Tradable credits system design and cost savings for a national low carbon fuel standard for road transport

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HIGHLIGHTS

▶ We model credit markets for low carbon fuel standards.
▶ Costs depend on supply of low carbon fuels, estimates of which vary widely.
▶ Credit trading across fuel markets significantly reduces compliance costs.
▶ With trading average costs range from \$33 to \$284/tCO_2e, depending on supply.
▶ Banking further lowers average costs 5% to 9% and reduces yearly fluctuations.

ABSTRACT

This research examines the economic implications of different designs for a national low carbon fuel standard (NLCFS) for the road transportation sector. A NLCFS based on the average Carbon Intensity (CI) of all fuels sold generates an incentive for fuel suppliers to reduce the measured CI of their fuels. The economic impacts are determined by the availability of low carbon fuels, estimates of which can vary widely. Also important are the compliance path, reference level CI, and the design of the credit system, particularly the opportunities for trading and banking. To quantitatively examine the implications of a NLCFS, we created the Transportation Regulation and Credit Trading (TRACT) Model. With TRACT, we model a NLCFS credit trading system among profit maximizing fuel suppliers for light- and heavy-duty vehicle fuel use for the United States from 2012 to 2030. We find that credit trading across gasoline and diesel fuel markets can lower the average costs of carbon reductions by an insignificant amount to 98% depending on forecasts of biofuel supplies and carbon intensities. Adding banking of credits on top of trading can further lower the average cost of carbon reductions by 5%–9% and greatly reduce year-to-year fluctuations in credit prices.

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1. Introduction

In the quest to reduce greenhouse gas (GHG) emissions regulators face the question of whether to target specific sectors of the economy or simply set reduction targets for the nation as a whole. Most economic models projecting the effects of economy-wide carbon targets find that the transportation sector is likely to be unresponsive to carbon pricing compared to other sectors of the economy. For example, in perhaps the most comprehensive analysis to date, the Energy Information Administration estimated the financial and sectoral impacts of the American Clean Energy and Security Act of 2009 (ACES).[1] This bill required a 17% reduction in GHG emissions by 2020 and 83% by 2050 relative

to a 2005 baseline (US Congress, 2009). The EIA analysis estimated reductions in the transportation sector's emissions to be only 1% to 3.5% by 2020 and 2.6% to 8.5% by 2030 compared to the reference case(Energy Information Administration, 2009, p. 32). Because this reduction is projected to be less than other sectors, the transportation sector would have accounted for a larger percentage of total US GHG emissions by 2030.

The ACES and other cap and trade policies, at their heart, assume that the problem is one of getting the quantity of emissions right and letting the credit market determine the efficient price. Alternatively, the Pigouvian world view aims to get the prices right via a carbon tax. There is no surprise that, according to static measures of efficiency, directly pricing the climate externality with a Pigouvian tax or setting an economy wide emission target is an efficient way to reduce carbon. However, the problem is not a static one. Substantial reductions in transportation carbon emissions likely require a dramatic transformation of vehicle and fuel infrastructure, a dynamic

[1] This bill passed the House of Representatives in 2009.

process of investment, development of network and scale economies, and technological change over many years. Initial carbon reduction costs may be high, compared to those in other sectors. This is the basis of one case for policies directly targeted at vehicles and fuels, to initiate this process. Regardless of the strength this dynamic economic argument for sector-specific policies however, a national low carbon fuel standard (NLCFS) may also be more politically feasible than an economy-wide carbon tax or cap-and-trade system.

Thus, if the transport sector is to play a significant role in reducing GHG emissions, sector-specific policies may be necessary. As noted by Fulton (2010), no single technology or policy action offers a promising means of achieving 50%–80% reductions in emissions in the transport sector. This level of emission reduction calls for a mix of technologies, policies, and strategies. The mix will likely require sustained increases in vehicle fuel economy, switching to fuels that emit lower GHGs per mile, and reducing the demand for transport services through actions ranging from modal diversion to changing urban form.

The EPA's 2007 endangerment finding allows the EPA to regulate GHG emissions under the Clean Air Act (US Environmental Protection Agency, 2007). Using this authority, the EPA and the National Highway Safety Administration (NHTSA) have promulgated a set of much stricter standards that controls for the first time GHG emissions and fuel efficiency of new vehicles as opposed to NHTSA's historic focus on fuel efficiency alone.

Addressing the fuel side of the fuel-vehicle unit is EPA's Renewable Fuel Standard (RFS). The RFS was implemented pursuant to the Energy Policy Act of 2005 (EPACT). It was updated by the Energy Independence and Security Act of 2007 (EISA) and is now generally known as RFS2. EISA established minimum annual volume requirements—and minimum GHG reduction targets—for several categories of renewable fuels that must be sold by producers and importers of petroleum-based transportation.

This paper looks at the implications of different designs for a NLCFS. A NLCFS would set the maximum average carbon intensity for fuel supplied to the road transport sector. We examine how different designs impact compliance costs, credit price volatility and possible saving from different credit trading systems for the on-road transportation sector. We do this while taking into account existing policies such as the RFS2 and other policies that impact the prices and availability of biofuels.

1.1. Literature review

The literature examining the economic, environmental and energy security impacts of biofuel mandates and ethanol subsidies is expanding. In comparing various biofuel policy options de Gorter and Just (2010) acknowledge that the interaction of biofuel policy with other policies is very complex but find that a quantity-based biofuel mandate is superior to a price-based consumption subsidy. The consumption subsidy decreases welfare because of taxpayer burden and externalities from additional driving. A biofuel mandate, they note, is both a subsidy to biofuel production and a tax on conventional fuels, providing a rare example of when a biofuel policy is complementary to an environmental policy. A related literature looking at renewable portfolio standards in the electricity market finds that they can either raise or lower generation costs and alter the demand for electricity. A paper by Fisher shows that the driving factors are the elasticity of electricity supply from renewable energy sources relative to nonrenewable ones and the effective stringency of the target (Fischer, 2010).

Holland et al. (2009) find that a LCFS effectively cross-subsidizes the lower-carbon fuels, incentivizing their production. They find that there is a theoretical possibility that carbon emissions could increase under a LCFS because additional emissions from producing more low carbon fuels can more than offset the gains from reduced production of high carbon fuels. However, despite their identification of this theoretical possibility, their numerical estimates find this outcome to be unlikely. Whether carbon emissions actually increase or decrease (as in a paper by de Gorter and Just (2009)) depends on the relative magnitude of fuel supply and demand elasticities. They point out that theoretically, if the sole goal is to reduce carbon, each fuel should face carbon tax proportional to its lifecycle carbon content. In a later paper, Holland (2009) finds that – in a world with incomplete regulation where some jurisdictions do not regulate carbon – a LCFS can be more efficient than an emissions tax. This result comes from recognizing that a LCFS is an intensity standard that relies more on substitution effects than output effects to reduce emissions. Thus, an intensity standard can be superior to a carbon tax or emission cap since it distorts output decisions less.

What is clear in the literature, as noted by de Gorter and Just (2010) is that the effects of individual biofuel policies and their interactions with other biofuel policies are very complex due to the intricate interrelationships between energy, commodity markets and the environment. In reality, an analysis of biofuels policy is deep in the realm of the second best. The US DOE's Alternative Fuels & Advanced Vehicles Data Center shows that there are currently 28 federal incentives, laws or programs for ethanol (US Department of Energy, 2010); there is also a multitude of state incentives and programs. Some of these have no near term impact (e.g., advanced energy research grants), while others including the volumetric ethanol excise tax credit (the ethanol tax credit), RFS2, the import duty for fuel ethanol, and the Alternative Motor Fuels Act (which relaxes fuel economy regulations for ethanol flexible fuel vehicles) have driven or still drive the market for ethanol and other biofuels.

Despite the excellent research noted here, no research adequately incorporates enough of the complementary policies, programs and international trade considerations that impact energy, commodity and carbon markets to make a definitive judgment on the wisdom or net benefit of biofuel subsidies and mandates. One of the key shortcomings of this current research is that it ignores one of the fundamental reasons to cross subsidize biofuels and other low carbon fuels: to overcome transitional barriers and coordination problems that are inherent in fuel–vehicle systems (Leiby and Rubin, 2004).

The critical difference between RFS2 and a LCFS is that the former specifies volume targets for broad categories of biofuels, while the latter specifies an average CI across all fuels, including natural gas and electricity, without any requirement for volumes of specific fuels. Moreover, A LCFS is thought to have two distinct advantages over a RFS. First, a LCFS is technologically neutral. It does not promote any type of fuel (i.e., biofuel) or fuel–vehicle system over another. Second, a LCFS, unlike a RFS, rewards inframarginal reductions in CI. That is, rather than viewing each fuel as attaining a particular biofuel carbon target or not, as is done in the RFS2 program, it also rewards further reductions in CI for fuels within each category.

2. Designing a LCFS trading system

A LCFS can have significantly different impacts depending on its scope. The potential fuel and fuel–vehicle system for regulation under the LCFS can include both on and off-road vehicles, as well as the aircraft, rail and marine sectors. A primary consideration for determining the appropriate range of fuels to regulate is to insure adequate coverage to prevent a LCFS from simply shifting high carbon fuels to an uncovered sector. This poses a

particular challenge for marine and aviation fuels where offshore fueling is the norm. Also, in this regard, heating oil is important to consider since it represents 55% of total distillate fuel use in the Northeast exceeding the use of distillate fuel for transportation (Cooper et al., 2009, p. 4–12).

2.1. Lifecycle emissions and fuel–vehicle systems

There is now consensus that the best metric for comparing fuel–vehicle systems is full lifecycle emissions. Three potential approaches to consider when setting up standards for vehicle fuel are (Farrell et al., 2007):

- At-the-pump/plug: emissions are measured per unit energy entering the vehicle either as a liquid or electron (g/MJ);
- Per-mile: emissions are measured per mile (g/mi);
- At-the-wheel (motive energy): emissions are measured per unit of energy delivered to the wheel to move the vehicle (g/MJ).

We follow the lead of California and the Northeast and Mid-Atlantic regional initiatives and assume that the regulated parties for a national LCFS should be the fossil fuel producers and importers and adopt the system of emissions per motive energy (Cooper et al., 2009), (California Code of Regulations). This system has the advantage of focusing the regulation on the fuel side of the fuel–vehicle system. Unlike a system based solely on emission per mile, this approach has a separate standard for each conventional fuel category, v, (gasoline or diesel). This is appropriate for a policy targeted on fuels. It does not encourage or inhibit a mix shift between gasoline and diesel vehicles. It accounts for the inherent difference in fuel efficiency of some fuel/vehicle types, but does not incentivize fuel efficiency improvements within each fuel/vehicle type. At the same time, this system requires using an Energy Economy Ratio (EER), $\in$, to adjust for the additional motive energy efficiency of an alternative fuel vehicle compared to a conventional gasoline or diesel vehicle.

For a regulated firm m, the average fuel CI (AFCI$_m$) of the mix of fuels f sold in each regulatory category v (gasoline or diesel) is:[2]

$$\text{AFCI}_m = \frac{\sum_{f \in F_v} E_{fm} \times I_f}{\sum_{f \in F_v} E_{fm} \times \epsilon_f} \tag{1}$$

where: AFCI$_{mv}$ is the Average Fuel CI value of fuel producer m, in grams of CO_2 equivalent per megajoule (gCO$_2$e/MJ) for fuel category v; F_v is the set of all fuels f that can replace fuel in category v; I_f the CI value of fuel f, in gCO$_2$e/MJ; E_{fm} the Total energy of fuel f, in MJ, sold by firm m; $\in_{fv}$ the Energy Economy Ratio (EER) of fuel f, in units of motive energy in MJ per fuel energy in MJ which allows for the comparison of the energy efficiencies of alternative and conventional fuel vehicles in category v.

The CI of each fuel, including conventional fuels, can differ for each fuel producer m, and region, r. It may be above or below the default or regulatory-benchmark CI level $\bar{I}_{fv}$ for that fuel f used in fuel category v (gasoline or diesel).

Gasoline and Diesel fuel producers can adopt five methods to meet the LCFS targets:

1) Reduce the CI of gasoline and diesel;
2) Expand their use of alternative fuel blends in gasoline and diesel;
3) Substitute lower CI for higher CI biofuels in blends (e.g., substitute sugar cane ethanol for corn ethanol);

4) Sell more "neat" alternative fuels (e.g., E85 and B100 and CNG);
5) Use credits purchased from other regulated parties or banked in previous years.

This credit system views regulated parties as meeting the AFCI standard through competitive behavior alone, in the sales of fuels and changes in fuel carbon intensities. Given competitive forces, each fuel is sold at its marginal cost, including marginal credit cost/revenue. It does not address the net costs or consequences of "strategic" behavior such as a firm changing the demand for various fuels by cross-subsidizing fuels or vehicle technology. For example, the quantity of hybrid electric vehicles is assumed to be determined in the vehicle market.

The costs to move liquid fuels from one location to another may also give rise to market power dominated by a small number of local producers. This will raise compliance costs and possibly limit fuel choices. It could also occur if, for example, an electric utility operator were reluctant to support widespread retail charging of electric vehicles due to concerns about peak-load impacts or in the face of separate carbon limit such as is the case in the Northeast with the Regional Greenhouse Gas Initiative.[3]

The actual level of carbon emissions for each fuel is based on the firm's choice of feedstock, production, refining and transportation technologies. For each firm and fuel class v, the total credits (or deficits) generated (G) each year (in units of grams CO_2e) is given by the quantity of emissions below (or above) what would have been allowed at the regulatory standard CI:

$$G_v = \sum_{f \in F_v} R_{fv} \times E_f \tag{2}$$

here, for each fuel f, variable R_{fv} is the amount by which the replacement fuel CI ($I\omega$) differs from standard fuel CI ($\bar{I}_v$) adjusted for the EER, ϵ_{fv}. In other words, R_{fv} gives the rate of credit generation in units of gramsCO$_2$e per megajoule of fuel sold (adjusted for motive energy). The sum in Eq. (2) is over all fuels that can replace fuel category v. Without credit trading or banking, or any other flexibility provision, the NLCFS would require that G_v be non-negative for each firm and year (those subscripts being suppressed here). In determining R, we also allow for a reference CI scaling parameter $\bar{\omega}_{fv}$ and choice variable is ω_{fv} to account for different carbon intensities of conventional and replacement fuels.

$$R_{fv} \equiv \left(\left(\bar{I}_v - \frac{I_f \omega}{\epsilon_{fv}} \right) \times \epsilon_{fv} \right)$$
$$= \bar{I}_v \epsilon_{fv} - I_f \omega \tag{3}$$

This form of a regulatory standard allows for the regulatory CI to be counted as lower than actual on-road CI, per unit of fuel energy input to vehicles. This accounts for the greater end-use efficiency of some advanced fuels and the fact that 1 MJ of those fuels replaces $\epsilon_{fv} > 1$ MJ of conventional fuel use. It is the correct rate of credit generation to ascribe per unit of each fuel use, provided the goal of the regulation is to achieve intensity $\bar{I}_v$ per unit of motive energy.

2.2. Mathematical model of national low carbon credit trading system

A profit maximizing regulated firm participating in a credit market in a specific region has the following objective function, given its sales of fuel ($P_f \cdot E_f$), minus the costs of fuel production, $C(E_f)$ and net revenues from credit sales or purchases (N)less any

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[2] The v index indicating fuel category here and below has been suppressed to increase readability.

[3] http://www.rggi.org/

credits (S) purchased at a safety valve price (P_s). Credits sell at market determined price (π_{vrt}) that varies by fuel category v for region r at time t. Safety valve prices for credits are sometimes included in credit markets to allow for regulatory compliance at a predetermined maximum price. Safety valve prices insure against the outcome that future compliance is more expensive than anticipated or otherwise technologically infeasible. For example, the RFS2 program allows the EPA to sell cellulosic biofuel credits when it determines that quantities of available cellulosic biofuels are below levels required in EISA. For 2011 the EPA has set the price at \$1.13 per credit (75 FR 76,790).[4] We have set the credit safety-valve price in our model at \$300/MtCO₂e, which is equivalent to a \$0.38/gallon ceiling on the cost of reducing gasoline CI by 10% (1.25 kg CO_2e/gallon of gasoline).[5]

The price of fuel (P_f) is assumed by a price-taking firm as given.[6] Credits produced, G, or purchased N, can be banked B for future use.[7]

$$\underset{E,N,B,S}{\text{Max}} \sum_{t=1}^{T} \delta_t \sum_{v=1}^{2} \sum_{f \in F_v} \sum_{r \in R} [P_f E_f - C(E_f)] - \pi_{vrt} N_{vmt} - P_s S_{vmt} \qquad (4)$$

Subject to:

$$B_{vt} = G_v + N_{vmt} + S_v + \gamma B_{v(t-1)} \geq 0 \qquad (5)$$

The special case of no banking corresponds to □ = 0, in which case credit generation plus credit purchase plus safety-valve purchase must be non-negative: $G_v + N_v + S_v > 0$. This construction assumes that firms are allowed to aggregate credits over the various regions in which they sell fuels. It can be shown that these equations imply that that the ratio of discounted marginal net revenue from selling more fuel to its rate of production of credits is equal to the discounted price of a credit. Together, the policy mechanisms of banking, trading, and a safety-valve credit price provide protection against extreme prices and price fluctuations.

2.3. Complementary regulations

A NLCFS must take into account existing complementary and overlapping regulations. The most important complementary regulations are RFS2, harmonized CAFE/tailpipe GHG emissions regulations, credits for alternative fuel vehicles in the Alternative Motor Fuels Act (AMFA) and tariffs on imported ethanol. Both the CAFE and AMFA regulations affect the GHG intensity per mile of vehicle travel. However, they are targeted at the vehicle side of the market through vehicle fuel efficiency. The fuel tariffs affect fuel prices and, therefore, import quantities. These policies influence the fuel and vehicle markets through their impacts on the costs of driving per mile and the cost of fuels. In contrast, the RFS2 program directly affects fuel suppliers, like the LFCS.

It mandates the sale of 36 billion gallons of biofuels by 2022 with limits on the lifecycle CI of these replacement biofuels.[8]

An interesting policy question is: to what extent do LCFS and RFS2 regulations reinforce or substitute for each other? That is, does compliance with RFS2 ease or make redundant compliance with the LCFS and vice versa? As we show formally elsewhere, LCFS and RFS2 regulations are partial substitutes for each other in that they have the same general impact—they force a cross-subsidization of low carbon fuels. That is, although the covered fuels and requirements differ, the RFS program will have the same general incentive system as a NLCFS. This is because the RFS program is implemented each year in terms of a percentage of each fuel suppliers' sales, rather than a firm volume mandate, it forces fuel suppliers to cross-subsidize renewable, lower carbon fuels, rather than necessarily expanding the total domestic supply of mandated fuels. In this sense, the NLCFS and RFS2 complement one another, differing in scope and details but not in the way they affect the market. A crucial difference is that the rate of credit generation per unit of fuel for the RFS is based on volumes, while for the NLCFS the rate is based on CI. So the NLCFS incentivizes continued reduction of CI for all fuels, while the RFS only incentivizes CI reduction to the point that a fuel can qualify in a certain renewable fuel category.

3. Numerically implementing the model

To quantitatively examine the implications of a NLCFS, we built the Transportation Regulation and Credit Trading (TRACT) Model. The model implements the equations shown in Eqs. (4) and (5) and is solved using GAMS non-linear optimization algorithms (GAMS, 2011). The primary source for fuel quantity and price data used in TRACT is the Annual Energy Outlook (AEO) 2010 as captured by Argonne National Laboratory's VISION model (ANL Transportation Technology R&D Center, 2011). The scope of the TRACT model corresponds to that of VISION: light- and heavy-duty vehicle use in the United States. While VISION has data for the years 2010 through 2100, we limit our analysis from 2012–2030.[9] The primary and composite fuels and fuel–vehicle systems used in TRACT are shown in Table 1.[10]

We take the primary and final fuel quantities as supply-demand equilibrium market outcomes for each year. Thus, for each year we have price-sensitive demand curves for final fuels based on VISION's projections of quantities and prices. Additionally, we have variable elasticity supply curves for each primary fuel based on VISION's primary fuel quantities and prices. The primary fuels are either blended, as is the case for ethanol and gasoline (E10) and diesel (B5), or neat for CNG. We combine blended final fuels with vehicle technologies to determine final fuel demands. Thus, petroleum gasoline can be used in conventional vehicles (E10), E85 vehicles, or gasoline plug-in electric vehicles. In each of these applications, the blend of ethanol is endogenously determined based on the price and CI of primary ethanol types.

We base our primary fuel supply elasticity estimates for biofuels on the work by Parker (2011). These variable elasticity

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[4] The waiver price is set by EISA as the higher of or \$0.25 or the inflation-adjusted value of \$3.00 minus the wholesale price of gasoline. For 2011, EPA determined these latter values to be \$3.10 and \$1.97 which yields a credit waiver value of \$1.13 per credit.

[5] Safety-valve credits sufficient for a 60% reduction of gasoline CI (comparable to the target reduction for cellulosic biofuels under RFS2) would cost \$2.26, double the cost of the RFS2 escape credit price. Nonetheless, a direct comparison of the EPA waiver price and our safety valve price should not be overstated since they apply to different fuel volumes. The cellulosic waiver price only applies to the quantity of cellulosic biofuels required under EISA.

[6] In the numerical simulations we solve for the market outcome for all firms simultaneously, at the regional level and, hence, determine fuel price and quantity endogenously by integrating under the demand curve. This solution also yields the market permit price π.

[7] Without banking, this multiperiod problem is separable in time t, absent any dynamic constraint on capital stock evolution or technological change.

[8] The replacement fuels are broken out into certain percentages of categories of fuels: renewable fuel, advanced biofuel, biomass-based diesel, cellulosic biofuel. The respective minimum declines in CI's for these categories are 20%, 50%, 50%, and 60%, compared to the 2005 baseline average gasoline or diesel fuel that it replaces.

[9] The AEO2010 projects vehicle and fuel use through 2035, VISION extends the timeframe through 2100.

[10] Unfortunately, we are not able to credibly estimate the firm-level cost of producing, transporting and retailing the various transportation fuels. We therefore collapse firm-level trading down to national fuel availability.

Table 1
Primary fuels, composite fuels and fuel-vehicle systems in TRACT.

Primary fuels
Gasoline from petroleum
Diesel from petroleum
Ethanol from US corn
Ethanol from cellulosic biomass (various feedstocks)
Ethanol (imported) from sugarcane
Biodiesel from vegetable oils and fatty esters
Diesel from Fischer–Tropsch conversion of cellulosic biomass feedstock
Electricity from average generation sources
Compressed natural gas
Hydrogen

Composite fuels
Composite ethanol, a blend of the primary ethanol types
Composite advanced diesel, a blend of the primary non-petroleum diesel types

Fuel-technology services
Conventional vehicle, with petroleum gasoline blended with composite ethanol, 10% ethanol by volume (E10)
Conventional vehicle with biodiesel blend fuel with diesel vehicle services, petroleum diesel blended with composite advanced diesel, 5% advanced diesel by volume
Flex-Fuel Vehicles (FFVs) using a mix of E10 and E85 (petroleum gasoline blended with composite ethanol, 10% or 85% ethanol by volume)
Plug-in hybrid electric vehicle (PHEV) with electric and gasohol fuel
Battery-electric vehicle (BEV) with electric fuel
Compressed natural gas vehicle with CNG
Hydrogen fuel cell vehicle with H_2

curves, which are consistent with those estimated recently by DOE (2011), are highly elastic for a lower range of supply, but then become steep and inelastic as estimated maximum supply limits are approached. Supply elasticities vary across fuel types, and depending on whether the model base case is benchmarked to AEO/VISION or BEPAM. At the base case (unconstrained by LCFS) outcome, supply elasticities vary between 1.0 and 5.0, with corn ethanol and biodiesel elasticities being at the lower end, cellulosic ethanol intermediate, and sugar cane ethanol in the high range. In the policy case, where the LCFS is binding, then quantities driven up the supply curves to inelastic regions for some fuels. For example, under AEO/Vision assumptions the elasticity of cellulosic ethanol supply drops to 0.22, and under the alternative supply case Fischer–Tropsch diesel supply falls to 0.125. Total final fuel demand is either fixed or taken as inelastic (-0.1). Given the opportunity for imperfect substitution among final fuels, the own-price elasticity of individual final fuels is on the order of -0.5.

3.1. Carbon intensity of fuels

The estimated well-to-wheel (WTW) CI of conventional fuels (gasoline and diesel) and alternative fuels varies significantly by analyst or organization (see Table 2). This variation is inevitable given the complexity of the fuel production systems and the lack of precise standardization of LCA techniques, particularly with regards to capturing the indirect -land use change impacts associated with biofuels. For example, the US EPA estimates that US average gasoline has a CI of 93 (gCO$_2$e/MJ) while the California Air Resources Board uses a figure of 96 (gCO$_2$e/MJ) ((California Code of Regulations), (US Environmental Protection Agency, 2010)). More significantly, the EPA's estimate for US corn-based ethanol in 2022 is 75 with low and high estimates of 51 and 92 (gCO$_2$e/MJ), while California estimates that (current) average Midwestern corn ethanol has 91 with a range 77 to 121 (gCO$_2$/MJ) depending on process (wet or dry mill) and heat source

(biomass, natural gas, oil, coal) (California Air Resources Board, 2011).[11]

There is a similar, but smaller range of estimates for the CI of gasoline and diesel depending on the source of the oil. While the estimates can vary significantly from study to study, there is general agreement that the most significant differences in CI come from variations in the production and refining of petroleum types (Skone and Gerdes, 2008; Jacobs Consultancy Inc, 2009; Rosenfeld et al., 2009; IHS Cambridge Energy Research Associates, 2010; Isaacs, 2010). Approximately 20%–30% lifecycle WTW emissions comes from crude production, refining and distribution with the remaining 70%–80% from combustion (IHS Cambridge Energy Research Associates, 2010). The "lighter" crudes such as Saudi and Iraq have significantly lower GHG emissions than "heavy" crudes including Venezuelan, California and SAGD Canadian Oil Sands with a range in CI of 20%. (Jacobs Consultancy Inc, 2009; IHS Cambridge Energy Research Associates, 2010). The result is that Canadian oil sands have about a 10% greater CI on a lifecycle WTW basis with a range of 5% to 15% (IHS Cambridge Energy Research Associates, 2010).[12] As we discuss elsewhere it may be possible to reduce the CI of petroleum from Canadian oil sands by about 10%, making it equivalent to US average petroleum, for $9 per barrel. This represents a future optimized system rather than current production Leiby and Rubin (2011).

An additional consideration is that the WTW CI of all fuels, but especially that of biofuels and petroleum-based fuels, is changing over time. Significantly, the CI of corn ethanol is falling due increased corn yields and process improvements (Wang, 2011). At the same time, as US imports more petroleum and petroleum products that originate from Canadian oil sands (COS) or other heavy oil sources, the CI of petro-based gasoline and diesel are increasing. Fig. 1 shows the changes in CI of the two primary petroleum-based fuels using the EPA historical estimates for each and VISION's projected rate of change. The increase in CI reflects a projected increase in oil from COS, among other factors. GREET's default scenario assumes COS to rise from 9.4% of US domestic petroleum consumption in 2010 to 18.1% in 2020.[13]

3.2. Policy scenarios

We examine the implications of a potential LCFS with various CI phase-down paths. Several factors influence the stringency of the phase-down schedule: the base CI, the target CI and the rate of decline from the baseline to target. We choose three baseline carbon intensities: the CI of 2005 gasoline and diesel—the same baseline used to evaluate replacement biofuels in the RFS2 regulations; the 2012 CI of petroleum-based gasoline and diesel; and the average CI of all on-road transportation fuels in 2012. Complementing these base level CIs, are four phase down targets: 10% by 2022, 10% by 2030, 15% by 2030, 20% by 2030. For each of these cases we impose a linear phase-down schedule until the target year and maintain the final CI thereafter.

A key difference between the various scenarios is the starting point base level CI. This is primarily because the CI of petroleum feedstocks and the quantity of ethanol blended into gasoline changes significantly over time. The least stringent baseline from

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[11] For a comparison of EPA's and California's approached to LCA of biofuels see the report by Air Improvement Resources, Inc. Air Improvement Resource Inc. (2010). A Comparison of Corn Ethanol Lifecycle Analyses: California Low Carbon Fuels Standard (LCFS) Versus Renewable Fuels Standard (RFS2).

[12] The GHG intensity of each barrel of oil sands production is projected to decline more than 10% over the next 20 years (IHS Cambridge Energy Research Associates (2010). Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right, IHS CERA: 41).

[13] Vision uses carbon coefficients based on GREET 1.8C, Run December 18, 2009.

Table 2
Carbon intensities of primary fuels.

Fuel	Base case 2012–2030	BEPAM RFS case 2012–2030[J]	No COS scenario 2012–2030
Carbon intensity (gCO$_2$e/MJ) (: constant)*			
2005 gasoline	93.1–96.33[A]	93.1–96.33[A]	93.97*[M]
2005 diesel	91.9–97.09[A]	91.9–97.09[A]	95.79*[M]
FT diesel	36.78*[B]	8.67*[K]	36.78*[B]
Bio-diesel	43.0*[C]	47.54–11.52	43.0*[C]
Corn ethanol	74.8*[D]	84.22–75.84	74.8*[D]
Cellulosic ethanol	25.6*[E]	33.40–3.33[L]33[L]	25.6*[E]
Sugarcane ethanol	48.52–36.02[F]	29.86*	48.52–36.02[F]
CNG	67.05–66.81[A,G]	67.05–66.81[A,G]	67.05–66.81[A,G]
Electricity	199.52–191.12[H,G] (66.51–63.71)	199.52–191.12[H,G] (66.51–63.71)	199.52–191.12[H,G] (66.51–63.71)
H$_2$	95.72–93.38[I,G] (41.62–40.60)	95.72–93.38[I,G] (41.62–40.60)	95.72–93.38[I,G] (41.62–40.60)

[A] EPA, Regulatory impact analysis RFS2.
[B] 60% of 2005 petro–diesel per RFS2 advanced biofuel.
[C] Federal Register,V. 75(58), Friday, March 26, 2010/Table V.C–2.
[D] Federal Register,V. 75(58), Friday, March 26, 2010/Table V.C–1.
[E] Fed Register, Vol. 75(58),Friday, March 26, 1020/Table V.C-4.
[F] Federal Register/Vol. 75, No. 58/Friday, March 26, 2010/Table V.C–3.
[G] VISION 2010 uses GREET 1.8C, Run December 18, 2009.
[H] The EER ratio for an electric vehicle is 3 yielding an on-road equivalent of 64 g/MJ,
[I] The EER ratio for hydrogen fuel cell vehicles is 2.3 yielding an on-road equivalent of 40.8 g/MJ.
[J] Simplified coefficients, see BEPAM reference case details on pg. 21.
[K] BEPAM's weighted average CI from RFS (AEO) solution plus 15 gCO$_2$e/MJ to account for ILUC, from Fed Register, Vol. 75(58), Friday, March 26, 1020/Table V.C-5.
[L] BEPAM's weighted average CI from RFS (AEO) solution plus 12 gCO$_2$e/MJ to account for ILUC, from Fed Register, Vol. 75(58), Friday, March 26, 1020/Table V.C-4.
[M] Assumes COS petroleum has a 10% greater CI than other sources. Values are left constant over entire time period.
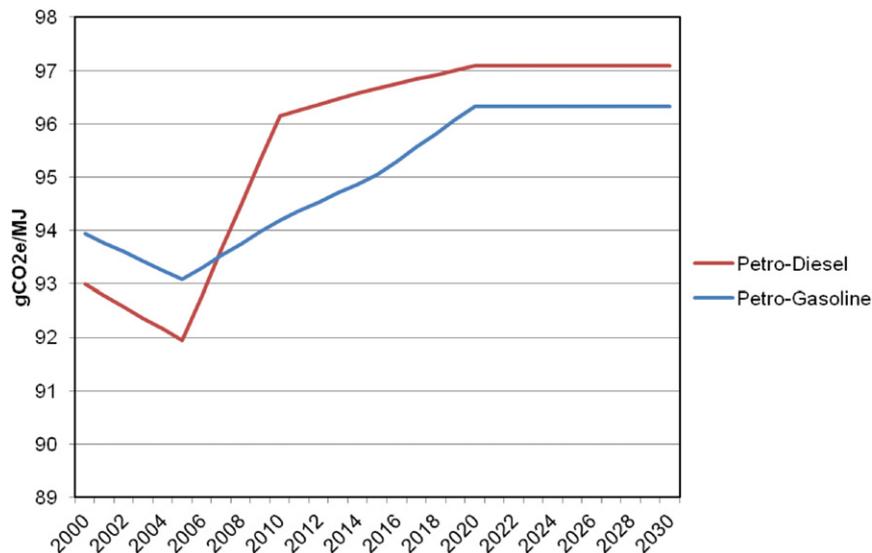
Fig. 1. Changes in carbon intensity of Petroleum-based fuels.

a regulatory perspective is to use the estimated actual 2012 petro–gasoline and petro–diesel fuel CI's. The most stringent is the RFS2 baseline. The AFCI 2012 baseline is an intermediate case given the substantial percentage of ethanol blended into gasoline.

3.2.1. BEPAM comparison case

In order to compare model outcomes, we used biofuel data from the Biofuel and Environmental Policy Analysis Model (BEPAM) model (Önal et al., 2011). The BEPAM team sent data comprising their model's predicted fuel usage and carbon intensities from 2007 to 2035 under the RFS (AEO) scenario. Our representation of their data simplifies their results in that spatial variability, among other

factors, is not taken into account. BEPAM CI values for primary fuels (e.g., cellulosic or corn ethanol) change endogenously over the course of their scenarios. We estimated final fuel (e.g., ethanol–gasoline blends) demand quantities and CIs based on goodness of fit using VISIONs reference E85 demand levels (since BEPAM does not separately track ethanol use in E10 and E85 vehicles).

3.2.2. No Canadian oil sands (COS) case

The no COS case is presented to provide perspective on the impacts on the NLCFS if, in response to a LCFS, petroleum derived from Canadian oil sands did not enter the US market. To examine this scenario we derive the no COS carbon intensities of

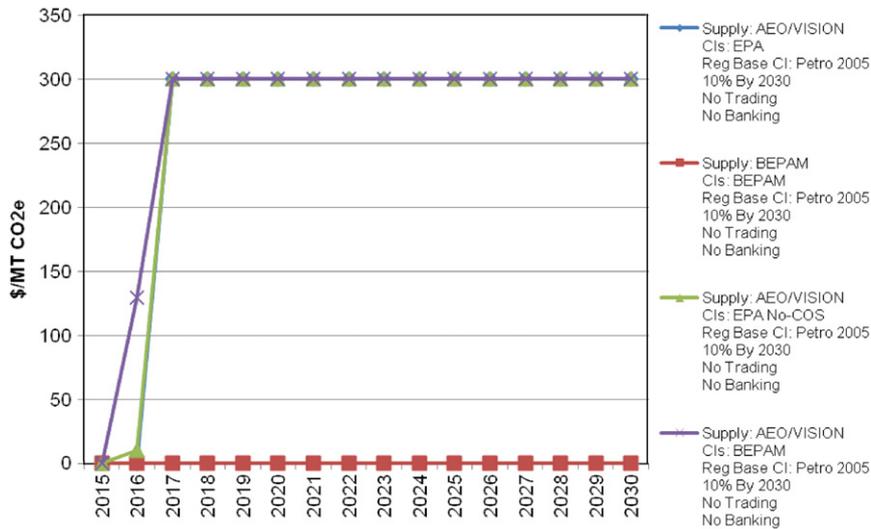**Fig. 2.** Diesel-market credit price, Multiple scenarios (No trading or banking).

petro–gasoline and petro–diesel by adjusting for the percentage of COS in US petroleum fuels (using production data from Canadian Association of Petroleum Producers) and assuming a 10% reduction of CI from COS to non-COS oil (Rosenfeld et al., 2009).

3.2.3. Sensitivity analysis[14]

To examine the sensitivity of our results to changes in assumptions we also looked at cases that use AEO's high oil price scenario, a scenario where fuel suppliers comply by using twice as much imported Brazilian ethanol as currently projected, and the implications of a large fleet of plug-hybrid and battery electric vehicles (PHEVs and BEVs). For the high EV case we rely on the projection from Yang's "aggressive" EV scenario (Yang, 2011) which results in 0.408 quads of BEV and PHEV usage in 2030 compared to VISION's 0.156 quads.

4. Results

4.1. Credit prices—Multiple scenarios

4.1.1. Separate diesel and gasoline credit market segments

Shown in Fig. 2 are projected credit prices in the diesel-fuel market when there is no credit trading with the gasoline market allowed, and no banking. What becomes immediately apparent is that the credit price hits the safety valve price using BEPAM's quantity and CI data. Using the AEO-VISION supply and quantity data, the credit price starts at about $150 t, hitting the safety valve price and falling in later years. Credit prices are lower if we exclude COS from supply.

There is a very large drop in credit prices using AEO-VISION's estimated fuel supplies and BEPAMs CIs. This reflects the differences in projections between AEO-VISION and BEPAM in the use of biomass to replace petroleum. The AEO-VISION projections are much more heavily weighted towards diesel substitutes while BEPAM's are more heavily weighted towards gasoline substitutes (cellulosic ethanol). This is shown in Fig. 3 for gasoline market

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[14] The details of these scenarios can be found in the Support Materials available on the journal website.

credit prices for the same cases. Here we get very different results; BEPAM gasoline credit prices are at zero – a non-binding constraint – while the AEO-VISION credit prices are much larger, often at the safety valve price.

One reason for is a difference in the estimated cost of supplying low-CI ethanol. Another is that by 2012 approximately 9% of gasoline (by volume) is corn ethanol. Given the 10% blend wall, there is not much room to add more ethanol except through FFVs and E85; the major compliance path is to substitute cellulosic and sugarcane ethanol for corn ethanol. This is expensive given the corn ethanol production volumes estimated by AEO-VISION which are substantially larger than projected by BEPAM.

4.1.2. Value of trading flexibility

The same scenarios with gasoline and diesel sector credit trading show that the excess credits produced in the gasoline market, given the BEPAM data, lead to a low and slowly increasing credit price over the phase down path (Figs. 4 and 5). The rising credit price over time – indicating increasing marginal compliance costs as the standard becomes stricter – means that there will be value to time-flexibility – that is, banking.

The AEO-VISION data still yield credit prices that quickly hit the safety valve price. We get an interesting credit price for the mixed case of AEO-VISION supply quantities and BEPAM CI's. This mixed case shows an increasing credit price that hits the safety valve price in 2018.

4.1.3. Value of time flexibility

We now allow the credit system to have the maximum level of flexibility: cross fuel market trading combined with the ability to bank credits for later compliance. As is seen in Fig. 6, the ability to bank credits smoothes out and lowers credit prices across all scenarios.

Our results show that with BEPAM supply quantities and CI's, credit prices start out at about $60/Mt and rise to $125/Mt over the 2015–2030 time horizon. This smoothly rising path under banking reflects the deterministic nature of the model with foresight. Actual permit price paths would be less regular, but

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Fig. 3. Gasoline-market credit price, Multiple scenarios (No trading or banking).
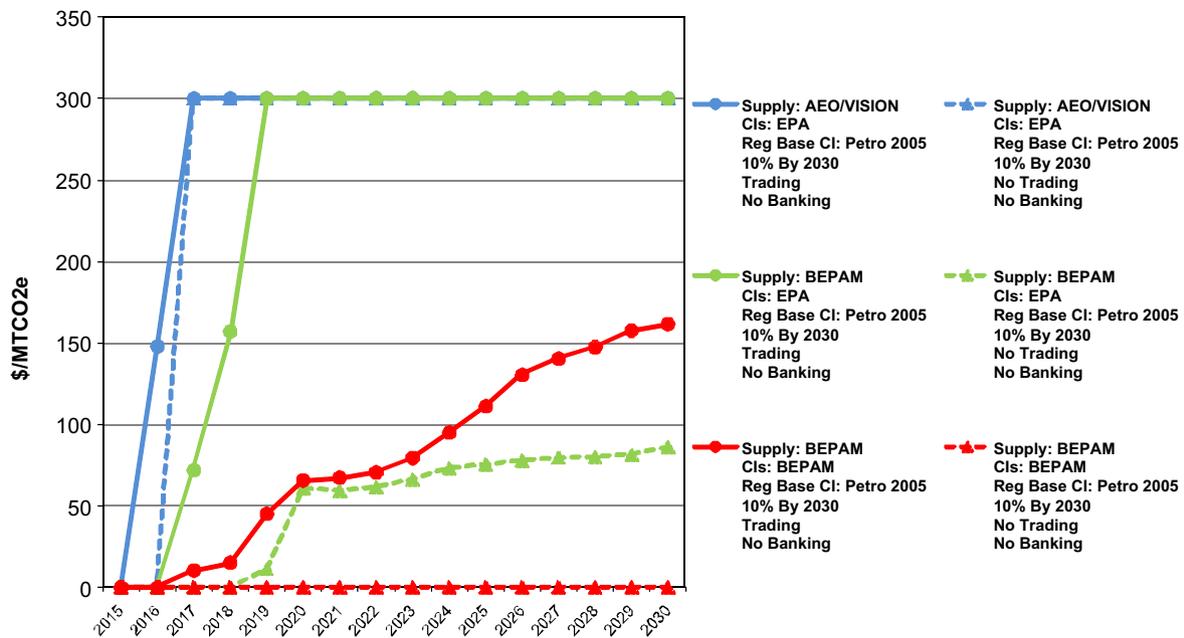

Fig. 4. Effect of trading on gasoline-category credit prices (no banking).

banking would still tend to smooth discounted expected compliance costs over time though intertemporal arbitrage.

If the AEO-VISION quantities are correct, but using BEPAM's CI, then we get credit prices rising from $225/Mt to $300/MT. If AEO-VISION quantities of biofuels are correct and we use EPA estimates of CI, then credit prices start around $250/Mt and rise to the safety valve price of $300/MT. We see that the credit prices for the no COS are approximately $20/MT lower with the BEPAM supply.

The impact of banking flexibility is further explored in Fig. 7. This figure shows three cases: BEPAM supply with BEPAM CI, BEPAM supply with EPA CI, and AEO-VISION supply with BEPAM CI. Each of these three cases is shown with and without banking (but they do allow credit trading across fuel markets). Here again we see that banking lowers compliance costs for most periods and smoothes out credit prices (sometimes dramatically). Banking helps address unevenness in compliance costs across time (credit price spikes or collapses) that may result from the uneven evolution of either regulatory targets or low-carbon fuel supplies.

In terms of sorting out the impacts of supply and CI estimates on credit prices we see that the combination of BEPAM quantities and CI gives the lowest credit prices—significantly so. Focusing on the banking cases (solid lines), we see that the adoption of BEPAM's CIs or biofuel supplies has a large impact on credit prices with a larger decrease for supply.

4.1.4. Average cost of carbon reductions

So far we have been looking at marginal costs of emission reductions; here we present results for the average cost of reducing emissions calculated as the difference between the unconstrained and constrained objective functions (which includes safety valve costs). Trading lowers the average costs of carbon reductions from $289 to $284 (EPA/AEO), $708 to $127 (EPA/BEPAM), $267 to $112 (BEPAM/AEO) and $1352 to $33
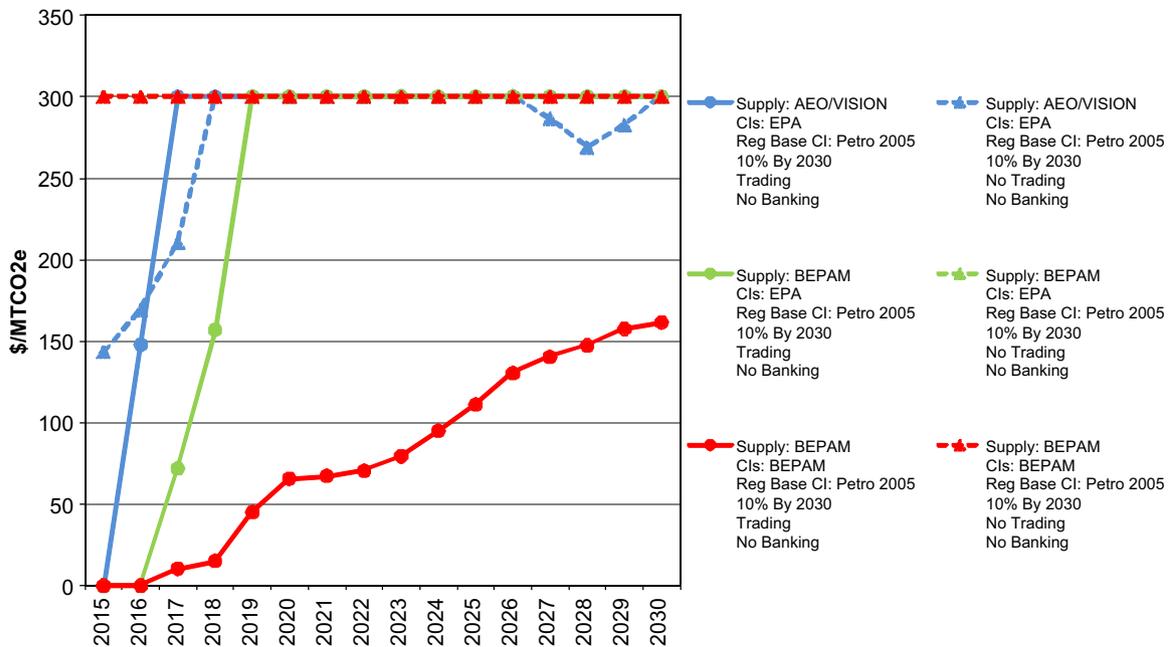
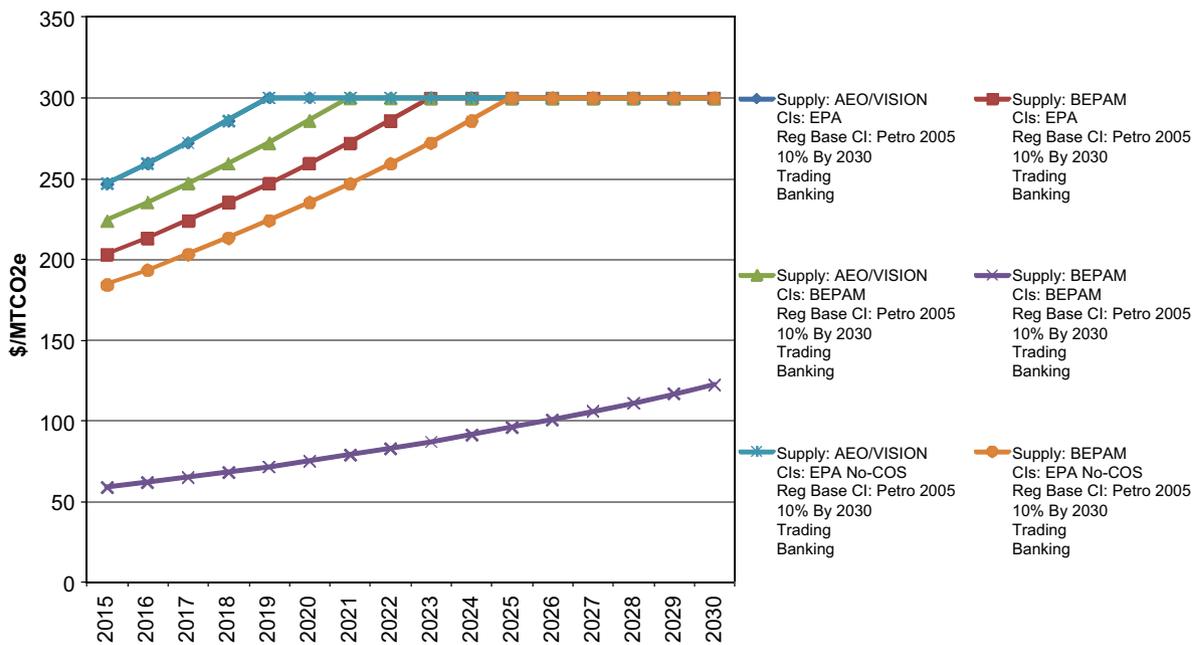**Fig. 5.** Effect of trading on diesel-category credit prices (no banking).

Fig. 6. Impact of banking on credit prices.

(BEPAM/BEPAM) per mtCO$_2$e for the respective CIs and supply estimates (see Fig. 8).

The great amount of savings from trading with the BEPAM supply estimates reflects the pessimism about advanced biodiesel production as compared to the AEO estimates. The average costs of carbon reduction can exceed safety valve costs once safety valve credits are used since penalties are incurred with no corresponding reduction in carbon. Adding banking on top of trading further lowers the average costs of carbon reductions from $284 to $271 (EPA/AEO), $127 to $116 (EPA/BEPAM), $112 to $103 (BEPAM/AEO) and $33 to $30(BEPAM/BEPAM) per tCO$_2$e for the respective CIs and supply estimates. Trading and banking can actually lead to greater reductions in carbon emissions, by reducing the number of safety valve credits purchased.

4.2. Carbon intensity impacts–Multiple scenarios

Using the same scenario, a 10% reduction in CI by 2030 with trading and banking, we get different implied impacts on the CI of blended gasoline (10% by volume) depending on the data source: AEO-VISION or BEPAM. The CI of blended gasoline is endogenous to the model since it reflects the costs of primary fuels and credits Fig. 9.

We see that the implied CI of gasoline (10% ethanol by volume) is significantly lower when we use BEPAM's supply and CI data. This reflects BEPAM's more optimistic outlook for the supply quantities of cellulosic ethanol.

The Average Fuel CI (AFCI) takes into to account all fuels sold in the both the gasoline and diesel markets. Shown in Fig. 10 are the results for a 10% phase-down by 2030 with credit trading in fuel
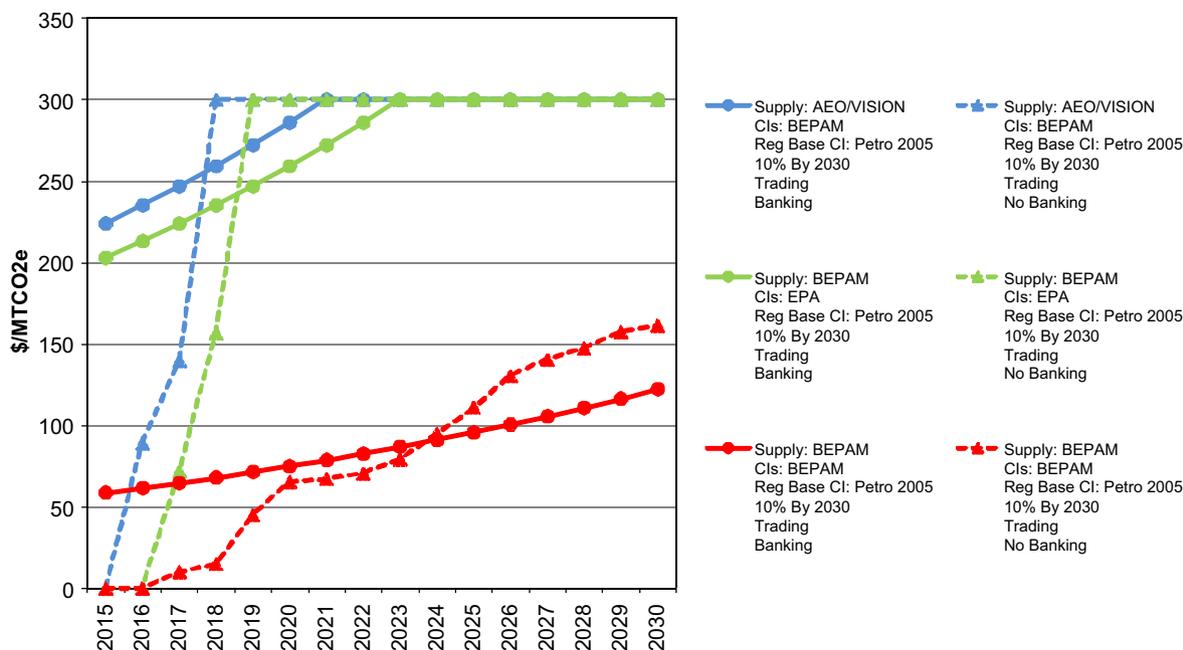
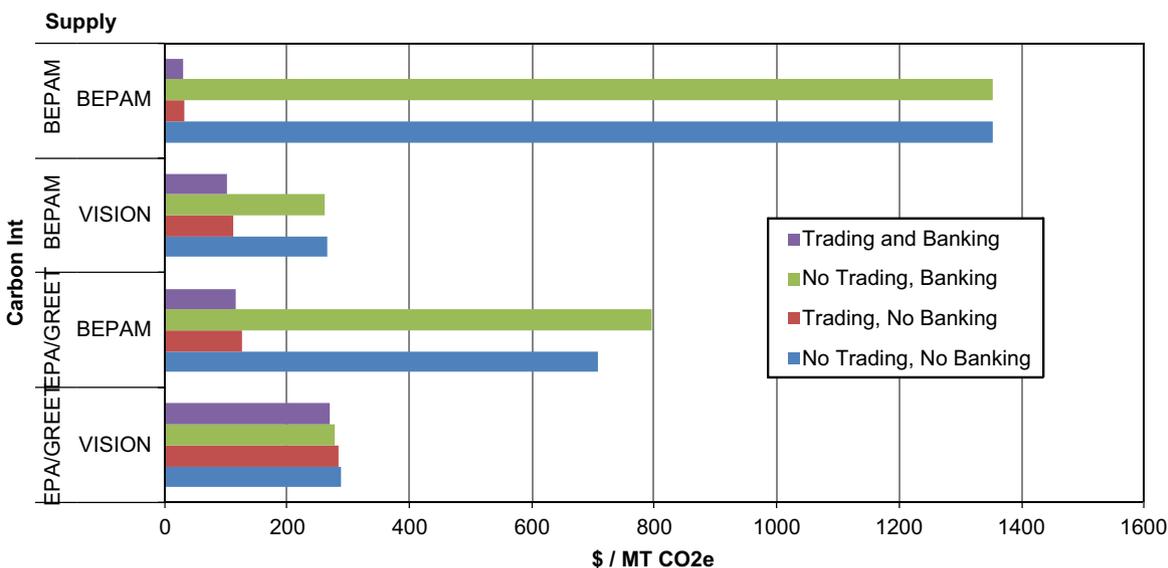**Fig. 7.** Comparing banking and no banking cases.

Fig. 8. Average cost ($/MTCO$_2$e) 10% by 2030.

markets with banking. With the AEO-VISION data, the model does not achieve the 10% phase-down by 2030, because the high cost leads to the purchase of safety-valve credits. In both cases, the base case (unbound) CI is falling mainly due to increased use of biofuels pursuant to RFS2 and some additional use of CNG and electricity. Our high electric vehicle sensitivity case results in noticeably lower credit prices in the later years (after 2027). None of our cases shows significant use of hydrogen fuel in our model time horizon.

5. Policy insights and discussion

5.1. Different baselines, carbon intensities and scenarios

We estimate the costs of reducing the CI from a reference starting intensity. The credit price is the marginal cost of compliance given a phase down schedule. A critical piece in the design of a NLCFS is choosing the baseline starting CI, as well as the magnitude and rate of carbon reductions. For a 10% phase-down in CI from 2015 to 2030 we find that credits costs can range from approximately $55 – $240/tCO$_2$e in 2015 to $120 – $300 tCO$_2$e in 2030. The wide range in costs large reflects different projected quantities and CIs of biofuels.

The $300/MtCO$_2$e credit price represents our safety valve price in our model. This is roughly equivalent to $2.25/gallon of gasoline double the 2011 cost of the RFS2 escape valve credit price, $1.13/credit. This higher value was selected to retain a strong incentive for CI reduction under the LCFS. Safety valve credits allow for regulatory compliance at a predetermined maximum price. Safety valve prices insure against the outcome that future compliance is more expensive than anticipated or otherwise technologically infeasible.
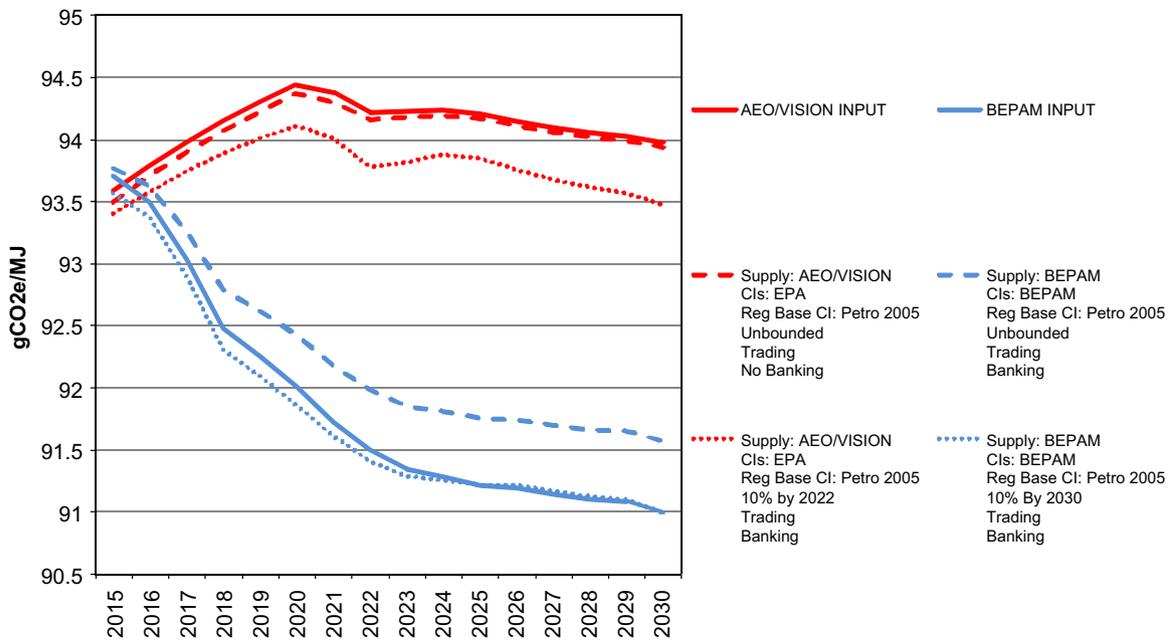
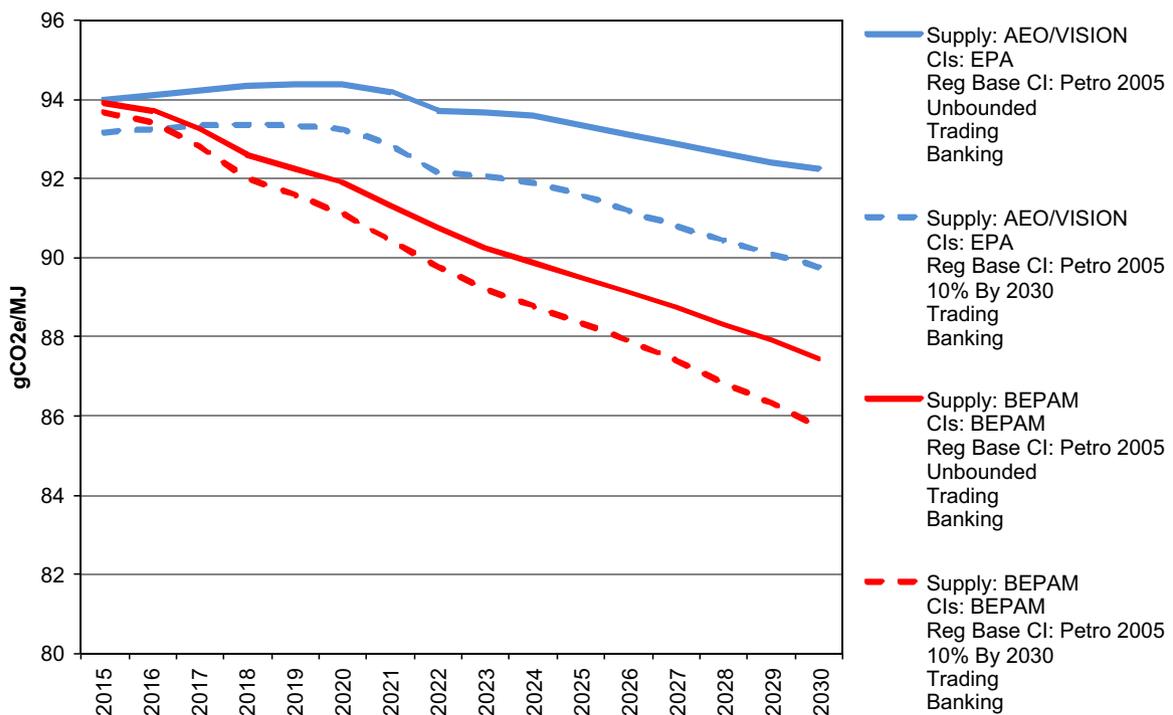**Fig. 9.** Blended gasoline carbon intensity, multiple scenarios.

Fig. 10. Average fuel CI results for 10% target reduction by 2030.

5.2. Value of trading flexibility

There is significant unresolved uncertainty in the projected technological advancements in producing cellulosic biofuels. The DOE-VISION models estimate greater progress in using cellulosic biomass to make replacement fuels for diesel. Alternatively, the BEPAM model results suggest that cellulosic biomass will be preferentially utilized for producing gasoline replacements. These two different views of the world mean that the costs of compliance will differ in the gasoline and diesel markets. This also means that it is significantly more expensive to attain the NLCFS requirements for equally stringent phase-down paths

when each market must meet its target separately. However, we, and regulators, remain uncertain about which market would be more constrained and burdened by higher compliance costs.

The ability to trade credits across gasoline and diesel markets provides a straightforward mechanism to solve this fundamental underlying uncertainty about the future advances in biofuel technology. Thus, policy makers are able to focus on determining the overall level of carbon reduction from the transportation fuel sector and allow unrestricted credit trading across fuel markets. This is consistent with the technology neutrality objectives of the NLCFS and with the approach taken by state and regional LCFS policy initiatives. However, it contrasts with the approach taken

in the RFS2 program, where quantity mandates are specified for each biofuel category, which requires that regulators define optimal fuel production levels for each fuel type.

5.3. Value of time flexibility—Credit banking

Our results indicate that allowing banking of credits lowers the costs of meeting the LCFS and stabilizes credit prices. Banking provides additional temporal flexibility for regulated parties to meet increasingly stringent CI standards (e.g., over the phase down schedule). This is because regulators do not know the most cost effective time path for reducing fuel CI. Were they clairvoyant, an optimal phase-down path could be specified and banking would be redundant. Trading across time, as banking allows, is particularly suited to a carbon mitigation system like a LCFS. This is because the environmental impacts of CO_2 emissions result from the cumulative emissions across time, and earlier reductions can only reduce the total effect.

The adoption of a base level CI, from which reductions are specified, that is greater than the then current average fuel CI (e.g., a petroleum-only CI baseline) results in surplus credits in the early years of implementation (hot air). Banking of these surplus credits could result in achieving future compliance obligations without actual emission reductions. The resulting depressed credit prices may be too low to stimulate increasing supply of low carbon fuels. At the same time, over-compliance in early years may provide a mechanism for implementing increasingly stringent standards in the future, which may not be technologically or politically feasible without the ability to bank early period surplus credits.

Banking carbon credits provides a system level (collective) action for all firms when credit trading is allowed (otherwise one firm's credit purchase is another firm's sale). If trading is not allowed – or firms do not wish to trade credits – then banking can be accomplished by an individual regulated party. Depending on the stringency of the CI standard and how petroleum feedstocks are treated (individually tracked or placed into bins), the base level CI for some firms may or may not be below the initial CI standard. Thus, trading and banking, even with net excess carbon emissions (hot air) may still result in significant compliance response by regulated parties with higher CI petroleum feedstocks.

Assuming prioritization of climate-motivated policies targeting fuel CI, our recommendation is that any LCFS include provision for substantial flexibility and trading of credits, with a safety-valve credit price and at least limited banking. While these mechanisms can entail tradeoffs between managing the uncertain cost of compliance and assuring regulatory effectiveness, they seem essential for the workability of a national fuel CI standard in a global motor fuel market. Further examination of the implications of alternative safety-valve levels and alternative banking systems is merited.

5.4. NLCFS v. RFS2

We conclude that a NLCFS and RFS2 policies impact fuel suppliers via the same broad market mechanism—cross subsidization of low carbon fuels. As such, these two policies can be mutually re-enforcing in advancing development of low carbon fuels. Because the RFS2 program is implemented in terms of a percentage standard on each fuel suppliers' fuel sale mix, rather than a firm volume mandate, it leads to cross-subsidization of renewable fuels, rather than necessarily expanding the supply of mandated fuels to a fixed level regardless of cost or demand. In this sense, the NLCFS and RFS2 can serve as complementary policies that differ in scope and details, each setting a performance standard on fuels. A crucial difference is that compliance with RFS2 is based on volumes of certain categories of lower carbon biofuels, while for the NLCFS compliance is based on CI directly, and can also be achieved by lowering the CI of fuels (including biofuels) sold. This difference reflects a duality of policy objectives: the focus on the displacement of oil volumes is particularly relevant for energy security and the reduction of CI most relevant for climate protection.

At the same time, as we argue in a related paper, because the NLCFS is based only on CI, we estimate that shuffling COS and other high CI fuels to foreign destinations could be a least-cost response to a NLCFS (Leiby and Rubin, 2011). There may be no clear solution to this problem. A fundamental limitation of a regional (e.g., US only) – as opposed to the world – energy regulation to address a global environmental problem is that patterns of use and trade may shift across boundaries. A countervailing argument is that there is value to the US taking on a leadership role since there is no likely legal framework to deter the use of higher CI oil; just as there is no world regulation on the use of coal or coal-to-oil production.

Beyond the "binned" approach of the RFS2 that incentivizes production of fuels within broad regulatory categories, a NLCFS provides an incentive for continuous improvement of CI. For example this provides an incentive to make each type of ethanol have a lower CI, compared to the bin approach embodied in RFS2. With trading and banking it supports more robust and stable credit markets, since such flexibility reduces the likelihood of points where compliance costs are either very high or low depending on the particular phase down paths and fuel availability in a given year, fuel category, or region. A more level and stable credit price is important for supplier planning.

At the same time, a lifecycle assessment requires determining the WTW emissions of each fuel and technology pathway—a considerable information challenge. Since each fuel's energy is essentially the same in end use (e.g., the energy content is the same for all petro–gasoline regardless of petroleum source) this requires tracking the CI of each batch of fuel for each fuel pathway. Although similar in concept to EPA's renewable identification numbers (RINs) for biofuels under RFS2, expansion is required to include all conventional and unconventional oils and other fuels. Although potentially burdensome, it is unavoidable to reduce unintended favoring or penalizing of domestic and foreign oil based on a presumption of relative CI. As the data on CI of oil shows, both domestic and foreign oil can have a wide range of CI from both conventional and unconventional sources. Further research on the implications and practicality of different levels of CI discrimination and binning is needed.

In our view, the compliance cost of a NLCFS cannot be separated from the impacts of the RFS2 program. This is because, like a NLCFS, the RFS2 regulations are technology forcing. Their implementation advances research, development and deployment of biofuels affecting cost estimates of both RFS2 and NLCFS regulations. That said, attaining the same level of carbon emission reductions is likely to be less expensive with LCFS than with a RFS2. This is because RFS2 does not provide any incentive to reduce the CI of conventional fuels and biofuels beyond those necessary to place them into appropriate bins. Additionally, the proposed LCFS is broader in scope than the current RFS2 by allowing a greater range of low carbon fuels to substitute for gasoline or diesel fuel.

5.5. Complementary policies needed

The LCFS is designed to reduce carbon emissions by targeting the fuel portion of the fuel–vehicle system. An important way to lower the CI of transportation is to move to lower-carbon,

alternative fuels such as advanced biofuels, electricity, CNG, and H_2, some of which cannot be directly substituted for gasoline or diesel. This can be assisted by providing incentives to build low-carbon vehicle–fuel systems not using gasoline or diesel. The purchase of credits by gasoline and diesel fuel providers generates revenues for the cross-subsidization of these alternative fuels and their infrastructure. What is missing is a way to incentivize the incremental vehicle costs needed to use these alternative fuels. That is, the sale of credits by alternative fuel suppliers provides them revenue to produce lower carbon fuels, but does not directly provide revenues to vehicle producers or consumers. This may require complementary policies. If a NLCFS is implemented it should be done with explicit consideration of the need to harmonize other fuel and vehicle policies to facilitate the coordination of fuels, fuel infrastructure, and vehicle systems.

5.6. Limitations

The NLCFS model presented here does not address the net costs or consequences of changing the demand for various fuels based on a cross-subsidy of vehicle technology. For example, the quantity of hybrid electric vehicles is assumed to be determined in the vehicle market. Finally, there is much current discussion about the impact of "drop-in" replacement biofuels for gasoline and diesel. The promise of these fuels is that they get around the coordination problem regarding retail infrastructure that exists with E85 and they potentially have significantly lower CI's since they are likely to come via cellulosic biofuel pathways. We have not quantitatively characterized them in our model since we do not yet have a sufficient empirical basis for estimating their costs or CIs.

Acknowledgments

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.enpol.2012.05.031.

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