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March 2002 • Discussion Paper 02–14

RESOURCES FOR THE FUTURE

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Abstract

Planning of the electricity transmission system generally focuses on the pros and cons of providing generation close to the source of the power demand versus remote generation linked via the transmission system. Recent electricity supply problems in the western United States have renewed interest in the role of transmission in assuring the reliability of electricity supply. Recently, the Western Governors' Association led the development of a planning exercise that examined the tradeoffs over the next 10 years between locating new natural gas powered generation close to the load centers versus new coal, wind, hydro, and geothermal generation in remote areas. Although the analysis concentrated on the direct system costs, the choice of new generation will have both local and global environmental impacts. This paper examines some of the "ancillary" environmental effects of electricity transmission decisions using a suite of models that combine to provide an integrated assessment.

Key Words: electricity, transmission, air pollution, ancillary benefits, nitrogen oxides, sulfur dioxide, carbon dioxide

JEL Classification Numbers: L94, Q25, Q41

Contents

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Introduction

The value of the transmission system is usually characterized as the value to an electric utility of moving electricity from their generators to their customers. However, the emerging interest in the potential role of distributed generation—locating generation close to the demand and often independent of the transmission grid—along with a variety of other economic and social concerns have cast the role of transmission in a new light.

Historically, the most common justification for investments in transmission has been the possibility of obtaining inexpensive surplus power from distant locations and transporting the power to load centers. Since the 1960s, the value of transmission to the reliability of the electricity system has been recognized. An expanding list of benefits are associated with transmission, including assurances against the exercise of market power in competitive wholesale power markets, the provision of ancillary services, the opportunity to maintain diversity of fuels in meeting electricity demand in various regions and maintenance of energy security.

Traditionally, environmental concerns have been relevant to decisions about transmission investments only insofar as they provide obstacles to siting. The main environmental concern surrounds obtaining easements and protecting the environmental integrity of the physical location of transmission paths. There also is concern about longterm exposure to electromagnetic forces that may affect the health of individuals in the immediate proximity of transmission.

Decisions in the past have usually ignored the role of transmission policy and siting in meeting environmental goals related to the impacts of electricity generation. Electricity

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generation accounts for approximately 40% of carbon dioxide (CO_2) emissions, 25% of nitrogen oxide (NO_X) emissions, 33% of mercury emissions and 67% of sulfur dioxide (SO_2) emissions in the United States. These emissions are dramatically affected by the choice of fuel and technology that is used for electricity generation. As importantly, the effect of emissions on the environment and public health are greatly dependent on the timing and location of emissions. Fuel and technology choice, timing of and location of types of generation are strongly influenced by the availability of transmission. Hence, the availability of transmission service plays a central role in determining the profile of emissions from the electricity sector and in determining whether and how environmental goals will be achieved.

In addition to the environmental implications of different transmission scenarios, the issue of cost adds another dimension to the generation planning equation. The tradeoffs between capital and operating costs have always been at the center of generation planning. The largest component of the operating cost for a generator is usually the fuel cost. Hence, the tradeoff is often viewed as choosing a low-cost fuel with a high-cost plant (for example, a steam turbine using coal as fuel) compared to low cost plant with a potentially high cost fuel (for example, a gas turbine using natural gas as fuel). More recently, this debate seemed to be resolved, with the expectation that the choice of natural gas provides both a low fuel cost and low facility cost. However, recent volatility in the natural gas market, which saw spikes to all time highs of $58 per million Btu, showed the risks involved in moving towards a single-fuel generation policy. Transmission adds other elements to the planning process because it is capital intensive and has a long lead time, yet provides value to both generation that is close to the load—in that it allows the sale of excess power—and to remote generation by providing the necessary link to the load.

The modeling of transmission is very complicated. Nonlinear relationships about the location of generation and demand on the transmission grid, plus the requirement of ancillary balancing services on the grid, make transmission modeling a difficult mathematical exercise. Also important is the distinction between the capacity of a transmission line, which is simply a measure of the throughput of the wire, and the capability of a transmission line, which is a measure of how much electricity a line can support within the context of system dynamics.

Electricity Transmission in the West

The electricity transmission grid in the region that includes the states of Washington, Oregon, California, Montana, Wyoming, Utah, New Mexico, Arizona, Colorado, Nevada, and Idaho, faces a number of unique issues because of its generation capacity, location of load centers, and geography. The current generation is characterized by base-load coal in the eastern part of the western region, natural gas and nuclear in the western part, and a growing amount of renewables in the form of wind and geothermal that are often located away from the load centers. The electricity loads are also diverse, with the colder northwest seeing peak loads in the winter while the warmer southwest sees peaks in the summer months. Geography also plays a role in transmission siting as the West contains the highest mountains in the United States, as well as its largest deserts and sparsely populated plains.

To investigate questions about what transmission enhancements might be needed, the Western Governors Association recently sponsored a modeling exercise to examine future scenarios in the year 2010 for the western states (Western Governors Association, 2001). The study developed two "bookend" scenarios to bracket the range of plausible transmission needs over the next decade. In one scenario that is labeled the "Gas" scenario, it is assumed that new generation is fueled with natural gas and is located near the load centers. Consequently, there would be less congestion on the transmission system and lower investment values in new transmission lines in this scenario.

The other scenario is labeled "Other Than Gas (OTG)," in which there is substantial new investment in transmission and concomitant development of new coal, wind, hydro, and geothermal generation. These sources are assumed to be in areas remote to load centers and therefore would lead to greater use of the transmission system. The new capacity additions for each scenario are shown in Table 1.

Both scenarios took as a baseline a forecast of incremental investment in new transmission capacity that would be added to the western system by 2004, and expected to cost $2.1 billion (2010 dollars). Little new investment in transmission was needed to support the 2010 Gas scenario; however, about $8 billion to $12 billion of investment in new transmission was needed to support the 2010 OTG scenario. The assumed amounts of transmission path capacity under each scenario is presented in Table 2. The Gas scenario included new transmission to interconnect Canadian gas-fired generation with the United States, as well as between the Four Corners, Phoenix, and Marketplace to support additional gas fired generation in Arizona, Colorado, and New Mexico. In the OTG scenario, about half of the new generation was added in remote areas and thus a significant amount of new transmission capacity was necessary. In addition, the OTG scenario included new 500 kV transmission lines in three major corridors that connected the transmission-constrained central and eastern areas to both the northern and southern transmission hubs that bring power in to California (WGA, 2001).[1]

Table 1: WGA 2010 New Capacity Estimates

Capacity (MW)	**Gas Scenario**	**OTG Scenario**
Gas	46,345	24,744
Coal	80	18,010
Hydro	762	2,362
Wind	487	4,167
Geothermal	100	1,500
Other	770	770
Total	48,544	51,553

Source: WGA, 2001.

To predict electricity generation under each scenario, the WGA used the Market Assessment and Portfolio Strategies (MAPS) model. MAPS is a complex model that simulates electricity market behavior on an hour-by-hour basis subject to the transmission constraints on the system. Generation is modeled as a least-cost dispatch while the transmission module tracks individual flows and obeys real limits.

The major result of the WGA study for the baseline case was that fuel savings of about \$4.3 billion occurred in the OTG scenario, which resulted from using coal at an average cost of \$0.73 per million Btu versus gas at an estimated cost of \$4.68 per million Btu. Since, it was recognized that the resulting fuel savings would be sensitive to the costs of coal and natural gas in the future and the availability of low cost hydro power, several additional scenarios were constructed to show the impact of key parameters on estimated savings. However, it was beyond the scope of the WGA study to examine the environmental implications of new electricity transmission.

[1] The new transmission estimates were made by a Transmission Working Group which was cochaired by Jack Davis, president of Pinnacle West Capital Corporation and Marsha Smith, commissioner for the Idaho Public Utilities Commission.

Table 2. WGA Transmission Options

	Existing Transmission	2004 Baseline	2010 Gas Scenario	2010 OTG Scenario
Capacity (MW)	87,934	94,272	102,332	122,052
Incremental Costs: Total (billion, 2001 dollars)		$1.259	$1.751	$6.959
Incremental Costs: Dollars/kW-Year (2001 dollars)		$21.07	$23.05	$27.57

Source: WGA, 2001.

Modeling the Environmental Impacts of Transmission in the West

Environmental impacts of new transmission will be driven largely by fuel choice—that is, the choice of gas, coal or renewables, and by the location of the generation facility. The location of electricity generators becomes important when one considers the environmental pathways whereby emissions are translated into impacts on the environment and society. There are a variety of environmental pathways and endpoints that may be affected by the availability of transmission, because of the role of transmission in influencing the choice, location, and timing of electricity generation. Comprehensive fuel cycle studies have attempted to quantify these relationships and they find that by far the most important of the problems that have been quantified is the relationship between air pollution and human health (Lee et al.,1995; Hagler Bailly, 1995; European Commission, 1995). Among environmental pathways that have not been quantified and valued meaningfully, clearly the contribution of greenhouse gases from electricity generation is the most significant, again pointing to air pollution as the major environmental impact of electricity generation. Consequently, we focus exclusively on the effect of investments in transmission on the profile of emissions of air pollutants.

To examine the environmental impacts of the WGA transmission scenarios, we use a suite of models that combine to provide integrated assessment. The Haiku model is used to simulate electricity generation capacity and generation. Changes in emissions that result from policy experiments are fed into an integrated assessment model of atmospheric transport and environmental effects called the Tracking and Analysis Framework (TAF).

The Haiku electricity model simulates equilibrium in regional electricity markets and inter-regional electricity trade with an integrated algorithm for pollution control. The model endogenously calculates electricity demand, electricity and fuel prices, the composition of electricity supply, inter-regional electricity trading activity among 13 NERC subregions, and emissions of key pollutants such as NO_X, SO_2, CO_2, and mercury from electricity generation. Electricity demand is represented through three customer classes (residential, industrial, and commercial). Detailed demand functions are provided and supply curves are estimated for four time periods (super-peak, peak, shoulder, and base-load hours) in each of three seasons (summer, winter, and spring/fall combined). Investment in new generation capacity and retirement of existing facilities are determined endogenously, based on capacity-related costs of providing service in the future ("going forward costs"). Generator dispatch in the model is based on minimization of short run variable costs of generation.

Inter-regional power trading in Haiku is identified as the level of trading necessary to equilibrate regional electricity prices (accounting for transmission costs and power losses). These inter-regional transactions are constrained by the assumed level of available inter-regional transmission capability as reported by NERC regions. Factor prices such as the cost of capital and labor are held constant. Fuel price forecasts are calibrated to match EIA price forecasts for 2000 (U.S. EIA 1999). The model includes fuel market modules for coal, natural gas, oil, and biomass that calculate prices that are responsive to factor demand. Coal is differentiated along several dimensions, including fuel quality and location of supply, and both coal and natural gas prices are differentiated by point of delivery. All other fuel prices are specified exogenously, with most changing over time.

The algorithm for compliance with emissions constraints in Haiku solves for the least costly set of post-combustion pollution control investments. The variable costs of pollution controls plus the opportunity cost of emission allowances under cap and trade programs are added to the variable cost of generation. The post-combustion controls that can be selected for NO_X emissions are selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). We have also tried a hybrid control that combines SCR and SNCR, and we find that it is never selected as a compliance option. The primary control options for SO_2 include switching among coals with varying sulfur content and installation of scrubbers (or flue gas desulfurization).

Under each scenario, the changes in generation capacity and transmission capability forecast by the WGA were imposed in the Haiku electricity market model. In addition, the forecast of electricity demand by region (especially, in the West) was imposed in the model. Fuel prices were fixed to the levels forecast by WGA, with the price of natural gas equal to $4.68 per million Btu throughout the western region. The model was then allowed to solve for least cost of operation of capacity. Following the WGA, we assume the three NERC subregions in the western states operate under regulated prices (average cost pricing), although in a few other regions of the country we assume prices are set according to current commitments to deregulation. However, electricity imports from Canada are parametrically specified, so the portion of transmission investment dedicated to improving cross-border transmission is not reflected in the study.

The changes in emissions of NO_X and SO_2 that result from electricity generation under the transmission scenarios are fed into the Tracking and Analysis Framework (TAF), a nonproprietary and peer-reviewed integrated assessment model (Bloyd et al. 1996). TAF integrates pollutant transport and deposition (including formation of secondary particulates but excluding ozone), visibility effects, effects on recreational lake fishing through changes in soil and aquatic chemistry, human health effects, and valuation of benefits. We assume that PM 2.5 is about 51% of PM10, and that PM10 is about 55% of total suspended particulates. All effects are evaluated at the state level and changes outside the United States are not evaluated. We report annual health-related impacts, which are the lion's share of quantifiable impacts according to previous papers (Krupnick and Burtraw 1996; Burtraw et al. 1998).

Changes in health status are predicted to result from changes in air pollution concentrations. Impacts are expressed as the number of days acute morbidity effects of various types last, the number of chronic disease cases, and the number of statistical lives lost to premature death, based on concentration-response (C-R) functions found in the peer-reviewed literature. The C-R functions are taken, for the most part, from epidemiological articles reviewed in EPA's Criteria Documents that serve as the scientific foundation for establishment of the national air quality standards, and that appear in key EPA cost-benefit analyses, such as the EPA Section 812 prospective and retrospective studies (USEPA 1997; USEPA 1999). The health effects module contains C-R functions for PM10, TSP, SO_2, sulfates (SO_4), nitrogen dioxide (NO_2), and nitrates (NO_3). In this paper, we examine changes in concentrations resulting from changes in emissions of both NO_X and SO_2. It should be recognized, however, that, due to the cap on aggregate SO_2 at the national level, emission changes in the western region will be offset by changes outside the region. The change in the location of emissions is a factor in their ultimate impact on public health and the environment. We only account for changes in the region in the results presented below.

A variety of mortality concentration-response functions are available in the model using inputs that consist of changes in ambient concentrations of NO_X and SO_2, and demographic information on the population of interest. For morbidity, changes in NO_2, NO_3, SO_2, and SO_4 are modeled according to a scheme designed to avoid double counting of effects—such as symptom days and restricted activity days—using a variety of studies from the literature. NO_X is included for respiratory symptom days, eye irritation days, and phlegm days. For mortality, we assume SO_4 is distinct and it is associated with relatively greater potency than other constituents of PM10, while NO_3 is characterized as ordinary PM10. The change in the annual number of impacts on each health endpoint is the output that is valued.

The health valuation sub-module of TAF assigns monetary values taken from the environmental economics literature to the health effects estimates produced by the health effects module. The benefits are totaled to obtain annual health benefits for each year modeled.

Model Results

Our estimates of the annual social costs of electricity expansion in the two WGA scenarios labeled Gas and OTG are shown in Table 3. Capacity-related costs reflect the annual capital cost, calculated by Haiku, of the changes in generation capacity specified by the WGA for each scenario. We find the Gas scenario would incur $277 million dollars more generation-related capital cost per year than the OTG scenario. As in the WGA study, the largest impact on costs is due to the fuel expenditures. We find the Gas scenario would incur fuel costs that are $2.7 billion greater than the OTG scenario; however, this difference is somewhat smaller than the difference forecast by WGA. The transmission capital cost reflects the annual cost for the investments in expanded transmission, using the low-end of the estimates in the WGA study because the study suggests technological developments point in this direction.

The NO_X PM-health externality estimate in Table 3 is reported separately from the SO_2 PM-health estimates because the SO_2 changes will be offset to some degree by changes outside the western region. Only the difference between scenarios is relevant, because the epidemiological and economic benefit functions in TAF are only valid for relatively small changes in health status, so we do not report externality estimates individually for each scenario. We find the Gas scenario leads to a $152 million reduction in health effects from NO_X and SO_2 compared to the OTG scenario. Compared to the direct economic costs of electricity supply, this estimate is relatively small. However, we emphasize that it does not include a number of environmental endpoints that could be important in the western states, including the role of NO_X reductions in reducing ground-level ozone, improving visibility, and reducing nitrogen and sulfur deposition to ecosystems. Also, the choice of parameter values in the estimate is uncertain. We chose values that represent our best understanding of the literature and are in the middle of those suggested by the literature. However, the EPA has chosen values in recent studies that could lead to estimates of health damage from air pollution that are four-fold or more greater than the estimates we calculate (Burtraw, Bharvirkar, and McGuinness, 2002).

Table 3: Annual Social Costs in the Western States in 2010

(million, 1997 dollars)	**Gas**	**OTG**	**Difference (Gas – OTG)**
Capacity	2,600	2,340	277
Fuel	13,030	10,296	2,739
Transmission capital	156	621	-465
NO_X PM-health Externalities			-26
Subtotal			2,525
SO_2 PM-health Externalities			-126
Carbon @$25/tonne			-398
Total			2,001

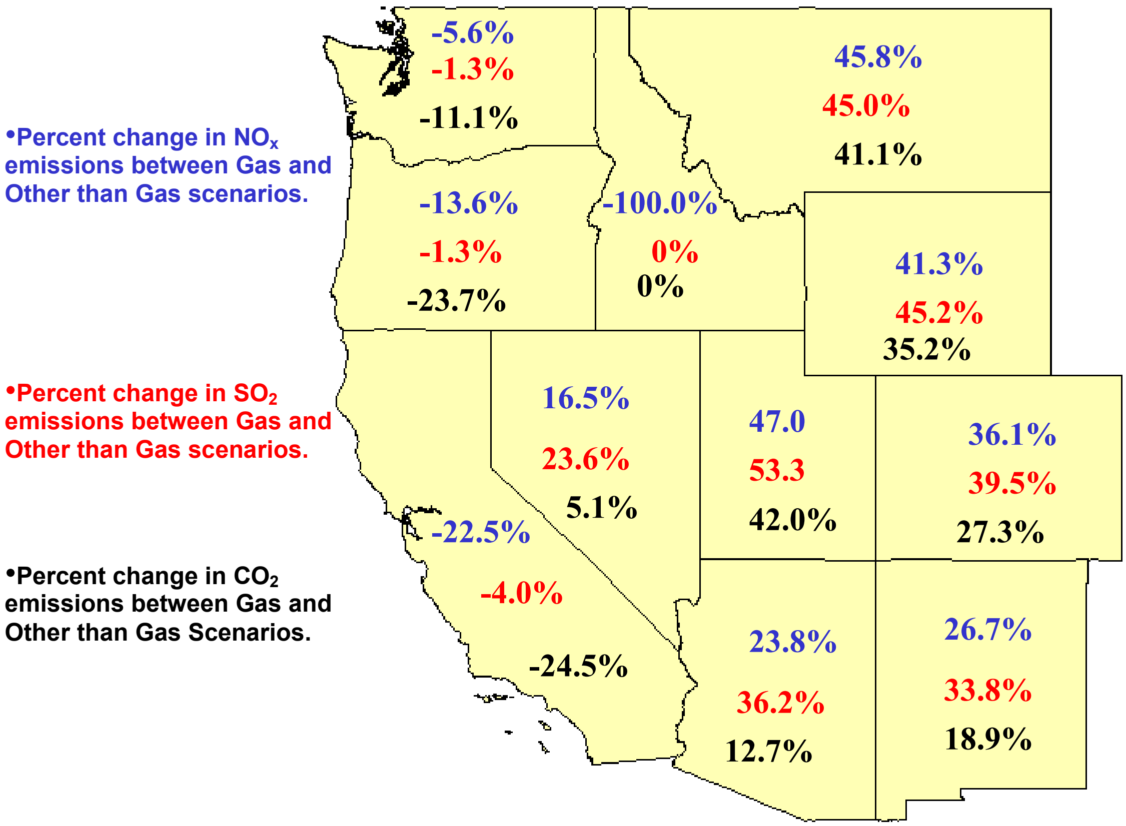
A surprising result in Table 3 is the estimated cost of increased carbon emissions. Using a carbon emissions value of $25/metric ton, the OTG scenario amounts to $398 million in greater costs than the Gas scenario. This value could be viewed as the cost of obtaining offsets under a nationwide carbon-trading program. For example, Burtraw et al. (2001) find that $25 per metric ton of carbon would be the cost in 2012 of achieving a modest (6%) reduction in carbon emissions from the electricity sector, and similar values have been obtained by other studies. This is about 2.6 times the cost of NO_X- and SO_2-related health impacts alone and shows the importance of future carbon policies on the estimation of overall costs and benefits of electric power in the West. A larger commitment to carbon reductions could yield much greater costs associated with the increase in emissions that would result under the OTG. However, it is important to note that the bottom line advantage seen for the OTG scenario does not change, given our assumptions, and shows potential savings in 2010 of just over $2 billion (1997 dollars) after accounting for major air emission-related costs, including a carbon control policy.

The impacts of the two WGA scenarios vary from state to state. Those differentials are shown, by state, in Figure 1. Here it is seen that Washington, Oregon, and California show decreased emissions while all the other states in the western power grid show increased environmental emissions. The state showing the largest percent increase in the emissions of NO_X, SO_2, and CO_2 was Utah, which was closely followed by Montana and Wyoming.

When interpreting the scenarios, it is important to remember that the results are dependent on a number of highly uncertain parameters, in addition to the measure and valuation of health effects, or the future costs of coal and natural gas. For example, renewable resources such as wind have significant environmental advantages but are intermittent and cannot be dispatched in the same manor as fossil-based systems, hydro power can be impacted by seasonal changes in precipitation, coal is subject to potential future environmental controls while natural gas has been shown to be subject to extreme price volatility. In addition to these resource-related uncertainties, there is the issue of future electricity price changes that are being seen resulting from market restructuring.

One way to examine the impacts of these and other uncertainties is to run the Haiku electricity model utilizing all of its base assumptions with the exception of the available new transmission capability. Significant differences in our base Haiku assumptions and those for the WGA report include lower gas prices (we use EIA projections which showed 15% lower coal costs and 12% lower gas costs in the west), the transition to competition in California, demand that is responsive to changes in electricity prices, and changes in generation capacity that is optimized to match available transmission capability. The results of running Haiku in 2010, given the WGA assumptions about transmission capacity for both the Gas and the OTG scenarios, but otherwise allowing Haiku to determine other variables, are shown in Table 4.

Figure 1: Emission Changes in 2010 Resulting from Transmission Expansion



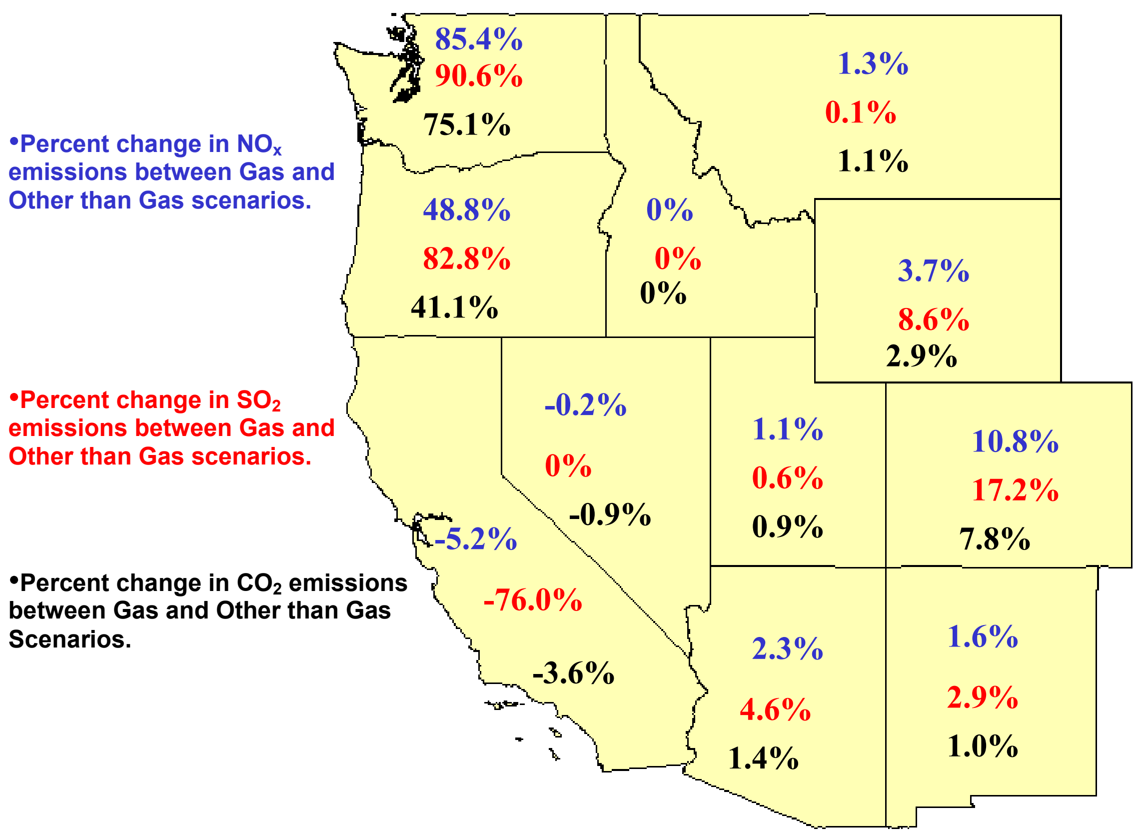
Several surprising results are seen in the Haiku analysis. Overall, the WGA assumptions yielded a $2 billion advantage for the OTG scenario but under the Haiku base case assumptions the scenario yielded $284 million in greater costs. It also is interesting to note that wind capacity was more then doubled under the economic dispatch conditions of the Haiku simulation than the OTG scenario in the WGA study. Since there are no significant differences in the fuel use (or, in other words, generation mix) between the two scenarios, Haiku assumptions yield relatively fewer ancillary benefits and savings in fuel expenditures. Consideration of the cost of offsets for carbon emissions would further exacerbate the relative cost of the modeled expansion in transmission capability. Hence, under the Haiku assumptions, we find that the additional investment for expanding the transmission capability would not benefit the western states.

Table 4: Haiku 2010 Projected New Capacity & Social Costs

	Transmission Scenario		
	Gas	**OTG**	**Difference (Gas – OTG)**
Capacity (MW)			
Gas	40,789	41,156	-367
Coal	3,278	3,317	-39
Wind	9,064	8,434	630
Other	1,076	1,273	-197
Total	54,200	54,180	20
Cost (million 1997$)			
Capacity	6,797	6,712	85
Fuel	8,409	8,240	169
Transmission	156	621	-465
NO_X PM-health Externalities			-2
Subtotal			-213
SO_2 PM-health Externalities			-30
Carbon @$25/tonne			-41
Total Cost			-284

The changes in emissions in 2010 resulting from the transmission expansion as forecast by the Haiku analysis are shown in Figure 2. Dramatic changes in forecast emissions are seen when the results shown in Figure 2 are compared with the WGA assumptions in Figure 1. A comparison of the two figures shows that when new plant construction was chosen via regional least-cost calculations, new gas-fired facilities were constructed closer to the load, despite the availability of additional transmission lines. Thus, in the Haiku modeled case, we saw emissions in Washington and Oregon increase significantly while the interior states (Montana, Wyoming, Colorado, and Utah) showed significant decreases when compared to the WGA study.

Figure 2: Haiku Forecast Emission Changes in 2010 Resulting from Expansion of Transmission



Conclusions

In the past, questions concerning the expansion of electricity transmission were relegated to state public utility commissions and the generation companies operating within their borders. However, recent electricity delivery problems that have occurred on both coasts of the United States have shown that, indeed, the electricity transmission system should be better thought of as a critical infrastructure element to the U.S. economy. The failure of that infrastructure has been shown to be costly. Estimates suggest the 2000-2001 California blackout increased wholesale electricity prices by as much as $20 billion (California Energy Commission, 2001). This is in addition to the indirect costs to businesses, which are themselves estimated to be in the billions of dollars.

If we view the transmission system as a critical element of the national economic infrastructure, the question is how planning to strengthen the system can properly include all the costs and benefits that may accrue as a result. This paper has utilizes computer models initially developed for the integrated assessment of national air quality issues associated with the electric utility sector to gain insights into the potential impacts of environmental emissions related to different transmission system expansion scenarios. The starting point for our study is a study done at the request of the Western Governors' Association on alternative electricity transmission options for the west.

In conducting our analysis, we utilize our models under the assumptions of the Western Governors' report, as well as the baseline assumptions from other federal agencies. We find that the availability of additional transmission capability has significant impacts on the emissions of NO_X, SO_2, and CO_2 in the western United States under both sets of baseline assumptions. However, the choice of the baseline assumptions (such as fuel prices, generation expansion plans, competitive markets, etc.) have a larger impact on overall system costs than that of the transmission expansion plans.

Our analysis also suggests that, although the impact of future carbon policies should be an important cost consideration (and are potentially greater than our valuation of the costs of conventional emissions), they are not large enough to rule out the role of high carbon fuels (such as coal) in the future generation mix. What is important is that planners agree upon a potential value of future carbon-based emissions so that informed decisions can be made on the use of high carbon fuels as part of our mix of generation fuels.

Overall, our analysis suggests that the WGA "bookend" cases are indeed just that, and an intermediate investment in electricity transmission is preferable. The results also suggest that existing transmission capability is not fully constrained, especially in the WGA OTG scenario. We also see that, although environmental costs seem to be small, the potential carbon-related impacts are double that of health-related impacts. Although we feel that fuel costs are very important, the overall value of transmission additions in the West remains uncertain. The analysis illustrates the importance of considering the potential impacts of changes in environmental emissions, and the value of an integrated assessment that includes broader boundaries for both costs and benefits, when considering alternative transmission expansion policies.

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