Climate Change Mitigation Policy and Energy Markets: Cooperation and Competition in Integrating Renewables into Deregulated Markets

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Abstract: In the last ten years the electricity sector has undergone a comprehensive restructuring. This process has transformed a vertically integrated industry into a balkanized market with complicated interactions between regulated and unregulated firms, private companies and public institutions. At the same time, GHG reduction policies have multiplied the regulatory requirements with which electric companies need to comply. In this paper we analyze the characteristics of the restructured energy markets and the characteristics and evolution of renewable portfolio standards (RPS) in California. Through a case study, we analyze the issues that arise when a municipal energy company is required to transport renewable energy across another firm's transmission assets to meet its RPS. We conclude that current institutions are not fully addressing the inherent problems of integrating renewables into restructured markets.

1. Introduction

The energy sector, despite active efforts toward deregulatory restructuring, remains a highly regulated and quasi-competitive sector. As a sector, there exist three main functions, namely generation, transmission and retail distribution. Regulatory restructuring has only really deregulated generation, while simply reregulating transmission and retail to accommodate the changes in generation. This was necessary because of the scale economies inherent to the industry (Joskow and Schmalensee 1983; Joskow 1998; Wilson 1998). As a result of the regulatory changes, there have been voluminous additions to the scholarly literature pertaining to energy markets and competitiveness and efficiency. One interesting subset to this literature, is the intersection between environmental regulation and energy markets. This subset of literature advances theories of political economy inherent to energy markets, and suggests that environmental regulatory efforts, including market-based institutions, may actually impugn the efficiency of the product market itself.

This political economy literature builds upon the work of Stigler (1968), who suggests that barriers to entry may result from alterations to the market environment, such as changes in cost or regulatory regime. This sort of environmental regulatory intervention may fundamentally alter the natural competition that exists between firms. One naturally then questions the impact these effects have on extant industrial organization, such as market power or other anti-competitive behavior. More recent scholarship has suggested that environmental regulation can change the cost structure of product markets, such as energy, and exacerbate the already prevalent economies of scale inherent to the industry (Heyes 2009). Theories of scale economies would suggest that larger firms, who may hold market power, are less adversely affected by environmental regulations by virtue of their size and impact on the product market, as compared to smaller fringe firms. This line of literature builds upon Salop and Scheffman (1983), who suggest that firms may seek to raise their rivals' costs to gain dominance in a market, or firmly entrench their monopoly. Other scholars have suggested that environmental regulations, because of the nature of scale economies, increase the natural concentration of industry within the product market (Dean *et al*. 2000; Helland and Matsuno 2003; Kohn 1998).

The effect of emissions markets on the industrial organization of energy markets has also been analyzed. Hahn (1984) has suggested that emissions markets can exacerbate the extant monopoly or oligopoly position of dominant firms in energy markets. Similarly, Misiolek and Elder (1989) have suggested that anticompetitive behavior in emissions markets can lead to exclusionary manipulation in the product market; when a monopolistic firm influences the market in such a way as to exclude new entrants or gain market share. And, building upon the work of Salop and Scheffman, Sartzetakis (1997) has argued that pollution permits markets may serve to raise costs to rivals in common product markets, and Von der Fehr (1993) has argued that emissions permits can be used strategically for predatory or exclusionary purposes by dominant firms.

This line of inquiry motivates this paper. As energy markets in industrialized nations move closer toward deregulatory institutions, they are confronted with difficult problems of climate change and constrained resources. National and sub-national governments are developing newer institutions to mold and alter these deregulated markets, such as transferable property rights markets and renewable portfolio standards. We introduce a specific case of cross-jurisdictional competition and renewable resource acquisition for the City of Los Angeles.

To comply with a renewable portfolio standard, the City of Los Angeles is pressured to acquire geothermal energy from outside its service area. The Southeastern deserts of California, which have been identified as one of the nation's most promising locations for renewable development, require the transmission of that energy across a competing firm's transmission lines and service area. In delivering these important renewable resources to its demand centers, the City of Los Angeles is experiencing a dilemma that is inherent to the interrelationship between energy markets and environmental regulations. Market distortions result from the requirement to increase the use of renewables, while their use also requires that the city overcome significant geographic, environmental and social hurdles along the way. The current market is an odd amalgam of private and public ownership, and regulated and deregulated sectors, in which firms are asked to cooperate in building the very markets on which they are forced to compete. The case of Los Angeles is illustrative of the larger problem of integrating renewable resources into restructured energy markets, which is relevant to US markets, as well as restructured markets in the European Union and other foreign nations.

Section 2 of this paper will begin with a general discussion of US energy markets, classifying them by their structure. Section 3 will provide a detailed discussion of California's energy markets, with respect to that classification, and will elaborate on the fundamental aspects of the market, including wholesale markets, transmission markets, property rights issues, and pricing. Section 4 will then provide the details of California's renewable portfolio standard, with an analysis of its impact on California's energy markets. We then introduce the case of Los Angeles' integration of a renewable portfolio standard in section 5, and analyze the market distortions that result from this regulation. Section 6 introduces some of the collaborative efforts California's policymakers are pursuing to minimize these distortions, and section 7 concludes.

2. US Energy Markets- Structure and Form

Contemporary energy markets are vast and complex, perhaps the most complicated sector of any macroeconomy. Some energy economists have even suggested that energy markets are so complex, that standard economic logic borrowed from other types of markets, such as agriculture or manufacturing will lead to incorrect conclusions when applied to energy (Joskow and Schmalensee 1983). Given the nature of these complications, it is perhaps more appropriate to classify energy markets by class of market structure, so that generalizations can be made. This will enable us to speak more broadly about them in relation to the effect that environmental regulations have on energy markets.

All energy markets must consist of at least three primary functions: generation, transmission and distribution, and retail delivery. Generation consists of the production of energy at the generator, power plant, or renewable facility. Once generated, that energy must be transported from the generator to the wholesale marketplace or user, on a system grid. Retailers, usually regulated utilities or publicly owned firms and cooperatives, purchase energy at the wholesale marketplace, and must then divvy out that energy to each end consumer. The relationship that exists between each of these three functions constitutes the market design of the energy market. Although there are numerous combinations, there are three general classes of market design, determined by the interrelationship between these three primary functions.

The Wheeling Arrangement

The first class of market design is known as a *wheeling* arrangement. This market structure is used in much of the United States, and in many other nations that have regulated energy markets. In this type of arrangement, the same firm usually owns and operates each of the three functions of generation, transmission and retail; usually a large utility. This type is closest to a vertically integrated natural monopoly, under which the utility is required to guarantee reliable energy supplies to end consumers, at a price that is approved by regulatory authorities, which includes a guaranteed rate of return on investment. Since the same firm owns and operates all three functions, it becomes quite difficult for independent energy producers to operate within the market, and therefore rules for energy wheeling are put in place. Wheeling refers to the delivery of energy supplied by one party, across another party's transmission lines.

Since the same firm owns and operates all three functions, rules must be put in place to ensure that self-serving does not occur when independent generators attempt to sell their energy to the incumbent natural monopoly, or when two firms attempt to trade energy across a region operated by a third incumbent firm. In 1996, the United States Federal Energy Regulatory Commission (FERC) mandated “open access” for wheeling, with Order No. 888. This ensured third parties prudent access to incumbent firms' transmission facilities and wholesale markets. However, some researchers have suggested that there are fundamental flaws with the wheeling arrangement (Hunt 2002), as it is generally non-competitive because the incumbent utility maintains transmission priority, and open access can only occur once the utility's native load has first been served.

The Decentralized Arrangement

The second class of market design is what Hunt (2002) refers to as the *decentralized* arrangement. This arrangement is more competitive than a wheeling arrangement, yet has flaws of its own. It was the original restructuring design of the New Electricity Trading Arrangement (NETA) in the UK, and was the intended market restructuring in California. In decentralized markets, an independent party controls the dispatch of energy; often referred to as an Independent Systems Operator (ISO) or Regional Transmission Operator (RTO). Whereas in a wheeling arrangement, independent generators rely upon the good graces of whichever natural monopoly controls that area's transmission lines, in decentralized markets an independent operator schedules the dispatch of electricity. Decentralized markets operate fundamentally by use of bilateral and independent contracting. Any two parties that agree upon the purchase and sale of energy, submit the parameters of that sale to the grid operator, who then is required to schedule the dispatch of that energy to match that contract. The parameters specify the quantity and price of the energy, the origin and sink, and the timing for delivery. The system operator simply receives contracts that have been scheduled between generators and retailers.

Although there are many complicating factors inherent to this class of market, the issue of *imbalances* is particularly important. Imbalances occur when there is over/under supply at any one point on the energy grid. The system operator simply receives contracts and puts them into play, regardless of whether or not an imbalance results. In the event of under supply, the retailer will then be required to go to short term (imbalance) markets to maintain system reliability. This produces a conflict of interest for both generators and retailers, when opportunities for arbitrage exist as a result of differing prices between bilateral and imbalance markets, which has obvious implications for system reliability, as well as system gaming (Hunt 2002). Because of this, the exercise of market power and anticompetitive behavior in the original NETA restructuring in England and Wales, as well as California and Pennsylvania, has been well documented within the literature (Borenstein *et al*. 2003; Green and Newberry 1993; Hunt 2002; Mansur 2001; Newberry 1995; Puller 2001; Sweeting 2007; Wolfram 1996; Wolak and Patrick 1996).

The Integrated Arrangement

And finally, the third general class of market design is what Hunt (2002) refers to as an *integrated* arrangement. Whereas in a decentralized arrangement, the system operator is constrained from making efficient market operations that optimize reliability, in an integrated model, the system operator has the ability to alter contracts to ensure an efficient market. In the integrated model, bilateral contracts are financial in nature, and do not distort the physical transport of energy, thus keeping reliability decisions centralized, while maintaining a competitive marketplace. Transactions between generators and retailers are financial in nature, and are not intended to affect the supply of energy available for consumption, but rather allow for a consistent hedging arrangement against pricing volatility.

The integrated arrangement allows for bilateral contracts between generators and retailers, with advance scheduling notice provided to an independent systems operator. In addition to bilateral contracts, the system operator also operates a regularly scheduled short-term auction for wholesale power, in which generators are permitted to bid their supply into the market to alter contracts in the short term. This requires that the system operator run a spot market for short term procurement, which allows for supply adjustment and can help to minimize the imbalance problem (Borenstein, Bushnell and Wolak 2002; Siddiqui, Marnay and Khavkin 2000).

The decentralized approach, on the other hand, attempts to keep the system operator separate from the spot market, leaving those short-term adjustments to traders indirectly. In a vertically integrated market under a wheeling arrangement, these problems are simplified greatly. In the event of a transmission differential, the monopolistic dispatcher simply adjusts supply between generators. No contracts have to be altered, and no short-term adjustment markets need be run. In competitive markets, however, coordination becomes a rather significant issue. As such, the integrated model allows for more centralization of these short-term decisions and optimization (Hunt 2002).

3. California's Energy Markets

Past and Current Restructuring

Throughout history, California has been the proving ground for new and innovative policies. A common phrase among American policymakers is: "S*o goes California, so goes the nation."* Throughout its history, California has led the nation in social policies such as educational reforms, civil rights, and employment and labor laws. California's economy has frequently signaled the direction for national markets, and it has invariably led the nation in the environmental arena. Many of the policy experiments that have been put into place in California have led to economic and social prosperity, however many have not. California's energy markets have similarly provided the nation with examples of both successful and unsuccessful policies.

Throughout the past decade, California's energy markets have been in a state of near-constant policy flux. The state has made revision after revision in an attempt to adjust to the difficult transition to more competitive energy markets, at different times incorporating different aspects of each of the three models above. Although there was discussion and conjecture much earlier, California's first attempt with energy market restructuring occurred in 1996 with the passage of Assembly Bill 1890. The adjustment period to near-complete competitive markets took about three years, as price fixes continued to allow for stranded cost recovery. By the summer of 1999, consumers noticed dramatic increases in the price of power, as once-regulated private utilities began to accumulate debt on asset development, and pass those costs onward. Although what has commonly been referred to as the California energy crisis was truly a confluence of many different events, there were several fatal flaws in market design that led to

California's failure to integrate market restructuring. These flaws consisted of incoherent market incentives in the relationship between the three different market functions of generation, transmission, and distribution.

Contrary to the advice of utility companies, California's policymakers adopted a perverse market design for the initial restructuring. Although an ISO was created, a Power Exchange (PX) was also created. Whereas the ISO handled transmission scheduling and dispatch issues, it was forced to coordinate with the PX, which handled wholesale market transactions. There were coordination problems between these two institutions, which led to blackouts and exceptionally volatile markets. Furthermore, the deregulatory plan eliminated all bilateral long-term contracts, and required all wholesale power purchases to be facilitated through the PX, and only on short-term forward markets or the spot market. In addition to the dramatic coordination problem this posed between the generation, transmission and distribution sectors, it also provided an insufficient hedge against pricing differentials, which led to significant arbitrage behavior across markets (Chandley, Harvey and Hogan 2000; Fabrizio 2005; Hogan 2002).

Since this first failed experiment with market restructuring, California has rather consistently amended and adjusted its Market Redesign and Technology Upgrade (MRTU) Tariff, or restructured market design. Following the crisis, it quickly eliminated the PX, as well as other institutional bottlenecks. The current California market is a far call difference from the early markets, which resembled an odd amalgam between wheeling and decentralized arrangements. In April, 2009, California released its most recent tariff, which moves the markets closer toward Hunt's integrated model specification.

Jurisdiction

Before discussing the current California market, it should be mentioned that California is both large geographically, as well as heavily populated. Three investor-owned utilities (IOUs) serve a majority of California: Pacific Gas and Electric (PG&E), San Diego Gas and Electric (Sempra Energy), and Southern California Edison. California also has many publicly owned and municipal utility companies, some of which serve a rather large population of customers, such as the Los Angeles Department of Water and Power (LADWP), or the Sacramento Municipal Utility District (SMUD). Those firms make up the retail sector. The distribution sector is still facilitated through an ISO, which in California operates statewide, and which operates both bilateral contracts, as well as generator bids through short-term markets. The physical transmission capacity (substations and power lines etc.) are owned mainly by the three IOUs, and operated mainly by the ISO.

At the generation level, much of the generation is produced by those IOUs, or by assets owned and operated by publicly owned firms. Although legally, no government has the authority to order private utilities do divest their assets, during initial restructuring California's legislature “encouraged” the three IOUs to divest at least 50 percent of their generation assets (Hunt 2002), although a significant portion of that divestiture was to firms that were simply subsidiaries of the three IOUs (Wolfram 2005). However, IOUs are not the only source of power into California's wholesale markets. Private utilities and interstate sales make up a large portion of the power that is consumed by Californians. As of July 2009, slightly less than 50 percent of net power generation into California comes from IOUs (EIA 2009).

Wholesale Markets

California has some rather complicated wholesale markets into which that power is sold. Both bilateral contracting and short-term auction-based markets are utilized. Long-term contracts are favored by regulators for their strengths in producing market stability and reducing volatility. They play a rather significant role in ensuring the incorporation of renewable sources of power, as that power is still relatively high in price relative to fossil-fuel based sources, and would be at a pecuniary disadvantage in competitive short-term markets. Long-term contracts are also favored by many smaller publicly owned utilities, because they offer reliable service and near-constant rates for baseload power. Short-term markets allow generators to bid their supply into the system, and enable firms to make short-term changes. California presently operates two forward markets, a day-ahead market (DAM), and an hour-ahead market (HASP), as well as a real-time market (RTM)/spot market (CAISO 2009a). As discussed above, the incorporation of both contracting and generator bids into short-term markets is one of the key transitions from decentralized to integrated market designs.

Property rights play a rather significant role in the California markets as well. Per the interstate commerce implications of the Federal Power Act of 1935, only generation is subject to federal regulatory authority, however the transmission and retail sectors exist under a diminished federal regulatory authority (Hunt 2002). Within most restructured markets like California, owners of transmission assets are permitted transmission ownership rights (TORs) that allow them principal access to transmission assets. They may also be allotted a marginal quantity of use beyond that as well, known as a capacity benefit margin (CBM). The competitiveness of any restructured energy market may be fundamentally crutched by an uncompetitive transmission system. If a firm with transmission rights monopolizes any transmission route, the market may look like the original wheeling arrangement, and it may become quite difficult for competing firms to engage in contracts or to bid into short-term markets, even if they are competitive in the generation sector (Joskow 1998; Wilson 1998).

Market Available Transmission Capacity

Although various open access rules have been established at both the federal and state level, it is still quite difficult to ensure competitive access to transmission assets. California's revised tariff, although slightly more complicated, incorporates this principle only in part. The Total Transmission Capacity (TTC), which is the absolute maximum quantity of electricity that can be sent or received between two points on a grid, is constrained by other factors. What is left is referred to as Available Transmission Capacity (ATC), and is set by the following assessment methodology:

$$ATC = TTC - OTC - TRM - ETComm - CBM - AS$$

OTC refers to Operating Transfer Capability, which includes any limitations due to down lines or constraints due to system failure. TRM refers to Transmission Reliability Margin, and accounts for stochastic factors influencing transmission capacity; the value is usually set to zero. ETComm refers to existing transmission commitments, and includes two items, ETCs and TORs. Existing Transmission Commitments (ETC) include extant transmission contracts for that line, usually arranged prior to the operation of the short-term market. Transmission Ownership Rights (TOR) permit the owner of those transmission assets to pre-reserve transmission capacity on its own lines. CBM refers to the capacity benefit margin, discussed above. And AS refers to Ancillary Services, and includes any short-term adjustments to be sent or received by the system operator.

Utilities with TORs reserve transmission access through reservations with the system operator, who takes existing contracts into account. These reservations occur at least 20 minutes prior to the real time market operations (CAISO 2009b). When ATC is not large enough to facilitate a third party's trade, that third party becomes resource constrained in the short-term markets. If this occurs on a regular basis, it can be difficult for that third party to operate or compete on transmission assets owned by an incumbent firm.

Physical and Financial Transmission Rights

Another unique aspect of the recent California markets is its use of financial tools to allocate property rights. Earlier restructured markets used physical property rights to allocate scarce transmission resources, known as Physical Transmission Rights (PTRs). Owners of generation assets were allocated PTRs, which they could either acquire by auctions or by direct allocation, and could sell them on a secondary market to third parties who sought to use the transmission system. PTRs were then submitted to the ISO with transmission reservations and power purchases, and firms without PTRs were physically restricted from transmitting their electricity. Some scholars have suggested that this system of physical rights led to misallocation, and the ability to physically and directly restrict access to transmission for competing firms (Bushnell 1998; Hunt 2002; Sun 2005). See Kench (2004) for an opposing view.

More contemporary markets use Financial Transmission Rights (FTRs) instead[1]. FTRs are considered the "perfect hedge" in the allocation of transmission capacity. Just like a PTR, an FTR can be allocated directly or purchased at an auction or on a secondary market. A firm that transmits power from one location on a transmission network to another may encounter differences in pricing between those locations due to congestion charges. These occur when a transmission network is capacity constrained. In the event of capacity constraints, congestion charges become liabilities (Wilson 1998).

If acquired, FTRs enable the firm to hedge against these price differentials, as the possession of an FTR entitles the holder to the rents from said congestion charges for the given location. However, congestion charges may also be negative values, in which case they become a liability to the holder. Their suggested improvement over PTRs is that they are a purely financial instrument, and do not restrict physical transmission capacity in the way a PTR can. In a physical system, the grid operator will not execute a power purchase that is not accompanied by a PTR, however; in a system of financial instruments like California, the only restrictions are the available physical capacity of the transmission infrastructure. Other American jurisdictions that presently use FTRs are the New England ISO service area (ISO New England 2006), and the Pennsylvania, New Jersey, and Maryland ISO service area (PJM 2009).

Locational Marginal Pricing

A further distinction of current California energy markets is the manner in which wholesale purchases of energy occur across the three functions of generation, transmission and retail. The demand side of energy markets is even more complex than the supply side. Demand is a highly stochastic process both spatially and temporally, with demand fluctuating at each location throughout a complex energy grid, at different times of the day and seasons of the year. Demand patterns for power in industrial load centers may be fundamentally different from demand patterns in suburban residential zones. This locational and temporal specificity produces what Williamson (1975, 1979, 1982, 1985) calls transaction costs. It can be quite difficult for system operators to match such temporally and spatially stochastic demand patterns to the generation resources available throughout the system (Joskow 1998). To minimize these transaction costs (e.g. avoid imbalances), energy markets must incorporate a suitable method for pricing (Wilson 1998).

There are two main styles of pricing that occur in deregulated energy markets, zonal

[1] In California markets they are referred to as Congestion Revenue Rights (CRRs).

pricing and nodal pricing. Zonal pricing is an aggregation, in which the entire region or portion of a state, is priced equally as an average of the true costs within that region. High cost areas with transmission constraints and peaky demand will be cross-subsidized by low cost areas with few transmission constraints. Nodal pricing on the other hand is often referred to as locational marginal pricing (LMP). LMP is a disaggregation, and requires the differentiation of transmission and generation costs at very minute sections across a larger grid. California's recent energy markets had used zonal pricing, in which the state was broken down into three subregions, or zones; Northern, Central and Southern California approximately. All short-term energy markets were priced equivalently within each of those three zones. Today's California markets however, use LMPs. The state is broken down into over 2,000 nodes, with differing prices at each node. Prices at each of the over 2,000 nodes, change every five minutes.

The use of locational marginal pricing is almost unanimously lauded within the energy literature. Scholars suggest that LMPs offer a more accurate accounting of true transmission and generation costs in meeting temporally and spatially-stochastic demand, as well minimize the problem of cross-subsidization (Fabrizio 2005; Hogan 1998; Hunt 2002; Hunt and Shuttleworth 1996; Joskow 1998). They furthermore suggest that zonal pricing brings enormous rents to generators who can profit from capacity payments over the sale of energy over congested lines (Joskow 1998; Stoft 1997), and that it hides the exercise of market power in the aggregation (Hogan 1998).

Within the current California market, LMPs have three components. Aside from the cost of energy itself, prices vary at each location due to losses and congestion. A common example of losses is when transmission lines heat up and must have their capacity reduced. Congestion occurs when there is a differential in the amount of energy scheduled and the capacity permitted over the transmission resources. This is important because it relates back to our discussion of FTRs. When congestion charges occur, they must be paid to the FTR holder for that location. This can become problematic when for example; one party seeks to transmit electricity over another party's transmission lines, and does not own FTRs to those lines. When congestion occurs, it becomes a financial liability for the non-incumbent party.

Transmission Markets and Renewable Portfolio Standards

This section has discussed the restructuring of California's energy markets and the most recent changes to the current market design. We have discussed the complexity of each of the short-term and spot markets, and addressed issues pertaining to transmission ownership and the market structure for determining transmission availability. We have similarly discussed the use of financial tradable property rights for the acquisition of capacity and congestion charges, as well as the locational mechanism for determining prices.

In the next sections of this paper we will discuss California’s renewable energy policy, and how the current market structure complicates, and can attenuate the acquisition of renewable energy needed to reduce GHG emissions. It will provide a case that is emblematic of the problem faced by many municipalities within restructured markets. The acquisition of renewable energy is limited by the market design itself. Municipalities seek to incorporate renewable energy into their portfolios, however, when that energy is located outside of their service area, they may find it difficult to transmit that energy over another firm's transmission lines. The owners of those lines may hold transmission ownership rights, or existing transmission contracts, which will limit the availability of capacity for that municipality. If there is any transmission capacity available, the delivery of that renewable energy is further attenuated by the fact that the owner of those transmission lines is awarded FTRs, and thus receives payments from firms that use its lines. If that renewable energy is located at a significant distance from the municipality, it may have to pay congestion charges at each location along that route. As such, the design of the market can highly complicate the full integration of renewable resources.

4. Renewable Energy In California

California has been at the forefront of renewable resources energy policies. At this time, the state energy sector relies on renewable sources to produce about 11.1 percent of its supply (CEC, 2007, Figure 1) and generates more electricity from geothermal, solar, and wind energy sources than any other state (EIA, 2008). Considering electricity consumption, the fraction of renewables is relatively smaller, but still much higher than any other state in the nation (Figure 2).

Fig. 1 - California in state electricity generation - 2008

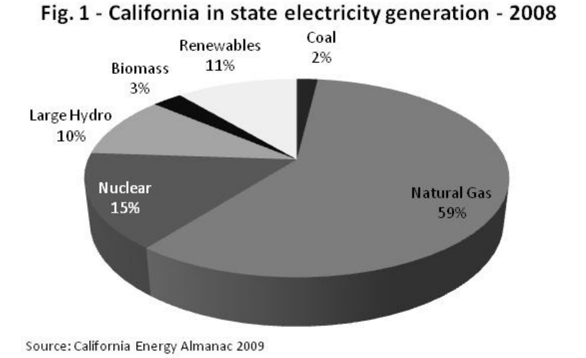
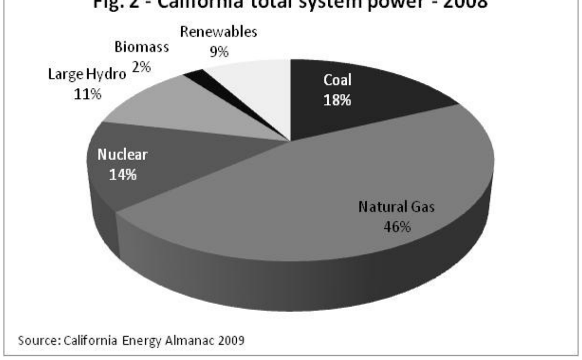


Fig. 2 - California total system power - 2008



The strength of the California renewable energy sector derives from initial federal policies and from past and current state policies. Federal tax breaks for renewable energy sources from the 1970s spurred the creation of new utility-scale solar and wind electricity systems. Thanks to these incentives, wind turbines sprouted on California's windiest hillsides, companies began investing in solar technologies and between 1985 and 1990 about 5,000 MW of renewable capacity were added to California’s electricity system (CEC 2009). Although in the following years the phasing out of federal policies to support the development of renewable resources hit the alternative energy sector also in California, in the late 1990s the industry was ready to take advantage of the renewed interest in renewable sources.

State policies picked up where federal policies had let off. They are a mix of incentives, rebates, tax deductions and feed in tariffs administered throughout all levels of government, mixed with a very ambitious RPS. The California Energy Commission (CEC), the California Public Utilities Commission (CPUC), the investors owned utilities (IOU), and the publicly-owned utilities (POU), each manages some form of renewable energy program, with obvious overlapping.

Since 1996 California mandated financial support for electricity production from renewable sources offering IOUs rebates to reduce (buy-down) the initial cost of renewable energy systems installed by their customers. Later, in 2000, the CEC drafted a Renewable Energy Plan and mandated IOUs to collect $135 Million annually for ten years beginning in 2002 to support it. With Senate Bill 1078, in 2002, IOUs were requested to buy back surplus energy produced by independent producers that used renewable sources and the CEC was directed to issue an Energy Action Program that would introduce a Renewables Portfolio Standard (RPS) “requiring annual increases in energy generation from renewable resources equivalent to at least 1 percent of sales, with an aggregate goal of 20 percent by 2017” (CEC 2007: 20). RPS set a standard for the entire electricity industry of an individual state and require electricity suppliers to sell a certain amount of electricity generated with renewable resources (wind, solar or geothermal) by a specific date. They usually become more stringent as time goes by and require suppliers to demonstrate compliance on an annual basis. The rationale behind this policy is that committing suppliers to provide renewable energy creates demand for renewables and private investors will find it profitable to invest in generators that satisfy that demand.

After a few years of slow adaptation to the new requirements, Senate Bill 1250 accelerated the 20 percent goal to 2010 and Governor Schwarzenegger's Executive Order S-21-09 additionally raised the post to a 33 percent renewable energy supply by 2020 in order to comply with AB32, the state plan to reduce greenhouse gases emissions approved in 2008. This amounts to 20 minutes of every hour of electricity consumed.

Table 1 - Timeline for Electricity from Renewables Portfolio Standards in California
2002: Senate Bill 1078 establishes the RPS program, requiring 20% renewable energy by 2017.
2003: Energy Action Plan I accelerated the 20% deadline to 2010.
2005: Energy Action Plan II recommends a further goal of 33% by 2020.
2006: Senate Bill 107 codified the accelerated 20% by 2010 deadline into law.
2009: Governor Schwarzenegger issues Executive Order requiring 33% renewables by 2020.

RPSs have become a linchpin of the state's climate action policy. According to the California Air Resource Board a 33 percent RPS would reduce GHG emissions by 21.3 mmtCO2e, nearly twelve percent of the total reductions required to reduce California GHG emission at 1990 levels by 2020- the goal of AB32.

The program's organization, however, is quite cumbersome. Every entity involved (IOUs, Electric Service Providers and others), presents an annual plan designed to increasing its share of renewable energy to the CPUC for approval. The Commission sets annual procurement targets that establish the amount of renewable energy the entity must procure each year. The energy operators hold annual solicitations and select the offers based on a least-cost – best-fit criteria. Subsequently, they negotiate with the renewable energy generators and submit the contract for approval to the CPUC. In the mean time, the Commission sets the market price referent (MPR)[2], a benchmark price used to evaluate the offers.

The CPUC approves the contracts where the energy price is equal or below the benchmark and authorizes the energy operators to recover the costs through their retail rates.

[2] The market price referent (MPR) represents the cost of a long-term contract with a combined cycle gas turbine facility,

The contracts where the price is higher are analyzed in depth and if the price is deemed reasonable for technical and siting reasons the contract is approved. In order to limit the burden of more expensive renewable energy on consumers, the energy operator is authorized to tap into the Above-MPR-Fund (AMF) to compensate for the differential between MPR and the final price. The penalty for non-compliance is 5 cents per kWh, up to $25 Million per year.

These major state objectives and procedures do not apply to municipally owned local utilities that supply about 26 percent of the local demand. POUs are required to develop their own RPS, but with more flexibility, less control and less incentives. The governing board of each POU has the authority to determine the resource eligibility rules under its RPS program and is provided with the flexibility of developing its own targets and timelines. This has created a "double standard" for IOUs and municipally owned electricity providers that are "de facto" allowed to purchase low cost, out of state generated electricity, while the IOUs have had to develop a portfolio of renewables. However, as of 2008 (CEC 2008), thirty-seven POUs representing 98 percent of statewide POU retail sales, have established specific RPS targets and timelines. The City of Los Angeles has deliberated an Action Plan to fight climate change that commits the city to providing 35 percent of its power from renewable sources by 2020.

Table 2 - Major California Municipal Renewable Portfolio Standards

Jurisdiction	Renewable Portfolio Standard
California IOUs (Statewide RPS)	33% by 2020
City of Anaheim Public Utilities	20% by 2015
City of Los Angeles Department of Water and Power	35% by 2020
City of Palo Alto Municipal Utilities	33% by 2015
City of Riverside Public Utilities	20% by 2020
City of Sacramento Municipal Utilities	33% by 2020
City of Santa Clara (Silicon Valley Power)	31% by 2010
Source: CEC 2008	

levelized into a cent-per-kWh value.

According to the CEC, "California has roughly 7,400 MW of utility-scale renewable generating capacity, ranging in size from a few hundred kilowatts to large projects in the hundreds of MW. In addition, the amount of grid connected distributed photovoltaic systems continues to grow with about 440 MW installed as of 2008" (CEC 2009: 45). However the overall assessment of the renewable energy effort cannot be considered positive. In 2008 the amount of renewable energy delivered on line by IOUs has increased for the first time since 2003 (see Table 3), but the pace at which it has grown is insufficient to meet the target to triplicate the amount of renewable energy sold in California by 2020, as required by AB32.

Table 3 – IOUs Aggregate RPS Percentage

		2003	2004	2005	2006	2007	2008
PG & E	RPS Eligibible GWh	8,828	8,676	8,643	9,114	9,047	9,774
	RPS GWh as % of bundled sales	*12.4%*	*11.6%*	*11.7%*	*11.9%*	*11.4%*	*11.9%*
SCE	RPS Eligibible GWh	12,613	13,248	12,930	12,706	12,486	12,673
	RPS GWh as % of bundled sales	*17.9%*	*18.2%*	*17.2%*	*16.1%*	*16.7%*	*16.6%*
SDG & E	RPS Eligibible GWh	660	678	826	900	881	1,047
	RPS GWh as % of bundled sales	*3.7%*	*4.3%*	*6.2%*	*6.3%*	*6.2%*	*6.1%*
Total	RPS Eligibible GWh	21,9901	22,600	22,298	22,719	22,393	23,384
	RPS GWh as % of bundled sales	*14.0%*	*13.9%*	*13.6%*	*13.2%*	*12.7%*	*13.0%*

Source: CPUC 2009a, P.6

POUs, a recent study reports, although do not profit from the contribution of the public goods charge to compensate higher renewable energy prices, have made a relevant effort in increasing their renewable supply. In fact, between 2003 and 2006 their RPS eligible renewable sales have grown 2.5 percent (CEC, 2008: 24). Some small POUs located in Northern California have already reached the RPS they had initially set, but LADWP and a wide number of medium-size public utilities in Southern California still have a long way to go to reach their targets and are facing serious hurdles.

To spur the integration of renewables further, the state has adopted feed-in tariff measures. In order to create more financial stability for developers of renewable energy plants, the California legislature and the CPUC have established a feed-in tariff system that will begin in January 2010. According to its critics, the current incentive structure does not give investors in renewable energy enough certainty about the return on their investments. In order to give them long term security, the system allows installations with a capacity of 1.5 MW and below to enter into purchase agreements that have a 10, 15 or 20 year term, capped at 500 MW total statewide. Generators are certified by the CEC and can opt to sell either 100 percent of their power, or only their excess electricity.

Unlike the feed-in tariffs in Germany and Norway, the California feed-in tariff does not include any form of incentive to the renewable energy operation; it only guarantees stability across time. In fact, it is equal to the Market Reference Price (MPR) established by the CPUC, adjusted for peak time, mid peak or off peak and for seasonality. In order to guarantee stability both to sellers and buyers, the baseline tariff is set the year their electricity is delivered on line and will remain constant for the entire contract. Since the rate and the standard terms of contract have been already approved by the CPUC, the agreements between utilities and operators do not need to be approved by the commission, but enter into effect at signing (Rickerson *et al.* 2008).

Under current policy however, the CEC 2009 Energy Policy Report reiterates its 2007 assessment:

> "So far, however, the RPS results have not kept pace with its mandate, due principally to insufficient transmission infrastructure and complex administration […]. Even with almost 400 megawatts from new renewable energy facilities added to the system, load growth has matched these additions, and California remains at the same percentage of electricity from renewables as when the law was passed [..]"

Numerous studies have shown that the fact that renewable resources are sited in remote areas, far from the existing transmission lines is a big hurdle for their development and new transmission lines are urgently needed. At the same time, there are serious concerns on the impact of new transmission construction on the fragile desert ecosystem, on the impact that intermittent sources of energy will have on the reliability of the overall energy supply and on the financial uncertainty of investments in the renewable energy sector. In addition renewable energy project approval times are still very long and there is the need to streamline the relationships between authorizing agencies.

5. LADWP's Green Path North Project

In its unilateral efforts to reduce GHGs, California has set some rather tough standards for emissions and implemented an array of programs to increase the contribution of renewable resources to energy production up to at least 33 percent of baseload electricity consumed within the state by the year 2020, as mentioned above. Achieving these targets may prove rather difficult, particularly considering the nature of renewable energy resources and their geospatial location within the California topography. In fact, photovoltaic and wind resources are intermittent, as well as low in energy concentration; therefore they provide neither a hearty nor a steady supply of baseload generation. As such, the most abundant and steady source of renewable power comes from geothermal sources. Unlike most other states, California is blessed with a rich endowment of geothermal capacity. As of 2005, the state possessed more geothermal capacity than any nation in the world, and presently has 2,555 MW of installed capacity (Geothermal Energy Association 2008).

In order for the state's IOUs to meet the aggressive AB32 mandate, and in order for the municipalities to meet their ambitious targets, geothermal energy must be incorporated into their energy portfolios. However, there are two rather significant hurdles that limit the ease with which this is going to occur. First, the geothermal activity exists in rural desert and mountainous areas, and procurement and delivery to urban energy demand centers is quite difficult. Second, the complexity and quasi-competitive aspects of the current California market further complicate access to and delivery of geothermal capacity. Overcoming these two hurdles requires policy makers to also consider the interrelationships between generation and transmission in California's complex energy markets (Appendix A) and may require alterations to its very design and structure.

LADWP And Its RPS: A Problem of Procurement

At present, only 6.6 percent of the baseload energy supplied by LADWP is renewable (CEC 2008). In its efforts to attain its ambitious RPS (33% renewable by 2020), LADWP has sought to incorporate renewable sources of generation in different ways. In the spring of 2009, the City of Los Angeles ran a special election, seeking voter approval for a charter amendment to fund an equally ambitious solar program. City Measure B, also known as the Green Energy and Good Jobs for Los Angeles Act, would have installed 400 Megawatts of solar capacity on public buildings throughout the city. Voters narrowly opposed the measure amid criticisms of administrative capture (see Stigler 1971, and Peltzman 1976) by local unions.

LADWP has also tried to incorporate more consistent and reliable geothermal energy from the Imperial Valley in California's Southeastern deserts, seeking bilateral power contracts with geothermal generators in the Imperial Valley. However, without adequate transmission capacity, it will be rather difficult for LADWP to transport that power to the businesses and residences within its service area. The geothermal area in the Southeastern region, in fact, is not connected to the main grid. As an alternative, LADWP intended to develop its own transmission lines between the Imperial Valley and Los Angeles, known as the Green Path North Project (GPN). In a joint effort with the Southern California Public Power Authority (SCPPA) and the Imperial Valley Irrigation District (IID), in 2006 the LADWP sought a federal property agreement for a right of way through the region.

In accordance with the National Environmental Policy Act of 1969, and the California Environmental Quality Act of 1970, projects such as transmission lines require the development of a full and complete Environmental Impact Assessment (EIA). This assessment requires a detailed analysis of the potential environmental impacts associated with any project, as well as a detailed consultation process with the affected communities. Presently, the GPN project is stalled in this phase. Each of the proposed routes draws transmission construction through or near, pristine desert habitat that surrounds the Imperial Valley (Appendix A). Local community activism opposing the GPN has erupted in an anti-Los Angeles conflagration, centered in the Southeastern regions of the state. Community organizations have formed in opposition to the project, and there has been significant involvement from both local and national political elites.

Throughout the past century, there has been a significant cultural divide between California's eastern and western residents that has made the consultation phase of the environmental impact assessment difficult. Since that time, residents in the Eastern portion of the state have maintained both incredulity and cynicism regarding development by the LADWP. As such, geographic, historical and cultural barriers each attenuate the ability for municipalities such as LADWP to incorporate renewable sources of generation into their portfolios.

LADWP And Its RPS: Market Complications

One additional significant hurdle also exists, that is the hurdle of a quasi-competitive energy market. As mentioned above, the transmission of energy over another firm's transmission resources presents problems, as the market available transmission capacity may be circumscribed by both physical capacity constraints as well as market-oriented limitations. Anti-competitive behavior may further limit the ability for neighboring firms to utilize resources of a neighboring incumbent firm. Despite the use of an ISO, municipalities are forced to compete for open access to transmission lines that are owned by the IOUs and operated by the ISO. Those IOUs, which are frequently the owners of the transmission assets, are allocated FTRs that give them a defacto property right over any incurred congestion charges. Those municipalities may acquire FTRs at auctions, if the IOUs are willing to sell them, and if the IOUs do not require them for their own transmission and hedging purposes.

The issue of competitive access to transmission resources is rather significant for municipal utilities that are now required to import renewable sources of power from outside their service areas. The LADWP, for example, receives a majority of its current energy supply from two out of state sources, one located in the neighboring state of Nevada, and one located in the neighboring state of Arizona. Fossil fuel and nuclear-driven fuel is particularly inexpensive in those two states, which have relaxed environmental regulations for the energy sector.

The LADWP has historically contracted for power with plants in both of these areas, and transmitted that power over one of two lines. The transmission of power from Nevada occurs on transmission assets owned and operated by LADWP, which are outside of the control of the ISO. The transmission of power from Arizona occurs through an inter-tie on the Palo Verde line, which is operated by the ISO. In order to safely integrate renewable energy into their portfolio, LADWP has sought to build non-ISO controlled lines from the Imperial Valley, to connect to its main non-ISO line between Los Angeles and Nevada. This is the intent behind the GPN project. Competing with the IOUs for access to transmission lines for which they maintain FTRs, is quite difficult for municipal utilities. If they can build transmission assets to transmit that power over lines that they do not have to compete with the large IOUs for access to, they may safely integrate renewables without incurring monopolistic rents from the IOUs.

The actual market available transmission capacity (ATC) for the GPN area is illustrative. As mentioned previously, ATC is that capacity over which a third party may utilize to transmit their power after existing contracts and rights have been accounted for. We have calculated the ATC for two nearby branch group regions along the proposed GPN routes. Graphical analyses are provided in appendix B. Depending upon the proposed routing option, the GPN will deliver renewable energy from the Imperial Valley region, and import it across the Palo Verde region to the Victorville region; from that point the lines are owned and operated by LADWP. Graphs in appendix B also provide a listing for the Path 15 route, which is the main intra-state transmission line, which delivers power between Northern, Central and Southern California. We consider this to be an accurate competitive benchmark to use as a baseline for comparison of the other two. Our figures report values from the past four months from the date of this paper's submission.

As can be seen from each of the four months, the Path 15 competitive benchmark well exceeds the GPN route's ATC. The month of October is particularly striking. The average available transmission capacity during that month is only 3.7 percent of the total transmission capacity for the Palo Verde line, and only 5.6 percent for the Victorville line. However, the Path 15 line has, on average, over 25 percent of its total transmission capacity available. In the aggregate, current transmission resources along the GPN proposed route are anywhere between two times and 12 times less accessible than our competitive benchmark. This indicates that in the absence of an alternative transmission system like the GPN, LADWP would be resource constrained in delivering renewable energy to its service areas.

In addition to historical, cultural and geographic barriers, municipalities must also contend with quasi-competitive energy markets in delivering renewables to their demand centers. Because of the significant hurdles that must be overcome in delivering this geothermal capacity to California's urban centers, California may lose these important resources to neighboring states. In August of 2008, the Imperial Irrigation District reached an agreement with the State of Arizona for the purposes of trading power across state lines. The state of Arizona is interested in procuring California's abundance of renewable energy, while the Imperial Irrigation District is interested in receiving Arizona's abundant fossil-driven energy to help decrease the cost of their portfolio (IID 2008). The complications of California's energy markets, combined with its rigid environmental siting requirements, may actually be an impediment to the development of renewable power within the state. Owners of renewable generating facilities may find it easier and more cost effective to sell that renewable power elsewhere.

6. California's Collaborative Efforts- Overcoming Hurdles

Planning and collaborative processes have been launched to address the problems of renewable energy generation and transmission. The Governor, with Executive Order S-14-8, has established a Renewable Energy Action Team that includes the Energy Commission, the Department of Fish and Game, the Bureau of Land Management and the U.S. Fish and Wildlife Service, that will develop a Desert Renewable Energy Conservation Plan to identify areas where the development of renewable resources is feasible and conservation areas where development should be prohibited. In addition, the CPUC has signed protocols of understanding with the involved agencies in order to expedite the approval processes of new renewable resource projects.

California's governor has also launched the Renewable Energy Transmission Initiative (RETI). RETI is a statewide initiative that involves representatives of IOUs, POUs, renewable energy generators, transmission providers, authorizing agencies, consumer and environmental advocacy groups. It has the goal of identifying needed areas of renewable energy and transmission development that will help utilities achieve their individual RPS goals, and minimize the impact on the environment.

RETI, guided by a steering committee, has created working groups to address economic and environmental problems of renewable energy development and has divided its task into three phases. In the first, it identified areas where economic and environmental constraints are less compelling (Competitive Renewable Energy Zones – CREZs). In a second phase, it analyzed transmission issues and produced a statewide conceptual transmission plan that identifies where new connections are needed. In the third phase, it will recommend a list of priority lines that the CAISO and the CEC should take into account in the process of planning for the future of the California transmission grid.

RETI's goal is to reduce the conflict that usually arises when new transmission lines are planned and it is still too early to say whether it will be successful. However the process has highlighted one of the major issues of energy markets in California- the lack of coordination among stakeholders (ISO, IOUs, POUs, and cooperatives) that require additional transmission infrastructure. Through RETI, these different stakeholders have started a conversation that is bound to continue. In fact, they have formed a California Transmission Planning Group that intends to be the promoter the State Transmission Capacity Plan.

Following up on RETI, the CAISO has proposed a comprehensive state transmission capacity planning procedure that involves all utilities, independent generators, and regulators, and intends to integrate and coordinate the future transmission needs of renewable and non-renewable energy, considering both system reliability and siting problems. The planning process will consider long term needs beyond the ten year time horizon and will take into account national and regional needs along with state energy strategies. It will also incorporate utilities' plans. Its main goal is to rationalize the siting of new electric lines, to maximize the use of existing and proposed corridors in order to minimize the environmental disruption and optimize the cost effectiveness of these needed investments (Anderson *et al.* 2009;CAISO, 2008).

7. Final Thoughts- Are Collaborative Processes The Answer?

We began this paper by describing the general structure of American energy markets, and then elaborated on the details of the current restructured energy market in California. We then described the details of California's energy policy as it pertains to the integration of renewables via a RPS. We showed how there is a disconnect between current energy markets and current renewables policy. This was further illustrated through our brief case of the LADWP's attempted integration of renewables from the Imperial Valley in Southeastern California. In addition to overcoming the difficult geographic, historical and cultural hurdles, California's utilities also face significant difficulty in managing the complexity of a quasi-competitive market.

Beyond the standard resource constraints, utilities also face complex financial property rights constraints for transmitting their energy between generators and consumers. We provided an analysis of the available transmission capacity for the regions pertaining to one of California's most controversial transmission infrastructure projects- LADWP's Green Path North Project. Our analysis indicates that available transmission capacity for the importation of energy across the GPN areas is significantly smaller than a competitive benchmark. Smaller third party institutions and municipalities may be disadvantaged both by market complexity, as well as by available capacity.

The California government has initiated several collaborative planning efforts, such as RETI, to help minimize some of these hurdles that we have addressed. Through these discursive processes, historical and cultural barriers to infrastructure building will be addressed directly.

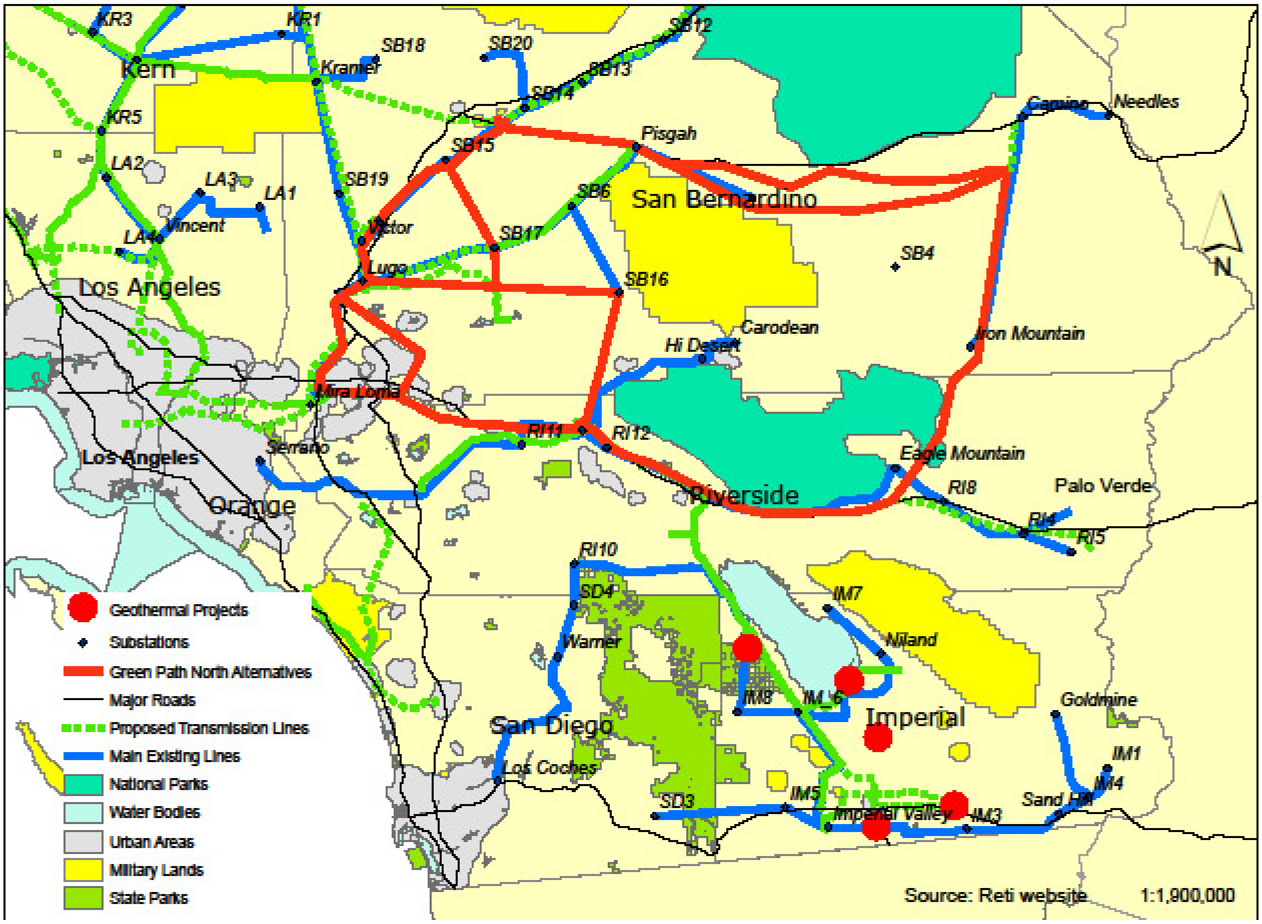
The impasse that has been reached in the current environmental review process will also hopefully be overcome, as the least-environmentally destructive routing option will emerge through negotiation and consultation.

However, it is unclear whether or not these collaborative processes will fully address the market complications that we have discussed. The problems that arise from a quasi-competitive market with uncertain financial and physical property rights, complicated locational marginal pricing, and transaction specific assets that arise out of multiple long-term and forward market arrangements- pertain more to the failure of certain market mechanisms than to a breakdown in consensus.

We suggest, that perhaps these complications are what Mazmanian and Kraft (2009) identify as shortcomings of the first and second epochs in environmental policy. Whereas the first epoch, characterized by top-down command-and-control policies, aligned more closely with regulated energy markets that required contortions such as wheeling arrangements to operate across jurisdictions, the second epoch aligns more closely with our present restructured market. The second epoch, characterized by market-based and collaborative efforts, aligns closely with our current system of integrated energy markets with market-based institutions that allocate both financial and physical property rights between generators, transmission asset owners and retailers. These scholars suggest that the second epoch is transitory, as certain stakeholders dominate its regulatory apparatus, and its ultimate outcome suffers from the shortcomings inherent to a system with flawed incentives.

Furthermore, we suggest that a more appropriate solution to these problems is a closer alignment between community goals and stakeholder motivations, in which institutional rules are designed to coordinate stakeholder preferences, rather than cajole them. Whereas the current collaborative processes, such as RETI, may address the environmental and siting issues that we have identified, they may ultimately fall short of solving these larger motivational issues. The current market is an odd amalgam between private and public ownership, and regulated and deregulated sectors, in which firms are asked to cooperate in building the very markets on which they are forced to compete.

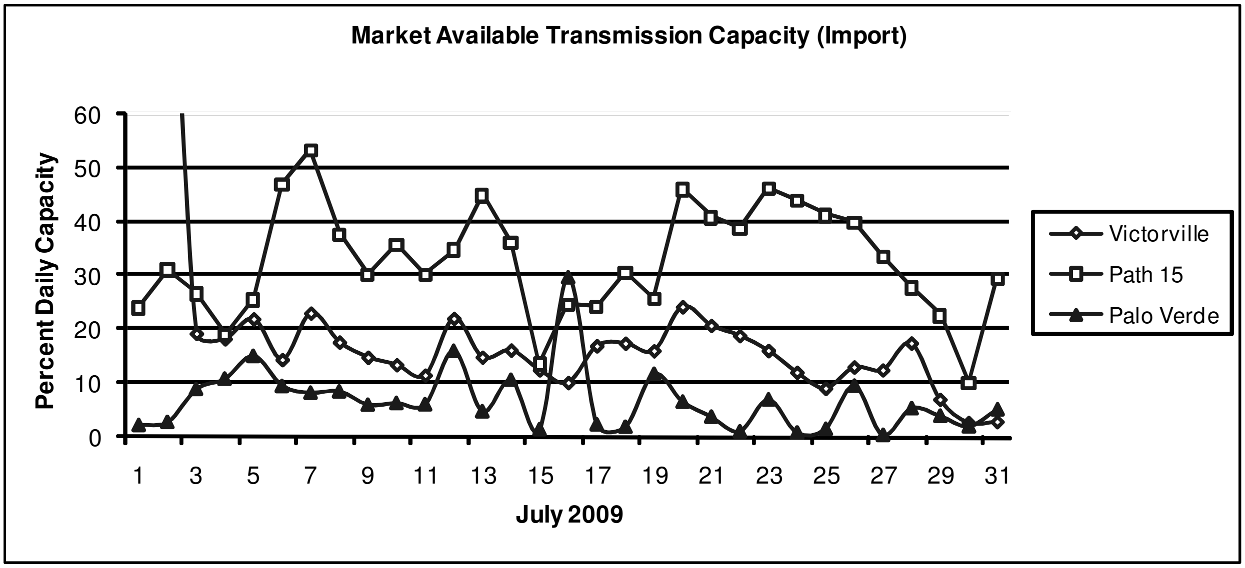
Appendix A- Southern California Geothermal Resources and Connecting Transmission Lines



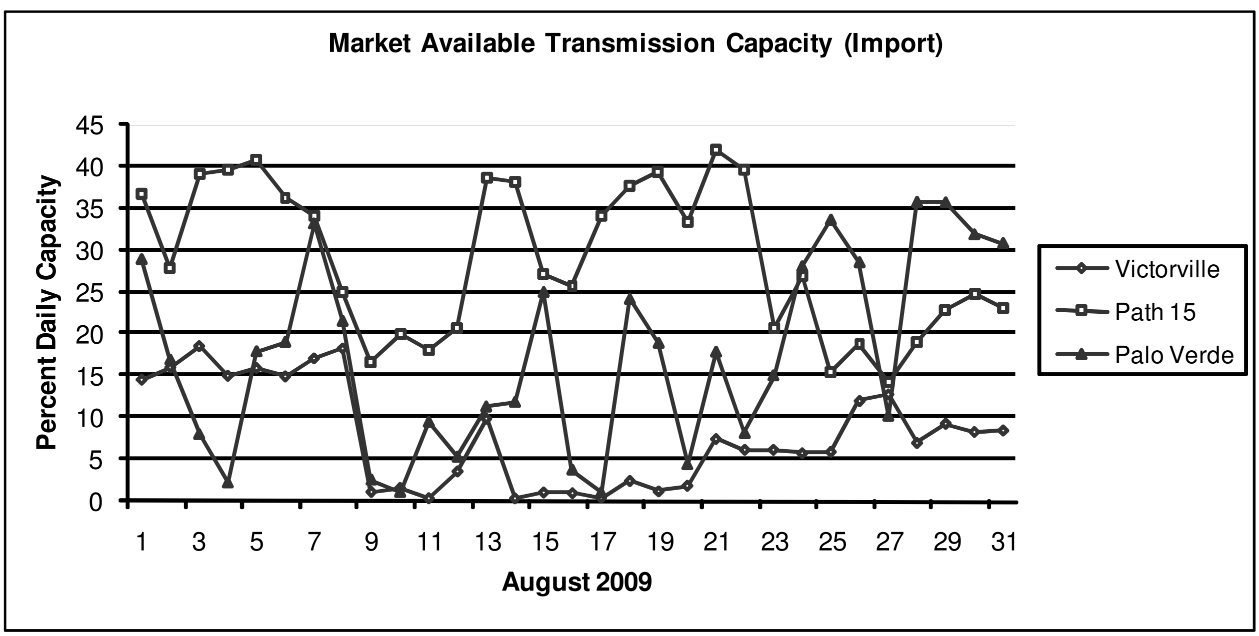
Appendix B – Market Available Transmission Capacity

This data is provided by the California ISO's OASIS database, and is publicly available. Data provided are from the short-term Day-ahead Market (DAM). For each day, an ATC is provided separately for each hour. Values reported reflect the average of each day's hourly ATC. Because of the stochastic nature of energy markets, it would be nonsensical to report hourly values from either the HASP or DAM, and would be even more nonsensical to report spot-market (5-minute interval) values. Values reported are for the import side, and do not reflect export ATC as the GPN would more appropriately utilize import capacity.

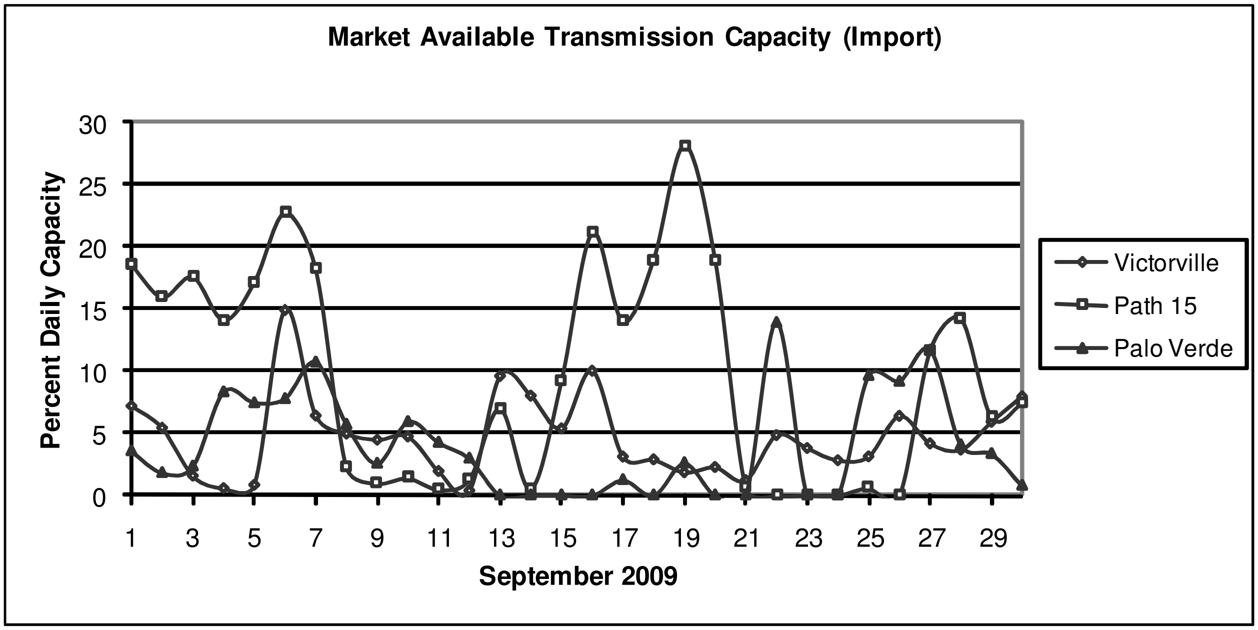
ATC for GPN Regions- July 2009



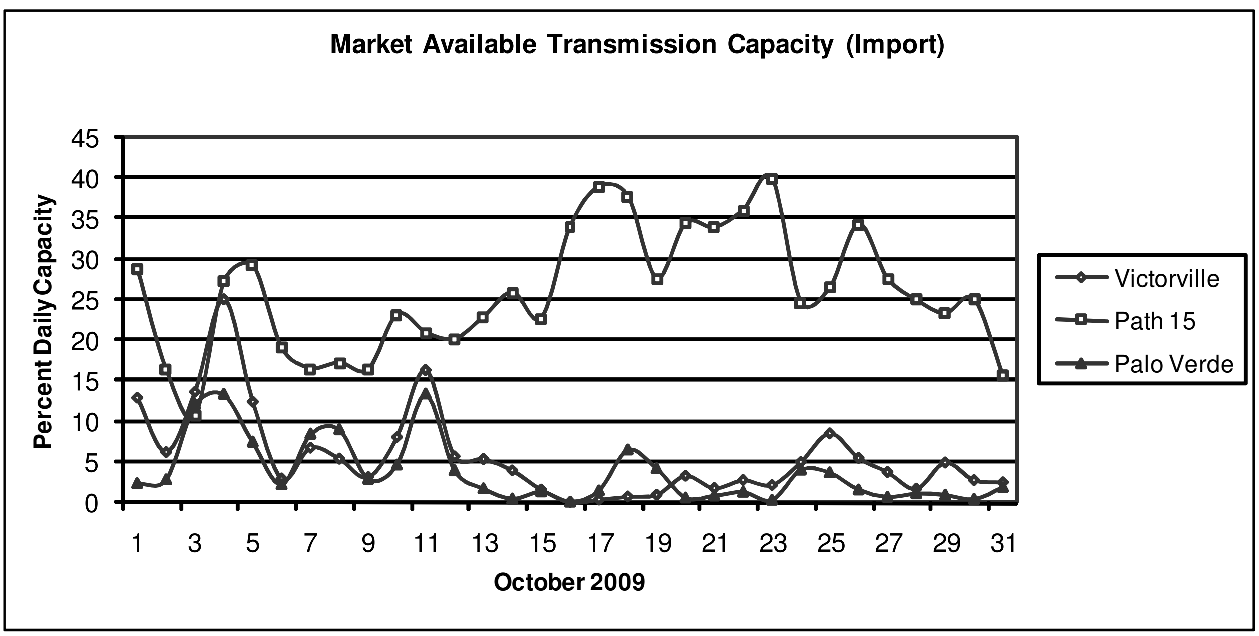
ATC for GPN Regions- August 2009



ATC for GPN Regions- September 2009



ATC for GPN Regions- October 2009



Appendix C – Useful Acronyms Reference

AMF	Above-MPR-Fund
AS	Ancillary Services
CAISO	California Independent Systems Operator
CBM	Capacity Benefit Margin
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRR	Congestion Revenue Rights
DAM	Day-ahead Market
EIA	Energy Information Administration
ETC	Existing Transmission Contracts
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GEA	Geothermal Energy Association
GHG	Greenhouse Gas
GPN	Green Path North
HASP	Hour-ahead Scheduling Process
IID	Imperial Irrigation District
IOU	Investor-Owned Utility
ISO	Independent Systems Operator
LADWP	Los Angeles Department of Water and Power
LMP	Locational Marginal Price
MPR	market price referent
NETA	New Electricity Trading Arrangement
NLP	Native Load Priority
OTC	Operating Transfer Capability
PG&E	Pacific Gas and Electric
PTR	Physical Transmission Rights
PX	Power Exchange
RETI	Renewable Energy Transmission Initiative
RPS	Renewable Portfolio Standard
RTM	Real-time Market
RTO	Regional Transmission Operator
SMUD	Sacramento Municipal Utilities District
TOR	Transmission Ownership Rights
TRM	Transmission Reliability Margin
TTC	Total Transmission Capacity

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