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Simulating price patterns for tradable green certificates to promote electricity generation from wind

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Abstract

This article uses computer simulation to anticipate the price dynamics in a market for Tradable Green Certificates (TGCs). These markets have been used in Europe to promote generation of electricity from renewable resources like wind. Similar markets have been proposed in the United States of America (USA) where the certificates are called Renewable Energy Credits (RECs). The certificates are issued to the generating companies for each megawatt-hour of renewable electricity generation. The companies may sell the certificates in a market, and the revenues from certificate sales provide an extra incentive to invest in new generating capacity. Proponents argue that this market-based incentive can be designed to support government mandates for a growing fraction of electricity generation from renewable sources. In the USA, these mandates are set by the states and are known as Renewable Portfolio Standards (RPS).

We simulate the price dynamics of a market designed to support an aggressive mandate for wind generation in the northwestern USA. The simulations show that the certificate price climbs rapidly to the cap in the early years after the market opens. Investors then react to these high prices with construction of new wind capacity. After a few years, wind generation meets, and then exceeds the requirement. We show that this pattern appears again and again when the simulations are repeated with wide variations in the estimates of behavioral parameters. We use the model to study the impact of different trading strategies by the wind companies and by the distribution companies. We also study the simulated market response if the USA adopts the carbon allowance market envisioned in The Climate Stewardship Act. The article concludes with recommendations for policy makers involved in TGC market design.

Keywords: Renewable portfolio standards; Tradable green certificates; Renewable energy credits

1. Introduction

The purpose of this article is to help policy makers anticipate the pattern of prices that could appear in a market for Tradable Green Certificates (TGCs) to encourage electricity generation from wind. Wind generation is expected to be the primary form of renewable generation in many western states that have called for a growing fraction of electricity from renewable sources. These mandates are called Renewable Portfolio Standards (RPS). The article begins with a review of RPS in the United States of America (USA) and TGCs in Europe. The early experience with the Nordic market for TGCs shows the potential for major oscillations in prices. We use computer simulation to anticipate whether similar oscillations will appear in a market to encourage wind generation in the Northwestern USA.

The heart of the article is a simulation analysis of an idealized market for TGCs. The market participants are wind generating companies (GenCos) and electricity distribution companies (DisCos). We adopt a collection of assumptions to allow the simulated market the best possible opportunity to function in a stable manner. The analysis indicates that even an idealized market is vulnerable to major oscillations in prices. The simulated TGC price climbs rapidly to the cap after the market opens. Investors react to these high prices with construction of new wind capacity, and total capacity eventually exceeds the RPS requirement. This pattern reappears when we

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Acronyms and abbreviations

CCs	combined cycle, gas-fueled generating units
DisCo	distribution company
GenCo	generating company
MRET	mandatory renewable energy target (used in Australia)
NREL	National Renewable Energy Laboratory
NTNU	Norwegian University of Science and Technology
NWPP	northwest power pool
PTC	production tax credit (for renewable generation)
REC	renewable energy credit
RGGI	regional greenhouse gas initiative
RPS	renewable portfolio standard
S139	Senate Bill 139, The Climate Stewardship Act of 2003
TGC	Tradable Green Certificate
USA	United States of America
WGA	Western Governors' Association
WSU	Washington State University

Units of measure

aGW	average GW, the electric energy from 1 GW of power operating for the entire year
btu	British thermal unit, a measure of energy
kW	kilowatt, a measure of electric power
kWh	kilowatt-hour, a measure of electric energy
GW	gigawatt, a measure of electric power or generating capacity
GWh	gigawatt-hour, a measure of electric energy
MW	megawatt, a measure of electric power or generating capacity
MWh	megawatt-hour, a measure of electric energy
$mtCO_2$	metric tons of carbon dioxide emissions
SEK	Swedish Kronor (in July 2005, 7.88 SEK = 1 US$)
$	US dollar
$/MWh	$ per MWh, the standard measure of the price of a TGC

repeat the simulations with different values for the uncertain parameters. We attribute the consistent pattern to time lags in the response of the key feedback loops in the system. The price oscillations described in this article raise serious questions for the design of TGC markets. We discuss these policy questions in the concluding section of the article. Suggestions for future research are presented in Appendix A.

2. Renewable portfolio standards

An RPS is a state[1] requirement for electricity generation from renewable generating resources like wind. In the USA,[2] 20 states plus the District of Columbia have enacted RPS calling for regulated investor-owned utilities to include a specified fraction of renewable generation in their generation portfolio. Moseidjord (2005) shows that states with a higher per capita income or higher exposure to gas-fired generation are inclined to adopt these standards. He has concluded that "global warming concerns and reduced exposure to the volatile natural gas markets are the driving forces behind the state adoption of an RPS." We are particularly interested in the western USA where there are RPS programs in Arizona, California, Colorado, Nevada, and New Mexico. The California RPS calls for 20% renewable generation by 2017.[3] The New Mexico RPS calls for 10% renewable generation by 2011. The governors of California and New Mexico have sponsored a Western Governors' Association (WGA, 2004) resolution for the west to aim for even more aggressive goals for the entire region. It calls for 30 GW of clean energy by the year 2015. The RPS rules vary significantly in terms of percentage targets, time frames for compliance, qualifying fuel types and incentive programs.[4] Moseidjord (2005) reports goals for non-hydro generation from 1.1% to 24% of total generation. The intervals for compliance range from 6 to 16 years.

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[1] The states have taken the lead in calling for RPS. However, a national RPS has been proposed by Sen. Bingaman (D-NM) as part of the Senate Energy Bill under debate in June 2005. His amendment called for 10% renewable generation by 2010 with a REC market to be run by the Department of Energy. The Bingaman amendment passed the Senate but was not adopted when the House of Representatives sent the Energy Policy Act of 2005 to the President for signature (Neff, 2005).

[2] Similar programs are used outside the USA. For example, Australia has a Mandatory Renewable Energy Target (MRET) which imposes an obligation on electricity retailers and large consumers to purchase a percentage of their power requirements from renewable sources (MMA, 2003). Also, the European Commission White Paper (CEC, 1997) suggests that member states aim to double the renewable share of inland energy consumption from 6% to 12% by 2010 (Madlener and Stagl, 2000).

[3] Moseidjord (2005) believes the California RPS is by far the most important in terms of "expected volume of green power." He reports that the California plans calls for a state incentives of around 7 to 9 $/MWh to encourage investment in renewable generation.

[4] RPS programs are summarized by Deutch (2005), Hunt (2005) and Knutson and McMahan, (2005). A catalog of state programs is provided by the NWCC (2002), and a table of state RPS policies is given by Wiser et al. (2000). Detailed information is available on several web sites: www.eere.energy.gov/state_energy_program, www.pewclimate.org, www.dsireusa.org, www.cleanenergystates.org. One of the earliest RPS was adopted in Texas in 1999 under Gov. Bush as part of the restructuring of the Texas electricity market. The Texas RPS required the installation of 2000 MW of new renewable capacity by 2009. According to Deutch (2005, p. 14), the RPS led to a "Texas Wind Rush" that produced 10 new wind projects in the year 2001 with a combined capacity of 930 MW. An early assessment of the Texas RPS is provided by Langniss and Wiser (2003).

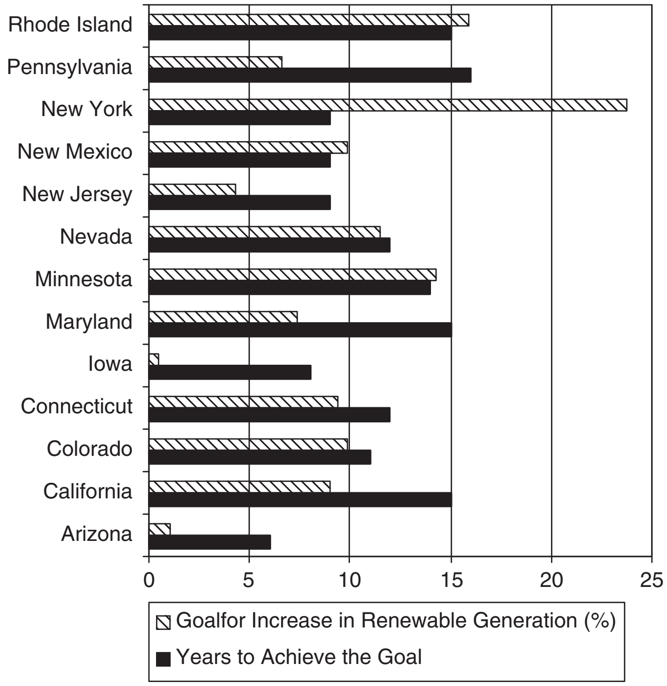

Fig. 1. Comparison of RPS goals and intervals.

Fig. 1 arranges the goals and intervals for 13 of the states summarized by Moseidjord.[5] One bar shows the goal for an increase in the percentage of generation. The second bar shows the interval for achieving the increase. In Minnesota, for example, the RPS target is 19% by 2015. Relative to 4.7% renewable generation in 2001, the goal is to increase renewable generation by 14.3%. Their RPS was first enacted in 2001, so the "years to achieve the goal" is 14 years. The Minnesota RPS is similar to several other states which aim to increase generation by around 1% for each year of the RPS. The New York RPS stands out in Fig. 1. It has adopted the ambitious goal to increase renewable generation by nearly 24%, and it plans to do so in only 9 years.

Knutson and McMahan (2005) review the many RPS programs and draw important conclusions for the nation as a whole. They estimate that the current programs apply to just over half of the nation's retail electricity revenues. The current targets would translate into a need for an additional 53 GW of non-hydro renewable electric output by the year 2020, requiring a cumulative capital investment of $53 billion. They believe that wind investment will provide 76% of the total investment because of its attractive economics and resource availability.

This article focuses on a region of approximately the size of the Northwest Power Pool (NWPP). In the northwestern USA, availability of wind sites has been estimated at 141 GW (Elliott et al., 1991). Many of the sites are in Montana, a state thought to have enough wind resources to supply 15% of the electricity needs of the entire USA.[6] However, wind generation accounts for only 1% of the generation in the Northwest.[7] The low contribution stems partly from relative economics, which we describe below.

3. Wind economics

Table 1 compares the economic factors that govern the relative attractiveness of wind generation versus gas-fueled power plants with combined cycle (CC) technology. The CC technology dominated the recent building boom, and the EIA expects that CCs will be the dominant choice for investors in the future.[8] The values in Table 1 were drawn from a variety of state, regional and national studies.[9] They are presented here as one example of relative economics. Any comparison of wind and CCs can vary widely with changes in each of the uncertain inputs. Given the high

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[5] We exclude Maine, Massachusetts, Texas and Wisconsin from the bar chart comparison because Moseidjord's tabulation shows their RPS targets as lower than the renewable generation in 2001.

[6] The 15% estimate is from a June 2004 visit to the website for the Renewable Northwest Project www.rnp.org/RenewTech/tech_wind.html.

[7] Our area is the NWPP which includes the northwestern USA plus the provinces of British Columbia and Alberta. The NPPC issues plans for the US portion of the NWPP; their most recent plan estimates that wind provides 1% of the region's generation (NPPC, 2005, pp. 2–5).

[8] The appeal of CCs in the recent building boom is described by Ford (2001). The EIA (2003) view of the future of attractiveness of CCs is apparent from their reference projection in the S139 study. The reference case shows CC capacity growing from 46 GW in the year 2000 to 311 GW by the year 2025. The extra capacity is 266 GW. The EIA reference case envisions some growth in other generating technologies as well, but they are must less significant. Coal-fired capacity, for example, is projected to grow by 70 GW during the same time interval.

[9] The estimates in Table 1 were obtained from a combination of studies by the California Energy Commission (CEC, 2000), the Northwest Power Planning Council (NPPC, 2005) and the Energy Information Administration (EIA, 2003). Starting from the top of the table, the construction costs ($/kW) are based on estimates from all three studies and rounded off to the nearest 100$. The fixed charge rate for CCs was taken from the CEC, and the same rate was applied to wind. The 90% availability factor for CCs is mentioned in several studies, however, we believe that many CCs will not be able to achieve 90% operation because of the massive building boom of 2000–2001. The fixed and variable O&M costs in Table 1 were taken from the NPPC. The NPPC estimates that most generating units will incur a transmission cost of 15 $/kW per year. Because some wind sites are located more distant from the transmission lines, the NPPC (2005, pp. 5–25) estimates their transmission cost at 20 $/kW per year. Projections of future prices for natural gas vary widely. The estimate of 5.50 $/million btu is within the range of values expected by the EIA. Estimates of heat rates for new CCs vary across a narrow range, say from 6800 to 7100 btu/kWh. Shaping costs deal with the problem of integrating intermittent wind generation into the hydro-thermal system. According to the NPPC (2005, pp. 6–8), "wind power shaping costs are reported to range from 3 to 8 $/MWh, lower than expected several years ago." The NPPC uses models to estimate the "deterministic shaping costs" which are said to range from 5 to 11 $/MWh depending on the amount of wind capacity. Kalich (2003) estimates wind integration costs to range from 5 to 10 $/MWh depending on the amount of wind and the size of forecasting error. As a general rule, these shaping cost estimates are higher than costs in the Nordic system that has more experience integrating wind with hydro operations (Holttinen, 2004). Table 1 shows a shaping cost of 5 $/MWh, a value from the low range of estimates by the NPPC.

Table 1
Comparison of investor costs for wind and CCs

	CCs	Wind
Fixed costs		
Construction cost ($/kw)	600	1000
Fixed charge rate (1/year)	0.145	0.145
Annualized construction cost ($/kw yr)	87	145
Fixed O&M ($/kw yr)	10	20
Fixed transmission ($/kw yr)	15	20
Total fixed costs ($/kw-yr)	112	185
Capacity factor to convert to $/mwh	0.9	0.33
Levelized fixed costs ($/mwh)	14.2	64.0
Variable costs		
Variable O&M ($/mwh)	2.8	1
Cost of natural gas ($/million btu)	5.5	
Heat rate (btu required per kwh)	6,900	
Fuel cost ($/mwh)	38.0	
Shaping costs ($/mwh)		5
Total variable costs	40.8	6.0
Total cost ($/mwh)	55.0	70.0
Production tax credit ($/mwh)		13
Total investor cost ($/mwh)	55.0	57.0

fixed costs of wind, the most influential parameter in Table 1 is the capacity factor.[10] The 33% estimate was taken from a NPPC (2005) study which anticipates capacity factors ranging from a low of 28% to a high of 36%.

For our purposes, the important part of Table 1 is the "bottom line estimate" of total investor cost. The cost is 70 $/MWh, which is 15 $/MWh above the cost of a new CC. However, wind investors in the USA receive a substantial benefit from the federal Production Tax Credit (PTC). The benefit for Northwest investors has been estimated as equivalent to 13 $/MWh (Global Energy Decisions, 2005, pp. 3–1; NPPC, 2005, pp. 6–7). When the full benefit of the PTC is included, the total cost of wind is only slightly higher than the cost for a CC. However, if the PTC were allowed to lapse,[11] wind investors would require a benefit of 15 $/MWh to compete with CCs. That benefit could take the form of a TGC.

4. Tradable green certificates

A TGC is a market-oriented instrument to achieve targets for renewable electricity generation in deregulated electricity markets. TGCs have been implemented in several countries in Europe (Hass et al., 2004; Madlener and Stagl, 2005; Morthorst, 2000; Verbruggen, 2004; Vogstad, 2004). They correspond to Renewable Energy Credits (RECs) discussed in the USA (Hunt, 2005; Langniss and Wiser, 2003) and the Renewable Energy Certificate implemented in Australia (MMA, 2003). We use the term TGCs throughout this paper, but our findings apply to both RECs and TGCs.

TGCs are designed to work in conjunction with a RPS. The main goal of TGC markets is to increase the share of renewable generation at costs below the costs of direct subsidies such as the PTC.[12] Another goal could be the promotion of a diverse mix of renewables, some of which may be more attractive from a socio-economic–ecological perspective.[13] We believe that policy makers should include price stability as a third objective. Recent experience with boom and bust in electricity markets has made price stability an important consideration in electricity market design (CEC, 2002; Ford, 2002). We believe this is true for TGC market design as well.

TGC markets are quite new, so the evidence on price stability is extremely limited. The longest running market is in Sweden which opened in May of 2003 with expectations for a price of 100 SEK/MWh (just under 13 $/MWh). The expectation was based on the cost of renewable generation and the likely electricity prices in the Nord Pool (Vogstad, 2005). However, prices from the first year of operation were over twice as high as expected. Indeed, the first year prices were nearly pegged at the penalty price which serves as the price cap in the TGC market. Prices are currently

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[10] To illustrate the importance of the capacity factor, imagine that wind generators could achieve 36% operation. This single change would lower the total investor cost from 57 $/MWh to 51.7 $/MWh. Wind's competitive position would change dramatically.

[11] The PTC was originally provided by the Energy Policy Act of 1992. The PTC provision has been repeatedly renewed and extended, with a recent extension slated to expire at the end of 2005. In July, The Energy Policy Act of 2005 extended the PTC to cover facilities placed in service by the end of 2007. This 2-year extension is helpful, but it leaves lingering uncertainty over the longer term. Enacting a long-term extension of the PTC is the first of the "top ten" recommendations the Wind Task Force Report to the Western Governors' Association (CDEAC, 2005).

[12] Direct subsidies for wind may take the form of a PTC in the USA or a "guaranteed feed-in tariff" scheme in Europe (Madlener and Stagl, 2005; Vogstad, 2005). The PTC has led to substantial investment in wind generation in the USA, and the feed-in tariff has led to similar success in Denmark, Germany and Spain (Bird et al., 2005; Haas, 2000). However, proponents of market incentives prefer TGCs over direct subsidies because the TGC market can function in concert with a RPS target. (There is no guarantee that a PTC or feed-in tariff will deliver exactly the investment needed to meet a state mandated target.) Market proponents also hope the TGCs will encourage investors to exploit the most attractive wind sites, regardless of their location. Thus, they hope that the TGC approach will allow wind generators to meet targets at total costs lower than a direct subsidy. And finally, market proponents hope that TGCs can promote renewable investment without the problems of distortion in transnational markets said to occur with national subsidies. Overall, these perceived advantages add up to the general view that TGCs are more "compatible with open markets" (Vogstad, 2004, p. 187). This paper takes a neutral position on the appeal of a market-based TGCs versus direct subsidies like the PTC. (We are not arguing on behalf of TGCs, nor do we argue against the continuation of the PTC. Rather, our purpose is to help policy makers anticipate the price dynamics that could appear with new markets for TGCs.)

[13] The importance of a diverse mix of renewables is described by Madlener and Stagl (2005). They describe a conceptual scheme for TGCs to be issued to renewable generators based on both MWh of generation and an index of the socio-economic-ecological impacts. For example, a "high SEE impact" generator might receive only one MWh of TGCs for every three MWh of generation. A low impact generator might receive a MWh of TGCs for every MWh of generation. TGCs from all renewable generators would then be traded in a single market to promote liquidity.

around 230 SEK/MWh which is close to the effective price cap for the early years.[14]

Some researchers have turned to experimental economics to gain insight on the performance of TGC markets. Vogstad (2005) summarizes experimental results from 5 buyers and 5 sellers participating in a laboratory experiment at the Norwegian University of Science and Technology (NTNU). The NTNU experimental market adopted the Swedish market design, and the simulations showed that "the price was driven far above the expected equilibrium price, followed by a subsequent price crash." In a similar experiment at the University of Amsterdam, 6 sellers and 6 buyers interacted in a laboratory market for an imaginary country with electricity demand comparable to Norway or The Netherlands. The RPS target increased from 3% to 10% in a decade (Schaeffer and Sonnemans, 2000, p. 414). In an experiment with the price penalty set sufficiently high to ensure compliance with the RPS, the simulated price rose to twice the expected equilibrium price within the first year. By the fourth year, the TGC price was almost three times higher than the expected equilibrium price. These higher prices were then fed into an investment model which led "to massive investment in renewable capacity" and "an enormous overproduction is the consequence leading to a total collapse of prices in the last periods" of the experiment.

This brief review of the Swedish market and the experimental markets alert us to the possibility that TGC prices could be highly variable, especially in the early years after the markets open. We consider whether this variability might appear in a TGC market to support an RPS mandate in the northwest.

5. An ambitious RPS scenario

There have been calls for renewables to climb to 20% of electricity generation, and a common estimate is that wind will account for around 75% of renewable generation. Since our focus is on wind, we consider the challenge of building wind generation from 1% to 15% of total generation. For this article, we assume that the federal PTC is not extended, so the TGC market must provide the 15 $/MWh to counter the cost difference in Table 1.

A key question is the time interval to reach the 15% target. We adopt the aggressive strategy of reaching that target in a single decade, from 2008 to 2018. The ambitious nature of this RPS is apparent by comparison with the state plans in Fig. 1. We will study a 14% increase in renewables in only 10 years, an RPS that is more aggressive than the RPS adopted by 12 of the 13 states in Fig. 1. (Our example is less aggressive than the RPS adopted in New York.)

We now use computer simulation to translate the 15% RPS target into the required fraction of new power plant investments from wind. To keep the simulation simple, we assume that the demand for electricity grows at the constant rate of 3%/year, a value used in some utility planning. Retirements of older capacity occurs at the constant rate of 0.5%/year, a low value to reflect the unusually small number of retirements in the past decade. We assume that construction of new generating capacity is exactly the amount needed to counter the retirements and to keep pace with the growth in demand. Fig. 2 shows the results. We learn that the ambitious RPS scenario could be achieved if wind capacity comprises 50% of the new capacity construction during the 10-year interval.

Fig. 2A shows the GW of wind under construction and the installed capacity. Fig. 2B shows the RPS goal: wind generation must increase from 1% to 15% during the interval from 2008 to 2018. There is over 2 GW of wind under construction in 2007, the year before the RPS target climbs above 1%. The construction increases over time because of the growth in the regional demand. By 2017, around 2.75 GW of wind would be under construction. The total installed wind capacity increases to around 26 GW by the year 2018. At 33% operation, the wind capacity would provide 8.58 aGW of electric energy, enough to satisfy 15% of the electricity demand in the region. We estimate the potential wind sites in the Northwest at 141 GW, so this scenario would use less than 20% of the potential sites. Nevertheless, this is an ambitious scenario, one that envisions five times more wind capacity than the 5 GW in the NPPC (2005) plan for the Northwest.[15] We now turn to the pattern of TGC prices that would encourage wind investors to make this scenario possible.

Note on graphs format: The simulation graphs in this article are generated directly from the simulation software. The format is somewhat different than graphs with more common software such as spread sheets. Variable names are listed in the legend below each graph, and a label (i.e., "50% Case") is assigned to each simulation. The units are apparent from the variable names and the list of units at the start of the paper.

The software allows for multiple scales on the vertical axis, as in (0,40) for wind installed capacity and (0,8) for wind capacity under construction in Fig. 2A.

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[14] The price cap in the Swedish TGC market is set at 150% of the previous year's average price. Recently, there have been major conversions of CHP (combined heat and power) units into bio-fueled units. These conversions can be done quite quickly by replacing the burner unit, and the new unit qualifies as a renewable resource. As a result of the CHP conversions, the Swedish market now has more than enough renewable generation for the immediate time period (which extends to 2010). Nevertheless, the TGC price is still around 230 SEK/MWh.

[15] The NPPC takes a cautious approach to wind because of uncertainties about transmission and shaping that need to be resolved. Their plan incorporates around only 1.1 GW of wind capacity between 2005 and 2014. In contrast, Fig. 1 shows around 15 GW of installed wind capacity by the year 2014. The NPPC plan states that beyond 2014, "additional wind generation figures prominently in the next decade." The scenario examined in this paper looks for a prominent contribution from wind in the current decade.

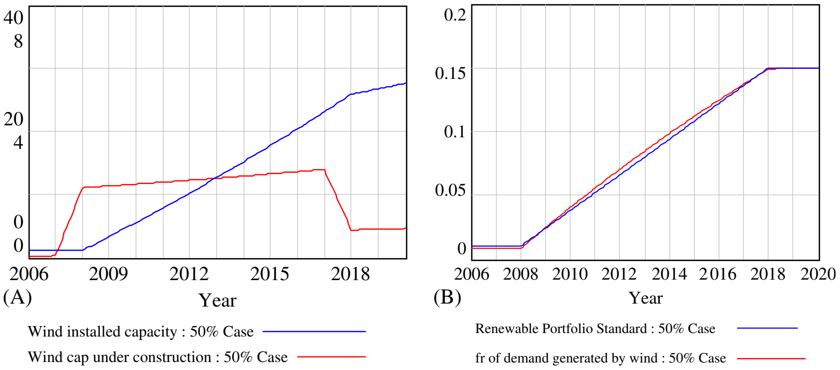

Fig. 2. (A). Wind construction and installed capacity in a scenario with wind at 50% of new construction. (B) Wind generation would grow from 1% to 15% of total generation in the 50% scenario.

6. General patterns for TGC prices

At this point, we ask about the TGC price pattern to stimulate wind companies to capture 50% of new construction of electric generating capacity. To keep the scenario simple, we assume that gas-fired CCs are wind's only competitor. We assume that the federal PTC is not in effect, so the TGC market must provide an incentive of 15 $/MWh for wind to be competitive with the CCs. With a 1-year lead time, the TGC price would have to be in effect in 2007, and the incentive would have to be maintained until the year 2017. By this point, the construction of new wind capacity would be sufficient to reach the RPS goal of 15%. The 15 $/MWh might be called a "fundamental" price, a price that would be expected by an expert on market fundamentals.

Fig. 3 shows the fundamental pattern as one of several possible patterns of behavior. The price increases immediately to 15 $/MWh and remains at that fundamental value for the 10-year interval.

A similar pattern is the "delayed fundamental," a pattern which might account for some of the delays in the system. For example, there may be a delay for investors to observe the TGC price before taking it into full consideration in making their investment decision. And there is certainly a construction delay before new wind capacity can be brought into operation.[16] We also consider the possibility that the TGC market could exhibit oscillatory behavior. The "minor oscillations" pattern assumes that oscillations may appear, but they do little to alter the overall pattern of prices. Based on the evidence from the Swedish market, it is important to consider a more volatile scenario, one that envisions the TGC price rising quickly to cap. Fig. 3 shows a "major oscillation" pattern in which the price reaches the cap with the first few years of market operation. We don't know how long the price may remain at the cap, so the pattern shown here is simply one example of "major oscillations." In this example, the price remains at the cap for two years, twice the length of the construction interval for new wind capacity. Fig. 3 shows declines in prices at the end of the 10-year interval. By this time, it is no longer necessary for wind investors to capture 50% of the market for new construction, and we would expect the TGC price to fall below 15 $/MWh. (This decline could cause problems for wind investors who were counting on the 15 $/MWh for the life of their investment. We comment on this problem in the concluding section of the paper.) For now, we turn to computer simulation to help us anticipate which of these patterns might appear in the TGC market.[17]

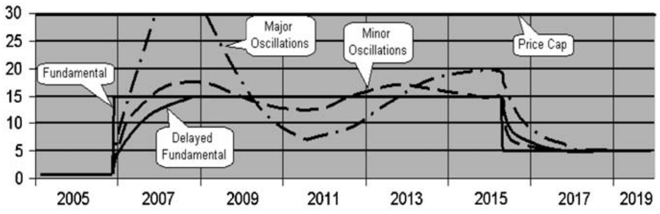

Fig. 3. Possible patterns for the TGC price.

7. Method of analysis

We analyze the TGC market using the system dynamics approach pioneered by Forrester (1961) and explained in recent texts by Ford (1999) and Sterman (2000). System dynamics has been put to good use in the study of electricity markets in the western USA (Ford, 2002) and in Norway (Vogstad, 2004). The approach is valued in a rapidly changing electricity industry with high risk (Dyner and Larsen, 2001) and as a complement to traditional optimization methods (Bunn et al., 1993).

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[16] The construction delay for wind capacity is around 12 months. There are also delays for site studies and permitting.

[17] The goal of the computer simulation is a general understanding of price patterns. We are not constructing a predictive model to forecast TGC prices in the future. We do not believe it is possible for anyone to predict the future prices of TGCs. However, we do believe it is possible to use models to anticipate the general patterns of TGC prices if we pay particular attention to the feedback and delays in the system. This view of modeling is described in recent texts by Ford (1999) and by Sterman (2000) and in the analysis of TGCs by Vogstad (2004, 2005).

System dynamics models are normally implemented with visual software, as we illustrate in Fig. 4. Fig. 4A shows stocks and flows to keep track of the TGCs issued to GenCos and sold to the DisCos. The DisCos turn in the TGCs to meet their RPS obligation. The double lines in Fig. 4A represent the flow of TGCs through the system. The rectangles represent the accumulation of the TGCs in the system. Fig. 4B shows the same model with shorter names. The custom is to use long names to make the meaning clear. However, in Fig. 4B we use extremely short names to make it easier to show the equivalent set of differential equations in Fig. 4C. System dynamics models are comprised of a coupled set of nonlinear differential equations, with a separate differential equation for each stock in the model. The differential equations are "solved" through numerical integration, an approach which is applied to a wide range of environmental and economic systems (Ford, 1999; Zellner, 2002).

Fig. 5 shows the main variables in the model developed to simulate general trends in TGC prices. The amount of wind capacity will influence the amount of electricity generation from wind and the TGCs issued to the GenCo. (The GenCo receives 1 MWh of TGCs for each MWh of wind generation, so the TGCs are measured in MWh.) The GenCos may hold the TGCs or sell them to the DisCos. The DisCos are subject to the RPS requirement. They must turn the TGCs in to the redemption agency or pay the penalty. The interplay between the desired sales by the GenCos and the desired purchases by the DisCos will control the market price for the TGC. The price will then influence the attractiveness of wind investments and lead to increased construction of new wind capacity. Fig. 5 highlights the main stocks and flows in the model and some of the key interconnections that could allow the investment in wind capacity to respond as proponents of TGC markets intend. The five stocks in Fig. 5 are the main state variables in the model. Additional state variables are included to keep track of electricity demand, TGC borrowings and accumulations of costs to the GenCos and the DisCos. Space does not allow a description of the entire model; we will take the time to emphasize the additional relationships depicted with bold lines in Fig. 6.

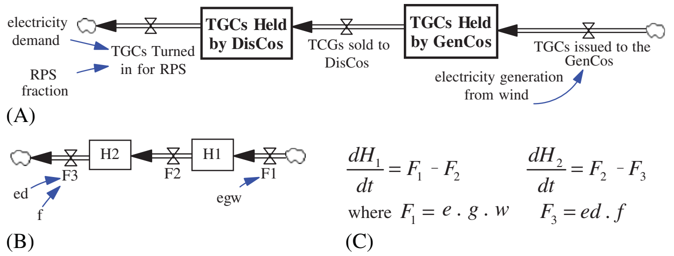

Fig. 4. (A). Main stocks to keep track of TGCs held by the GenCos and the DisCos. (B) Same model with short names. (The flow F2 is not defined in this example.) (C) Same model shown in the form of differential equations.

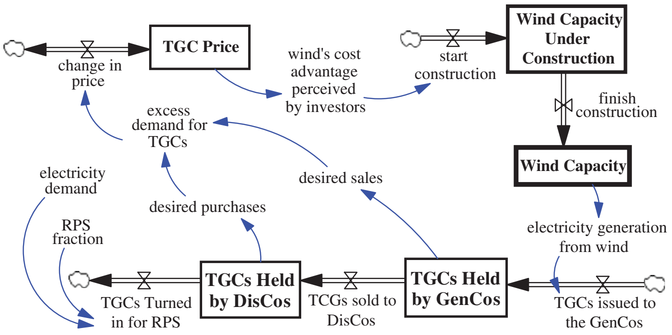

Fig. 5. Main portion of the TGC model.

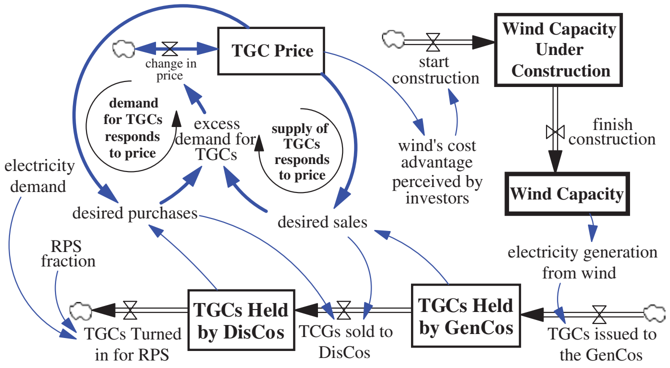

Fig. 6. Additional interconnections to show that the supply and demand for TGCs respond to the price.

Fig. 6 shows the feedback from the TGC price to the DisCos' desired purchases and the GenCo's desired sales. The model takes the average of the desired sales and purchases to determine the actual TGCs sold. The model compares the desired sales and purchases to learn if there is "excess demand" for TGCs. The additional interconnections form feedback loops which are labeled to denote their role in the market. Starting with the supply loop, let us imagine what would happen if there were an increase in the TGC Price. This will lead (everything else equal) to higher desired sales, a reduction in the excess demand and a downward change in the price. The supply loop acts as negative feedback in the system. Turning to the demand loop, we might imagine that there were a decline in the TGC price. This will lead (everything else equal) to higher desired purchases, an increase in the excess demand and an upward change in the price. The demand loop also provides negative feedback which might work to balance the market.

8. GenCos and DisCos assumptions

The GenCos' electricity generation depends on the amount of installed wind capacity. The base case assumption is that the wind capacity factor is constant at 33% for each month and each year of the simulation. The TGCs are issued to the GenCos at the end of each month. The GenCos may hold the TGCs for future sale, or they may sell them to the DisCos. We assume that the GenCos will desire to build their holdings of TGCs as a possible buffer against variability in wind generation. As a base case, we set their desired holdings to eventually achieve 12 months of coverage. Although their goal is to obtain 12 months of coverage, there is no guarantee that they will do so. Indeed, the simulations teach us that the GenCos will often find their holdings fall short of the desired coverage.

The GenCos are assumed to be fundamental traders who will balance the competing goals of building coverage and selling TGCs when the market price is relatively high. Relative value is calculated by comparing the TGC price to the GenCos's estimate of the fundamental price. If the TGC price exceeds the fundamental price, the GenCos will be inclined to sell. We parameterize this inclination with a price elasticity of 1. For example, if the TGC price were 20% higher than the GenCos' estimate of the fundamental price, they would be inclined to sell 20% more TGCs than normal.[18]

The DisCos are also assumed to be fundamental traders. Like the GenCos, they will strive to carry an inventory of TGCs as a buffer against unpredictability in the system. As a base case, we set their desired coverage to 12 months. Although their goal is to obtain 12 months of coverage, there is no guarantee that they will do so. Indeed, the simulations will often show that the DisCos' coverage is so low that they are unable to meet their obligation and must pay the price penalty. We assume that the DisCos strive to balance the competing goals of building coverage and buying TGCs when the market price is relatively low. If the TGC price is below the fundamental price, the DisCos will be more inclined to buy. We parameterize this inclination with a price elasticity of –1.[19] For example, if the TGC price were 20% lower than their estimate of the fundamental price, the DisCos would be inclined to buy 20% more TGCs than normal.

The DisCos are serving an electricity demand which grows at 3%/year. We ignore seasonal variations in the demand, so the demand is spread out evenly over the 12 months of the year. The monthly demand is multiplied by the RPS target to get the monthly obligation. Our base case simulation assumes that the DisCos are required to meet their obligation at the end of each month. If they do not have the TGCs to meet their obligation, they pay a penalty which serves as the effective price cap in the market. We set the price cap at 30 $/MWh, a value selected at twice the fundamental price. (Selecting the price cap is an important decision, one that we discuss in the concluding section of the paper.)

We assume that both the GenCos and DisCos are familiar with the fundamental price of 15 $/MWh. We assume that they will pay attention to the wind capacity, both the installed capacity and the amount that is under construction. They know the RPS target and the growth in demand, so they are able to estimate whether the wind construction is on target to meet the RPS. If construction is on target, they will assume that the likely price of a TGC will be the same as the 15 $/MWh mentioned previously. But if the wind construction is falling short of what is needed, they will adjust their expectation of the price upward. Alternatively, if the wind construction exceeds what is needed to comply with the RPS, they will adjust their impression of the expected price downward. These and other assumptions are implemented with the parameters shown in Table 2. The base case estimates are shown in the middle column. Many of estimates are based on values in a previous model by Vogstad (2004). These parameters are highly uncertain, so it is important to assume a wide range of uncertainty, as we do in the third column of Table 2.

9. Electricity market assumptions

We adopt a collection of simplifying assumptions to make the electricity sector behave in a constant, steady manner. The cost of natural gas is constant at 5.5 $/million btu, and the attributes of CCs are fixed at the values shown in Table 1. We assume that the cost of other fuels are constant and that the Northwest hydro-electric generation is based on average hydro conditions during every year of the simulation. The electricity demand is approximately the demand experienced in the NWPP, a large region that would allow for a good sized market for TGCs.[20] We assume that investors will choose between CCs and Wind when building new generating capacity. Total construction of new capacity occurs at a smooth, steady pace, exactly as need to counter the retirements and to allow total installed capacity to keep pace with demand.[21] When this occurs, the average annual wholesale price of electricity will match the total, levelized cost of a CC. This means that the wind investors can expect to receive 55 $/MWh for electricity sold in the wholesale market. If they can receive 15 $/MWh from the TGC market, their total income will be 70 $/MWh, the amount needed to cover the total cost shown in Table 1.

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[18] The equation for the GenCos desired sales is desired sales = (expected TGCs issued + adjustment for desired holdings) × (price/fundamental price)ˆprice elasticity of sales.

[19] The equation for the DisCos desired purchases is desired purchases = (TGC monthly obligation + adjustment for desired holdings) × (-price/fundamental price)ˆprice elasticity of purchases.

[20] Although RPS goals are issued by individual states, it makes sense to organize TGC markets across a larger area (Berry, 2002; Mozumder and Marathe, 2004). The NWPP is quite a large area, with an initial electricity demand of around 40 aGW.

[21] This final assumption stands in sharp contrast with the boom and bust pattern of construction that has dominated the western USA in the past few years (Ford, 2002). We have used computer simulation to help understand the reasons for the boom/bust pattern, and we have made recommendation for improved design of electricity markets. We do not repeat these recommendations here. Rather, we adopt the simplifying assumption that the electricity markets will respond in an even, steady fashion that will allow the price of electricity to eventually match the total, levelized cost of the new entrant.

Table 2
Parameters to describe GenCo and DisCo behavior in the model

GenCo variables	Base case values	Range of values
Desired coverage	12 months	6–24 months
Price elasticity	+ 1	0.25–1.75
Lag in making inventory adjustments	12 months	3–18 months
Lag in viewing and accepting TGC prices	12 months	6–36 months
New construction market share parameter[a]	20	15–25
Max feasible share of new construction[b]	80%	60–100%
DisCo variables	**Base case values**	**Range of values**
Desired coverage	12 months	6–24 months
Price elasticity	−1	−1.75 to −0.25
Lag in making inventory adjustments	12 months	3–18 months
Penalty price	30$/mwh	Fixed (policy)
Borrowing fraction allowed	0	Fixed (policy)

[a] The market share parameter controls the steepness of the "s shaped" curve that gives the market share for wind as a function of the ratio of the total cost of wind versus the total cost of CCs. This curve gives wind 50% of the market when the levelized cost (minus the benefit of the TGC) matches the levelized cost of CCs. However, wind will get less than 50% if it is more expensive than CCs. The market share parameter controls how rapidly the wind share declines when wind is more expensive than the CCs. Our base case estimate of the parameter is based on national studies adjusted for the reduced diversity of conditions that would be experienced in a region like the NWPP.

[b] The market share calculation could lead market shares approaching 100%. Our base case assumption is that the wind market share cannot exceed 80% because of a variety of financing and transmission connection issues. The 80% value is considered uncertain, from a range of 60–100%.

The electricity market assumptions are certainly highly simplified. We have intentionally created an idealized situation to allow the simulated TGC market to perform with constant conditions. This approach allows for a cleaner interpretation of the simulation results shown below. If the simulations show major oscillations, the oscillations cannot be attributed to changing conditions in the electricity market. Any oscillations in the model must come from inside the simulated TGC market.[22]

10. Base case simulation

Fig. 7 shows a base case simulation with our best estimates of model parameters. Fig. 7A shows the simulated market price compared to the fundamental price pattern. The price is below the fundamental price during the first year of the 10-year interval when the RPS takes effect. Then the price climbs quickly to the price cap of 30 $/MWh. The price remains at the cap for over 2 years. Fig. 7B shows the fraction of new construction captured by wind companies compared against the 50% market share that would be required to comply with the RPS. The market share lags behind the 50% target for the first year as investors observe the behavior of TGC prices. After a year or so, the market share climbs quickly to the maximum value of 80%. This large market share is sustained for several years because the TGC price is twice as high as the value needed for profitability. This aggressive level of construction causes the installed wind capacity to grow past the value required to comply with the RPS target. The extra capacity allows the wind generation to exceed the RPS requirement by around the year 2010.

Fig. 7A shows that the TGC price would finally fall from the cap around the year 2010. After a lag, the wind companies market share falls below the 50% share needed to keep pace with the RPS requirement. After bottoming out in the year 2012, the TGC price returns toward the fundamental price near the end of the 10-year ramp period. This simulation tells us that even an idealized market for TGCs would be inclined toward major oscillations in prices with our base case assumptions.[23] We now ask whether this pattern of behavior would emerge with variations in the assumptions.

11. Analysis of behavioral uncertainty

We conduct formal sensitivity analysis to learn if the major oscillations will appear across a wide range of parameter values. We ran the model 100 times with simultaneous changes[24] in all nine parameters listed in

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[22] In the real system, major oscillations in the TGC price could appear for a wide variety of reasons, such as boom and bust in power plant construction, major changes in the price of natural gas and electricity, and changes in the attributes of new CCs or new wind machines. Our approach is to hold these sources of oscillations constant. This allows us to focus our attention on the interactions depicted in Fig. 4. When we do this, we learn that the interactions can lead to major oscillations entirely on their own.

[23] We concentrate on wind generation as the only form of renewable generation eligible for TGCs. The only way to adjust the supply of renewable generation is through new investments. The 1-year lead time for new wind capacity is short compared to the construction lead times for gas or coal-fired capacity. Nevertheless, the 1-year lead time is sufficient to create the create the major oscillations shown here.

[24] The sensitivity analysis uses Latin Hypercube Sampling to ensure that the simulations cover the entire range of values for all of the parameters. The Vensim software is then used to show percentile intervals for the model results at each year of the simulation. The percentile intervals correspond closely to tolerance intervals on model output (Ford and Flynn, 2005).

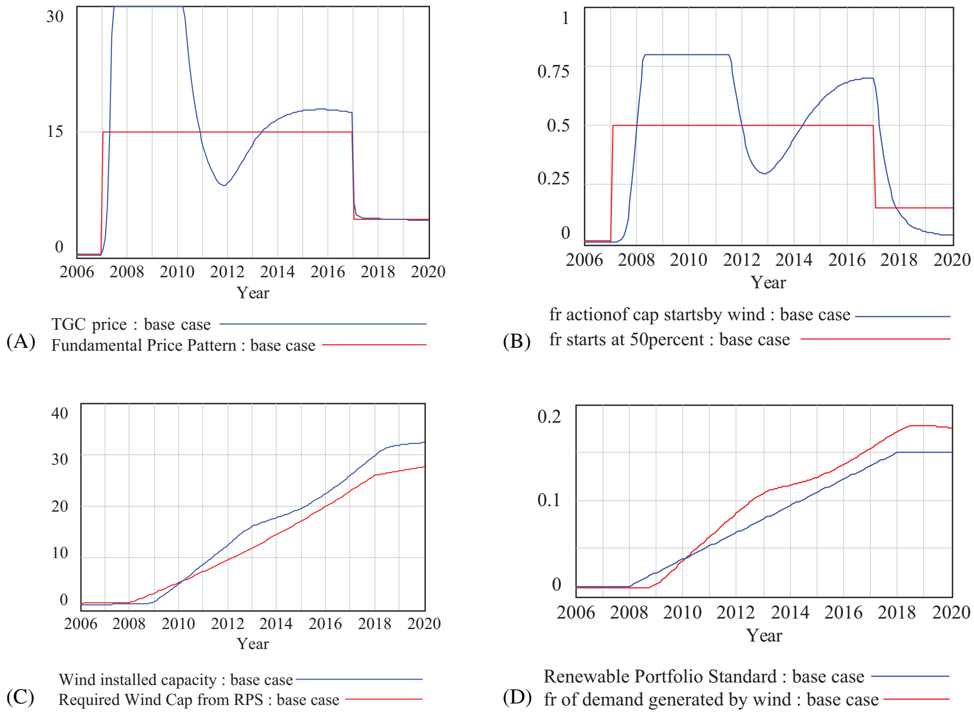

Fig. 7. (A) Base case simulation of the price of a TGC ($/MWh). (B) Wind's share of new construction in the base case simulation. (C) Installed and required wind capacity in the base case simulation. (D) Fraction of demand generated by wind in the base case simulation.

Table 2. The range of results are shown in Fig. 8 in the form of percentiles. Price percentiles are shown in Fig. 8A; the fraction of demand from wind percentiles are in Fig. 8B.

The 100% percentiles show the upper and lower curves to bound all 100 simulations. The 90% percentiles are drawn by eliminating the lower 5 and the upper 5 simulations. The shaded intervals confirm the simulated tendency for the price to rise rapidly to the price cap during the early years. The price percentiles show the price fixed at the cap until around 2010. Then the percentiles spread out across the range from zero to 30 $/MWh. This wide interval tells us that the price is highly uncertain in the second half of the 10-year interval. Fig. 8B shows the percentiles for the fraction of demand satisfied by wind generation. The percentiles should be compared to the RPS requirement (which increases from 1% to 15% over the 10-year ramp period). The comparison shows that the majority of the simulations exceed the RPS target by around 2013. By 2017, 90% of the simulations exceed the RPS requirement.

Fig. 8B indicates that wind generation will eventually comply with and then exceed the RPS targets. Policy makers intent on achieving the RPS targets could view these results as encouraging. On the other hand, investors would be concerned about the major swings in TGC prices during the 10-year ramp period. Furthermore, the decline in prices after the 10-year interval pose serious problems for the profitability of wind investments made only a few years earlier. The low prices after 2017 appear to be an inevitable result of the attempt to achieve the RPS goals in a single decade. From the investors' point of view, it might be more desirable to stretch out the time interval. We return to this idea in the concluding discussion.

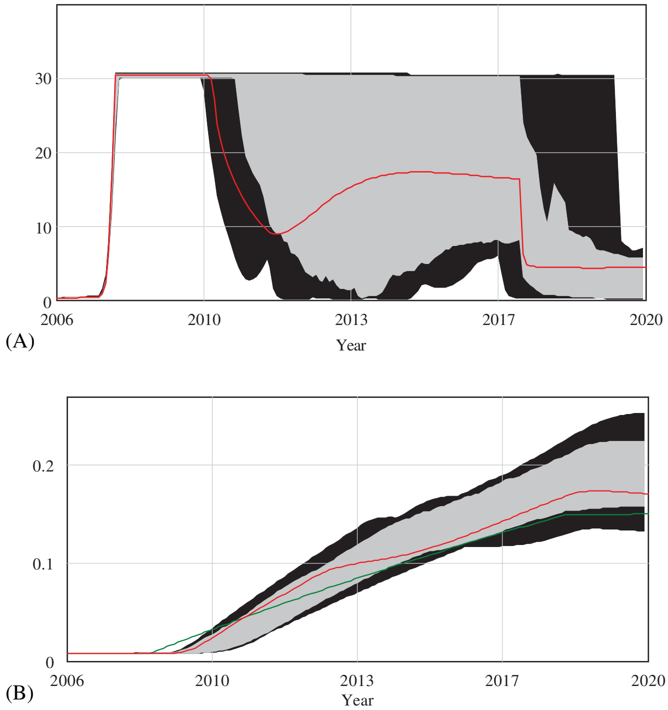

Fig. 8. (A) Percentile intervals for the TGC price from 100 simulations (90% intervals in gray; 100% intervals in black; the base case is the dashed line). (B) Percentiles for the fraction of demand satisfied by wind in 100 simulations (90% intervals in gray; 100% interval in black; the base case is the dotted line; the RPS target is the dashed line).

12. Discussion of simulated behavior

The analysis of behavioral uncertainty shows a strikingly consistent pattern in the beginning years of the market. Regardless of the particular values for the behavioral parameters, we see TGC prices consistently climbing to the price cap and remaining there for several years. Only after some time does the system respond with enough new capacity to allow the price to decline to values that one would expect from a fundamental analysis. The simulations show that wind investors eventually react with increased construction that allows the wind generation to exceed the RPS targets. When we see the same pattern in simulations with wide variation in behavioral parameters, we know that the pattern arises from the underlying feedback structure of the model. Fig. 9 shows two of the feedback loops that we believe are key to understanding the market dynamics.

The inner loop involves the GenCos' desired sales. To understand the feedback effect, imagine that the GenCos have succeeded in building their holdings. If we work through the actions of the loop, we should see a feedback effect that will lower their holdings in the future. So, starting with increased GenCo holdings, the model assumes the GenCos would be more willing to sell TGCs. Higher desired sales will tend to drive down the price and lower the tendency for more construction. With lower wind construction, there will be less wind capacity and fewer TGCs issued to the GenCos in the future. This example confirms that the inner loop provides negative feedback.

Now consider the actions of the outer loop in Fig. 9 which involves the desired purchases by the DisCos. As the DisCos build their holdings, they will have less need to purchase TGCs. Lower desired purchases will tend to drive down the price and lower the tendency for more construction. With lower wind construction, there will be less wind capacity, fewer TGCs issued to the GenCos, and fewer TGCs sold to the DisCos in the future. This example confirms that the outer loop also provides negative feedback.

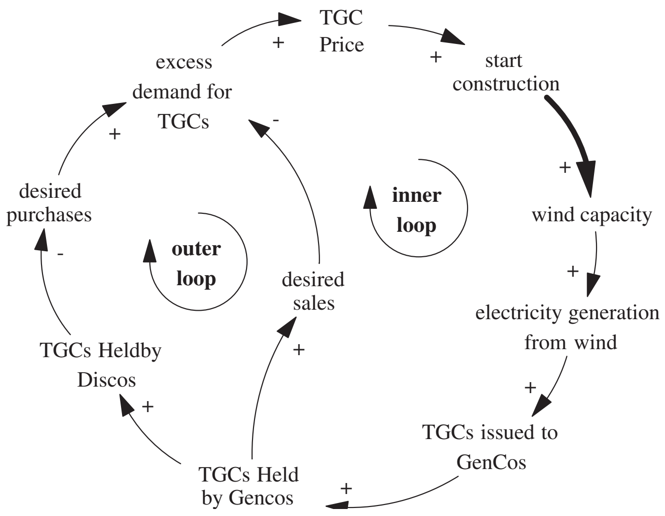

Fig. 9. Two of the feedback loops in the model.

These loops are two of the many negative feedback loops in the model. Negative feedback is essential for control and stability in a system, but negative feedback does not automatically guarantee that the system will perform in a stable manner. Delays in the action of negative loops can be an important destabilizing factor, and the loops in Fig. 9 are vulnerable to important delays. The most obvious delay is the 12-month lag to complete construction of new wind capacity. (We highlight this lag with the thick arrow in Fig. 9.) There are important behavioral lags in the system as well. For example, investors may require many months before they read a change in TGC prices as sufficiently permanent that they incorporate the higher prices into their assessment of investment profitability.

We believe that these delays are the main reason for the strikingly consistent pattern of behavior shown in Fig. 8. Even though the 1-year construction lag for wind is relatively short, this lag can create highly volatile oscillations in the TGC price during the 10-year ramp interval. We believe the oscillations would be even more severe if the TGC market were dominated by renewable generators with longer construction intervals. (An example would be biomass power plants with a 3-year construction interval.) On the other hand, the oscillations would be less severe if renewable capacity could be constructed in a much shorter interval. (An example would be conversions of combined heat and power units into bio-fueled units, a conversion that might be completed quickly by replacing the burner unit.).

We stress the importance of delays in feedback control, but we want to make it clear that delays are not the only reason for the simulation results in Figs. 7 and 8. The other contributing factor is the assumption that traders will desire to build an inventory of TGCs over time. We adopt this assumption because we believe the GenCos and DisCos would find the holdings useful as a buffer against the uncertainties in the system. The extent of their desired holdings is uncertain, but the fundamental assumption is that they want to build their holdings as the RPS requirement climbs over time.

Now, if the traders are to succeed in building their holdings of TGCs, the market must eventually respond with wind generation in excess of the RPS requirement. To illustrate this point, let us return to the Fig. 2 scenario where wind investors build new generation that matches the RPS target exactly. At first glance, one might think that this scenario is turning out perfectly, and the TGC price should remain at the fundamental price of 15 $/MWh. But this scenario would pose a problem for traders who wish to build holdings. They would be constantly frustrated because every MWh of TGCs issued to a GenCo would be erased by a MWh turned in by the DisCo. Through their trading decisions, the GenCos and DisCos create upward pressure on TGC prices in the early years of the market.

These higher prices eventually lead to wind generation that exceeds the RPS requirement. This extra wind generation appears time and again in the many simulations of the model. This extra wind generation is not a coincidental result of one or two parameter values; it is a fundamental result from a model that operates on the assumption that traders will attempt to carry some holdings as a defense against the uncertainties in the system. One such uncertainty is variability in wind generation.

13. Monthly variability in wind generation

Wind generation can vary considerably from month to month because of changes in monthly wind speeds. Data from the San Gorgonio site in southern California illustrate this phenomenon. The average monthly wind speed in May and June are around 41% higher than average for the year. These higher wind speeds could translate into over twice as much generation in May and June. In December and January, on the other hand, the generation at this site would be only around 20% of the average generation.[25] Although there can be major variations when studying a specific site, diversity of wind conditions across a broad region could lead to less variation in the market area. For this article, we are interested in the variation in wind generation across the Northwest. Fig. 10 shows a collection of multipliers from a recent NPPC (2005, pp. 1–43) analysis of three wind areas in the Northwest. The multipliers can be used to convert from an average monthly generation to the actual generation that would appear in each month. For example, the February generation in the coastal area would be around 60% higher than average. However, generation in the Cascades area would be around 10% below average in February. For our purpose, the relevant multipliers would be the average of the three curves for the Northwest. We highlight the average multiplier in Fig. 10. It shows more generation in winter months, less generation in summer months.

Fig. 11 shows the fraction of demand satisfied by wind in a simulation with monthly variations in wind generation. Fig. 11 also shows the RPS requirement and the base case results for comparison. As we would expect, wind generation peaks near the start of each year and declines in the summer months. By visual inspection of the variable wind generation graph, we can tell that the average annual wind generation exceeds the RPS requirement from around 2011 until the end of the simulation.

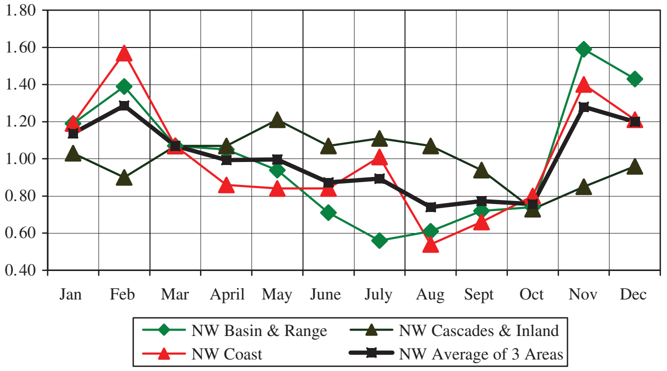

Fig. 10. Multipliers for monthly capacity factors for wind generation in the Northwest.

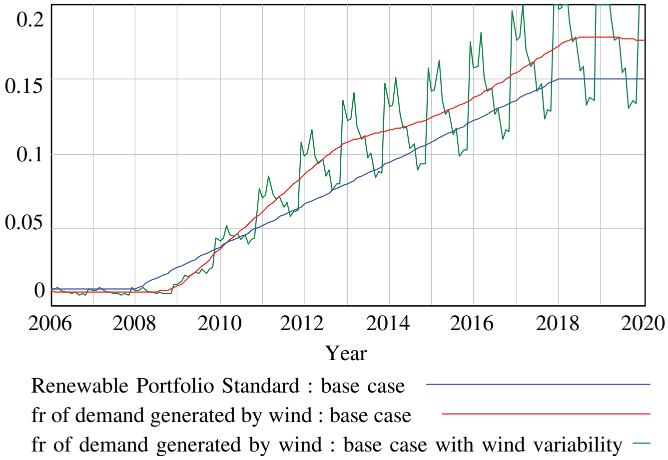

Fig. 11. Fraction of demand generated by wind with monthly variability in wind generation.

Fig. 12 shows the TGC price in two simulations with variability in monthly wind generation. The solid line shows prices from the simulation with the GenCos aiming for 12 months of coverage. This price is essentially the same as the base case price shown previously in Fig. 7A. This simulation reveals that the GenCos holdings can serve as a buffer against the variations in wind generation. The dashed line in Fig. 12 shows the TGC price if the GenCos aim for only 3 months of coverage.

When the GenCos aim for less coverage, the TGC price falls from the cap somewhat sooner. Once the price is free to move, the variations in wind generation leads to variations in the TGC prices. In the months following the low wind generation, for example, the TGC prices climb above the average trend. These simulations show the benefit of GenCos building up their inventory of TGCs. When they aim for 12 months of coverage, they can shield the market participants (including themselves) from variations in wind. Now we turn to the question of whether it is good for the market if the GenCos strive to hold the TGCs for an even longer interval

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[25] Translating variations in average wind speed into variations in generation involves the "power law" which indicates that wind generation will increase by the cubed power of the wind speed under certain conditions. We applied the power law with appropriate adjustments for the site developers original estimate of average capacity factors. The calculation suggested that a month with 40% higher average wind speeds would allow for over twice as much wind generation than in an average month.

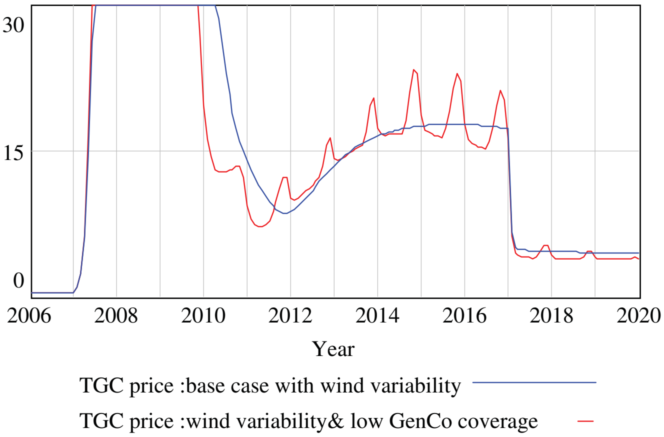

Fig. 12. TGC prices with monthly variability in wind generation.

14. Simulated impact of extensive banking

The GenCos' holding TGCs for an extended interval is called "banking," and many authors have commented on the desirability of allowing banking (Langniss and Wiser, 2003; MMA, 2003; Morthorst, 2000; Schleich et al., 2006; Schaeffer and Sonnemans, 2000; Vogstad, 2004). For example, Morthorst (2000, p. 1094) argues that "banking will moderate the volatility of prices especially in cases of a highly fluctuating production of electricity from renewables." This advantage has been demonstrated in Figs. 11 and 12 when the GenCos aim for 12 months of coverage. We use computer simulation to learn the impact of the GenCos striving for even longer coverage.[26] We set their desired coverage at 24 months,[27] but we emphasize that the GenCos' desire for 24 months of coverage does not mean that they will actually accumulate such large holdings. The model assumes the GenCos' desired sales is influenced by both the desired holdings and the attractiveness of the current price. When the price is at the cap, for example, GenCos will be much more inclined to sell their TGCs. One might think that the increase in desired sales will quickly reduce the price below the cap. But the GenCos' ability to sell off a large part of their holdings will be tempered by the DisCos' reduced desire to purchase the TGCs when the price is at or near the cap. The simulated price that results from the interactions among these competing factors is shown in Fig. 13.

Fig. 13A shows the impact of extensive banking on the TGC price. The comparison with the base case simulation shows that the GenCos' attempt to build extensive holdings would keep the TGC price at the cap for an additional 2 years. When the price finally falls, it declines to a lower value than in the base case. The price eventually adjusts toward the fundamental price around the end of the 10-year ramp period. It is not clear from the visual appearance of Fig. 13A whether the GenCos would benefit from the extensive banking strategy. They would certainly receive higher prices during 2010–2012, but they face lower prices in 2013–2016.

Fig. 13B shows the impact of the banking strategy on cumulative revenues earned by the GenCos. The base case simulation shows cumulative revenues climbing to $6,000 million. However, if the GenCos adopt the extensive banking strategy, their revenues would be around $5,100 million. This loss of revenue may appear surprising from a visual inspection of the TGC prices. The simulation tells us that the GenCo's revenues would decline from the loss of sales to the DisCos during the extra months when the DisCos are making penalty payments.

While the GenCos banking strategy builds their holdings of TGCs, it leaves the DisCos in a difficult position. With the GenCos reluctant to sell their TGCs, the DisCos will find themselves unable to meet their RPS obligation. When this happens, they meet their obligation by paying the penalty price to the market operator. Fig. 13C shows the impact of banking on the cumulative payments by the DisCos, which are now around $6,800 million, compared to $6,400 million in the base case simulation.

The difference is smaller than the simulated impact on the GenCos because the DisCos are forced to make greater penalty payments in the scenario with banking. Fig. 13D confirms the impact on penalty payments. This graph compares cumulative penalty payments in the two simulations. The penalties grow to around $1,700 million with banking, but they are limited to $400 million in the base case simulation.

This simulation suggests that extensive banking of TGCs would not be in the best interest of the GenCos. It would lead to higher prices in the short run, but it would lead to lower TGC prices later in the ramp interval. And it could force the DisCos to make penalty payments to the market organizer rather than buying TGCs from the GenCos.[28]

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[26] Banking is allowed in the US transferable discharge program to control SO2 emissions. According to Field and Field (2001, p. 317) "a permit dated for 1 year can be banked and used in a later program year." Ellerman and Montero (2002) believes that banking in the US Acid Rain program will provide better price signals to induce early investment in abatement measures. Some green markets are organized with discrete time frames with different goals in each time frame. An example is the carbon allowance market proposed by S139. Banking is needed in such a market if the market is to avoid a major jump in the carbon allowance price at the transition from Phase I to Phase II limits on carbon emissions (EIA, 2003, p. 27). Schleich et al. (2006, p. 112) describes the current markets for carbon allowances in member states of the European Union: unless member states decide differently, banking of carbon allowances from the 2005–2007 period to the 2008–2012 period is prohibited. Schleich et al. (2006, p. 119) then uses a simulation game to demonstrate that a ban on banking could "result in inefficient abatement choices and overall costs which are well above the theoretical optimum."

[27] Some argue that such extensive holdings will force the TGC price to the cap for an extended interval. This argument is partly responsible for some restrictions on the permissible holdings. In Texas, for example, TGCs lose their value 3 years after they are issued (Berry, 2002, Langniss and Wiser, 2003). The lifespan of a TGC in the New England Power Pool is 1 year (http://www.nepoolgis.com/NewsRoom/news03.asp).

[28] We caution the reader that the simulations assumes "value traders" who are acting on an assessment of market fundamentals. The simulation does not include trend followers which might be good trading strategy for

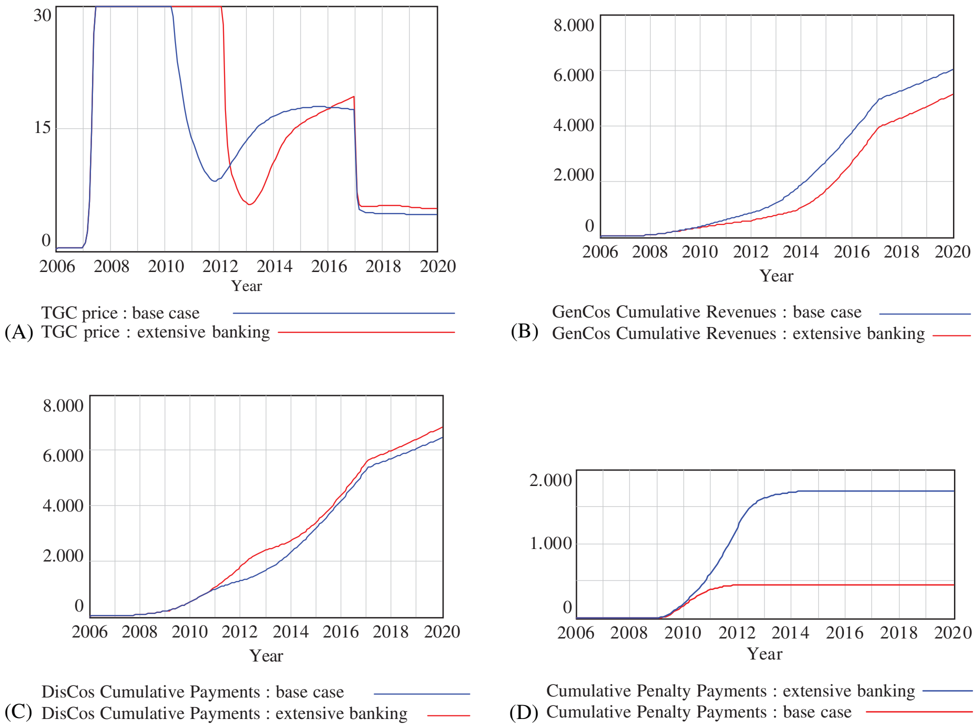

Fig. 13. (A) TGC price comparison to show the simulated impact of extensive banking by the GenCos. (B) Impact of extensive banking on cumulative revenues by the GenCos. (C) Impact of extensive banking on cumulative payments by the DisCos. (D) Cumulative penalty payments are increased when the GenCos adopt an extensive banking strategy.

Nevertheless, GenCos might be inclined to attempt this strategy. If extensive banking were allowed, it might make sense to allow borrowing of TGCs by the DisCos.[29]

15. Simulated impact of borrowing

Fig. 14 shows the additional variables to simulate the DisCos' borrowing of TGCs. We assume that DisCos will turn in their TGCs on time, as long as they have sufficient holdings. If they find themselves short, they may borrow up to 50% of their monthly obligation. The borrowed TGCs enter a backlog and are due 24 months later. If they find themselves without sufficient TGCs and borrowing authority, they pay the penalty price on the remaining obligation.

Fig. 15 shows the simulated impact of borrowing by comparing three simulations. The first is the "base case" in which the GenCos aim for 12 months of coverage and the DisCos are not allowed to borrow. The second case is "extensive banking" in which GenCos aim for 24 months of coverage and DisCos are not allowed to borrow. The third case is labeled "borrowing & ext banking." We allow DisCos to borrow up to 50% of their obligation and the GenCos aim for 24 months of coverage. Fig. 15A compares the prices in the three simulations; Fig. 15B compares the DisCos cumulative payments; and Fig. 15C compares the fraction of demand generated by wind.

Fig. 15A shows that price will remain at the cap for another 2 or 3 years when there is extensive banking. (This is the same result shown previously in Fig. 13A). If the DisCos are allowed to borrow 50% of their obligation, the new price is essentially the same. The slight difference between two dashed curves indicates that borrowing keeps the price at the cap slightly longer. Overall, borrowing does little to alter the price pattern. So, at first glance, one might think that borrowing is of little value to the DisCos.

But Fig. 15B shows that the DisCos would benefit if they were allowed to borrow 50% of their obligation. These borrowed TGCs enter the backlog and are due 24 months later. The comparison in Fig. 15B shows that the opportunity to pay for the borrowed TGCs 24 months in the future lowers the DisCos' cumulative payments.

Fig. 15C reveals that the fraction of demand satisfied by wind would exceed the RPS requirement in all three simulations. The base case simulation and the simulation with both extensive banking and borrowing show the same wind generation by the end of the simulation. The simulation with extensive banking (and no borrowing) shows the highest wind generation.

These comparisons teach us that the flexibility to borrow is not particularly important if we focus our attention on the TGC price. However, if we look at the DisCos total revenues, it appears that borrowing is useful because

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(*footnote continued*)
GenCos when banking is allowed. These and other concerns are beyond the reach of the current model; they are discussed in the appendix suggestions for future research.

[29] Schaeffer (2001) and Vogstad (2004, 2005) point out that one should be careful about only allowing banking.

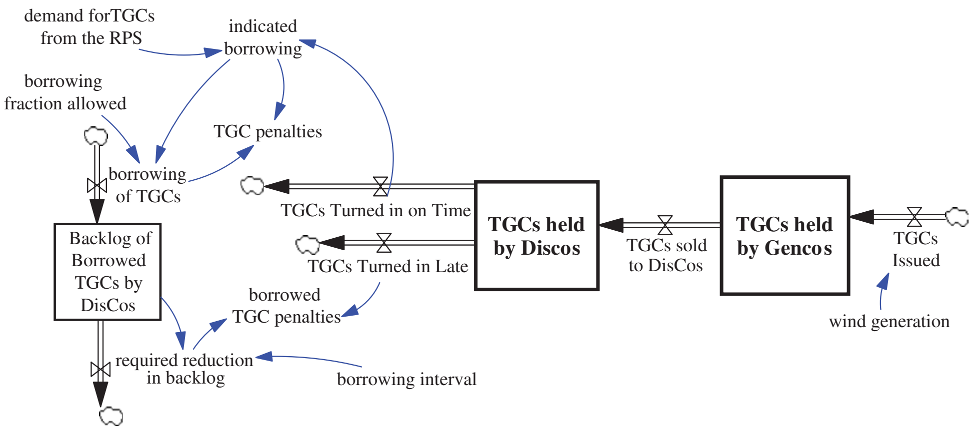

Fig. 14. Additional variables to include the option of borrowing by the DisCos.

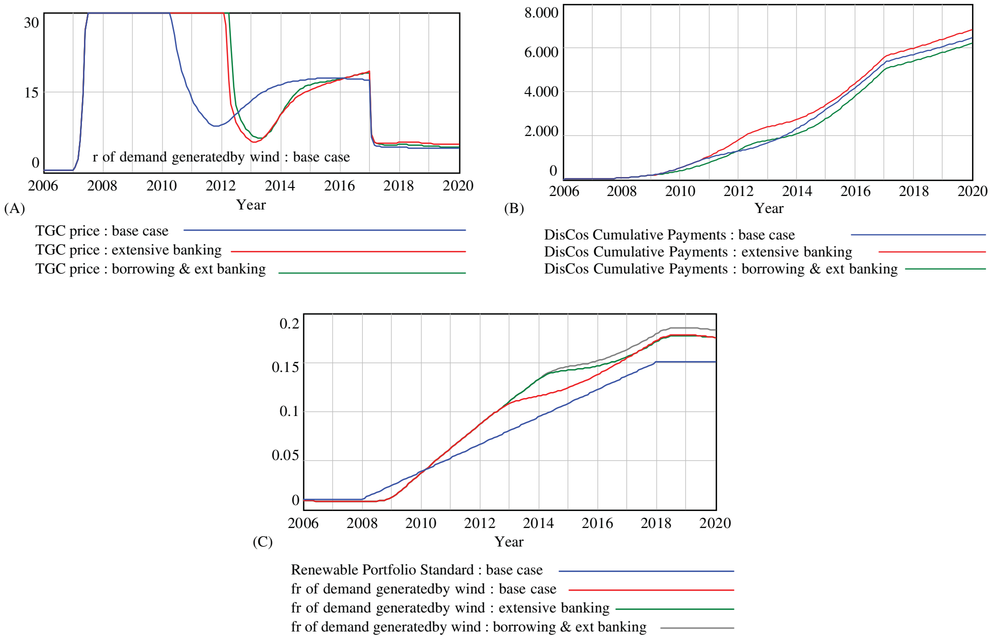

Fig. 15. (A) Comparison of TGC prices to show that borrowing does little to change the simulated price when the GenCos engage in extensive banking. (B) Comparison of cumulative payments by the DisCos. (C) Comparison of the fraction of demand generated by wind.

it lowers the DisCos' total costs while allowing incentives that lead GenCos to build wind generation beyond the RPS targets. From these results, we believe it makes sense to allow DisCos to engage in borrowing in markets where the GenCos are allowed to engage in extensive banking.

16. Simulating a combination of markets for TGCs and carbon allowances

This article began with a summary of state initiatives to promote renewable generation. In a parallel development, several states have called for the formation of regional markets for carbon allowances. The New England and Mid-Atlantic States, for example, have joined forces to establish a Regional Greenhouse Gas Initiative (RGGI; http://www.rggi.org). These states have agreed to enforce a cap-and-trade program aimed at limiting the greenhouse gas emissions specifically from power plants. The program is still in a development stage, but is expected to be operational in the near future. The Governors of California, Oregon and Washington have also declared their intent to take action against global warming with the West Coast Governor's Global Warming Initiative. Representatives of these states have been attending RGGI meetings to learn what they can do to implement a cap-and-trade program on the West Coast. The key to these regional proposals is the ability of the states to impose a carbon allowance price on the electric utilities in their states. Carbon emissions from power plants within the states and associated with electricity imported from other states would be subject to the carbon allowance price.

At the national level, Senators McCain and Lieberman proposed the Climate Stewardship Act of 2003 (Senate Bill 139). S139 was defeated by a close vote in the Senate. It would have initiated an allowance market via a cap-and-trade program. Allowances would be distributed to permit companies to emit greenhouse gases in quantities equal to the allowances they possess. The amount of allowances would be capped to a specified amount to induce emissions reductions. Once allocated, the allowances could be bought and sold among entities that were required to comply with the program. S139 would limit greenhouse emissions to year 2000 levels when the market opens in 2010. By 2016, the emissions would be limited to 1990 levels. A detailed analysis of S139 by the Energy Information Administration (EIA, 2003) indicates that the nation's electricity sector could play the largest role in helping the USA comply with these limits. The EIA found that the electricity sector would reduce its annual emissions by over 75% by the year 2025. The electricity sector was found to be the most responsive sector of the economy, and that response made it possible for the entire economy to achieve compliance with the emission limits.[30]

With the growing interest in carbon allowances, we believe it is important to anticipate the performance of a combination of markets for TGCs and carbon allowances. As a specific example, we anticipate the response of the TGC market if the carbon allowance market were to take the form of the market proposed in S139.

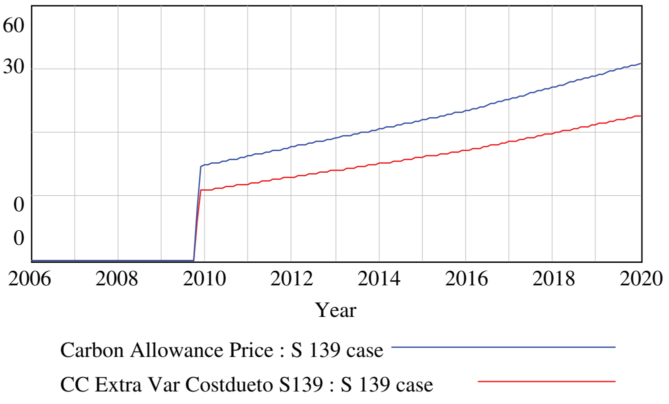

Fig. 16. Carbon allowance price ($ per metric ton of CO2) and the extra variable cost of CCs ($/MWh) due to the Climate Stewardship Act (S139).

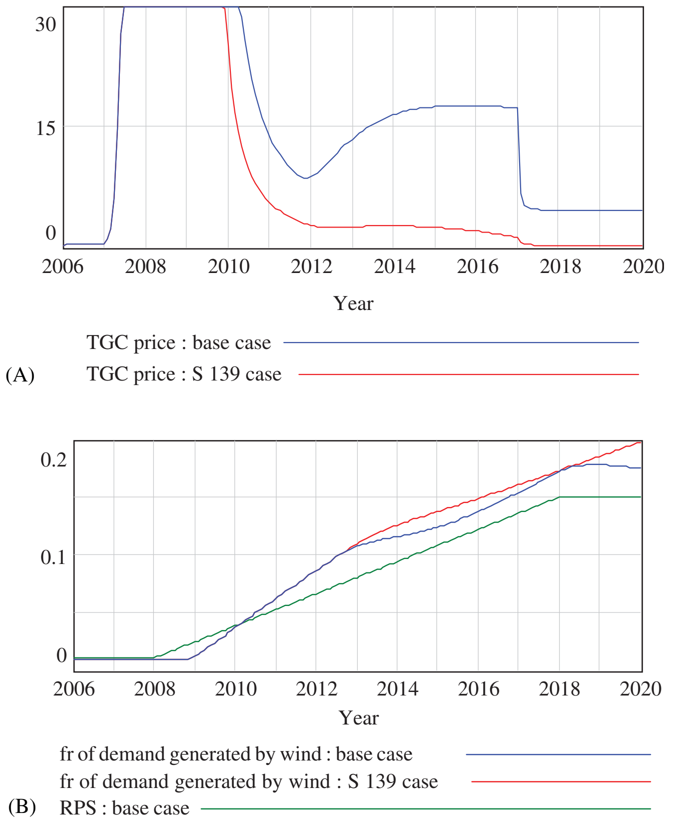

Fig. 17. (A) TGC price comparison to show the impact of S139. (B) Wind generation comparison to show the impact of S139.

Fig. 16 shows the carbon allowance price from the EIA study of S139. The market would open in 2010 with a price of $22 per metric ton of carbon dioxide.[31] The allowance price increases steadily over time due to the growth in the economy and the change in emissions limits.[32] It reaches $35 in 2016 and is headed toward $60 in the year 2025, the end point of the EIA study. Fig. 16 also shows the increase in the variable cost of a CC when the owner must buy the carbon allowances.[33] The extra cost would be around 8 $/MWh when the markets open in 2010. This cost would eliminate over half of the need for a 15 $/MWh TGC shown in Table 1. By 2018, the extra variable cost of a CC would reach 15 $/MWh, eliminating the remaining need for a TGC

Fig. 17 shows the simulated impact of S139. Fig. 17A compares the TGC price in the two simulations; Fig. 17B compares the fraction of demand from wind in the two simulations. Fig. 17A shows that the TGC market would react to these changes in an orderly manner. We assume that the RPS goals remain in effect, and the TGC market continues to operate. Fig. 17A shows that the TGC price falls rapidly toward zero in the years immediately after the

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[30] The reduction in emissions would be achieved, in large part, through a fuel switch from coal to renewables. Renewable energy is expected to be 143% higher with a carbon allowance market. Investment in wind capacity is expected to increase by 50-fold in 25 years in a S139 case. Biomass capacity would grow by 13-fold in the same interval.

[31] The EIA estimated the allowance price by iterative search for the prices that are sufficiently high to allow the entire nation to limit emissions to the Phase I and Phase II targets.

[32] The price of carbon allowances is projected to growth in a smooth, steady manner even though the emissions limit changes abruptly in the year 2016. The gradual change is made possible by banking of allowances.

[33] If the generators receive the allowances, they can sell them in the market. In this case, the allowance price is an opportunity cost. If the generators must buy the allowances, the allowance price is a direct cost. The market is expected to open at 22 $/mt$CO_2$ in 2010. This translates into an extra 8 $/MWh in variable costs for a new CC with a heat rate of 6,900 btu/kWh, assuming that there are 117 pounds of CO_2 in a million btu of natural gas.

opening of the carbon allowance market. By the end of the 10-year ramp, the TGC price is essentially zero.

Fig. 17B shows the fraction of demand generated by wind is greatest in the simulation with S139. The introduction of carbon allowance prices motivates wind investors to exceed both the RPS targets and the levels shown in the base simulation. Even though TGC prices fall to zero by 2017, the wind generation continues to grow in the final years of the simulation. This growth is powered by the continually increasing carbon allowance prices shown in Fig. 16. We find these results encouraging, as we believe both TGC markets and carbon allowance markets should be considered by policy makers in the USA.[34] This and other policy recommendations are summarized in the concluding section of the article.

17. Policy conclusions

The model described here simulates TGC price behavior under idealized market conditions with varying scenarios of interest to policy-makers. It provides a unique focus on price dynamics[35] and is a good starting point for additional analysis. Our ideas for additional analysis are described in Appendix A. Our recommendations for policy makers are discussed below.

17.1. The general view of TGC markets

The TGC is a market-oriented approach to achieve targets for renewable electricity generation. Proponents argue that the market offers a better chance to reach a target (compared to a fixed incentive such as the PTC) because the market prices will react to the investors' progress over time. But the proponents caution that one must expect uncertainty in market prices over time. The simulations shown here certainly confirm this general view. When looking at long-run compliance with the RPS, for example, the simulations indicate that investors will meet and then exceed the targets for wind generation. And when looking at prices, the simulations show a huge range of uncertainty. Indeed, the uncertainty intervals extend from essentially zero to the price cap during the final 5 years of the 10-year period of the RPS. We emphasize that these uncertain prices appear in a model with idealized assumptions that were selected to give the market the best possible opportunity to function in a stable manner. Despite these idealized conditions, the market responds with major oscillations in prices. We believe these oscillations would be even more severe if the market were dominated by renewable technologies whose construction lead times are longer than the 1-year lead time for wind capacity.

Although the simulated price is highly uncertain in the second half of the RPS interval, it is surprisingly consistent during the early years of the market. One simulation after another shows the same pattern: the price climbs quickly to the cap and remains there for a year or two, possibly longer. (In some simulations, the price remains at the cap for over half the 10-year ramp interval.) We attribute this pattern primarily to lags in the feedback response of the GenCos and the DisCos. The upward pressure on prices is also caused by the desire for GenCos and DisCos to build holdings over time as a defense against uncertainty. These results are consistent with the prices seen in the early years of the TGC market in Sweden. They are also consistent with the experimental results by subjects in Norway (Vogstad, 2005) and in The Netherlands (Schaeffer and Sonnemans, 2000). These results call for serious attention to the setting of the price cap.

17.2. Setting the price cap

The penalty price serves as the effective price cap in the TGC market. One approach is to let the penalty price vary with the observed market price. In Sweden, for example, the penalty price is set at 150% of the average price observed over the previous year.[36] We believe that the penalty price should not be allowed to float over time.[37] When the market is vulnerable to upward price pressures in early years, a floating cap could become a soaring cap as higher prices lead to a higher cap, and the higher cap allows for still higher prices.[38] We believe policy makers should commit to a fixed cap, so the major question is where to set that cap. When setting the cap in our own model, we found little advice from other authors.[39] We elected to proceed with a fixed cap of 30 $/MWh, a value selected at twice the

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[34] For other studies on the relationship between the markets for TGCs and carbon allowances, see del Rio et al. (2005), Jensen and Skytte (2002, 2003) and Morthorst (2003).

[35] We are aware of only two other models that provides an explicit treatment how prices might change over time. One is the dynamic model of the Nordic market described in the Ph.D. thesis by Vogstad, 2004; the other is the model of the Australian REC market described by MMA (2003).

[36] Another example of a floating penalty price is the penalty for failure to turn in the carbon allowances under S139. The penalty is set at three times the current market value of the allowances (EIA, 2003, p. 40).

[37] Some policy makers may be reluctant to impose a cap because they are concerned that the cap could serve as a focal point which could unduly influence GenCo and DisCo trading decisions. The focal point arguments are not well supported by experimental evidence (Issac and Plott, 1981; Smith and Williams, 1981). Furthermore, there is no choice but to impose a penalty price on TGC markets. (Absent a penalty price, the markets would be voluntary rather than manadatory.)

[38] Laboratory experiments by Vogstad (2005) and by Schaeffer and Sonnemans (2000) show that the penalty price could influence the formation of TGC prices, especially when the GenCos are engaging in extensive banking. If the price cap were allowed to float, the GenCos could benefit from holding TGCs over a longer period, leading to higher prices and still higher price caps. These actions amplify the tendency for investment beyond the mandated target and the subsequent price crash.

[39] Some ideas were provided by Schaeffer and Sonnemans (2000, p. 415) who experimented with the TGC penalties at a "high" value of four times equilibrium, a "medium value of 50% above equilibrium and a "low" value of 50% below equilibrium. They dismissed the "low" penalty approach for obvious reasons, and they were concerned about the "high" penalty because it puts "enormous pressure on buyers to acquire units." In the end, they concluded that "What is important is that a well-chosen level

fundamental price. This decision was based on the EPA's guide to designing a cap and trade program (EPA 2003, pp. 3–24). The EPA described the penalty price in the US SO2 allowance trading program at three times the expected market price, a value which they concluded "could, in retrospect, be too stringent."

17.3. Setting the length of the ramp interval

Our simulations are based on an aggressive plan to build wind generation from 1% to 15% in only 10 years. The 10-year "ramp interval" is similar to intervals adopted in RPS programs summarized in Fig. 1. The base case simulation showed the TGC price coming somewhat close to the fundamental price during the second half of the 10-year interval. At the end of the 10 years, however, the price falls dramatically as it is no longer necessary for wind investors to capture a large share of the market for new construction. Wind investors who bring wind capacity on line near the end of the ramp interval would be disappointed to find the TGC price falling far below the 15 \$/MWh needed to recover their costs.

How should policy makers approach this "end of the ramp problem"? Some might argue that investors will not worry about this problem since policy makers will probably extend the RPS target over time. Extensions may well occur as each state (or nation) accumulates more success with renewable generation. However, we believe that investors will be reluctant to commit to new construction based on the supposition of a continuous increase in the RPS target. (Their reluctance would be natural and similar to the reluctance to invest without a significant extension of the PTC.)

It makes better sense for the RPS target to be stretched out over a longer time interval in an explicit fashion. As an example, policy makers might consider a 20-year ramp, like the one suggested in Australia (MMA, 2003).[40] Our informal interviews with investors indicate that some aim to lock in the required profits during the first 10 years of the wind capacity operation. Such investors would have a greater opportunity to meet this goal when building wind capacity during the first half of a 20-year ramp period. As a simple test, we doubled the RPS goal and interval in the model. (The new goal is 30% wind generation;[41] the new interval is 20 years.) This simple test revealed that investors could count on the TGC price to be at or above 15 \$/MWh for almost the entire 20 years. Investors bringing wind capacity on line mid-way through the interval could count on 10 years of revenues at the required level.

17.4. Borrowing and banking

Our model makes explicit the goals for TGC holdings by the GenCos and the DisCos. The base case assumes these participants strive to build holdings to provide 12 months of coverage. But the simulations teach us that both the GenCos and the DisCos would find it difficult to reach these goals. The simulations demonstrate that the holdings that are accumulated over time can serve to buffer the TGC price against the monthly variations in wind generation.

We use the term "extensive banking" to describe a GenCos' strategy to strive for more holdings over time. The simulations show that this strategy could force the price to remain at the cap for a longer interval. But, surprisingly, the GenCos would not benefit economically from this strategy. Their total revenues would actually be lowered when the DisCos find themselves making greater penalty payments to the market organizer (rather than buying the TGCs from the GenCos).

If extensive banking by the GenCos is allowed, some argue that borrowing by the DisCos should be allowed as well. We simulate this combination of market rules with the DisCos allowed to borrow up to 50% of their monthly obligation with repayment due in 24 months. The simulation shows that borrowing would spread out the DisCos desired purchases over a longer interval. This, in turn, causes the TGC price to remain somewhat longer at the cap. Nevertheless, the borrowing would lower the DisCos total costs, while still permitting the GenCos to build wind capacity beyond what is required for the RPS. Our preliminary conclusion, therefore, is that it makes sense to allow the DisCos to borrow in a market where the GenCos are allowed to engage in extensive banking.

18. TGC and carbon allowance markets

Our policy simulations concluded with an examination of TGC prices if the nation were to adopt the carbon allowance market proposed in S139, The Climate Stewardship Act. We assumed that the RPS goals remain in effect, and the TGC market continues to operate. The simulation showed the TGC price would fall rapidly in the years immediately after the opening of the carbon allowance market. By the end of the 10-year ramp, the TGC price is essentially zero. But wind generation would continue to grow beyond the RPS targets because of the growing incentive from the carbon allowance market. We found these results encouraging, as we believe both TGC markets and carbon allowance markets should be considered by policy-makers in the USA.

(*footnote continued*)
of the penalty indeed has a significant influence on the price-development and will bring the market closer to a stable market development."

[40] This market deals with the end of ramp problem by alerting investors building after 2005 that they would only be eligible for 15 years worth of certificates.

[41] Achieving 30% wind generation is an extreme test. To conduct such a test in a more realistic manner, the model should be extended to include the higher costs of integrating so much wind generation into the system. This is one of several extensions described in the appendix. At this point, the purpose of the simple test was to learn that the investors could count on an adequate TGC price for most of the 20-year interval.

Acknowledgement

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Appendix A. Suggestions for future research

We encourage other researchers to expand on the work reported here. For our own part, we plan to explore the incentives for increased wind generation by a combination of experimental economics and simulation modeling. Our initial experience with the two methods suggests that the modeling informs the experimental design and the experimental results inform the modeling.

A.1. Modeling wind depletion and learning effects

Some argue that wind investors will exploit best sites available at the time. As the best sites are used up, the total wind costs will increase over time. On the other hand, there are important learning effects that could bring down the cost of wind machines over time. The learning benefits will grow as the industry accumulates more experience with construction and operation.[42] Both the depletion effects and the learning effects are ignored in the model described in this paper. Including these effects would be a useful expansion of the model. Useful information on the higher depletion effect on wind construction costs is now available from the National Renewable Energy Laboratory (NREL, 2005). Ideas on modeling learning effects are provided by Vogstad (2004).

A.2. Modeling TGC trading by non-industry participants

The model described here simulates market participants with a physical position in the TGC market. We focused on the interaction of the GenCos (who receive the TGCs) and the DisCos (who are obliged to turn them in). If the TGC market allows easy entry and exit of non-industry participants, their trades could outnumber the trades by the GenCos and DisCos by a huge margin. Vogstad (2004) simulated such speculative trading with the assumption that the non-industry traders buy TGCs on an up trend and sell on a downtrend. However, other non-industry participants might trade in an entirely different manner (buying on a downtrend and selling on an up-trend). For this article, we excluded non-industry trading for clarity. Our goal was to learn if major oscillations would emerge in a TGC market dominated by participants with a physical position. We leave it to future work to learn if the addition of non-industry traders would reduce or amplify the oscillations reported here.

A.3. Modeling oscillations in both TGC and electricity markets

This article describes TGC behavior when the TGC market interacts with an electricity market whose prices are fixed at the total levelized cost of new CCs. (This is a highly idealized electricity market that allows use to focus on the internal dynamics of the TGC market.) But electricity markets are vulnerable to major oscillations of their own (Ford, 2001, 2002). The recent evidence from the restructured power industry in the USA teaches us that construction of new power plants will not occur in a smooth, even fashion. Rather, the investment could well occur in waves of boom and bust. Wind investors are likely to be caught up in this same pattern, so we would expect wind generation to fall behind the RPS targets during years of low construction. We would then expect wind investors to catch up rapidly during a wave of construction. The interaction of these two, oscillatory markets is a subject well suited for computer simulation. An expansion of the model shown here could be used to simulate TGC price dynamics in a scenario with boom/bust patterns in power plant construction. In such a scenario, it may be useful to rethink the way RPS targets are specified. Rather than setting the fraction of total generation from wind, it might make better sense to set a target for the fraction of new generating capacity that comes on line each year.[43]

A.4. Modeling several renewable generating technologies

Wind generation is thought to be the main form of renewable generation in the USA. But other technologies (such as biomass and solar) could contribute as well. The model could be expanded to include other forms of renewable generation. It could also be expanded to include coal-fired generation. There could be two generating technologies qualifying for the TGCs and two conventional technologies. With competition among four technologies, the investors' impression of the fundamental price will be much more ambiguous than the Table 1 comparison of Wind and CCs.

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[42] The NPPC (2005) report is an example of a study with depletion effects for wind generation. The possibilities for learning are addressed by Vogstad (2004) who argues that depletion effects and learning effects appear on roughly the same time scale.

[43] For example, an RPS might call for 50% of new generating capacity coming on line to be wind. From Fig. 1, we know that this target is similar to an RPS target to achieve 15% wind generation at the end of 10 years. Targeting the new generating capacity coming on line is similar to the Corporate Average Fuel Efficiency Standards (CAFÉ) adopted for miles per gallon standards for the nation's vehicle fleets in the 1970s and 1980s. The legislated goal was to improve the average MPG for the new cars manufactured each year, rather than the average MPG of the total population of cars in operation.

A.5. Experimental economics

The previous ideas point to expansion of the simulation model described here. However; We believe that computer simulation should not be used alone. It makes better sense to use computer simulation in combination with experimental economics to anticipate the behavior of TGC markets. Previous laboratory experiments at the NTNU (Vogstad, 2005) and at the university of Amsterdam (Schaeffer and Sonnemans, 2000) have revealed the tendency for TGC prices to increase rapidly during the early years of the market. We believe such experiments can provide important insights to policy makers. They also provide useful insights for development of more realistic simulation modeling. At Washington State University (WSU), our research plan is to develop laboratory experiments to allow WSU graduate students to assume the role of the GenCos and DisCos described in this paper. At NTNU, experiments are already shedding more light on TGC market performance under different market designs (Vogstad et al., 2005).

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