WYOMING-CALIFORNIA CORRIDOR TRANSMISSION EXPANSION STUDY

CONSULTANT REPORT

Prepared For:
California Energy Commission

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EXECUTIVE SUMMARY

California Policy Context

California's overarching policy goal is stated in the Warren-Alquist State Energy Resources Conservation and Development Act[1], which created the California Energy Commission (Energy Commission). Public Resources Code Section 25000.1(a) states:

> The Legislature further finds and declares that, in addition to their other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and to encourage the diversity of energy sources through improvements in energy efficiency and development of renewable energy resources, such as wind, solar, and geothermal energy.

This is echoed in the Energy Commission's *2005 Integrated Energy Policy Report (2005 Energy Report)*[2]*,* which states that "The state must reinforce its commitment to these efforts and take immediate action to address problems in the energy sector to meet the state's policy goal of ensuring adequate, affordable, reliable, and environmentally sound energy services for its citizens." (pp. 1-2) In particular, two pressing challenges for California's policy makers with respect to electricity affordability and reliability are an increasing dependence on natural gas and an inadequate and aging electricity delivery system.

The *2005 Energy Report* provides recommendations and actions to address these critical challenges by advocating increasing fuel diversity via increased renewable generation:

> "California is also a national leader in the development of renewable resources. Over the past 30 years, California has built one of the largest and most diverse renewable generation portfolios in the world. In 2002, California established its Renewables Portfolio Standard program, with the goal of increasing the percentage of renewable energy in the state's electricity mix to 20 percent by 2017. The *2003 Energy Report* recommended accelerating that goal to 2010, and the *2004 Energy Report Update* further recommended increasing the target to 33 percent by 2020. The *Energy Action Plan* supported this goal." (*2005 Energy Report*, pp. E-7 to E-8)

The *2005 State Energy Action Plan II*[3], produced jointly by the Energy Commission and the California Public Utilities Commission, advocates increasing fuel diversity via increased renewables and increased access to out-of-state power consistent with the state's greenhouse gas emissions policy, as well as increasing investment in electric transmission infrastructure by ensuring that upgrades are completed to maintain reliability and allow access to preferred resources and by examining opportunities for interstate projects that promote state policy objectives:

> "California can reduce its greenhouse gas emissions, moderate its increasing dependence on natural gas, and mitigate the associated risks of electricity price volatility by aggressively developing renewable energy resources to meet the Renewables Portfolio Standard (RPS) requirements. As originally established, the RPS requires 20 percent of electricity sales to come from renewable sources by 2017. In the first EAP, we set a goal of accelerating the 20 percent target from 2017 to 2010. We are now identifying the steps necessary to achieve that target, as well as higher goals beyond 2010, such as Governor Schwarzenegger's proposed goal of 33 percent of electricity sales by 2020. To reach these goals, we must streamline and make transparent all of our approval processes, provide funding for renewable resources that reflects these policy priorities, and establish the necessary infrastructure for delivery of power from new renewable projects. We intend that our increasing reliance on renewable resources within California and from the western region will help mitigate energy impacts on climate change and the environment. We expect that all California load serving entities will contribute to these goals." (*2005 State Energy Action Plan II*, pp. 5-6)

> "Significant capital investments are needed to augment existing facilities, replace aging infrastructure, and ensure that California's electrical supplies will meet current and future needs at reasonable prices and without over-reliance on a single fuel source. Even with the emphasis on energy efficiency, demand response, renewable resources, and distributed generation, investments in conventional power plants will be needed…. An expanded, robust electric transmission system is required to access cleaner and more competitively priced energy, mitigate grid congestion, increase grid reliability, permit the retirement of aging plants, and bring new renewable and conventional power plants on line." (*2005 State Energy Action Plan II*, p. 7)

> "Governor Schwarzenegger signed Executive Order S-3-05 on June 1, 2005, clearly establishing California's leadership in and commitment to the fight against climate change. The Executive Order establishes greenhouse gas (GHG) emission reduction targets that call for a reduction of GHG emissions to 2000 levels by 2010; to 1990 levels by 2020; and to 80 percent below 1990 levels by 2050. The Executive Order also directs Cal EPA to lead a multi-agency Climate Action Team to conduct an analysis of the impacts of climate change on California and to develop strategies to achieve the targets and

> mitigation and adaptation plans for the State." (*2005 State Energy Action Plan II*, p. 12)

Two key climate change actions identified in the *2005 State Energy Action Plan II* include the following:

> #7: Ensure that energy supplies serving California, from any source, are consistent with the Governor's climate change goals.

> #11: Identify western state policies and strategies to achieve production of 30,000 MW of clean energy across the west by 2015, consistent with the Western Governors' Association Clean and Diversified Energy Advisory Committee and West Coast Climate Initiative goals.[4] (*2005 State Energy Action Plan II*, p. 13)

History

One of the studies which is cited in the Western Governors' Association June 22, 2004 Policy Resolution 04-14 titled *Clean and Diversified Energy Initiative for the West* is the Rocky Mountain Area Transmission Study. The Rocky Mountain Area Transmission Study group was formed in August 2003 to examine the potential for tapping relatively low-cost coal and wind generation for Rocky Mountain load growth or for export to other parts of the Western Interconnection. Recommendation two of the September 2004 report[5] describes possible benefits of transmission expansions that extend beyond the Rocky Mountain states to enable exports of generation to the West Coast. In particular, one option in recommendation two is a Wyoming-to-California transmission expansion project that would provide California with the benefits of increased access to both clean coal and wind generation as well as improved reliability due to additional interstate transmission. In response to the report, in April 2005, Governors Arnold Schwarzenegger (California), Kenny Guinn (Nevada), Jon Huntsman Jr. (Utah) and Dave Freudenthal (Wyoming) signed a Memorandum of Understanding to develop the "Transmission Project," their proposal for "providing economic benefits to all four states, as well as enhanced reliability for the West's overall high-voltage transmission grid."[6]

Study Method and Objectives

In August 2005 the California Energy Commission initiated the Wyoming-California Corridor Transmission Expansion Study as a follow-up to the Rocky Mountain Area Transmission Study report released in September 2004. The purpose of the current study is to bound the assumptions and refine the economic analysis used in the Rocky Mountain Area Transmission Study report to make a first determination regarding whether clean coal and wind in Rocky Mountain states, and transmission needed to move this power to California, can be an economic alternative to building generation in California while also contributing to meeting California's Renewables

Portfolio Standard goals, particularly an increased Renewables Portfolio Standard goal of 33 percent by 2020.

This report details the economic analysis of potential new transmission upgrades that would allow new generation resources built in the interior Western Electricity Coordinating Council states to serve load centers in California. Specifically, the transmission upgrades studied in this analysis would begin in southwest Wyoming and extend west through Utah and Nevada into California.

While the transmission and generation upgrades are similar to those recommended in the September 2004 report titled *Rocky Mountain Area Transmission Study*, Global Energy was asked to consider different investment scenarios and to assume, initially, that California would be responsible for the entire costs of upgrades, even though other states would receive benefits. Another bounding assumption is that California does not add new renewables in-state beyond those necessary to maintain the 20 percent goal.

Global Energy's report compares two transmission and generation expansion options located in the Rocky Mountain states (described below) with a base case in which load growth in California would be met by resources that would be built in California. The focus of this analysis is only on the economic impact to California, with the goal of determining if benefits exceed cost even under these conservative bounding assumptions in which California bears the full cost of the transmission upgrades and no other states are assumed to receive any benefits.

Base Case Analysis

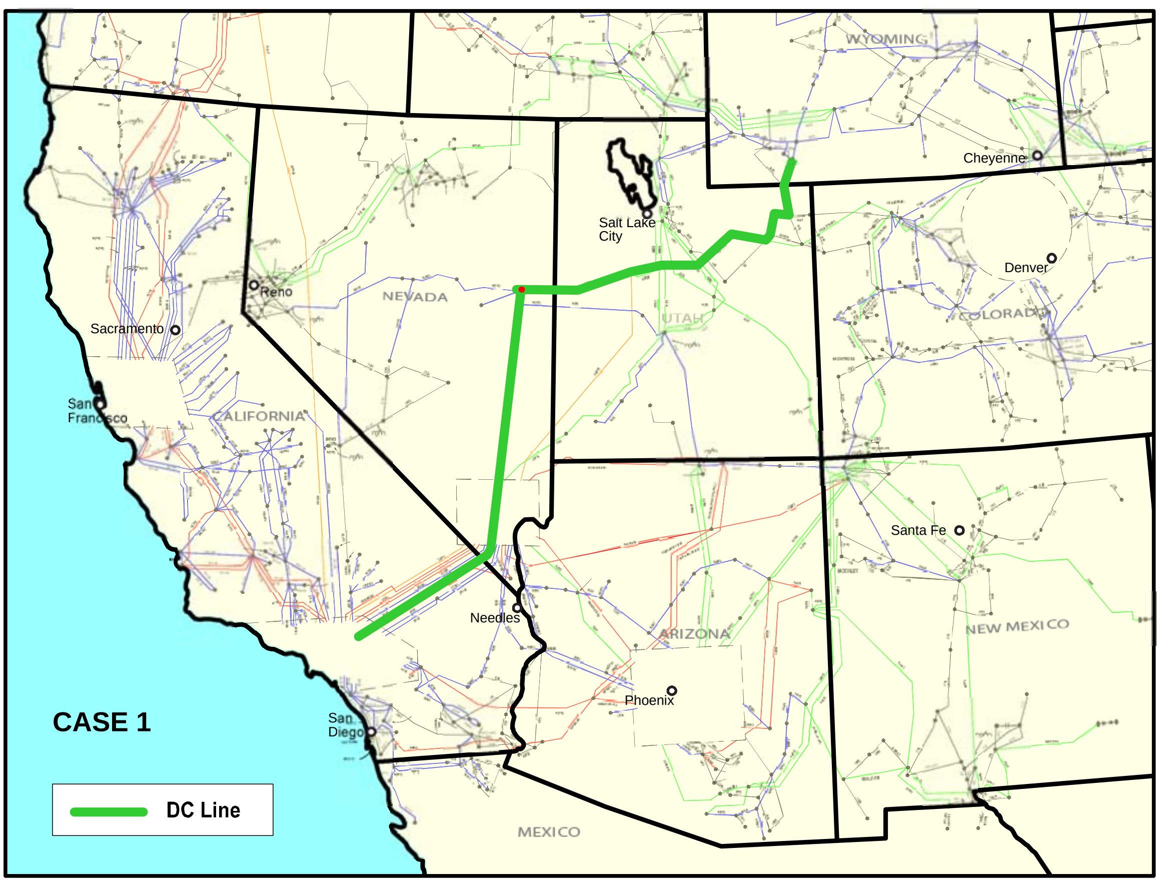
To estimate the economic benefits to California of the Base Case and these alternatives (referred to as Change Case 1 and Change Case 2), Global Energy performed hourly Direct Current – Optimal Power Flow network simulations of the Western Electricity Coordinating Council region for each case study. An hourly analysis for four typical weeks (one per season) in the year 2012, the first year the projects might be in place, was performed. See Chapters 1 and 2 and Appendix A for more details on the study method and assumptions.

The Base Case represents the status quo and is based on the Energy Commission's expectations of load, generation, and transmission expansion in the WECC region for the year 2012, assuming that no major transmission line is built between Wyoming and California. In the Base Case, California builds combined-cycle combustion turbines and renewable generation in California to meet its Resource Adequacy and Renewables Portfolio Standards goals. Global Energy used the California Independent System Operator's transmission database and the Energy Commission's resource database to perform the analysis along with other major assumptions provided by the Energy Commission, such as the natural gas price forecast and the cost and performance of new generation technology. These assumptions are detailed below in Chapter 2, "Assumptions."

Change Case 1 Analysis

The objective of Change Case 1 was to identify and evaluate the value of displacing new gas generation in Southern California with new clean coal generation in Wyoming to provide diversity benefits while achieving greenhouse gas (GHG) reduction. In Change Case 1, Global Energy assumed a new 1,500-megawatt (MW) direct current (DC) transmission line was built between southwest Wyoming and Southern California. Change Case 1 also assumed that a new 1,500-MW coal-fired, integrated gasification combined-cycle generation facility (with carbon sequestration technology) is built in southwest Wyoming to serve load in California. With the new integrated gasification combined cycle, California would be able to avoid the construction of 1,500 MW of new gas-fired, combined-cycle generation in California that was originally included in the Base Case. Figure ES-1 shows a conceptual route for the transmission line.

Figure ES-1: Change Case 1 Conceptual Transmission Route



Source: California Energy Commission

Benefits of Change Case 1 were calculated by comparing net variable production cost for meeting load. Net changes caused by different capital costs of generation and transmission in the cases were added to the changes in variable production costs and the cost of losses to determine the net benefits of Change Case 1. To provide an indication of longer-term benefits, the 2012 net benefit was assumed to represent net benefits that would occur in future years. Net present value calculations were then made under both a standard net present value analysis and a social discount rate analysis.

The analysis method, assumptions, and findings are discussed in greater detail in the body of the report that follows.

After taking into account the fixed (capital) and variable (production) costs, as well as transmission losses, Global Energy estimated that California would benefit by $87 million/year under Change Case 1 (See Table ES-1).

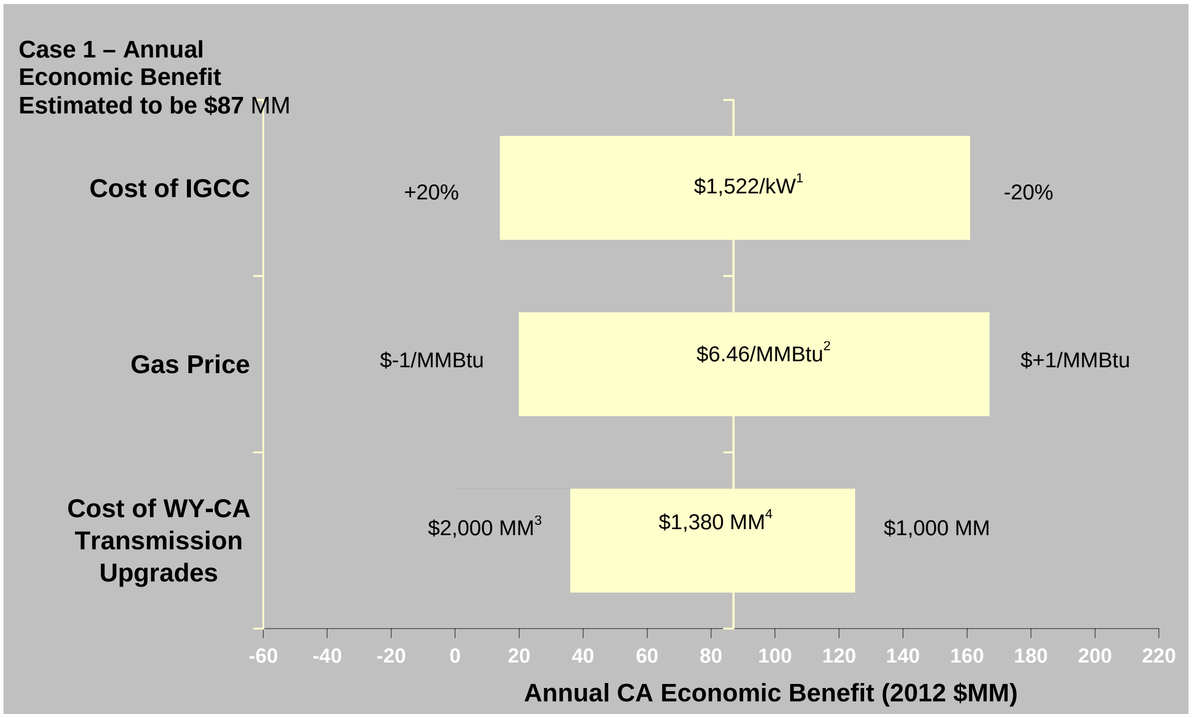
Table ES-1 Change Case 1 Study Results

Case	Transmission Upgrade	Generation Resources Changes	Annual CA Economic Impact (2012$)	CA NPV Benefits 2012-2025 @ 10% Discount Rate (2012$)	CA NPV Benefits 2012-2041 @ 5% Social Discount Rate (2012$)
Change Case 1	1,500 MW DC Transmission Line Expansion from S.W. WY to S. CA	1,500 MW of new coal-fired IGCC in WY replaces 1,500 MW of planned gas-fired, combined-cycle generation in CA.	87 MM	642 MM	1,340 MM

Source: Global Energy Decisions

Because the input assumptions used in the analysis can have a significant effect on results, Global Energy performed a sensitivity analysis to indicate how changes in certain key assumptions affected the results. These results are shown in Figure ES-2.

Figure ES-2: Input Sensitivity Diagram for Change Case 1



1a. GHG reduction requirements through carbon sequestration capability.
1b. Costs for carbon sequestration assumed covered by enhanced oil recovery.
1c. Annual benefits exclude any EPAct-05 financial incentives (tax credits).
2. Energy Commission September 2005 Natural Gas Forecast for PG&E in 2004$.
3. Based on $1.5 MM/mile est. + inverter/rectifier.
4. Based on $0.799 MM/mile est. + inverter/rectifier.

Source: Global Energy Decisions

These results indicate that displacing natural gas-fired generation in California with clean coal in Wyoming can provide economic benefits to California consumers under a wide range of assumptions for natural gas price and coal generation and transmission upgrade capital costs. In addition, California greenhouse gas policy as it relates to new coal development can be implemented at a net benefit to California consumers.

Change Case 2 Analysis

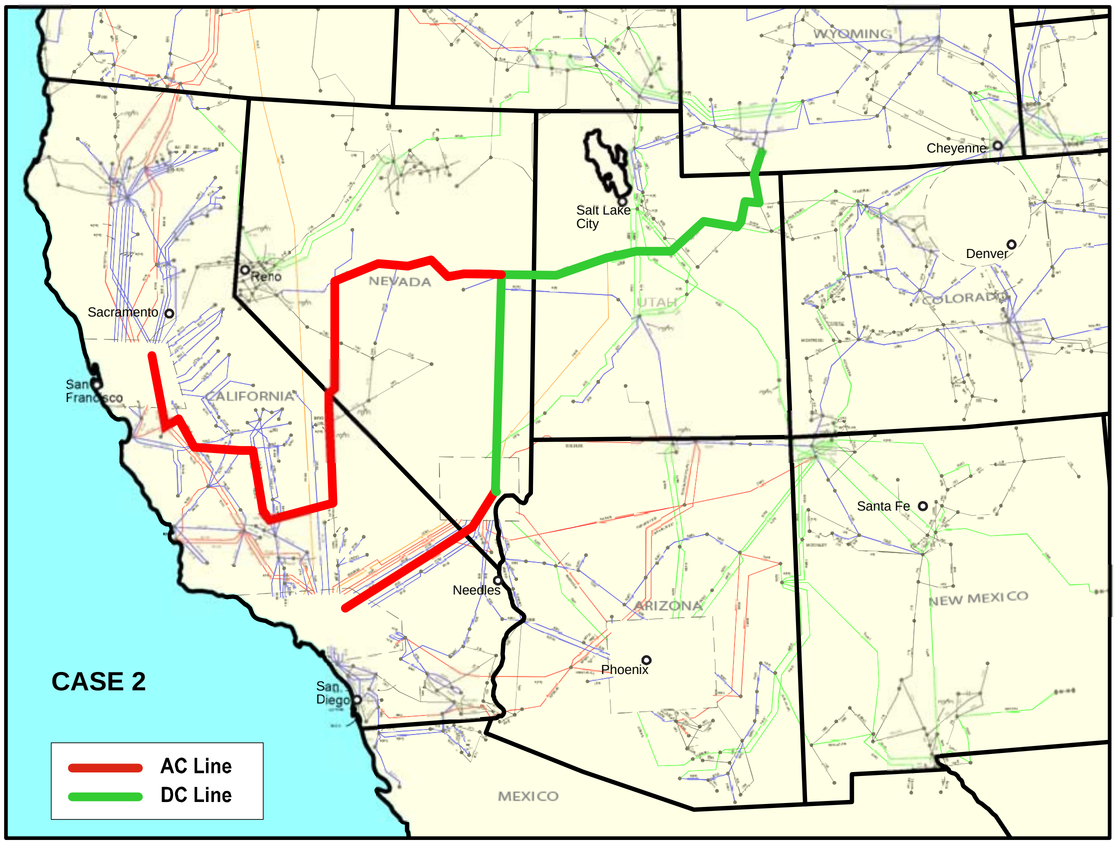
The objective of Change Case 2 was to identify and evaluate a strategy to replace new gas generation in California with clean coal from Wyoming and renewables that meets the following goals:

- Provides reliability benefits to Nevada and Utah.
- Accommodates desires of Nevada and Utah to provide renewable power to California and/or acquire renewable and clean coal power from Wyoming.

- Meets the 20 percent California Renewables Portfolio Standard with in-state resources and imports while providing improved transmission in California that could enhance the possibility of meeting a 33 percent Renewables Portfolio Standard target.
- Provides Northern California with the opportunity for greater access to renewable generation through the development of a direct link to the Tehachapi wind resource area.

Change Case 2 was characterized by the addition of significant transmission upgrades that included both 500 kilovolt (kV) alternating current (AC) and 500 kV DC sections from Wyoming to Southern and Northern California, in which the AC sections allowed for power off-take and injection along the way. Total transmission transfer capability into California was increased by 4,000 MW. In addition to the incremental integrated gasification combined-cycle generation described for Change Case 1, Change Case 2 adds 2,455 MW of renewable generation (wind, solar photovoltaic, and geothermal) in Wyoming and Nevada rather than 2,690 MW of new renewable generation (also wind, solar photovoltaic, and geothermal) in California that was assumed in the Base Case. The new renewables located in Wyoming and Nevada were estimated to produce the same amount of energy as the renewable capacity removed from California, primarily due to higher capacity factor wind regimes in Wyoming and Nevada (see discussion in Chapter 2). In Change Case 2, as in the other two cases, the California Renewables Portfolio Standard of 20 percent was assumed to be met by 2012. Figure ES-3 shows a conceptual route for this case.

Figure ES-3: Change Case 2 Conceptual Transmission Route



Source: California Energy Commission

As with Change Case 1, the benefits of Change Case 2 were calculated by comparing net variable production cost for meeting load. After taking into account the fixed and variable costs, as well as transmission losses, Global Energy estimated that California would benefit by $16 million/year under Change Case 2 (see Table ES-2). Benefits were lower in Change Case 2 compared with Change Case 1 because the added new renewable resources in Wyoming and Nevada were very similar to the renewable resources removed from California. While there were no major production cost benefits associated with the changes in renewable generation, the additional transmission line costs had to be included. As with Change Case 1, the results of Change Case 2 indicate that there is a net benefit to California of displacing natural gas-fired generation in Southern California with clean coal generation in Wyoming while addressing California's greenhouse gas policy goals. Furthermore, Change Case 2 demonstrates the potential for exceeding California's Renewables Portfolio Standard of 20 percent and contributing to meeting an accelerated goal of 33 percent.

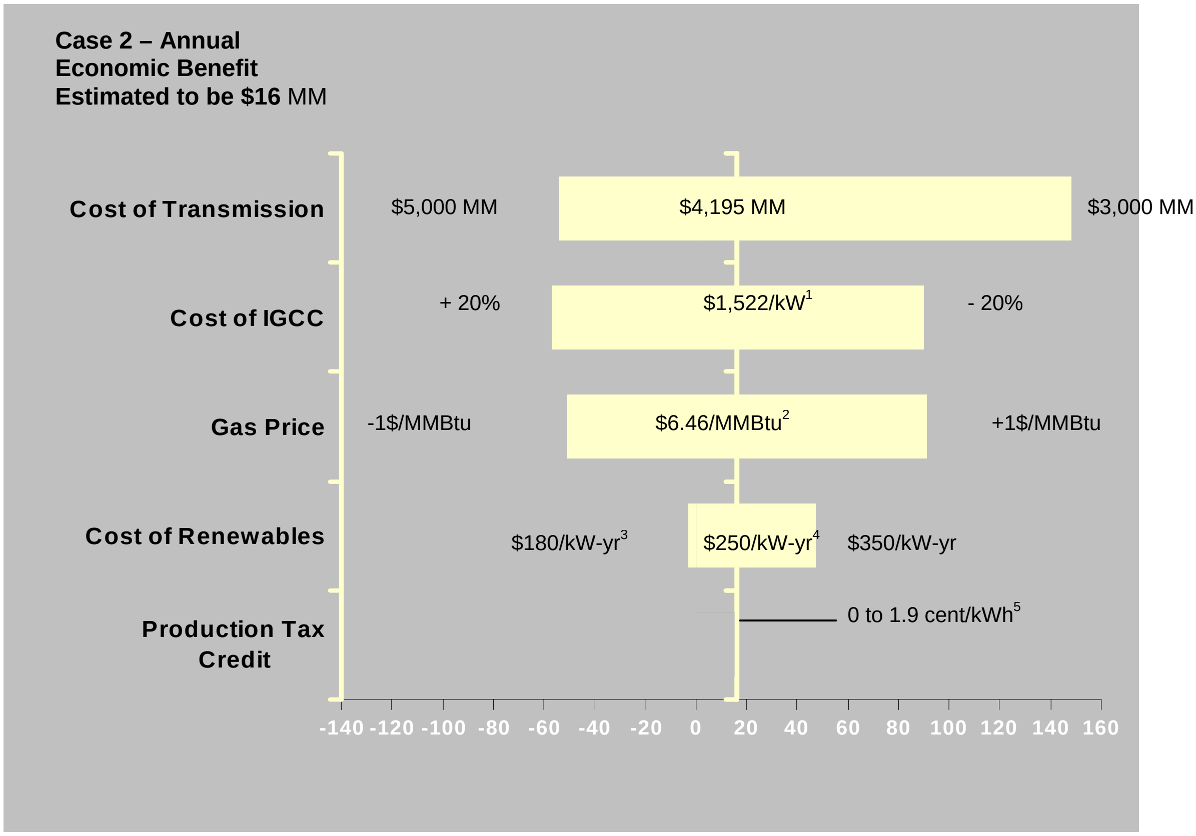
Table ES-2 Change Case 2 Study Results

Case	Transmission Upgrade	Generation Resources Changes	Annual CA Economic Impact (2012$)	CA NPV Benefits 2012-2025 @ 10% Discount Rate (2012$)	CA NPV Benefits 2012-2041 @ 5% Social Discount Rate (2012$)
Change Case 2	4,000 MW AC & DC Transmission expansion from S.W. WY to S. CA & N. CA. Avoided major T-line upgrades in Tehachapi area of CA, assumed in base	1,500 MW of new coal-fired IGCC in WY replaces 1,500 MW of planned gas-fired, combined cycle generation in CA. 2,455 MW of new renewable capacity in NV and WY replaces 2,690 MW of planned renewable capacity in CA	16 MM	119 MM	249 MM

Source: Global Energy Decisions

As with Change Case 1, Global Energy performed a sensitivity analysis on Change Case 2 to indicate how changes in certain key assumptions affected the results. See Figure ES-4.

Figure ES-4: Input Sensitivity Diagram for Change Case 2



1a. GHG reduction requirements through carbon sequestration capability.
1b. Costs for carbon sequestration assumed covered by enhanced oil recovery.
1c. Annual benefits exclude any EPAct-05 financial incentives (tax credits).
2. Energy Commission September 2005 Natural Gas Forecast for PG&E in 2004$.
3. Cost of wind generation.
4. Weighted average cost of wind and geothermal in Change Case 2.
5. No renewable production tax credit assumed in the analysis. The inclusion of a production tax credit would provide equal benefits in the Base Case and Change Case 2 because the volume of renewable energy generation is equal in both cases. Any benefits from a production tax credit in Change Case 2 would be offset by equal benefits in the Base Case.

Source: Global Energy Decisions

As noted earlier, these results are based on the overly conservative assumption that California bears the entire cost of the transmission upgrades. However, two objectives of this case are to provide reliability benefits to Nevada and Utah as well accommodate the desires of Nevada and Utah to provide renewable power to California and/or acquire renewable and clean coal power from Wyoming. Thus, using more realistic cost allocation assumptions among the participating states would increase the attractiveness of this case.

Finally, Change Case 2 supports the goal of coordinated regional transmission planning to achieve multiple benefits (economic, reliability, and renewables interconnection.) Given the shorter lead time of modular renewable generation technologies such as wind and solar compared with conventional technologies, it is possible for a transmission project like Change Case 2 to be routed in such a way as to create opportunities for increased in-state renewable generation (for example, to provide Northern California with the opportunity for greater access to renewable generation through the development of a direct link to the Tehachapi wind resource area.)

Western Congestion Study

Further support for the value of Change Cases 1 and 2 is found from the recent work conducted in support of Section 1221 of the Energy Policy Act of 2005, titled "Siting of Interstate Electric Transmission Facilities," which amends Part II of the Federal Power Act (Title 16 United States Code, Chapter 12, Subchapter II, Section 824 et seq.) to add Section 216(a) as follows:

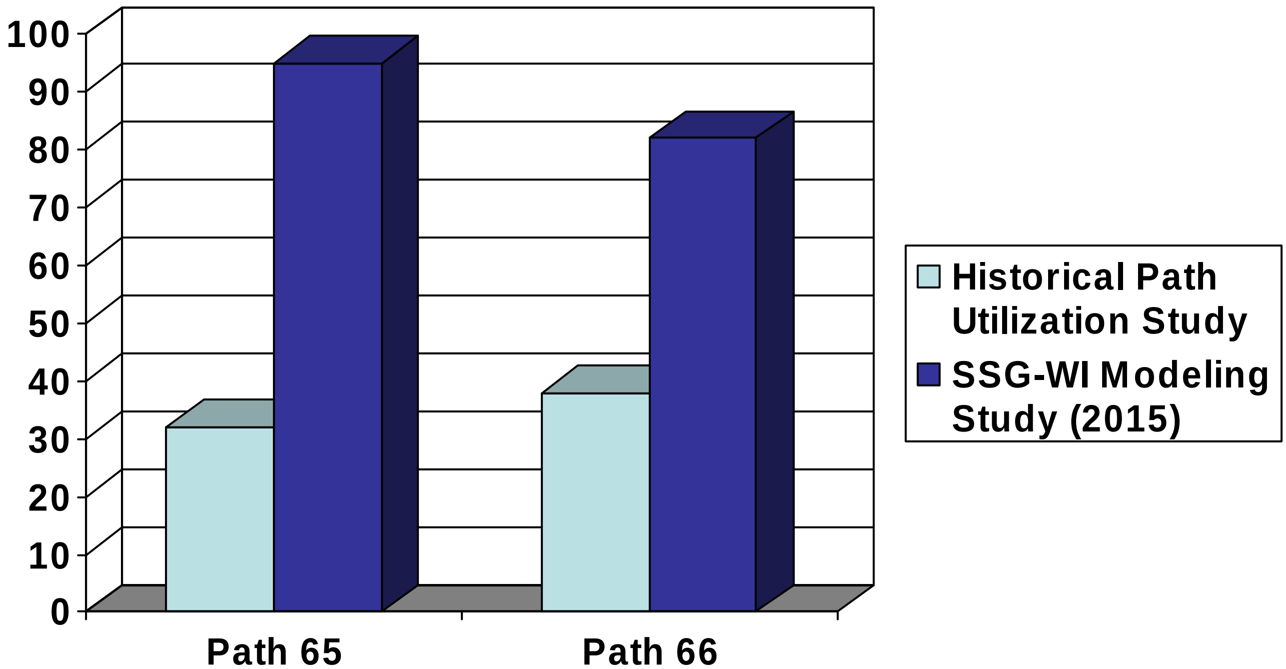
> Designation of National Interest Electric Transmission Corridors - (1) Not later than 1 year after the date of enactment of this section and every 3 years thereafter, the Secretary of Energy…in consultation with affected States, shall conduct a study of electric transmission congestion.

The U.S. Department of Energy accepted the proposal by the Western Electricity Coordinating Council (WECC) to conduct this study on behalf of the entities in the Western Interconnection, drawing upon the existing work of the Seams Steering Group – Western Interconnection (SSG-WI) and the work of the five western Subregional Planning Groups[7], supplemented by additional scenario analyses requested by DOE.

The SSG-WI 2006 path utilization study looked at historical (1998 through 2005) observed flows on all major WECC paths. Historical usage on two major interstate paths into California (Path 65, the Pacific DC Intertie; and Path 66, the Pacific AC Intertie) have summer U75 values (defined as the percentage of time the path usage exceeds 75 percent of the operating transfer capability) in the range of 30 to 38 percent, depending on hydro conditions. The SSG-WI/WECC 2005-6 modeling study predicted path usage for the years 2008 and 2015. These results show that the predicted summer U75 value for Path 65 increases to 95 percent in 2015, while the predicted summer U75 value for Path 66 increases to 82 percent in 2015, as shown in Figure ES-5.

Figure ES-5: Historic Usage vs. Modeled Usage

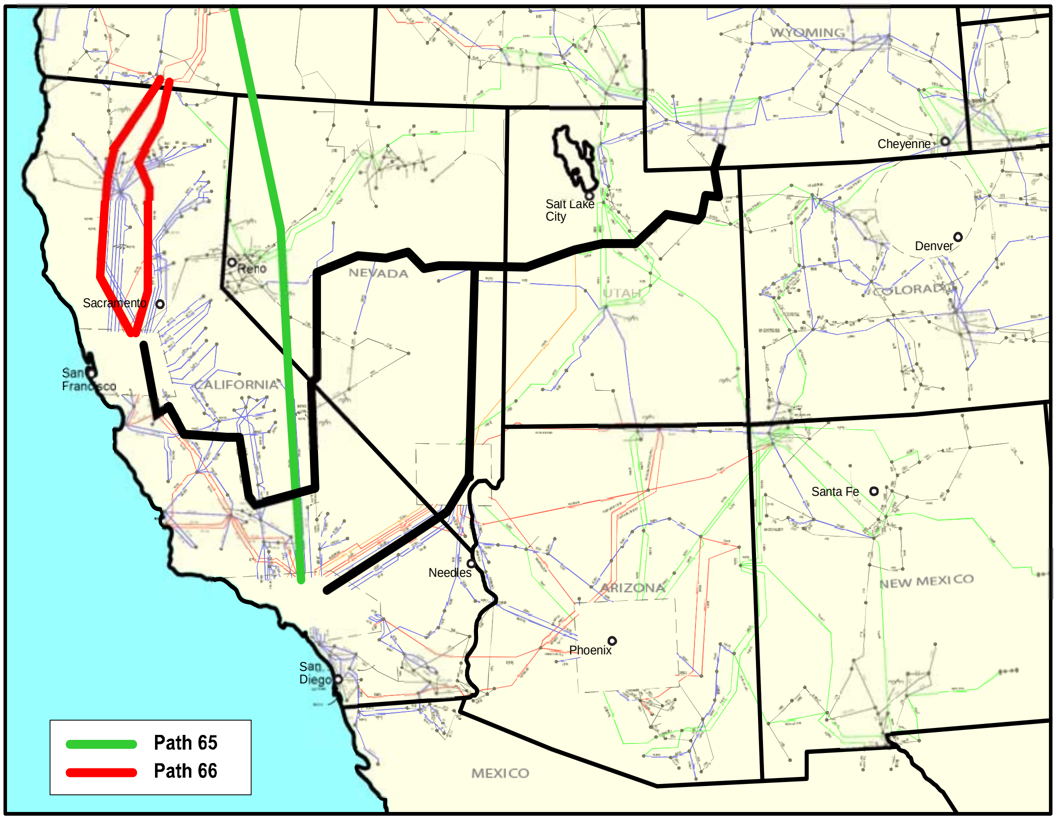
(Percentage of time the path usage exceeds 75 percent of the operating transfer capability; assumes an additional 4,000 MW of transfer capability to Southern California by 2015)



Source: California Energy Commission

Figure ES-6 shows the locations of Path 65 and 66 with an overlay of the conceptual routes for Change Cases 1 and 2. This figure demonstrates that Change Case 1 can help ease predicted Path 65 congestion in 2015; Change Case 2 can address both Path 65 and 66 predicted congestion in 2015.

Figure ES-6: WECC Paths 65 and 66 with Overlay of Change Cases 1 and 2



Source: California Energy Commission

Key Conclusions from Global Energy's Analysis

- Change Case 1 results indicate that displacing natural gas-fired generation in California with clean coal in Wyoming can provide economic benefits to California consumers under a wide range of assumptions for natural gas price and coal generation and transmission upgrade capital costs. In addition, California greenhouse gas policy as it relates to new coal development can be implemented at a net benefit to California consumers.
- As with Change Case 1, the results of Change Case 2 indicate that there is a net benefit to California of displacing natural gas-fired generation in Southern California with clean coal generation in Wyoming while addressing California greenhouse gas policy goals. Furthermore, Change Case 2 demonstrates the potential for exceeding California's Renewables Portfolio Standard of 20 percent and contributing to meeting an accelerated goal of 33 percent.

- Change Case 2 results are based on the overly conservative assumption that California bears the entire cost of the transmission upgrades. However, two objectives of this case are to provide reliability benefits to Nevada and Utah as well accommodate the desires of Nevada and Utah to provide renewable power to California and/or acquire renewable and clean coal power from Wyoming. Thus, using more realistic cost allocation assumptions among the participating states would increase the attractiveness of this case.
- Finally, Change Case 2 supports the goal of coordinated regional transmission planning to achieve multiple benefits (economic, reliability, and renewables interconnection.) Given the shorter lead time of modular renewable generation technologies such as wind and solar compared with conventional technologies, it is possible for a transmission project like Change Case 2 to be routed in such a way as to create opportunities for increased in-state renewable generation (for example, to provide Northern California with the opportunity for greater access to renewable generation through the development of a direct link to the Tehachapi wind resource area.)
- Change Case 1 can help mitigate predicted Path 65 congestion in 2015 based on the Western Congestion Study results, while Change Case 2 can address both Path 65 and 66 predicted congestion in 2015.

Next Process Steps

The results support the need for further analysis that achieves the following objectives:

- Coordinates with complementary projects[8];
- Identifies cost-sharing opportunities and cost allocation mechanisms;
- Connects to in-state California and regional renewables;
- Expands the range of potential benefits that should be evaluated; and
- Ensures maximum benefits to all states.

CHAPTER 1: ANALYSIS METHOD

The objective of this study was to determine the potential economic impact to California associated with investments in major transmission upgrades that would allow for the import into California of potential new renewable generation and clean coal generation in the interior Western Electricity Coordinating Council (WECC). Global Energy's analysis method compared the fixed and variable costs of the Base Case scenario to two Change Case scenarios. The Base Case represented the "status quo" expectations of the WECC in 2012 as if no new major transmission lines between Wyoming and California were added and load was met with generation sited near the load centers. The Change Case scenarios were modeled by modifying the Base Case with specific changes that represented two different transmission and generation investment alternatives. A detailed description of Global Energy's analysis method follows.

Establish Transmission/Generation Resource Portfolios for Analysis and Comparison

The first step in the analytical process was the formulation of transmission and generation resource databases for the Base Case. Next, these databases were modified to represent each of the two Change Cases in 2012. This modification entailed determining the resource need, consisting of load and reliability requirements (that is, reserve margins), and developing the WECC-wide generation and transmission resource options for each scenario.

The California Energy Commission (Energy Commission) licenses Global Energy's MARKETSYM and MARKETSYM-Locational Marginal Price (LMP) software and updates and maintains its own databases for use in the Global Energy software. For this study, Global Energy used the Energy Commission's most recent generation database and the California Independent System Operator's (CA ISO's) transmission database for the WECC. Each database was modified through a collaborative effort of the Energy Commission and Global Energy to accurately reflect the expected conditions of the Base Case and the Change Cases for 2012.

In the Base Case, new transmission upgrades that would likely be completed between now and 2012 under expected conditions were represented. However, the major transmission investments between southwest Wyoming and California that define Change Cases 1 and 2 were not included. Change Case 1 assumed the construction of a new DC transmission line from southwest Wyoming to Southern California with a transfer capability of 1,500 MW. Change Case 1 also assumed that a new 1,500 MW coal-fired, integrated gasification combined cycle (IGCC) with carbon sequestration technology would be built in southwest Wyoming and would be under contract to California. As a result, 1,500 MW of gas-fired, combined-cycle generation located within California that had been included in the Base Case to serve California load was removed from the database.

In Change Case 2, Global Energy assumed the addition of significant transmission upgrades that include both 500 kV alternating current (AC) and 500 kV direct current (DC) sections from Wyoming to Southern California and Northern California. In addition to the new incremental generation described for Change Case 1, 2,690 MW of renewable generation in California was replaced by 2,455 MW of renewable generation capacity in Wyoming and Nevada, where the renewable capacity added is capable of producing the same amount of energy as the renewable capacity removed from California. In Change Case 2, as in all cases, a California Renewables Portfolio Standard (RPS) of 20 percent energy production is assumed to be met by the study year 2012. These incremental generation and transmission changes made in the Change Cases 1 and 2 are summarized in Table 1-1 below. More detailed descriptions of the Base Case and Change Cases follow.

Table 1-1: Transmission and Generation Resource Portfolios

Case	Transmission Upgrade	Generation Resources Changes
Base Case	Based on CA ISO database w/ Energy Commission expectations of expansions through 2012.	Based on Energy Commission resource database
Change Case 1	Additional 1500 MW DC Transmission Line Expansion from Southwest WY to Southern CA.	1,500 MW of new coal-fired IGCC in WY replaces 1,500 MW of planned gas-fired, combined-cycle generation in CA.
Change Case 2	Additional AC & DC Transmission Expansion from southwest WY to S. CA (2,000 MW) and southwest WY to N. CA (2,000 MW).	1,500 MW of new coal-fired IGCC in WY replaces 1,500 MW of planned gas-fired, combined cycle generation in CA. 2,455 MW of new renewable capacity in NV and WY replaces 2,690 MW of planned renewable capacity in CA.

Source: Global Energy Decisions

Economic Assessment Method

Global Energy used a cost-benefit analysis approach in which the production costs simulated in the Base Case were compared to the production costs from simulations of each of the Change Cases. The difference in production costs minus the difference in incremental capital and fixed costs represented the economic impacts of the Change Cases. Specifically, the analysis estimated the economic impact that the transmission and generation investments in each of the Changes Cases would have on California.

California Economic Benefits Analysis Method

To assess the economic impact of each Change Case on California, California production costs were calculated in three steps. First, Global Energy assumed that all native generation within California would serve California load and computed the production costs for each of these generation units. This was done by computing and comparing the hourly production cost output from the MARKETSYM-LMP[9] simulations for California generation for the Base Case and Change Cases. In addition to native California generation, Global Energy accounted for remote generation contracted to California load serving entities and attributed the production and production costs of these generators to California. In each of the Change Cases, Global Energy assumed that all output from the new IGCC and new renewable generation (Change Case 2 only) served California load and assigned the production costs of these units to California. Finally, on an hourly basis, Global Energy determined whether the difference between California load minus native California generation, and minus contracted remote generation (including the new IGCC and renewable generation mentioned above), resulted in a net import or net export for that hour. Global Energy then priced each MW of net export or net import at the simple average LMP of all California interfaces based on the MARKETSYM-LMP simulation data. The cost of imports and exports were then added to the production costs for native and remote California generators to comprise the total California production costs. The change in production costs (between that Base Case and Change Case) was then compared to the change in incremental capital and fixed costs to calculate the economic impact of each Change Case. Since all new IGCC and renewable generation in Wyoming and Nevada was assumed to be contracted to California, all incremental capital and fixed costs associated with the transmission and generation investments were attributed to California.

Estimating the Value of Losses

Global Energy ran an AC-optimal power flow (AC-OPF) unit commitment and dispatch model for the peak hour of each year to study the economic impact of transmission losses associated with each of the case studies. A description of the AC-OPF model is provided below. Global Energy used the transmission losses data from the AC-OPF simulation to calculate the economic value associated with the change in losses between the Base Case and each of the Change Cases. Losses for the peak hour, expressed as a percentage of total WECC load were multiplied by the WECC expected annual load to estimate total annual losses (in megawatt-hours, MWh) for the WECC. The increase in losses associated with the Change Case was then valued at the marginal cost of a generic gas-fired combined cycle generation unit, expressed in $/MWh under the assumption that such a unit is a good proxy for the typical marginal unit in the WECC that would cover losses throughout the year. The generic gas-fired combined cycle was assumed to have a heat rate of 7,000 British Thermal Units/kilowatt-hour (Btu/kWh) and an annual average gas price of $6.46/million(MM)Btu (in 2004$).

Network Model

For this study, Global Energy simulated four typical week network analyses for 2012, where network flows are determined using an optimal power flow (OPF) unit commitment and dispatch model. Each scenario, consisting of the existing transmission network, generation resource base, new transmission, and generation additions, was simulated deterministically using Global Energy's MARKETSYM LMP nodal network model.

The four typical weeks—one week for each season—were simulated using a DC-OPF solution. Additionally, for the peak hour of the year, an AC-OPF unit commitment and dispatch model was run in order to compare an AC-OPF solution with a DC-OPF solution.

Global Energy's approach relied on two widely accepted industry standard models: Global Energy's MARKETSYM zonal production cost model and PowerWorld Simulator. The combined system and their associated databases are referred to as MARKETSYM–LMP.

The OPF simulation in the combined model is capable of capturing the effect of flows on every transmission line and tests for congestion. If congestion is present across a given path, PowerWorld optimally re-dispatches generator units to relieve this congestion. The OPF model is capable of calculating and reporting bus level prices, production costs, and other operational data. The MARKETSYM-LMP platform provides a complete solution to calculating nodal prices and operational costs that can be used to assess the impact of changes to the network and market and who they impact.

A zonal MARKETSYM simulation was used to develop the desired hourly commitment of generators. The hourly dispatch and commitment data from that simulation, along with bid curves of the units, were then transferred to the OPF model and an accompanying detailed transmission network model provided by the California Independent System Operator (CAISO). The OPF simulation utilized the initial MARKETSYM zonal solution and cost and performance characteristics of generators, combined with a detailed electrical model of the entire transmission network—including important constraints associated with the electrical network—to minimize power costs subject to generator bids or costs.

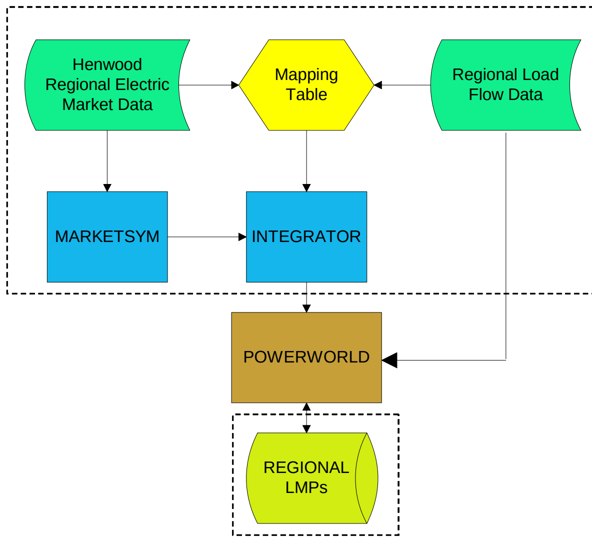
The workflow process employed by Global Energy in the use of MARKETSYM-LMP is shown in Figure 1-1. The workflow associated with the analysis can be best described as three steps:

- First, the MARKETSYM zonal simulation produces unit commitment and dispatch decisions that honor such important constraints as generator operating parameters, energy limited fuels (including hydro), inter-zonal transmission path constraints, and locational operating reserve requirements. This step is indicated in the top, dashed box in Figure 1-1.
- Next, the initial MARKETSYM solution is passed into PowerWorld Simulator, properly configured to compute nodal results subject to the initial solution conditions set in MARKETSYM as well as the transmission constraints represented in the network model. PowerWorld's Optimal Power Flow algorithm incorporates these constraints into its computations and seeks to minimize bid-

costs subject to these constraints. This step is indicated in the PowerWorld Box in Figure 1-1.

- Last, after the nodal simulations are complete, hourly results for all buses, branches, and interfaces are extracted from PowerWorld and placed in a Windows SQL Server database. This step is indicated in the Regional LMPs box in Figure 1-1.

Figure 1-1: MARKETSYM-LMP Nodal Workflow



Source: Global Energy Decisions

For MARKETSYM-LMP analysis, Global Energy divides the study area into OPF Areas, Non-OPF Areas, and External Areas (to balance supply and demand). For OPF areas, an OPF solution is computed that re-dispatches generation to meet the constraints of the OPF model and that produces LMPs at each bus. Production cost information can also be produced for generators within each OPF area.

For this study, Global Energy treated Arizona, California, Colorado, Idaho, Nevada, Utah and Wyoming as OPF Areas. Global Energy identified as Non-OPF Areas transmission areas for which line constraints are not monitored, and for which LMPs are not computed, but for which the transmission grid was included in the PowerWorld modeling. This allowed loads and resources in neighboring areas to impact the grid in the core OPF areas. Non-OPF areas included all other WECC market areas not designated as OPF areas.

A DC-OPF solution was found in PowerWorld for every hour of the four typical weeks, with a least-cost solution to serve loads, subject to being able to meet monitored line limits. The DC-OPF solution was a simplified approach in which voltage requirements, VAR requirements, switched shunt elements, and transformers with taps were not taken into account. For the peak hour of the year in each scenario, an AC-OPF solution was simulated. The AC-OPF algorithm produced a solution that satisfied the limits of all transmission elements at the levels specified. The OPF algorithm was applied to meet the load forecasts in the WECC forecast. For both DC-OPF and AC-OPF algorithms, LMPs, production costs, and other operational outputs were produced for all relevant elements in the OPF areas.

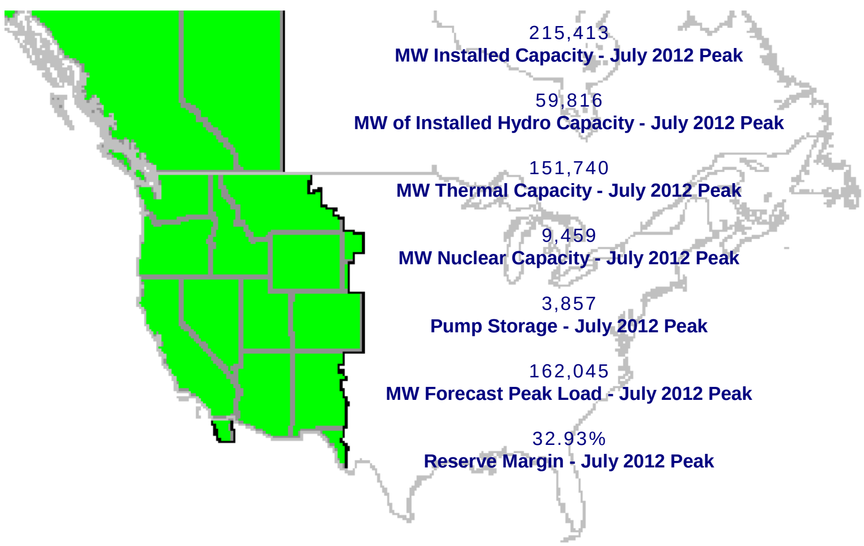
CHAPTER 2: ASSUMPTIONS

Base Case Assumptions

Base Case resource and transmission databases were developed for the entire WECC region to represent the expected "status quo" market conditions for the WECC in 2012 and to serve as a reference case when compared to each Change Case. Global Energy used the Energy Commission's own WECC database and CA ISO transmission data to perform the analysis.

The Energy Commission updated both resource and transmission data to reflect expected market conditions for 2012. Figure 2-1 summarizes key WECC Base Case metrics, and the major Base Case assumptions are discussed below in greater detail.

Figure 2-1: Key WECC Base Case Metrics



Source: Global Energy Decisions

WECC Transmission and Market Topology

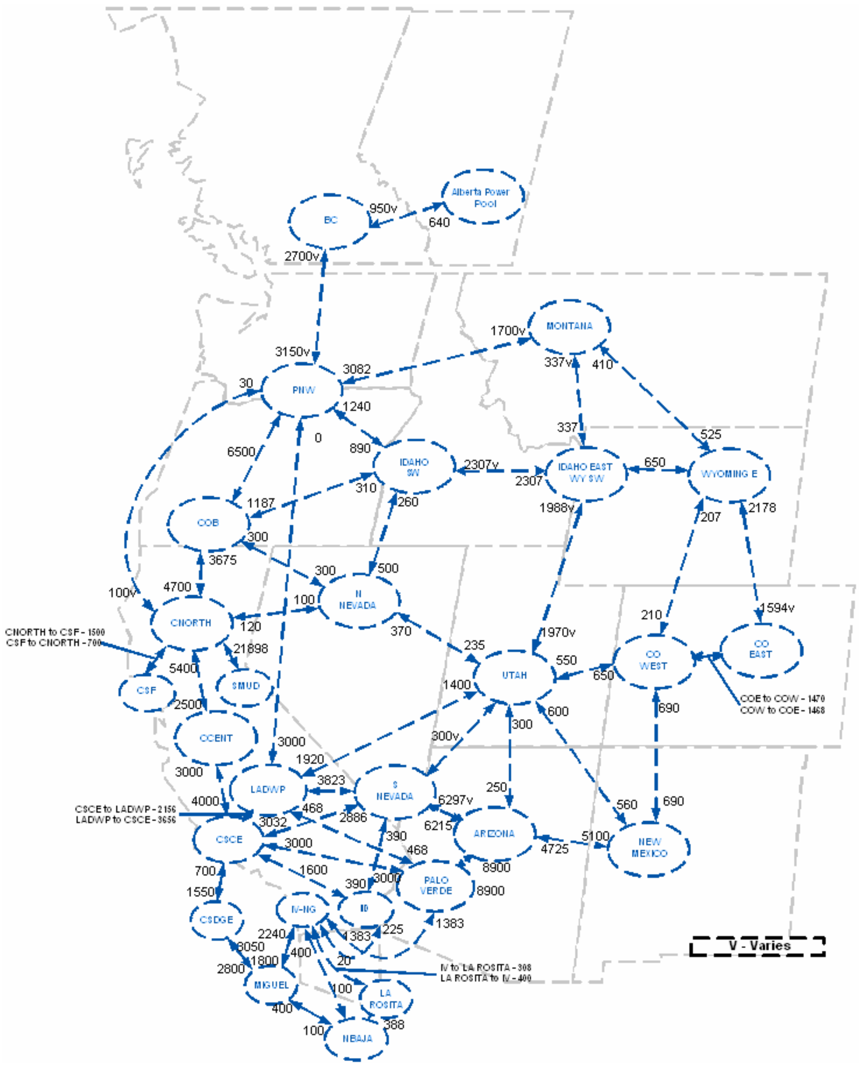
The WECC region extends from Canada to Mexico and includes the Canadian provinces of Alberta and British Columbia; the northern portion of Baja California, Mexico; and all or portions of 14 states. Electrically, there are no state/provincial or national boundaries that break up this system. With some limitation, generation from any area in the WECC can be used to meet electric load in any other area.

At the Energy Commission's request, the CA ISO's transmission data (provided by the CA ISO in November 2005) were used for this analysis. The data that were provided by the CA ISO were the (unofficial) Control Grid Study data. At the time the data was provided, the data were still being reviewed and finalized by the CA ISO and its members. The database was reviewed and updated by Global Energy to make it consistent with the MARKETSYM database provided by the Energy Commission for 2012 and with the MARKETSYM-LMP software platform. Changes included the addition/removal of generation consistent with the Energy Commission's assumptions, removal of hardwired transactions from the case and configuring the data so that it could take data such as DC line flows, generation, load, and interchange schedules from MARKETSYM (consistent with the PROSYM solution for the corresponding hour). The Base Case transmission database served as the reference case to which transmission upgrades included in each Change Case were added.

In modeling the WECC and the transmission paths between the sub areas of WECC, Global Energy's modeling reflected the lesser of the WECC accepted path rating or, if adequate information existed, a lower rating that anticipated reductions to WECC path ratings as reflected in day-to-day operational ratings.

For the purpose of the MARKETSYM zonal component of the present study, the WECC was divided into 28 different market areas, illustrated in Figure 2-2. The zonal model assumed that there was no congestion inside these areas. Based on this assumption, the model produced an initial solution (commitment, dispatch, interchange schedules), which was fed (hourly) into the nodal model. The nodal model then adjusted this initial solution as appropriate with the detailed transmission representation.

Figure 2-2: 2012 Base Case WECC Topology



Source: Global Energy Decisions

Load

The WECC peak load for 2012 was forecast at 162,045 MW, while total annual demand in 2012 was forecast at 945,000 gigawatt hours (GWh). For the same period, California's forecasted peak load was 61,156 MW, and annual demand was 332,000 GWh.[10]

Generation

Generation resources in the WECC database consisted of existing or installed capacity, defined additions, and generic additions. Installed capacity was composed of those generators that were currently in service. Installed capacity declines over time due to unit retirements. Defined capacity additions were those generators that are permitted or under construction and expected to be completed in the next few years. Generic additions were additional generators added to replace retired capacity, meet future load growth, and maintain reserve margin requirements. Based on the Energy Commission's WECC database used in this analysis, installed capacity as of January 1, 2006, was 197,233 MW. New generation in the WECC (defined capacity additions and generic capacity additions combined) between January 2006 and January 2013 was assumed to be 21,000 MW. Retirements of 2,300 MW were also modeled through the end of the study period. The new resource additions included adequate new renewable generation (wind, geothermal, and solar) to meet an RPS of 20 percent by 2012 for California, as well as all other RPS programs within the WECC.

Key Generation Fuel Prices

Natural Gas

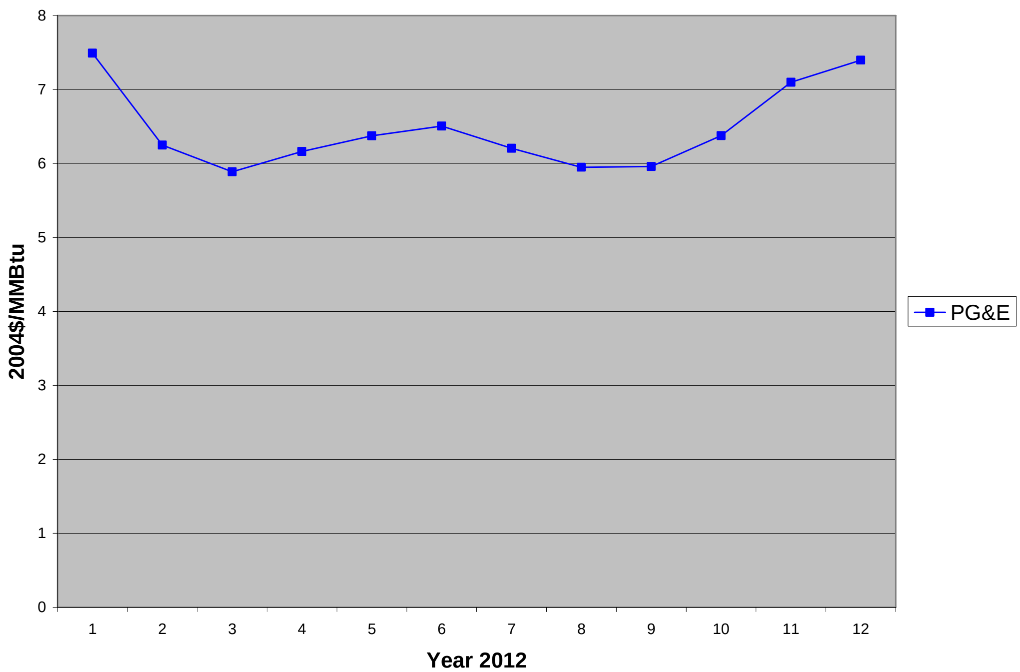
The Energy Commission's natural gas price forecast, issued in the *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment*[11] (Reference Case Report), was the basis for gas prices used in this analysis. The work to develop the Reference Case Report was conducted in parallel with a similar effort on behalf of the Western Governors' Association's Western Interstate Energy Board (WIEB). As a result, the Energy Commission staff coordinated with a WIEB team representing the 15 western states and Canadian provinces in the development of the gas price forecast.

The Energy Commission forecasted monthly natural gas prices for 2006-2016, which considered natural gas demand, supply, infrastructure, and price. The forecast was prepared without considering the long-term effects of hurricanes Katrina and Rita. Nevertheless, the forecast results show that natural gas prices are expected to remain high, relative to historical levels, as a result of supply, demand, and infrastructure fundamentals.

The Energy Commission staff's natural gas forecast is a long-run, marginal cost estimate of new gas supply to serve demand. The forecast is a fundamentals-based forecast that is built from the sum of costs of each function in the supply chain. It is not based upon a regression analysis or trend from historical and current natural gas prices. The costs include both fixed costs of new capacity (for example, pipeline, storage, liquefied natural gas (LNG) terminals) and operating costs (for example, variable costs of production, lost-and-unaccounted-for gas, and compression). The Energy Commission staff gathers inputs from many sources, monitors market behavior to identify trends, investigates specific issues, and conducts analyses using spreadsheets and computer models. The results for natural gas demand levels, supply, infrastructure needs, and price forecasts used in this report are products of the North American Regional Gas-Market Builder (NARG-MB) model.[12]

Based on the Energy Commission staff's analysis, wellhead prices in the basins supplying natural gas in the West are generally projected to increase from 2006 to 2016, reflecting the increasing marginal costs to produce gas in those regions as resources are depleted. However, the expected addition of LNG terminals in Baja California and elsewhere is expected to temper the overall trend of increasing natural gas wellhead prices. Pipeline expansions into California since the energy crisis of 2000-2001 have relieved constraints to regional supplies. As a result, California's natural gas prices no longer tend to be out of step with the rest of the North American market. Consequently, from 2006-2016, California's end-use natural gas prices are reflective of the national market. Figure 2-3 below illustrates the monthly natural gas price forecast used in this analysis (forecasted Pacific Gas and Electric Company (PG&E) prices shown).

Figure 2-3: 2012 Monthly Natural Gas Price Forecast for PG&E



Source: Global Energy Decisions, based on the Energy Commission staff gas price forecast described above.

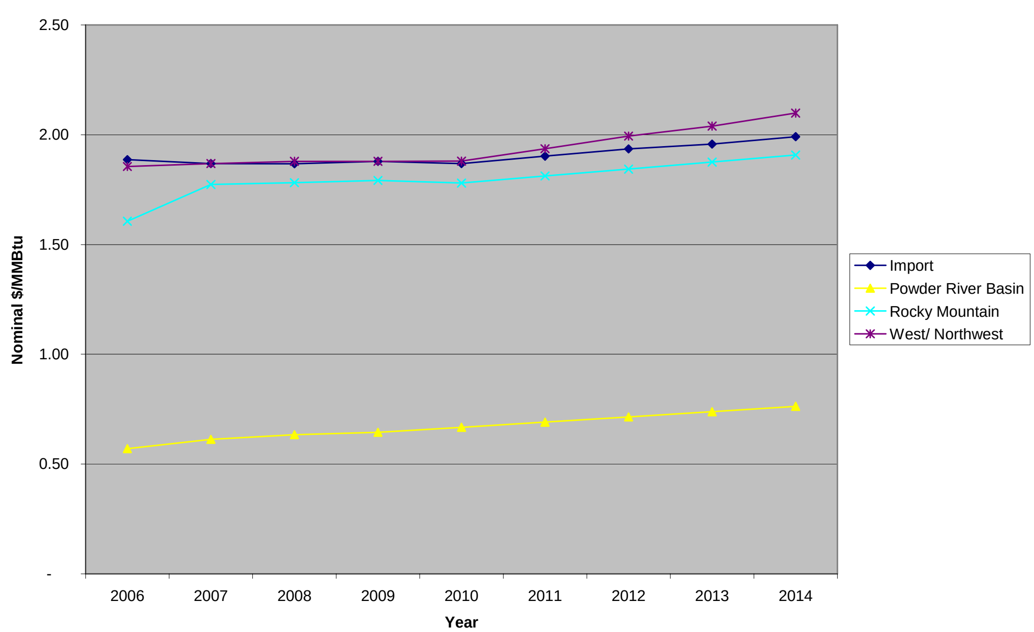
Coal

Coal price assumptions for the Base Case and Change Cases are based on the Energy Commission database assumptions for the WECC. The Energy Commission coal price forecasts were developed by Global Energy using Global Energy's econometric forecast method. Factors incorporated into the econometric forecast include regional long-term weather predictions, sulfur dioxide (SO_2) allowance price forecasts, future coal contract terms, New York Mercantile Exchange (NYMEX) futures gas prices, natural gas price forecasts, expected coal transportation constraints, regional reserve depletion, and future contracted coal prices. Sources used by Global Energy to derive long-term coal prices include:

- Energy Information Administration's (EIA's) Annual Energy Outlook (AEO) Report.[13]
- Federal Energy Regulatory Commission's Form 423 database, 1996 – 2002.[14]
- Numerous websites for individual generators, utilities, coal-mining companies, long-term weather forecasting services, gas and coal trading companies, and rail companies.

Forecasted delivered prices at each plant were based on historic transportation prices and historic "free on board" (FOB) mine prices to the particular plant. The transportation and FOB mine prices were increased over each time period by the escalation factors produced in the forecast. Coal originating from basins where significant transportation infrastructure investment was required, such as imported coal and Powder River Basin (PRB) coal, had transportation rates increasing at 1.5 percent per year. Figure 2-4 illustrates the selected coal price forecasts used in this analysis.

Figure 2-4: Annual Average Coal Price Forecast 2006-2014



Source: Global Energy Decisions

Fuel Oil

Fuel oils commonly used by power generators are distillate fuel oil #2, residual fuel oil #6, and jet fuel. While fuel oils are more important in terms of their price setting ability in the Northeast and Southeast, fuel oil-fired generation exists in the WECC. In comparison to natural gas, crude oil markets are characterized by worldwide commodity trades and are greatly influenced by world oil price shocks and trends. To develop regional fuel oil prices for generators, Global Energy used its West Texas Intermediate (WTI) Reference Case forecast[15] and applied regional price differentials to account for fuel transportation to the generator burner-tip.

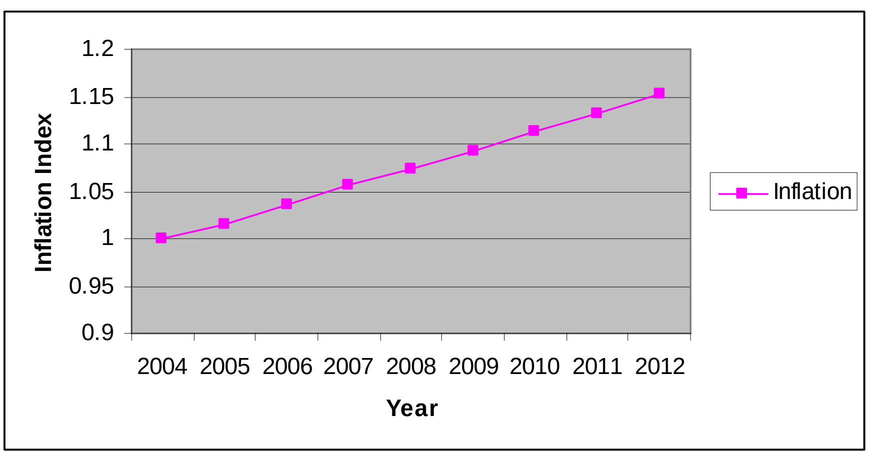
Other Fuels

Other technologies used to generate electricity in the WECC include nuclear, biomass, hydro, wind, geothermal, solar, and other industrial byproducts. Of these technologies, nuclear and hydro play the most important role. Nuclear fuel prices used in Global Energy's forecast were based on the average reported fuel costs from a representative group of nuclear plants using historical FERC Form 1 data. The "fuel cost" of hydro and other renewables are at or near zero and therefore have little impact on the dispatch costs. Biomass and other less common fuels are used in very small quantities and have little impact, if any, on electricity prices.

General Price Inflation

Inputs in this report were expressed in 2004 dollars, unless otherwise indicated. Final Results are reported in 2012 dollars, escalated based on the California Energy Commission inflation index assumptions as shown in Figure 2-5.

Figure 2-5: General Price Inflation Assumptions: 2004-2012



Source: Global Energy Decisions and California Energy Commission

Assumptions of Change Cases

Change Cases 1 and 2 represent the different investment case studies for transmission upgrades from Wyoming west to California. In addition, new clean coal and renewable generation investments included in the Change Cases replace California-based generation that was originally included in the Base Case. For each Change Case, Global Energy modified the Base Case databases to represent the new transmission upgrades and changes to the generation resource portfolio. These changes are discussed below.

Load

Load remained the same in each case (Base Case, Change Case 1, and Change Case 2).

Generation Resourced Added/Removed

Change Case 1: In Change Case 1 it was assumed that 1,462 MW of coal-fired, IGCC would be located in southwest Wyoming (near the Jim Bridger Substation). The IGCC replaced 1,462 MW of new gas-fired, combined-cycle gas turbines (CCGTs).[16]

Table 2-1 summarizes the incremental generation changes made to the resource database in Change Case 1.

Table 2-1: Incremental Generation Added to/Removed in Change Case 1

Action	Generator	Area	Capacity (MW)	Fuel
	Generation Removed From Change Case 1			
Removed	CCGT 1	ZP-26	300	NG PG&E BB
Removed	CCGT 2	ZP-26	300	NG PG&E BB
Removed	CCGT 3	ZP-26	300	NG PG&E BB
Removed	CCGT 4	NP-15	290	NG PG&E BB
Removed	CCGT 5	SDG&E	273	NG SDG&E
TOTAL			**1,462**	
	Generation Added To Change Case 1			
Added	IGCC	SW WY	1,462	PRB Coal
TOTAL			**1,462**	

ZP-26 = Zonal Path 26; NP-15 = North of Path 15; NG PG&E BB = PG&E “backbone” natural gas pipeline system; PRB = Powder River Basin

Source: Global Energy Decisions

Change Case 2: In Change Case Two, 2,690 MW of renewable generation capacity comprised of new generic wind, solar, and geothermal generation was replaced by 2,455 MW of renewable capacity located in Wyoming and Nevada. Sufficient renewable capacity from Wyoming and Nevada was added to replace an equal amount of energy production (GWh) expected from the renewable California generation removed from the Base Case. The 235 fewer megawatts of renewable capacity added to Wyoming and Nevada accounted for the higher efficiency of renewable generation expected in Wyoming and Nevada, as illustrated in Table 2-5. Table 2-2 below summarizes the incremental generation changes made to the resource database in Change Case 2.

Table 2-2: Incremental Generation Added to/Removed in Change Case 2

Action	Generator	Area	Capacity (MW)	Fuel
	Generation Removed From Change Case 2			
Removed	CCGT 1	ZP-26	300	NG PG&E BB
Removed	CCGT 2	ZP-26	300	NG PG&E BB
Removed	CCGT 3	ZP-26	300	NG PG&E BB
Removed	CCGT 4	NP-15	290	NG PG&E BB
Removed	CCGT 5	SDG&E	273	NG SDG&E
Removed	WIND	NP-15 & SP-15	2000	Wind
Removed	SOLAR PV	ZP-26 & IID	120	Solar
Removed	GEO	NP-15 & IID	570	Geothermal
TOTAL			**4,153**	
	Generation Added To Change Case 2			
Added	IGCC	WY	1,463	PRB Coal
Added	WIND	WY	1,607	Wind
Added	WIND	N. NV	208	Wind
Added	SOLAR PV	N. NV	123	Solar
Added	GEO	N. NV	516	Geothermal
TOTAL			**3,917**	

SP-15 = South of Path 15; IID = Imperial Irrigation District

Source: Global Energy Decisions

Performance Characteristics of Incremental Generation
Incremental Coal-fired Generation

The new IGCC plant was assumed to burn Powder River Basin (PRB) coal as a fuel source, with an approximate heat content of 8,340 Btu/lb. The IGCC plant was assumed to be located in southwest Wyoming in the Jim Bridger Substation area and to include carbon sequestration technology. However, the incremental capital and operating costs associated with carbon sequestration were treated separately from this analysis, based on the assumption that carbon sequestration is likely to be funded in part by revenues received for the sequestered carbon, which were not estimated in this analysis, and in part by federal funding, such as clean coal technology funding from the 2005 Energy Policy Act.[17] In addition, the *State Energy Action Plan II* supports clean coal technology research and development, as well as methods for capturing and storing significant amounts of carbon dioxide (CO_2), either as an integral part of the energy conversion process or in pairing with external CO_2 sequestration.[18] As a result, the cost (capital and operations and maintenance (O&M)) and performance (heat rate) parameters—except for carbon emissions—represented an IGCC without sequestration. The performance characteristics for the IGCC are summarized in Table 2-3 below.

Table 2-3: Performance Characteristics of IGCC Technology

Technology	Heat Rate (Btu/kWh)	VOM ($/MWh, 2004$)	Availability (%)	SO_2 Removal	NO_X (lb/MMBtu)	CO_2 (lb/MMBtu)
IGCC	8,300	2.50	87%	97.5%	0.09	21

VOM = Variable O&M; NO_x = oxides of nitrogen; CO_2 = carbon dioxide

Source: Global Energy Decisions

Incremental Gas-Fired Generation

The performance characteristics of the new, generic CCGT technology replaced in Change Case 1 and 2 are summarized in Table 2-4 below.

Table 2-4: Performance Characteristics of Replaced Gas-Fired Technology

Technology	Heat Rate (Btu/kWh)	VOM ($/MWh, 2004$)	Availability (%)	SO_2 Removal	NO_X (lb/MMBtu)	CO_2 (lb/MMBtu)
CCCT	6,800	2.50	90%	N/A	0.02	119

Source: Global Energy Decisions

Incremental Renewable Generation

The performance characteristics of incremental wind and solar generation were based on historical data, shown in Table 2-5. Hourly operating profiles were provided by the Energy Commission for this analysis.

Table 2-5: Performance Characteristics of Incremental Renewable Generation

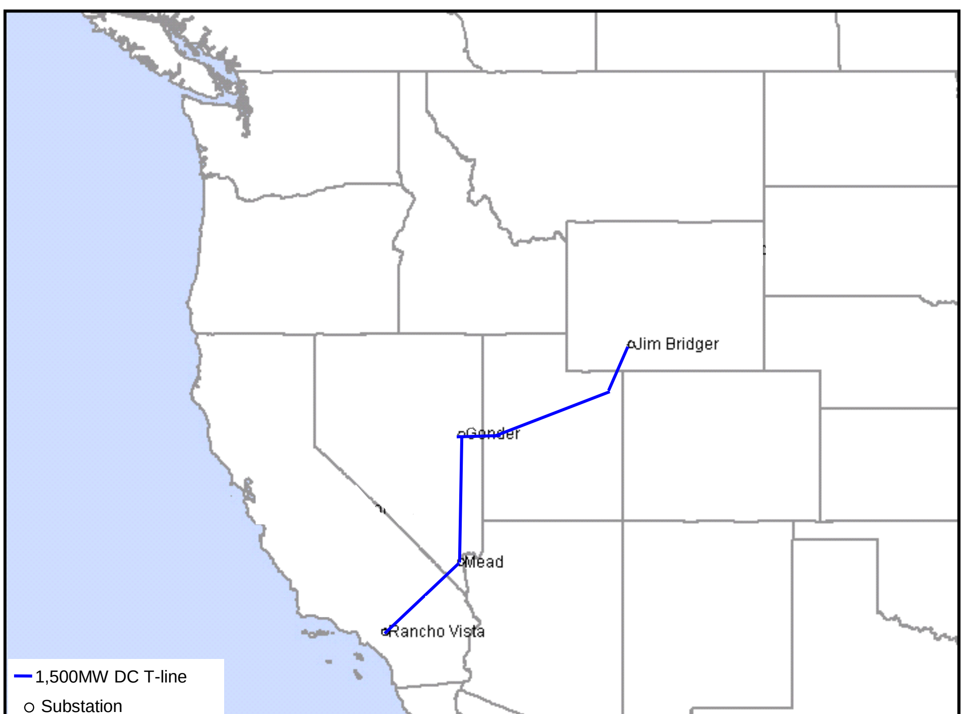
Technology	Location	Availability (%)	Fuel Cost ($/MMBtu, 2004$)	Heat Rate (Btu/kWh)	VOM[19] ($/MWh, 2004$)
Wind	WY	43%	-	-	-
Wind	NV	40%	-	-	-
Wind	CA	36%	-	-	-
Solar	NV & CA	27%	-	-	1.18
Geothermal	NV & CA	96%	1.77	10,000	1.18

Source: Global Energy Decisions

Transmission Upgrades Change Case 1 Transmission Upgrade

Change Case 1 was characterized by a new 1,500 MW capacity DC transmission line between southwest Wyoming and Southern California, starting at the Jim Bridger Substation in Wyoming and terminating at the proposed Rancho Vista Substation in Southern California. Figure 2-6 illustrates the path of the DC transmission upgrade studied in this analysis.

Figure 2-6: Change Case 1 Transmission Upgrade Map

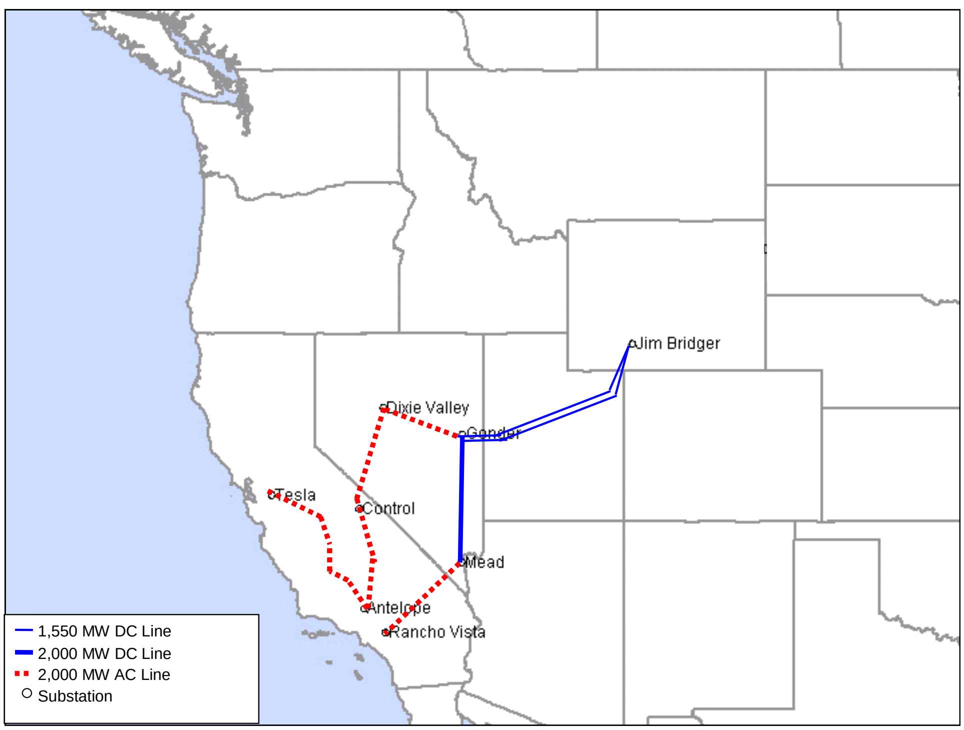


Source: Global Energy Decisions

Change Case 2 Transmission Upgrade

Change Case 2 was characterized by the addition of significant transmission upgrades that included both 500 kV AC and 500 kV DC sections between Wyoming and California. Two 1,550 MW capacity DC lines extend from the Jim Bridger Substation in Wyoming through Utah to the Gonder Substation in northeast Nevada. From Gonder, a 2,000 MW capacity AC transmission line extended to the Dixie Valley Substation in northern Nevada, south to the Control Substation near the California-Nevada border, then south to the Antelope Substation in Southern California Edison (SCE) territory and finally north to the Tesla Substation in PG&E territory. A southern leg from Gonder extends to the Mead Substation in southern Nevada as a 2,000 MW capacity DC line, then on to the proposed Rancho Vista Substation in SCE territory as a 2,000 MW capacity AC line. The map in Figure 2-7 provides a general illustration of the transmission upgrade studied in Change Case 2.

Figure 2-7: Change Case 2 Transmission Upgrade Map



Source: Global Energy Decisions

Additionally, in Change Case 2, the transmission needs related to later phases of new renewable generation in the Tehachapi area were met with the northern leg of the Wyoming-to-California transmission expansion. As a result, Global Energy removed the longer-term Tehachapi-related upgrades from the transmission database for Change Case 2.

Capital and Fixed Costs Assumptions

A major element of the cost-benefit analysis was the difference in capital and fixed operating costs between the Base Case and the Change Cases. Using cost estimates for each of the infrastructural changes studied in this analysis, Global Energy estimated annual, levelized fixed and capital cost using Global Energy's Levelization Model. The calculated levelization estimates included the impact of relevant parameters that affected the life cycle, capital and fixed costs of power generation facilities such as financing rates, debt life, project life, taxes, inflation, and other factors. Key assumptions were provided by Global Energy and the Energy Commission.

Generation

Table 2-6 shows the capital cost assumptions for the incremental generation stations that were either removed or added in the Change Cases. Since approximately the same amount of solar generation capacity was removed from California as added to northern Nevada in Change Case 2, Global Energy assumed zero incremental capital and fixed costs associated with the solar generation, precluding the need to develop cost estimates for that technology.

Table 2-6: Detailed Capital and Fixed O&M Assumptions for Incremental Generation

Key Assumptions	Gas-Fired Combined Cycle	IGCC	Wind	Geothermal
Overnight Cost (2004$/kW)	$665	$1816	$1020	$2128
Fixed O&M (2004$/kW-yr)	$11	$31	$78	$120
Construction Period (yrs)	2	5	1	2
Debt/Equity Ratio	60/40	60/40	60/40	60/40
Book Life (yrs)	30	30	20	30
Debt Life (yrs)	12	20	12	20
Depreciation Period	12	20	5	20
Cost of Equity	17.6%	17.6%	17.6%	17.6%
Cost of Debt	7.50%	7.50%	7.50%	7.50%
Amortization Style	Mortgage	Mortgage	Mortgage	Mortgage
Inflation Rate (2004-2010)	1.80%	1.80%	1.80%	1.80%
Inflation Rate (2011 – Forward)	1.73%	1.73%	1.73%	1.73%
Income Tax Rate	State & Fed	State & Fed	State & Fed	State & Fed
Property Tax Rate	1.2%	1.2%	0.0%	1.2%
Insurance Rate	0.15%	0.15%	0.15%	0.15%
Levelized Cost (2004$/kW-yr)	$102	$291	$214	$446

Source: Global Energy Decisions

Table 2-7 shows how total incremental capital and fixed costs, expressed in millions of 2004 dollars per year ($MM/Yr, 2004$) for the year 2012 were computed using the levelized cost estimates.

Table 2-7: Incremental Generation Capital and Fixed Costs per Year

Change Case 1 Incremental Generation				
	CA Incremental MW	NV/WY Incremental MW	Capital/Fixed Cost ($/kW-yr, 2004$)	Incremental Cost ($MM/Yr, 2004$)
IGCC		1,462	291	425
CCGT	-1,462		102	-149
Total	-1,462	1,462		276
Change Case 2 Incremental Generation				
	CA Incremental MW	**NV/WY Incremental MW**	**Capital/Fixed Cost ($/kW-yr, 2004$)**	**Incremental Cost ($MM/Yr, 2004$)**
IGCC		1,462	291	425
CCGT	-1,462		102	-149
Renewable*	-2,690	2,454	250	-59
Total	-4,152	3,916		218

Source: Global Energy Decisions

The $250/kW-year value for renewable generation capital/fixed costs was approximately the weighted average of incremental wind and geothermal generation between the Base Case and Change Case 2.

Transmission

Table 2-8 shows the capital cost assumptions for the three transmission upgrades that distinguish Change Cases 1 and 2. Transmission cost estimates ($/mile) were based on the transmission cost estimates included in the RMATS study. Global Energy categorized each line segment estimated in RMATS by type (AC or DC), voltage, and location and computed weighted average ($/mile) cost estimates as shown below. The construction cost estimated for the Tehachapi transmission line upgrades removed in Change Case 2 were provided by the Energy Commission and were based on a report of the Tehachapi Collaborative Study Group submitted to the California Public Utilities Commission[20] for the Tehachapi upgrades required to support new renewable generation in that area.

Table 2-8: Incremental Transmission Capital and Fixed Costs

Transmission Capital & Fixed Costs			
	Change Case 1	Change Case 2	
Key Assumptions	Transmission Case1 (DC)	Transmission Case2 (AC & DC)	CC2: CA Tehachapi T-Line
INTERIOR - Miles 500 kV AC		312	
INTERIOR - Miles 500 kV DC	690	690	
INTERIOR - Miles 230-345 kV AC	0	0	
CA Miles 500 kV AC		997	
CA Miles 500 kV DC	215	0	
CA Miles 230-345 kV AC	0	0	
INTERIOR - 2004$k/Mile/500 kV AC	$1000	$1000	
INTERIOR - 2004$k/Mile/500 kV DC	$779	$779	
INTERIOR - 2004$k/Mile/230-345 kV AC	$750	$750	
CA - 2004$k/Mile/500 kV AC	$2000	$2000	
CA - 2004$k/Mile/500 kV DC	$779	$779	
CA - 2004$k/Mile/230-345 kV AC	$1500	$1500	
Other Capital Costs ($MM, 2004$)[21]	$675	$1350	
Total Miles	905	1999	
Construction Cost ($MM, 2004$)	$1,380	$4,194	(1,260)
O&M $/Mile/year	$1,000	$1,000	
Fixed O&M ($MM-yr, 2004$)	$1	$2	(0.5)
Debt/Equity Ratio	50/50	50/50	
Book Life (yrs)	70	70	
Debt Life (yrs)	30	30	
Cost of Equity	12%	12%	
Cost of Debt	6%	6%	
Tax Rate	39.55%	39.55%	
Levelized Cost ($MM/yr, 2004$)	$104	$317	(95)
Levelized Cost % of Capital Cost	7.50%	7.50%	7.50%

Source: Global Energy Decisions

CHAPTER 3: RESULTS

Cost-Benefit Analysis Results

Global Energy's analysis indicated that California would benefit from the transmission and generation resource expansions as presented in each case study. Under the conditions presented in Change Case 1, the benefits to California were estimated at about $87 million/year, while under Change Case 2 conditions, benefits to California were estimated at about $16 million/year.

Global Energy assumed that all native generation within California would serve California load and computed the production costs for each of these units. The hourly production cost output from the MARKETSYM-LMP simulations for California generation for the Base Case and Change Cases were compared. Global Energy also accounted for remote generation contracted to California load-serving entities (generation from units such as Palo Verde, Intermountain, and others) and attributed the production and production costs of these generators to California. In each of the Change Cases, Global Energy assumed that all output from the new IGCC and new renewable generation (in Change Case 2 only) served California load and assigned the production costs of these units to California. Finally, on an hourly basis, Global Energy determined whether the difference between California load minus native California generation, and minus contracted remote generation (including the new IGCC and renewable generation mentioned above) resulted in a net import or net export for that hour. Global Energy then priced each MW of net export or net import at the hourly simple average LMP of all California interfaces based on the MARKETSYM-LMP simulation data. The cost of imports and exports were then added to the production costs for native and remote California generators to comprise the total California production costs. The change in production costs (between the Base Case and that Change Case) was then compared to the change in incremental capital and fixed costs to calculate the economic impact of each Change Case. Since all new IGCC and renewable generation in Wyoming and Nevada was assumed to be contracted to California, all incremental capital and fixed costs associated with the transmission and generation investments were attributed to California. The results of this analysis, which exclude the cost of transmission losses, are provided in Table 3-1.

Table 3-1: California Economic Benefits Analysis Results before Losses (2012$)

Scenario	(a) CA Generator Production	(b) Remote Generator Production	(c) New Generator Production	(d) Net Imports	Total Production (a+b+c+d)	Incremental Generator Capital/Fixed Costs	Incremental Transmission Capital/Fixed Costs	Net Benefit
Base Case Costs ($MM/Yr)	$9,181	$652	-	$2,085	$11,918	-	-	-
Base Case (GWh)	256,827	35,111	-	37,691	329,629			
Change Case 1 Costs ($MM/Yr)	$ 8,765	$648	$110	$1,930	$11,453	$247	$120	$97
Change Case 1 (GWh)	248,870	34,963	10,919	34,893	329,645			
Change Case 2 Costs ($MM/Yr)	$8,724	$653	$199	$1,846	$11,422	$180	$255	$60
Change Case 2 (GWh)	238,526	35,184	22,546	33,379	329,635			

Source: Global Energy Decisions

Impact of Losses - AC-OPF Analysis

Global Energy ran an AC-OPF unit commitment and dispatch model for the peak hour of each year to study the economic impact of transmission losses associated with each of the case studies. Based on this analysis, Change Case 1 would increase the cost of transmission losses throughout the WECC by $10 million/yr and Change Case 2 would increase the cost of transmission losses by $44 million/yr. The AC-OPF simulation results indicated losses as a percent of load of 3.44 percent, 3.46 percent, and 3.53 percent for the Base Case, Change Case 1, and Change Case 2, respectively. To calculate the economic value associated with the change in losses between the Base Case and each of the Change Cases, losses for the peak hour, expressed as a percentage of total WECC load, were multiplied by the WECC expected annual load of 945,000 GWh to estimate total annual losses for the WECC in each case. The increase in losses associated with each Change Case was then valued at the marginal cost of a generic gas-fired combined cycle generation unit, expressed in $/MWh, which Global Energy assumed as a proxy unit to represent the average production costs to cover losses throughout the year.[22] The results of this analysis are provided in Table 3-2.

Table 3-2: AC-OPF Analysis Results

AC OPF - Peak Hour Analysis			
	Base Case	**Change Case 1**	**Change Case 2**
WECC Load (MWh)	945,000,000	945,000,000	945,000,000
Losses (% of Load)	3.44%	3.46%	3.53%
Annual Losses (MWh)	32,508,000	32,697,000	33,358,500
Annualized Difference (MWh)		189,000	850,000
Cost of Losses ($/MWh, 2012$)		52	52
Cost of Losses ($MM, 2012$)		(10)	(44)

Source: Global Energy Decisions

Based on the AC-OPF analysis of losses, Global Energy adjusted expected benefits to California associated with Change Case 1 and 2 to $87 million/year and $16 million/year, respectively, which assumed that all incremental WECC losses were incurred by California (see Table 3-3).

Table 3-3: CA Economic Benefits w/ Losses

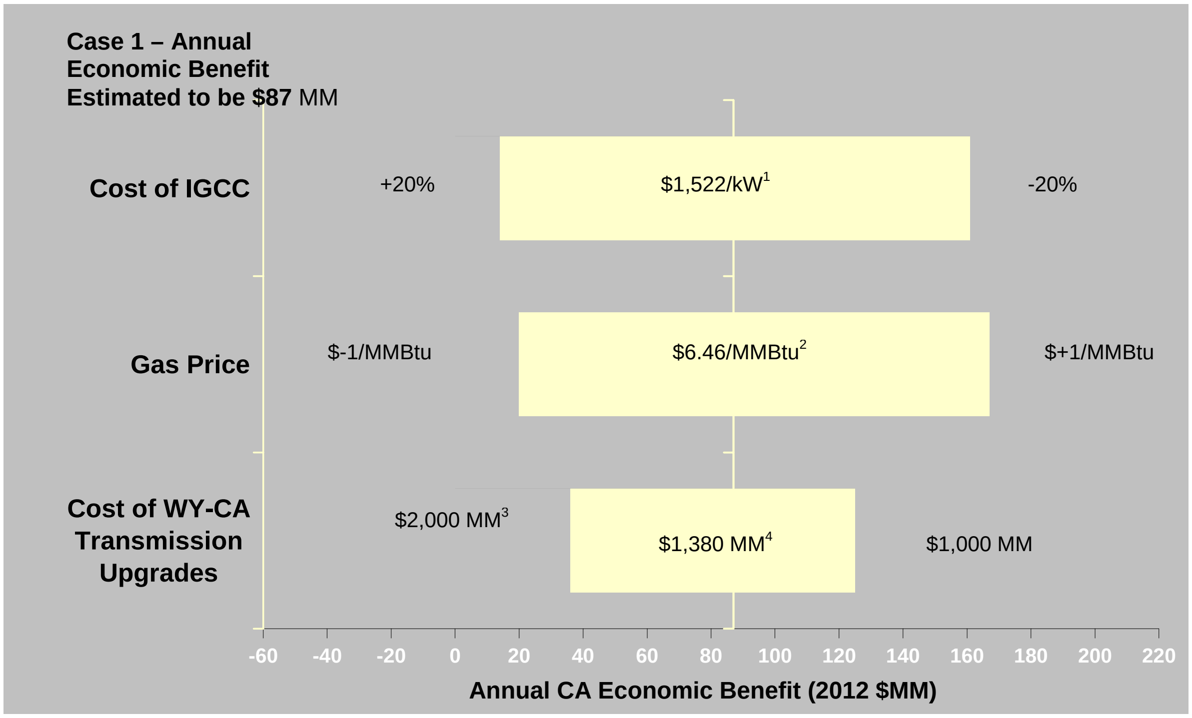
Case	**CA Economic Benefit ($2012 MM/Yr)**	**AC-OPF Analysis - Value of Losses ($2012 MM/Yr)**	**CA Economic Benefit w/ losses ($2012 MM/yr)**
Change Case 1	97	(10)	87
Change Case 2	60	(44)	16

Source: Global Energy Decisions

Input Sensitivity Diagrams

The input assumptions used for this analysis had a significant impact on the results. For this reason, Global Energy performed a sensitivity analysis to indicate how changes in certain key assumptions affect results. Figure 3-1 shows how changes in key assumptions affected Change Case 1; Figure 3-2 addresses Change Case 2.

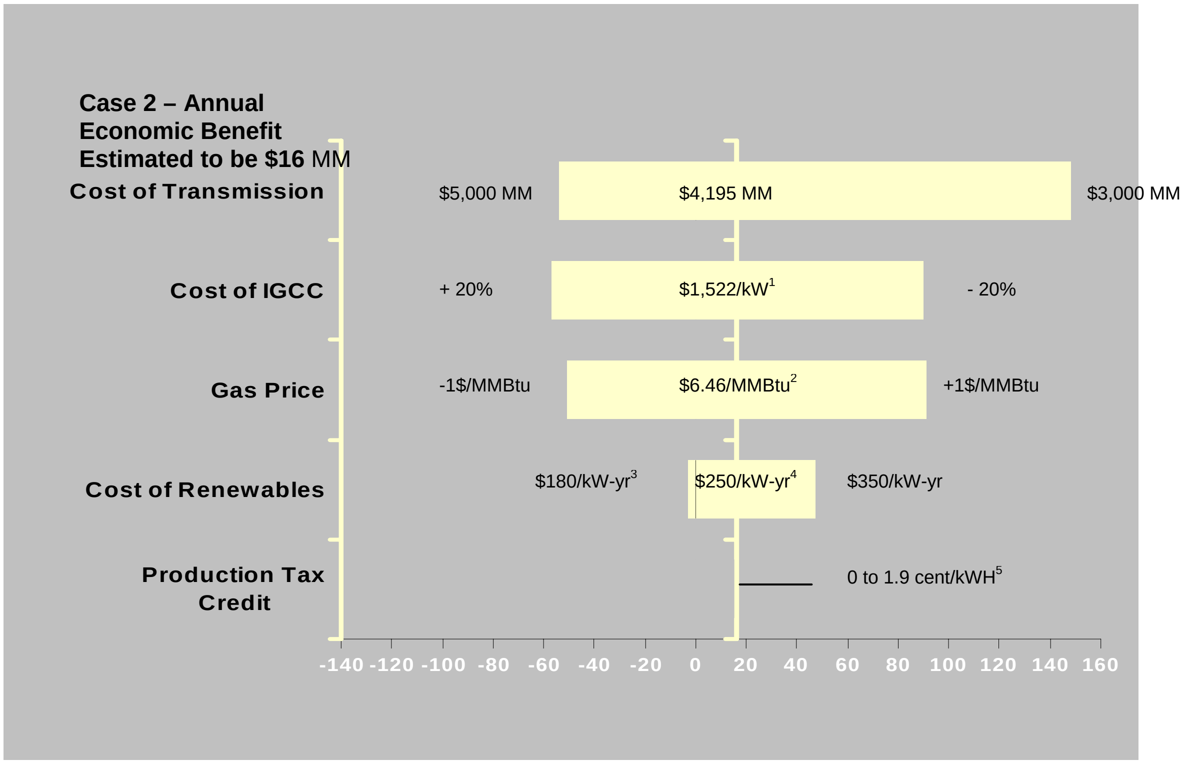
Figure 3-1: Input Sensitivity Diagram for Change Case 1



1a. GHG reduction requirements through carbon sequestration capability.
1b. Costs for carbon sequestration assumed covered by enhanced oil recovery.
1c. Annual benefits exclude any EPAct-05 financial incentives (tax credits).
2. Energy Commission September 2005 Natural Gas Forecast for PG&E in 2004$.
3. Based on $1.5 MM/mile est. + inverter/rectifier.
4. Based on $0.799 MM/mile est. + inverter/rectifier.

Source: Global Energy Decisions

Figure 3-2: Input Sensitivity Diagram for Change Case 2



1a. GHG reduction requirements through carbon sequestration capability.
1b. Costs for carbon sequestration assumed covered by enhanced oil recovery.
1c. Annual benefits exclude any EPAct-05 financial incentives (tax credits).
2. Energy Commission September 2005 Natural Gas Forecast for PG&E in 2004$.
3. Cost of wind generation.
4. Weighted average cost of wind and geothermal in Change Case 2.
5. No renewable production tax credit assumed in the analysis. The inclusion of a production tax credit would provide equal benefits in the Base Case and Change Case 2 because the volume of renewable energy generation is equal in both cases. Any benefits from a production tax credit in Change Case 2 would be offset by equal benefits in the Base Case.

Source: Global Energy Decisions

Benefits Over Time

While Global Energy studied a single year, benefits are likely to occur for multiple years beyond 2012. As an approximation of potential long-term benefits associated with the transmission and generation investments studied in each Case Study, Global Energy performed a net present value calculation from 2012 – 2025, assuming that benefits would remain at the levels estimated for 2012. Based on a discount rate of 10 percent, the NPV of benefits from 2012 – 2025 is $642 million (in 2012$) for Change Case 1 and $119 million (in 2012$) for Change Case 2, as shown in Table 3-4.

Table 3-4: Net Present Value of California Benefits

			Social Discount Rate
		NPV	NPV
Year	2012	2012-2025	2012-2041
		10% PV	5% PV
Benefits for Change Case 1 ($2012 MM)	87	642	1,340
Benefits of Change Case 2 ($2012 MM)	16	119	249

Source: Global Energy Decisions

Emissions

The change in plant CO_2 emissions for each case study was attributed to the replacement of gas-fired, combined cycle generation with the new IGCC with carbon sequestration as well as other changes in WECC economic dispatch in Change Case 1. In Change Case 2, additional renewable generation resulted in an even greater reduction of CO_2 emissions. The results showed a reduction in WECC CO_2 emissions by 3,805,000 tons in Change Case 1 and 4,220,000 tons for Change Case 2. Table 3-5 summarizes these results.

Table 3-5: Emissions Output

Case	CO_2 (1000 Tons)	Difference (1000 Tons)
Base Case	456,874	
Change Case 1	453,069	(3,805)
Change Case 2	452,654	(4,220)

Source: Global Energy Decisions

APPENDIX: DEFINITIONS OF AC-OPF AND DC-OPF

AC Power Flow modeling analysis is the most accurate method to estimate the flow on the transmission grid. AC power flow modeling is designed to calculate flows on the power grid in a manner that most accurately reflects the physical attributes of the system. Such modeling needs to compute voltage magnitude, angle, real and reactive power injections at each bus, real and reactive power flows, tap settings on tap-changing-under-load (TCUL) transformers, phase shifter settings, settings for switched shunts, and others. A power flow represents an instant in time (snapshot). Hence, it does not directly reflect time-related issues such as ramp rates, minimum up and down times, and other factors. Solution of such systems involves the application of iterative numerical techniques such as the Newton Raphson Method, which involves the computation of the well-known power flow Jacobian matrix (commonly referred to as “the power flow Jacobian”). When transmission planners run AC power flow models, they typically do not attempt to perform economic dispatch when choosing which generators to activate in any study. Transmission reliability studies are always done with AC power flow-based modeling, and load/generation assumptions are designed to stress the transmission grid for reliability study purposes rather than to accomplish economic dispatch.

AC-OPF (AC-Optimum Power Flow) modeling uses AC Power Flow equations but also incorporates modeling techniques designed to represent the most economic dispatch of resources needed to meet loads. Such generation dispatch modeling should include complex unit commitment and dispatch algorithms for generation (both for thermal plants and for hourly dispatch of available hydro generation).

Unfortunately, it is often difficulty to get AC-OPF model analysis to converge (that is, find a dispatch solution that meets all criteria). As such, modelers seek to find alternative load flow modeling techniques that are easier to model. Any such alternative technique will be trading off accuracy in modeling with ease in modeling.

DC-OPF (DC-Optimum Power Flow) is a method for estimating load flows using simplifying assumptions to reduce problem complexity. It is similar to AC-OPF based analysis except resistances are neglected, voltages are assumed to be nominal (1.0 pu), voltage issues are neglected (for example, TCUL transformers are ignored) and reactive power is neglected. Other elements, such as phase shifters, load and generators are still modeled, subject to the simplifying assumptions (for example, reactive portions of loads and generators are neglected). Another definition of DC-OPF in the industry is similar to the above, except that non-linear elements of the grid are not handled. DC-OPF analysis is not as accurate as AC-OPF analysis because of the simplifying assumptions.

Some entities define Power Transmission Definition Factors (PTDF) based transmission flow analysis as a version of DC-OPF analysis. PTDFs are a less accurate solution than DC-OPF. PTDF based analysis can provide severely misleading indications of transmission line flows. Global Energy did not use PTDFs in this analysis.

ENDNOTES

[1] California Energy Commission, September 2005, *Warren-Alquist Act*, Sacramento, CA, CEC-140-2005-001-ED2, [http://www.energy.ca.gov/2005publications/CEC-140-2005-001/CEC-140-2005-001-ED2.PDF].

[2] California Energy Commission, November 2005, *2005 Integrated Energy Policy Report*, Sacramento, CA, CEC-100-2005-007, [http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF].

[3] State of California, September 21, 2005, *Energy Action Plan II: Implementation Roadmap for Energy Policies*, [http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF].

[4] See WGA Policy Resolution 04-14, June 22, 2004, at http://www.westgov.org/wga/policy/04/clean-energy.pdf and WGA's Clean and Diversified Energy Initiative webpage at <http://www.westgov.org/wga/initiatives/cdeac/index.htm>. The Resolution defines clean energy as energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies. Also see <http://www.climatechange.ca.gov/westcoast/index.html> for information on the West Coast Governors' Initiative.

[5] Wyoming Public Service Commission, September 2004, *Rocky Mountain Area Transmission Study*, [http://psc.state.wy.us/htdocs/subregional/FinalReport/rmatsfinalreport.htm].

[6] "Memorandum of Understanding Among the Governors of California, Nevada, Utah and Wyoming Concerning Electric Transmission Development," April 4, 2005, http://www.westernroundtable.com/energy/Frontier_Line_MOU_Final.pdf

[7] The five Subregional Planning Groups in the Western Interconnection are the Colorado Coordinated Planning Group, The Northwest Transmission Assessment Committee, the Rocky Mountain Area Transmission Study Group, the Southwest Transmission Expansion Plan group, and the Southwest Area Transmission Group.

[8] For example, after Global Energy initiated this work, Arizona Public Service announced its TransWest Express Project, consisting of two new AC or one new DC transmission line from Wyoming to Utah, northern Arizona, and southern Nevada that would provide access to coal and wind resources in Wyoming. Although the project does not terminate in California, it would meet many of the same objectives of Change Case 2 in that it appears to use similar transmission corridors and it achieves the objectives of access to Wyoming wind and coal, improvement in fuel diversity, and improvement in Western transmission grid reliability. For more information see http://www.frontierline.org/summit/presentations/Wheeler.pdf.

[9] Global Energy's approach relied on two widely accepted industry standard models: Global Energy's MARKETSYM zonal production cost model and PowerWorld Simulator. Powerworld Simulator is developed and owned by the Powerworld Corporation. The combined system and their associated databases are referred to as MARKETSYM–LMP.

[10] The figures for WECC and California annual demand are estimations based on the total GWh for four weeks simulated in 2012.

[11] California Energy Commission, September 2005, *Revised Reference Case In Support of the 2005 Natural Gas Market Assessment*, Sacramento, CA, CEC-600-2005-026-REV, [http://www.energy.ca.gov/2005publications/CEC-600-2005-026/CEC-600-2005-026-REV.PDF].

[12] The NARG-MB model, developed and owned by Altos Management, is licensed by the Energy Commission and was the model used by Energy Commission Staff to develop the *Revised Reference Case In Support of the 2005 Natural Gas Market Assessment* issued in September 2005 (CEC-600-2005-026-REV).

[13] Energy Information Administration, *Annual Energy Outlook 1997* through *Annual Energy Outlook 2004*, DOE/EIA-0383(2004), [http://www.eia.doe.gov/oiaf/archive/aeo04/pdf/0383(2004).pdf].

[14] See [http://www.ferc.gov/docs-filing/eforms/form-423/overview.asp#skipnavsub].

[15] Global Energy Decisions, Fall 2004 Power Market Advisory Service, Electricity and Fuel Price Outlook, WECC Fall 2004, Page 2-23.

[16]In Change Cases 1 and 2, Global Energy removed five new, generic CCGT units that were originally included in the Base Case database. The combined capacity of the five units is actually 1,462 MW. 1,462 MW of new IGCC capacity replaced these five units. We refer to this incremental capacity approximately as 1,500 MW in parts of this document.

[17] Energy Policy Act of 2005, August 8, 2005, Title IV – Coal, Subtitle A – Clean Coal Power Initiative, Go to http://thomas.loc.gov, then type in “HR6,” check “Bill Number,” and then click on Search.

[18] State of California, September 21, 2005, *Energy Action Plan II: Implementation Roadmap for Energy Policies*, [http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF]. See Research, Development and Demonstration Key Action #6, p. 12.

[19] All wind O&M costs were included in the Fixed O&M estimate.

[20] California Public Utilities Commission, Report of the Tehachapi Collaborative Study Group, “Transmission in the Tehachapi Wind Resource Area”, March 16, 2005, OII 00-11-011, page 14.

[21] Includes the cost of DC inverters and rectifiers.

[22] The generic gas-fired combined cycle marginal cost was estimated at 2012$52/MWh based on a heat rate of 7,000 Btu/kWh and an annual average gas price of 6.46 2004$/MMBtu and converted to $2012.