%
Micropterus salmoides	Largemouth bass	1	0.2%
Lucania parva	Rainwater killifish	1	0.2%
Dorosoma petenense	Threadfin shad	1	0.2%
Hysterocarpus traski	Tule perch	1	0.2%
	Total	**608**	

B.3.2.2 2009—505 micron mesh net collections

Data provided in this section are from the 15 PGS entrainment samples collected with the 505-micron mesh net during the 2009 entrainment study. A total of 640 m^3 of water was filtered by the 505-micron mesh net during the study (Table B-7). A total of 228 fishes comprised of five species was collected during entrainment sampling with the 505-micron mesh net at the PGS Units 5&6 intake from January 7, 2009–March 3, 2009 (Table B-9).

Table B-9. Information regarding the fishes collected during Pittsburg Generating Station Units 5&6 Amendment 1 entrainment surveys using the 505-micron mesh net from January 7, 2009–March 3, 2009.

Taxon	Common Name	Total Number Collected	Percent Composition of Total Number Collected
Cottus asper	Prickly sculpin	126	55.3%
Clupea pallasii	Pacific herring	65	28.5%
Spirinchus thaleichthys	Longfin smelt	23	10.1%
Acanthogobius flavimanus	Yellowfin goby	12	5.3%
Hypomesus transpacificus	Delta smelt	2	0.9%
	Total	**228**	

B.4 Amendment 2 Monitoring May 2010–April 2011

GenOn Delta submitted a draft Amendment 2 of the GenOn Delta Monitoring Plan to FWS, NMFS, and CDFG on December 15, 2009 for review and approval. Amendment 2 monitoring, which only tracks operations, was initiated in May 2010 once all collecting permits were approved, and will end April 30, 2011. The annual monitoring report will be submitted no later than August 31, 2011 as required by Amendment 2. The methods of collection for Amendment 2 monitoring are the same as those used during the 2007–2009 Amendment 1 monitoring. Impingement and entrainment collection and sample processing methods are described in Sections B.3.1 and B.3.2, respectively.

The Amendment 2 monitoring program differs from the 2007–2009 Amendment 1 monitoring program in the following ways:

- monitoring is conducted only when PGS's circulating water pumps are operated for the purpose of generation, and is initiated within 48 hours of continuous circulating water pump operation (i.e., monitoring is no longer tied to IEP sampling and circulating water pumps are not operated solely for the purpose of collecting impingement samples);

- the frequency of monitoring increases—impingement monitoring is conducted once every seven days, entrainment monitoring with the 505-micron mesh net occurs once per calendar month year-round, entrainment monitoring with the 1,600-micron mesh net occurs once every 48 hours year round; and

- the addition of nighttime sampling, thereby doubling each Amendment 1 survey's sampling effort.

The following sections provide a summary of the impingement and entrainment data collected from the study's inception, May 2010 through January 2011. The one-year study will end April 30, 2011.

B.4.1 2010–2011—Impingement Monitoring

Amendment 2 monitoring was initiated in May 2010. The PGS did not generate nor did circulating water pumps operate for 48 consecutive hours in May, June, October–December 2010 and January–February 2011; therefore no monitoring was conducted during these months. Monitoring occurred during July, August, and September 2010 when PGS was operating; results from these surveys are provided in this section. During each monitoring event, two 4-hour cycles were collected (one during the daytime and one at nighttime). Impingement samples were collected and processed according to the procedures used in Amendment 1 monitoring (see Section B.3.1).

Data presented in this section are those available to date from the three PGS impingement surveys conducted when generation occurred (July, August, and September 2010). The PGS Units 5&6 intake screens filtered a total of 1,539,459 m^3 of water during the three impingement surveys (Table B-10). A total of 92 gallons of impinged material (mainly filamentous algae and *Egeria densa*) weighing approximately 359 lb (163 kg) has been collected (Table B-10) during the surveys, and all was sorted for fishes, shrimps, and crabs.

From May 2010 through February 2011, a total of 37 fishes comprised of nine species has been collected during PGS Amendment 2 impingement monitoring (Table B-11); Amendment 2 impingement monitoring will end April 30, 2011.

Table B-10. Survey date, duration of survey, volume of water sampled, and volume and weight of impinged material collected during Amendment 2 sampling at the Pittsburg Generating Station Units 5&6 intake from May 1, 2010 through February 28, 2011. [1]

Survey Date	Duration of Survey (hours:minutes)	Volume of Water Sampled (m^3)	Volume of Impinged Material Collected and Sorted (gallons)	Weight of Impinged Material Collected and Sorted kg (lb)
05/2010	No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.			
06/2010	No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.			
07/15/2010	8:00	368,213	5	4.5 (9.9)
08/24/2010	8:07	591,698	33	22.3 (49.2)
09/27/2010	7:57	579,548	54	136.1 (300.0)
10/2010	No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.			
11/2010	No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.			
12/2010	No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.			
01/2011	No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.			
02/2011	No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.			
Total	**24:04**	**1,539,459**	**92**	**162.9 (359.1)**

1. Amendment 2 monitoring was initiated in May 2010 and will continue through April 2011.

Table B-11. Information regarding the fishes and selected invertebrates collected during Pittsburg Generating Station Units 5&6 Amendment 2 impingement surveys from May 2010–February 2011.

Taxon	Common Name	Total Number Collected	Percent Composition of Total Number Collected
Cottus asper	Prickly sculpin	9	24.3%
Tridentiger bifasciatus	Shimofuri goby	9	24.3%
Acanthogobius flavimanus	Yellowfin goby	5	13.5%
Dorosoma petenense	Threadfin shad	5	13.5%
Morone saxatilis	Striped bass	4	10.8%
Platichthys stellatus	Starry flounder	2	5.4%
Hysterocarpus traskii	Tule perch	1	2.7%
Lepomis macrochirus	Bluegill	1	2.7%
Pomoxis annularis	White crappie	1	2.7%
	Total Count:	**37**	

B.4.2 2010–2011—Entrainment Monitoring

To date, the PGS has not generated in all months. Specifically, the circulating water pumps did not operate for 48 consecutive hours in May, June, October–December 2010, and January–

February 2011; therefore, no entrainment monitoring was conducted during these months. A summary of information regarding entrainment monitoring at PGS is provided in Table B-12. From May 2010–February 2011, monitoring has occurred during July, August, and September when PGS was operating. During each monitoring event (referred to as a "survey"), six samples were collected (three during the daytime and three at nighttime). Entrainment samples were collected and processed according to the procedures used in Amendment 1 monitoring (see Section B.3.2). At PGS, total of 18 samples has been collected using the 505-micron mesh net and 30 samples have been collected using the 1,600-micron mesh net (Table B-12).

Table B-12. A summary of information regarding entrainment sampling with the 505-micron and 1,600-micron mesh nets at the Contra Costa and Pittsburg Generating Stations from May 2010 through January 2011.[1]

Pittsburg Generating Station				
Date Collected	**505 micron mesh net**		**1,600 micron mesh net**	
	Total Number of Samples Collected	**Total Volume of Water Filtered (m^3)**	**Total Number of Samples Collected**	**Total Volume of Water Filtered (m^3)**
05/2010	0[2]	–	0[2]	–
06/2010	0[2]	–	0[2]	–
07/15/2010	6	253.9	6	1,137.3
08/24/2010	6	273.0	6	1,175.0
08/26/2010	–[4]	–	6	1,120.6
09/27/2010	6	277.1	6	1,135.4
09/29/2010	–[4]	–	6	1,159.5
10/2010	0[2]	–	0[2]	–
11/2010	0[2]	–	0[2]	–
12/2010	0[2]	–	0[2]	–
01/2011	0[2]	–	0[2]	–
02/2011	0[2]	–	0[2]	–
Total	**18**	**804.0**	**30**	**5,727.8**

1. Amendment 2 monitoring was initiated in May 2010 and will continue through April 2011.
2. No circulating water pumps operated for 48 consecutive hours; therefore no monitoring was conducted.
3. Circulating water pumps were shut down; therefore no monitoring was conducted.
4. The Amendment 2 monitoring plan calls for entrainment sampling with the 505-micron mesh net once per calendar month. In September 2010, entrainment monitoring was conducted at PGS on September 29, 2010.

B.4.2.1 May 2010–February 2011 505-micron mesh net collections

Data presented in this section are from the three PGS entrainment surveys using the 505-micron mesh net, which have been conducted when generation occurred (July, August, and September 2010). A total of 18 samples has been collected (six samples per survey) from May 2010–February 2011 (Table B-12). All samples have been sorted for fishes and all specimens have been identified to the lowest taxonomic level practicable and all have been measured.

To date, a total of 109 fishes comprised of four species and one taxon has been collected during PGS Amendment 2 505-micron mesh net entrainment monitoring from May 2010 through February 2011 (Table B-13). Amendment 2 monitoring will be completed April 30, 2011.

Table B-13. Information regarding the fishes collected during Pittsburg Generating Station Units 5&6 Amendment 2 entrainment surveys using the 505-micron mesh net from May 2010–February 28, 2011.

Taxon	Common Name	Total Number Collected	Percent Composition of Total Number Collected
Engraulis mordax	Northern anchovy	89	81.7%
Tridentiger spp.	*Tridentiger* spp. gobies	12	11.0%
Dorosoma petenense	Threadfin shad	6	5.5%
Hypomesus transpacificus	Delta smelt	1	0.9%
Micropterus salmoides	Largemouth bass	1	0.9%
	Total	**109**	

B.4.2.2 May 2010–February 2011 1,600-micron mesh net collections

Data presented in this section are from the five PGS entrainment surveys using the 1,600-micron mesh net, which have been conducted when generation occurred (July, August, and September 2010). A total of 30 samples has been collected (six samples per survey) from May 2010–February 2011 (Table B-12). All samples have been sorted for fishes, and all specimens have been identified to the lowest taxonomic level practicable and measured.

To date, a total of eight fishes represented by two species and one taxon has been collected during PGS Amendment 2 1,600-micron mesh net entrainment monitoring from May 2010 through February 2011 (Table B-14). Amendment 2 monitoring will be completed April 30, 2011.

Table B-14. Information regarding the fishes collected during Pittsburg Generating Station Units 5&6 Amendment 2 entrainment surveys using the 1,600-micron mesh net from May 2010–February 28, 2011.

Taxon	Common Name	Total Number Collected	Percent Composition of Total Number Collected
Engraulis mordax	Northern anchovy	5	62.5%
Dorosoma petenense	Threadfin shad	2	25.0%
Tridentiger spp.	*Tridentiger* spp. gobies	1	12.5%
	Total	**8**	