# COMMUNITY CHOICE AGGREGATION PILOT PROJECT

# APPENDIX D:

## Key Assumptions Used in the Base Case Feasibility Reports

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*Governor*

PIER FINAL PROJECT REPORT

*Prepared For:*
**California Energy Commission**

*Prepared By:*
Local Government Commission

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CEC-500-2008-091-APD

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**Update Of Key Assumptions Used In CCA Feasibility Analysis and Modeling - Pacific Gas & Electric Territory**

1) Metering and Billing

   a) No new metering requirements for CCA customers.
   b) Billing charges same as direct access from Schedules E-ESP and E-EUS.
   c) Billing charges based on Rate-Ready Billing Option from Schedule E-ESP.

2) Financing

   a) Tax exempt financing for startup costs and any new generation development @ 5.5%.
   b) 100% debt financing.
   c) Financing term is 30 years.
   d) Minimum debt coverage ratio of 1.25.
   e) Bond insurance cost of 1.6% of par value.
   f) Bond transaction cost of 1% of par value.
   g) Debt reserve of 10% of par value.

3) Startup and Operations Costs

   a) Startup costs include regulatory and legal @ $350,000.
   b) Operational costs are outsourced @ $2.50 per MWh unless and until CCA reaches approximately 1.5 million MWh in sales.
   c) If performed internally, the cost is estimated at $3.9 M per year plus 10 cents per MWh, including IT.
   d) Activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, A&G, and IT.
   e) The CCA will begin serving customers in January 2006

4) Resource Adequacy

   a) CCAs subject to same resource adequacy requirement as IOUs, per D.04-01-050.
   b) Planning reserves are required to bring total reserves, including ISO required ancillary services, up to 15% of peak load.
   c) Costs of meeting planning reserves equal to market value of capacity.
   d) Spot market purchases limited to between 5% and 20% of CCA portfolio; the remainder of the portfolio is comprised of long-term contracts and/or resource ownership.

5) Renewable Energy Portfolio

   a) Renewable purchases are from a generic portfolio comprised of Class 4 Wind, Binary Geothermal, Solid Fuel Biomass, Land Fill Gas Biomass, and Concentrating Solar Power.
   b) The cost and resource mix comprising the portfolio is derived from the CEC's Renewable Resources Development Report (11/7/03) See RRDR, Table 4, page 37 and discussion at page 87. 2005 costs are escalated at a nominal rate of 1% per year.
   c) The cost of the generic renewables portfolio equals the estimated developers' costs, including return on investment. Market price of renewable energy equal to maximum of cost or market price of system energy
   d) The cost of wind energy assumes no extension of the production tax credit.
   e) Wind energy must be firmed via capacity contracts due to its intermittent nature. The cost of wind energy is adjusted for a capacity adder to firm the intermittent resource, at market value of capacity.

f) Renewable ownership costs are derived by applying municipal financing assumptions to the cost data in RRDR Appendix D, page D-6. 2005 costs are escalated at a nominal rate of 1% per year.
g) Ownership cost incorporate technology specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, and capacity cost adder applied to intermittent resources.
h) The ownership costs of intermittent resources also includes a risk factor of $5 per MWh related to the potential differences between energy prices for sales from excess production versus purchases for production shortfalls.
i) CCAs will rely primarily on large-scale renewable projects to meet and exceed the RPS. These are Wind, Geothermal, Solid Fuel Biomass, and Concentrating Solar Power.
j) CCA owned generation resources can be online by 2008.
k) Distributed generation options, such as rooftop PV systems, are incorporated in the feasibility analysis based on community specific planning. Renewable DG production, if any, will be in addition to the RPS minimums.
l) Supplemental energy payments are available to offset the incremental costs of renewable contract purchases (10-Year Terms) up to the minimum RPS requirement. PGC funds are sufficient to buy down 100% of the cost premium of renewables.
m) Supplemental energy payments are not available for city-owned resources and not available for purchases in excess of the RPS minimums.
n) CCAs are required to match the renewable energy percentage of the respective investor owned utility in the first year of CCA operations.
o) IOU renewable baseline percentages are derived from RRDR Appendix A, page A-2 and increased by 1% per year until 20% is achieved by 2017.

6) <u>Wholesale Energy Markets</u>

a) Electricity market price forecast based on projected market clearing system heat rates and natural gas price projections.
b) Natural gas price projections prepared by NCI in January 2005.
c) Implied system clearing heat rates for 2005-2010 are 8,000, 8250, 8700, 9000, 10,000, 10,500. Market equilibrium assumed at implied system heat rate of 11,000 after 2010.
d) On-peak energy priced at 15% premium; off-peak energy priced at 15% discount; real time energy at 10% premium.
e) Long term contracts priced at 5% premium to expected spot market prices.
f) Capacity costs valued at $100,000 per MW-Year, escalated at 2.5% annually; costs are embedded in energy prices derived as above.
g) Ancillary services and related costs estimated based on historical relationship to market prices, projected forward.
h) Ancillary services requirements based on percentage of CCA's load per current CAISO practice.
i) Ancillary services types are Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve.
j) California Independent System Operator (CAISO) administrative and neutrality charges are derived from current rates, escalated at 2.5% annually.
k) CAISO charges are Grid Management Charge - Control Area Service, Grid Management Charge - Inter-zonal Scheduling, Grid Management Charge - Ancillary Services and Real Time Operations, Unaccounted For Energy Charge, Neutrality Charge, Congestion Charge, De
l) No explicit modeling of impact from move to locational marginal pricing; assumed that loads will be protected from congestion costs by allocation of congestion revenue rights and zonal averaging of prices.
m) Distribution losses are 7%.

7) <u>Generation Cost</u>

a) CCA's choosing to own generation will acquire equity interests in combined cycle gas turbine facilities based on the following cost and operating parameters:
b) Installed cost of $700 per KW.
c) Heat rate of 7,000 mmbtu/MWh.
d) $3 per MWh fixed and variable O&M
e) 0.1 pounds per MWh emissions..
f) $10 per pound cost of NOx emissions.
g) 90% planned capacity factor.
h) 2% forced outage rate.
i) Excess sales sold at prevailing market clearing prices.

8) <u>Cost Responsibility Surcharges</u>

a) Cost responsibility surcharges calculated annually using total portfolio indifference method adopted in direct access proceeding (includes old and new resources) (R.02-01-011) and CCA Rulemaking (D.04-12-046)
b) CRS reduced by pro rata share of cost of ancillary services and planning reserves
c) No cap on cost responsibility surcharge for CCAs.
d) Cost responsibility surcharge includes DWR bonds, DWR power charge, utility CTC, and Regulatory Asset.
e) Uniform "indifference fee" per KWh for all CCA customers, regardless of rate class and CCA startup date. No baseline credits reflecting AB1X protections for residential consumption up to 130% of baseline allocation.
f) Uniform DWR bond charge per KWh, statewide.
g) CTC rate varies by customer class based on current tariffs.
h) DWR bond charge projections based on currently applicable rate as of January 2005.
i) No transfer to CCA of DWR contracts, renewable energy, or capacity contracts implied by payment of cost responsibility surcharges.

9) <u>IOU Rate Projections</u>

a) IOU rates for generation are the competitive reference point for assessing CCA cost savings potential.
b) Current IOU rate schedules (Advice Letter 2570-E-A) as of January 2005 applied to CCA customer billing determinants (estimated), aggregated by major rate group.
c) Generation rates and total rates (generation plus non-generation) projected forward based on percentage changes in IOU system average rates.
d) IOU generation costs projected based on current resource mix, adjusted over time for planned generation retirements, DWR contracts, QF contracts, and renewable energy contracts to meet RPS.
e) PG&E owned generation resources includes Nuclear (Diablo Canyon), Hydro, and Fossil facilities. Production and sales data are from PG&E's Long Term Resource Plan.
f) Generation costs and beginning rate base for each generation type are derived from 2003 General Rate Case filing.
g) Generation costs include operations and maintenance, return, depreciation, uncollectibles, A&G, franchise fees, taxes other than income, taxes based on income, fuel, thermal decommissioning, and other.
h) Future capital additions increased for Diablo Canyon turbine replacement anticipated in the 2007 - 2009 timeframe.
i) Purchased Power includes QF contracts, existing bilateral contracts, DWR contracts, new renewable contracts, new bilateral contracts, and spot market purchases.
j) New bilateral contracts entered into as needed to maintain spot purchases (residual net short) at or below 10% of IOU portfolio.
k) PG&E maintains planning reserves of 15% of annual peak load. Existing ancillary services requirements are included in the 15% planning reserves requirement.

l) Spot market purchases to meet the residual net short are priced at average of NP15 peak (6 X 16) and base (7 X 24) power prices.
m) Majority of QFs (80%) paid according to settlement price through 2005, and then based on annual short run avoided cost formula.
n) QF capacity payments derived from FERC Form 1 data.
o) QF capacity/energy projections derived from the Consultant's Report supporting DWR bond financing.
p) RPS purchases from generic renewable portfolio as described above; Supplemental Energy Payments fully offset incremental costs relative to non-renewable energy.
q) DWR costs and volumes adjusted over time based on terms of the individual contracts allocated to PG&E per D.02-09-053.
r) DWR "remittance rate" calculated using CPUC methodology (D. 04-12-014).
s) Regulatory asset cost calculated based on terms of approved Bankruptcy Settlement.
t) Cost offset for bundled customer generation costs from cost responsibility surcharges paid by Direct Access Customers based on capped collection rate from direct access proceeding (R.02-01-011)
u) Non-generation costs escalated at constant 1.5% per year. Non-generation rates are only used to express the CCA cost impacts as percentage of customers' total electric bills.
v) Same input assumptions as above for wholesale electricity prices, capacity prices, natural gas prices, ancillary services costs, CAISO charges, RPS % and prices, supplemental energy payments, and DWR bonds charges.

**Key Assumptions Used In CCA Feasibility Analysis and Modeling - Southern California Edison Territory**

1) Metering and Billing

   a) No new metering requirements for CCA customers.
   b) Billing charges same as direct access from Schedule ESP-DSF.
   c) Billing charges based on Bill-Ready Billing Rates from Schedule ESP-DSF

2) Financing

   a) Tax exempt financing for startup costs and any new generation development @ 5.5%.
   b) 100% debt financing.
   c) Financing term is 30 years.
   d) Minimum debt coverage ratio of 1.25.
   e) Bond insurance cost of 1.6% of par value.
   f) Bond transaction cost of 1% of par value.
   g) Debt reserve of 10% of par value.

3) Startup and Operations Costs

   a) Startup costs include regulatory and legal @ $350,000.
   b) Operational costs are outsourced @ $2.50 per MWh unless and until CCA reaches approximately 1.5 million MWh in sales.
   c) If performed internally, the cost is estimated at $3.9 M per year plus 10 cents per MWh, including IT.
   d) Activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, A&G, and IT.
   e) The CCA will begin serving customers in January 2006

4) Resource Adequacy

   a) CCAs subject to same resource adequacy requirement as IOUs, per D.04-01-050.
   b) Planning reserves are required to bring total reserves, including ISO required ancillary services, up to 15% of peak load.
   c) Costs of meeting planning reserves equal to market value of capacity.
   d) Spot market purchases limited to between 5% and 20% of CCA portfolio; the remainder of the portfolio is comprised of long-term contracts and/or resource ownership.

5) Renewable Energy Portfolio

   a) Renewable purchases are from a generic portfolio comprised of Class 4 Wind, Binary Geothermal, Solid Fuel Biomass, Land Fill Gas Biomass, and Concentrating Solar Power.
   b) The cost and resource mix comprising the portfolio is derived from the CEC's Renewable Resources Development Report (11/7/03) See RRDR, Table 4, page 37 and discussion at page 87. 2005 costs are escalated at a nominal rate of 1% per year.
   c) The cost of the generic renewables portfolio equals the estimated developers' costs, including return on investment. Market price of renewable energy equal to maximum of cost or market price of system energy.
   d) The cost of wind energy assumes no extension of the production tax credit.
   e) Wind energy must be firmed via capacity contracts due to its intermittent nature. The cost of wind energy is adjusted for a capacity adder to firm the intermittent resource, at market value of capacity.

f) Renewable ownership costs are derived by applying municipal financing assumptions to the cost data in RRDR Appendix D, page D-6. 2005 costs are escalated at a nominal rate of 1% per year.
g) Ownership cost incorporate technology specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, and capacity cost adder applied to intermittent resources.
h) The ownership costs of intermittent resources also includes a risk factor of $5 per MWh related to the potential differences between energy prices for sales from excess production versus purchases for production shortfalls.
i) CCAs will rely primarily on large scale renewable projects to meet and exceed the RPS. These are Wind, Geothermal, Solid Fuel Biomass, and Concentrating Solar Power.
j) CCA owned generation resources can be online by 2008.
k) Distributed generation options, such as rooftop PV systems, are incorporated in the feasibility analysis based on community specific planning. Renewable DG production, if any, will be in adaptation to the RPS minimums.
l) Supplemental energy payments are available to offset the incremental costs of renewable contract purchases (10-Year Terms) up to the minimum RPS requirement. PGC funds are sufficient to buy down 100% of the cost premium of renewables.
m) Supplemental energy payments are not available for city-owned resources and not available for purchases in excess of the RPS minimums.
n) CCAs are required to match the renewable energy percentage of the respective investor owned utility in the first year of CCA operations.
o) IOU renewable baseline percentages are derived from RRDR Appendix A, page A-2 and increased by 1% per year until 20% is achieved by 2017.

6) Wholesale Energy Markets

a) Electricity market price forecast based on projected market clearing system heat rates and natural gas price projections.
b) Natural gas price projections prepared by NCI in January 2005.
c) Implied system clearing heat rates for 2005-2010 are 8,000, 8250, 8700, 9000, 10,000, 10,500. Market equilibrium assumed at implied system heat rate of 11,000 after 2010.
d) On-peak energy priced at 15% premium; off-peak energy priced at 15% discount; real time energy at 10% premium.
e) Long term contracts priced at 5% premium to expected spot market prices.
f) Capacity costs valued at $100,000 per MW-Year, escalated at 2.5% annually; costs are embedded in energy prices derived as above.
g) Ancillary services and related costs estimated based on historical relationship to market prices, projected forward.
h) Ancillary services requirements based on percentage of CCA's load per current CAISO practice.
i) Ancillary services types are Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve.
j) California Independent System Operator (CAISO) administrative charges are derived from current rates, escalated at 2.5% annually.
k) No explicit modeling of impact from move to locational marginal pricing; assumed that loads will be protected from congestion costs by allocation of congestion revenue rights and zonal averaging of prices.
l) Distribution losses are 7%.

7) Generation Cost

a) CCA's choosing to own generation will acquire equity interests in combined cycle gas turbine facilities based on the following cost and operating parameters:
b) Installed cost of $700 per KW.
c) Heat rate of 7,000 mmbtu/MWh.

d) $3 per MWh fixed and variable O&M.
e) 0.1 pounds per MWh emissions..
f) $10 per pound cost of NOx emissions.
g) 90% planned capacity factor.
h) 2% forced outage rate.
i) Excess sales sold at prevailing market clearing prices.

8) <u>Cost Responsibility Surcharges</u>

a) Cost responsibility surcharges calculated annually using total portfolio indifference method adopted in direct access proceeding (includes old and new resources) (R.02-01-011) and CCA Rulemaking (D.04-12-046)
b) CRS reduced by pro rata share of cost of ancillary services and planning reserves
c) No cap on cost responsibility surcharge for CCAs.
d) Cost responsibility surcharge includes DWR bonds, DWR power charge, and utility CTC; No historical procurement charge.
e) Uniform "indifference fee" per KWh for all CCA customers, regardless of rate class and CCA startup date. No baseline credits reflecting AB1X protections for residential consumption up to 130% of baseline allocation.
f) Uniform DWR bond charge per KWh, statewide.
g) CTC rate varies by customer class based on current tariffs.
h) DWR bond charge projections based on currently applicable rate as of January 2005.
i) No transfer to CCA of DWR contracts, renewable energy, or capacity contracts implied by payment of cost responsibility surcharges.

9) <u>IOU Rate Projections</u>

a) IOU rates for generation are the competitive reference point for assessing CCA cost savings potential.
b) Current IOU rate schedules as of January 2005 (AL 1854-E) applied to CCA customer billing determinants (estimated), aggregated by major rate group.
c) Generation rates and total rates (generation plus non-generation) projected forward based on percentage changes in IOU system average rates.
d) IOU generation costs projected based on current resource mix, adjusted over time for planned generation retirements, DWR contracts, QF contracts, and renewable energy contracts to meet RPS.
e) SCE owned generation resources includes Nuclear (SONGS and Palo Verde), Hydro, and Coal facilities. Mohave shuts down in 2005. SONGS continues with steam turbine replacement as proposed by SCE. Production and sales data are from SCE Long-term Resource Plan (2004).
f) Generation costs and beginning rate base for each generation type are derived from 2003 General Rate Case filing.
g) Generation costs include operations and maintenance, return, depreciation, uncollectibles, A&G, franchise fees, taxes other than income, taxes based on income, fuel, thermal decommissioning, and other.
h) Mountain View project comes online in summer 2006 and is priced at cost based rates
i) Purchased Power includes QF contracts, existing bilateral contracts, DWR contracts, new renewable contracts, new bilateral contracts, and spot market purchases.
j) New bilateral contracts entered into as needed to maintain spot purchases (residual net short) at or below 10% of IOU portfolio.
k) SCE maintains planning reserves of 15% of annual peak load. Existing ancillary services requirements are included in the 15% planning reserves requirement.
l) Spot market purchases to meet the residual net short are priced at average of SP15 peak (6 X 16) and base (7 X 24) power prices.
m) Majority of QFs (80%) paid according to settlement price through 2007, and then based on annual short run avoided cost formula.

n) QF capacity payments derived from FERC Form 1 data.
o) QF capacity/energy projections derived from the Consultant's Report supporting DWR bond financing.
p) RPS purchases from generic renewable portfolio as described above; Supplemental Energy Payments fully offset incremental costs relative to non-renewable energy.
q) DWR costs and volumes adjusted over time based on terms of the individual contracts allocated to SCE per D.02-09-053.
r) DWR "remittance rate" calculated using CPUC methodology (D. 04-12-014).
s) Cost offset for bundled customer generation costs from cost responsibility surcharges paid by Direct Access Customers based on capped collection rate fromdirect access proceeding (R.02-01-011).
t) Non-generation costs escalated at constant 1.5% per year. Non-generation rates are only used to express the CCA cost impacts as percentage of customers' total electric bills.
u) Same input assumptions as above for wholesale electricity prices, capacity prices, natural gas prices, ancillary services costs, CAISO charges, RPS % and prices, supplemental energy payments, and DWR bonds charges.

**Key Assumptions Used In CCA Feasibility Analysis and Modeling - San Diego Gas and Electric Territory**

1) Metering and Billing

   a) No new metering requirements for CCA customers.
   b) Billing charges same as direct access from Schedule DA.
   c) Billing charges based on rates from Schedule DA.

2) Financing

   a) Tax exempt financing for startup costs and any new generation development @ 5.5%.
   b) 100% debt financing.
   c) Financing term is 30 years.
   d) Minimum debt coverage ratio of 1.25.
   e) Bond insurance cost of 1.6% of par value.
   f) Bond transaction cost of 1% of par value.
   g) Debt reserve of 10% of par value.

3) Startup and Operations Costs

   a) Startup costs include regulatory and legal @ $350,000.
   b) Operational costs are outsourced @ $2.50 per MWh unless and until CCA reaches approximately 1.5 million MWh in sales.
   c) If performed internally, the cost is estimated at $3.9 M per year plus 10 cents per MWh, including IT.
   d) Activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, A&G, and IT.
   e) The CCA will begin serving customers in January 2006

4) Resource Adequacy

   a) CCAs subject to same resource adequacy requirement as IOUs, per D.04-01-050.
   b) Planning reserves are required to bring total reserves, including ISO required ancillary services, up to 15% of peak load.
   c) Costs of meeting planning reserves equal to market value of capacity.
   d) Spot market purchases limited to between 5% and 20% of CCA portfolio; the remainder of the portfolio is comprised of long term contracts and/or resource ownership.

5) Renewable Energy Portfolio

   a) Renewable purchases are from a generic portfolio comprised of Class 4 Wind, Binary Geothermal, Solid Fuel Biomass, Land Fill Gas Biomass, and Concentrating Solar Power.
   b) The cost and resource mix comprising the portfolio is derived from the CEC's Renewable Resources Development Report (11/7/03) See RRDR, Table 4, page 37 and discussion at page 87. 2005 costs are escalated at a nominal rate of 1% per year.
   c) The cost of the generic renewables portfolio equals the estimated developers' costs, including return on investment. Market price of renewable energy equal to maximum of cost or market price of system energy
   d) The cost of wind energy assumes no extension of the production tax credit.
   e) Wind energy must be firmed via capacity contracts due to its intermittent nature. The cost of wind energy is adjusted for a capacity adder to firm the intermittent resource, at market value of capacity.

f) Renewable ownership costs are derived by applying municipal financing assumptions to the cost data in RRDR Appendix D, page D-6. 2005 costs are escalated at a nominal rate of 1% per year.
g) Ownership cost incorporate technology specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, and capacity cost adder applied to intermittent resources.
h) The ownership costs of intermittent resources also includes a risk factor of $5 per MWh related to the potential differences between energy prices for sales from excess production versus purchases for production shortfalls.
i) CCAs will rely primarily on large-scale renewable projects to meet and exceed the RPS. These are Wind, Geothermal, Solid Fuel Biomass, and Concentrating Solar Power.
j) CCA owned generation resources can be online by 2008.
k) Distributed generation options, such as rooftop PV systems, are incorporated in the feasibility analysis based on community specific planning. Renewable DG production, if any, will be in addition to the RPS minimums.
l) Supplemental energy payments are available to offset the incremental costs of renewable contract purchases (10-Year Terms) up to the minimum RPS requirement. PGC funds are sufficient to buy down 100% of the cost premium of renewables.
m) Supplemental energy payments are not available for city-owned resources and not available for purchases in excess of the RPS minimums.
n) CCAs are required to match the renewable energy percentage of the respective investor owned utility in the first year of CCA operations.
o) IOU renewable baseline percentages are derived from RRDR Appendix A, page A-2 and increased by 1% per year until 20% is achieved by 2017.

6) <u>Wholesale Energy Markets</u>

a) Electricity market price forecast based on projected market clearing system heat rates and natural gas price projections.
b) Natural gas price projections prepared by NCI in January 2005.
c) Heat rates for 2005 - 2010 are 8,000, 8250, 8700, 9000, 10000, 10500. Market equilibrium assumed at heat rate of 11000 after 2010.
d) On-peak energy priced at 15% premium; off-peak energy priced at 15% discount; real time energy at 10% premium.
e) Long term contracts priced at 5% premium to expected spot market prices.
f) Capacity costs valued at $100,000 per MW-Year, escalated at 2.5% annually; costs are embedded in energy prices derived as above.
g) Ancillary services and related costs estimated based on historical relationship to market prices, projected forward.
h) Ancillary services requirements based on percentage of CCA's load per current CAISO practice.
i) Ancillary services types are Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve.
j) California Independent System Operator (CAISO) administrative and neutrality charges are derived from current rates, escalated at 2.5% annually.
k) CAISO charges are Grid Management Charge - Control Area Service, Grid Management Charge - Inter-zonal Scheduling, Grid Management Charge - Ancillary Services and Real Time Operations, Unaccounted For Energy Charge, Neutrality Charge, Congestion Charge, De
l) No explicit modeling of impact from move to locational marginal pricing; assumed that loads will be protected from congestion costs by allocation of congestion revenue rights and zonal averaging of prices
m) Distribution losses are 7%.

7) <u>Generation Cost</u>

a) CCA's choosing to own generation will acquire equity interests in combined cycle gas turbine facilities based on the following cost and operating parameters:
b) Installed cost of $700 per KW.
c) Heat rate of 7,000 mmbtu/MWh.
d) $3 per MWh fixed and variable O&M.
e) 0.1 pounds per MWh emissions..
f) $10 per pound cost of NOx emissions.
g) 90% planned capacity factor.
h) 2% forced outage rate.
i) Excess sales sold at prevailing market clearing prices.

8) <u>Cost Responsibility Surcharges</u>

a) Cost responsibility surcharges calculated annually using total portfolio indifference method adopted in direct access proceeding (includes old and new resources) (R.02-01-011) and CCA rulemaking (D.04-12-046)
b) CRS reduced by pro rata share of cost of ancillary services and planning reserves
c) No cap on cost responsibility surcharge for CCAs.
d) Cost responsibility surcharge includes DWR bonds, DWR power charge, and utility CTC; No historical procurement charge.
e) Uniform "indifference fee" per KWh for all CCA customers, regardless of rate class and CCA startup date. No baseline credits reflecting AB1X protections for residential consumption up to 130% of baseline allocation.
f) Uniform DWR bond charge per KWh, statewide.
g) CTC rate varies by customer class based on current tariffs. AB 265 undercollection fully recovered by 2005.
h) DWR bond charge based on currently applicable rate as of January 2005.
i) No transfer to CCA of DWR contracts, renewable energy, or capacity contracts implied by payment of cost responsibility surcharges.

9) <u>IOU Rate Projections</u>

a) IOU rates for generation are the competitive reference point for assessing CCA cost savings potential.
b) Current IOU rate schedules (February 2005) applied to CCA customer billing determinants (estimated), aggregated by major rate group.
c) Generation rates and total rates (generation plus non-generation) projected forward based on percentage changes in IOU system average rates.
d) IOU generation costs projected based on current resource mix, adjusted over time for planned generation retirements, DWR contracts, QF contracts, new SDG&E generation (Palomar), new power purchase contracts (Otay Mesa and generic) and renewable energy contracts to meet RPS.
e) SDG&E owned generation resources includes 20% share of SONGS, declining to 17% in 2010. SONGS continues to operate due to steam turbine replacement. SONGS capital and operating and maintenance expenses based on SCE projections in its 2003 General Rate Case (A.02-05-004) and SCE's 2006 General Rate Case.
f) Generation costs and beginning rate base for each generation type are derived from 2003 Cost of Service filing (A.02-12-028).
g) Generation costs include operations and maintenance, return, depreciation, uncollectibles, A&G, franchise fees, taxes other than income, taxes based on income, fuel, thermal decommissioning, and other.
h) Purchased Power includes QF contracts, existing bilateral contracts, DWR contracts, new renewable contracts, new bilateral contracts, and spot market purchases.
i) New bilateral contracts entered into as needed to maintain spot purchases (residual net short) at or below 10% of IOU portfolio.

j) SDG&E maintains planning reserves of 15% of annual peak load. Existing ancillary services requirements are included in the 15% planning reserves requirement.
k) Spot market purchases to meet the residual net short are priced at average of SP15 peak (6 X 16) and base (7 X 24) power prices.
l) Majority of QFs paid according to settlement price through 2007, and then based on annual short run avoided cost formula.
m) QF capacity payments derived from FERC Form 1 data.
n) QF capacity/energy projections and SDG&E load forecast derived from the Consultant's Report supporting DWR bond financing.
o) RPS purchases from generic renewable portfolio as described above; Supplemental Energy Payments fully offset incremental costs relative to non-renewable energy.
p) DWR costs and volumes adjusted over time based on terms of the individual contracts allocated to SDG&E per D.02-09-053.
q) DWR "remittance rate" calculated using CPUC methodology (D. 04-12-014).
r) Cost offset for bundled customer generation costs from cost responsibility surcharges paid by Direct Access Customers based on capped collection rate from direct access proceeding (R.02-01-011).
s) Non-generation costs escalated at constant 1.5% per year. Non-generation rates are only used to express the CCA cost impacts as percentage of customers' total electric bills.
t) Same input assumptions as above for wholesale electricity prices, capacity prices, natural gas prices, ancillary services costs, CAISO charges, RPS % and prices, supplemental energy payments, and DWR bonds charges.